– ALTERNATIVE POSITION –
DOE EAC Electricity Adequacy Report
Transmission Section – September 15, 2008
DRAFT FOR DISCU.S.SION PURPOSES ONLY

1. NATIONAL GOAL: A ROBUST NATIONAL ELECTRIC TRANSMISSION NETWORK THAT ENABLES OUR ELECTRICITY FUTURE

There is a critical need to upgrade the nation's electric transmission grid. Two reasons in particular drive this need. First, increasing transmission capability will help ensure a reliable electric supply and provide greater access to economically-priced power. Second, with the growth in state-adopted renewable performance standards (RPS) and the increasing possibility of a national RPS, significant new transmission, much of it interregional, is needed to access renewable resources.

At the same time, it is critical that transmission planning and development be done in the context of comprehensive resource analysis, to ensure that demand-side resources, if available, and less expensive and less environmentally damaging options, are fully considered and pursued.

The existing grid has resulted from vertically integrated utilities that built generation and transmission to serve only their own service areas. That grid, designed to meet local customer needs, must now meet the needs of wholesale markets that have evolved since their establishment pursuant to the Energy Policy Act of 1992. The growth of competitive wholesale markets should have led to more efficient use of transmission lines. This has not occurred, in part because our limited transmission capabilities restrict efficient trading in the market.

The desire to develop renewable–rich resource areas also requires new transmission. Renewable-rich resource areas, such as wind, solar, and geothermal areas, are often located far from load centers, requiring transmission to support their development and to deliver energy to consumers. Thirty-two states have Renewable Portfolio Standards (RPS) or goals which may require utilities to import renewable energy in order to meet their legal obligations. Most of these states must meet their targets between 2010 and 2020. States such as Idaho and Wyoming do not have an RPS, but do have tremendous wind and geothermal potential that other states will seek to access.

An expanded transmission system, particularly one focused on intraregional infrastructure, is needed to meet these needs. Similar to the rapid expansion of electricity in the mid-20th Century, the U.S. electric industry, its regulators, and consumers, again face the challenge of facilitating the integration of new resources while at the same time addressing the continued need for reliability and meeting growing customer demand. Transmission is a small part of a customer's energy bill, generally less than 10%. Properly planned and sited transmission can facilitate lower consumer costs by creating intraregional efficiencies, and interregional markets for energy supply.

In the long run, the U.S. may see the electrification of transportation elements and industrial processes. While most of this demand is hoped to be met during off-peak hours and thus not require new transmission or generation, research is needed to understand the potential timing of such additional loads, and their impacts on future generation and transmission needs. In addition, greater interregional transfers of electricity will require greater regional coordination of grid operations to balance generation and load.

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Many important state, regional and national priorities, including grid reliability, economic energy supply, energy security, and climate change, can be addressed through the development of a robust transmission infrastructure. 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 requirements, by allowing greater sharing of resources and less dependence on local generation and constrained fuel supplies.
- Enhanced system reliability, security, and efficiency.
- Robust market competition that will benefit customers by eliminating bottlenecks in the U.S. transmission grid.
- Lower and more stable rates for consumers over the long term through increased access to lower cost resources and a diverse portfolio of energy sources made available through transmission.
- Access to renewables to meet state, and perhaps national, RPS requirements and greenhouse gas emission reduction goals.

There are 5 areas needing greater focus by DOE with regard to the national transmission infrastructure:

1. Planning, particularly interregional planning;
2. Permitting, including state and federal land use agency processes;
3. Financing, including cost allocation mechanisms for interstate transmission;
4. Grid operations;
5. Research and development (R&D) support for innovation.

In each of these areas, increased DOE support and guidance to build collaboration across diverse stakeholder groups is needed.

Overall Recommendation:

- DOE, FERC and other federal agencies should actively support state, regional, and interregional efforts to enhance the planning and development of a robust transmission system.

6. GREATER DOE AND FEDERAL SUPPORT FOR PROACTIVE STATE, REGIONAL AND INTERREGIONAL PLANNING EFFORTS IS NEEDED

There is a critical need for more transmission planning at a statewide, regional and interregional level. DOE's support for such efforts, particularly regional and interregional planning, is critical.

Fortunately, some efforts have begun to successfully address the need for regional planning. FERC Order No. 890 requires all transmission providers to participate in open, transparent regional planning processes that address economic as well as reliability needs. 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. 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 renewable-related transmission needs. In addition, WECC has begun an analysis and modeling effort to determine economic transmission plans for the Western Interconnection through their Transmission Expansion Planning Policy Committee. Similarly, many states have organized renewable-focused transmission planning bodies, including, among others, California, Kansas, Texas, Colorado, Arizona, Nevada, and Wyoming. Ultimately, these entities must work collaboratively to develop a long-range plan to move from concept to implementation.

Addressing our transmission needs for the future requires long-term state, regional, and interregional planning. In our efforts to create a more reliable and economic national grid, we must keep all options open, whether they be technological or behavioral. One option certainly is Extra-High Voltage (EHV) transmission lines.[1] One area of concern with the development of a nation-wide EHV transmission grid, however, is that its cost may place an inappropriate burden on ratepayers. Though a more connected grid will naturally reduce prices through market efficiency, these gains are not necessarily larger than the costs of EHV lines. A cohesive transmission planning process at all levels is needed to avoid eliminating from consideration other solutions, such as high-temperature superconducting cables, advanced composite conductors, or flexible AC transmission systems (FACTS), which could reduce the need for new transmission lines. Some of these technologies are in trial phases, but may be implemented in the next ten years. Non-transmission technologies, such as SmartGrid and battery storage, should be considered in such a planning process because they reduce the need for infrastructure investment.

Environmental and cost-benefit analyses must be employed in transmission planning at all levels to ensure our commitment to low prices and high quality for ratepayers. Planning analyses should consider all demand side options, and in states involved in generation planning, the results should focus on compliance with a Loading Order to guide investment decisions to the most environmental and economic options available. California has adopted such a Loading Order in its Energy Action Plan of 2003. California's policy requires cost-effective procurement of resources in the following order: energy efficiency, demand response, renewable generation, distributed generation, and fossil-fuel generation.

If adopted, a Loading Order should not be used chronologically, but it should be used in a concurrent fashion to prioritize where investments should be made. We should invest in

[1] [DEFINE EHV] Text is unclear.

transmission infrastructure to promote renewable, distributed, and fossil-fired generation only after all cost-effective demand side options have been exhausted.

There are several levels of planning issues that warrant greater attention and support from DOE. They include the development of expanded models that can analyze the need for transmission to renewable-rich areas and quantify the interregional cost-benefits of such transmission solutions.

Adapting to today's energy landscape requires a fundamental shift in the way that transmission planning occurs today. Long-range interregional planning is critical. Diversity of fuel sources, demand options, and transmission solutions must be thoroughly examined and planning must occur with a greater geographic scope and longer timeframe than traditionally used.

Planning must take into account various factors whose future is still unknown. One example is society's response to climate change and what significant efforts to reduce and avoid greenhouse gas emissions will mean for demand and supply side options. Another example is the trend toward electrified transportation, which generally will not require additional transmission since charting will be done off-peak and battery storage will continually improve, but at very high penetration levels may ultimately support the need for new transmission.

Greater use of non-dispatchable generation technologies will also increase the importance of regional transmission planning, as the ability to move electricity from region to region may help system operators balance energy supply with demand across wider areas.

The traditional focus of transmission planning has been at the state level. Increasingly, transmission planning efforts are expanding to multi-state regions. (See various examples cited above.) DOE can play a central role in supporting these planning efforts and, of even greater importance, supporting interregional planning efforts that cross multiple jurisdictional boundaries. Planning for transmission must start at the regional level and then become multi-regional in nature, stretching across regions to build a robust transmission overlay and allowing large percentages of the population access the clean renewable energy sources they need. State-focused approaches to planning, stopping at state or jurisdictional system boundaries, will not achieve the renewable objectives of our many states, nor will they fully support competitive wholesale markets.

The electric grid is a complex, interrelated network, and blackouts in any part of the grid may have widespread effects throughout the system. As the August 2003 blackout demonstrated, reliability in a broad region of the Eastern U.S. and parts of Canada can depend on a small number of transmission lines hundreds of miles away. Similarly, electricity customers in the Northeast U.S. face significantly higher electricity prices because of transmission constraints several states away. The planning process for transmission lines that impact consumers, regulators, and market participants across a wide area should involve those parties across the affected region. Current planning within regions or local planning areas is robust, but interregional planning is lacking and transmission development between regions nearly nonexistent. As highlighted by the August 2003 blackout, interregional reliability must have a high priority when planning, so that regional vulnerabilities are not spread to other areas.

For example, the "lake effect" remains for many decades, but has yet to be resolved. Power flow problems around the eastern great lakes have been around for decades. The "lake effect" was one of the causes to the 2003 blackout in the Eastern U.S. Certainly system controls and procedures were put in place to mitigate the effects, but relatively little transmission investment has been made over the decades to mitigate this issue. This area is governed by three regional transmission organizations (RTOs) and the operator in Ontario, Canada. RTOs (and ISOs or independent system operators) are beginning to plan inwardly very well, but they are not planning across regions as well.

Planning processes also need to incorporate the many purposes that transmission lines serve within an interstate network. Traditionally, transmission planning examines both "reliability" and "economic" benefits. More advanced planning models may be needed, particularly for EHV lines, to properly account for facilities that improve both economics and reliability over the lives of the assets. Likewise, many current planning processes use regional or jurisdictional boundaries as the limitation for transmission benefits. Such delineations can yield inappropriately quantified benefits, causing a dearth of investment across boundaries and creating less efficient solutions.

Another planning issue needing review is the transmission planning timeframe. Traditional transmission planning examines only a five to ten-year range. With a truncated planning timeframe, small, incremental projects may be identified to meet narrowly defined needs, leading to the construction of a transmission system that is sub-optimal. While consumers may save near-term costs by building lower voltage lines today, they may end up adding additional lines in the future as needs grow, resulting in more costs and environmental impacts in the longer term. Longer range transmission planning, beyond a ten-year timeframe, is critical to ensuring a reliable electricity supply that increasingly incorporates renewable energy resources

Better planning may lead to greater use of EHV transmission lines, including complementary HVDC (High Voltage Direct Current) connections for transferring the nation's rich 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 linked to form an expanded long-term interstate transmission grid. The highest voltage transmission in the country is 765kV. One 765kV line with a 200 foot right-of-way is equal in capacity to two to three 500kV lines (each with 200 foot right-of-way) and equal to numerous 345kV lines. HVDC transmission is most useful for long distance application (greater than approximately 500 miles without intermediate interconnection potential), and interconnecting large systems with no synchronous connections, such as the Western interconnection, the Eastern interconnection, and the Texas grid. The benefits of an EHV overlay can yield focused upgrades of existing lines within existing corridors and cause the retirement of older assets, recovering their right-of-ways.

Key Recommendations:

- DOE should support the regional and interregional development of planning methodologies that focus on compliance with a Loading Order to guide investment decisions to the most environmental and economic options available.
- DOE and FERC should encourage and support broad-scale, collaborative regional and interregional transmission planning efforts and such planning efforts should involve affected stakeholders.
- DOE should support the development of expanded planning models that can analyze the need for transmission to renewable-rich areas and quantify the interregional cost-benefits of such transmission solutions.
- DOE should support planning efforts and 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 renewable development, robust planning horizons, and widely distribute such best practice information to planning entities.
- DOE should periodically develop an interregional transmission plan coordinating among the plans already developed and provide guidance and leadership to current planning authorities.
- DOE should initiate a comprehensive study on the grid planning impacts of our changing energy future with respect to supply and demand options, and with a close look at electrification of transportation elements and industrial processes. These results should be input into regional and interregional planning efforts by current planning authorities.
- FERC should recognize the overarching economic, reliability and energy security benefits of interstate transmission over the lives of the assets.

3. STATE AND FEDERAL AGENCY PERMITTING OF TRANSMISSION FACILITIES MU.S.T BE IMPROVED

Currently, state and federal agencies share transmission line permitting jurisdiction. States retain central authority for the siting of transmission facilities. When proposed transmission projects cross federal lands, federal agencies, such as the United States Fish and Wildlife Service (U.S.FWS) and the Bureau of Land Management (BLM), also have permitting authority. In the West in particular, almost all large transmission projects require federal land or resource agency permits. This broad spectrum of interested parties - and the nature of interstate transmission crossing jurisdictional boundaries - complicates and may impede the siting process.

The institutional arrangements for permitting were not established to deal with interstate transmission lines or crossing federal lands, and thus no structure exists that aligns multi-agency permitting in an organized fashion. Each state and federal agency 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.

As a case in point, the 90-mile Jacksons Ferry-Wyoming 765 kV line energized by American Electric Power (AEP) in Virginia and West Virginia in 2006 was 16 years in the making. Almost 14 of those years were spent on siting, with just over two years devoted to construction. AEP spent $50 million on the project before beginning construction. A portion of the siting problems that plagued the project emerged from its interstate nature 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 is time consuming, inefficient and costly.

Unlike natural gas pipelines, the need for transmission lines stems from local or state need determinations and the environmental impacts from major above-ground large transmission impacts generally are significant. Under the National Environmental Policy Act (NEPA) and many similar state environmental review laws, extensive permitting review is required to analyze project need, alternatives, environmental impacts, and mitigation measures.

Several states, such as California, Texas [OTHERS] have streamlined their permitting processes and work proactively to expedite review. Yet a continuing problem is the failure of federal land management agencies to prioritize transmission line permitting and environmental review, particularly for lines needed to deliver renewable resources.

Permitting agencies, at both the state and federal level, need to develop cooperative and collaborative siting models that review, in an integrated fashion, multi-state benefits, costs, and environmental impacts. Only with the willingness to work jointly on siting will these impediments be overcome.

Key Recommendations:

- Identify the bottlenecks in federal agencies responsible for transmission line permitting, especially related to renewable development, and prioritize federal resources to expedite NEPA and other legal reviews.
- Encourage the development of a consistent framework for evaluating and siting interstate transmission facilities through multi-jurisdictional collaborative planning organizations and agreements.
- Identify “best practices” in the state and federal agency permitting processes and widely disseminate such information. Provide support to states to adopt such best practices

4. COST ALLOCATION & RECOVERY MU.S.T BE MADE MORE CERTAIN

Transmission expansion can provide access to new and diverse supply options, thus reducing consumer susceptibility to price spikes due to fuel cost increases, potential carbon impacts, and congestion. Transmission generally constitutes less than 10% of the average U.S. residential customer bill, and can lower the total cost of delivered energy. In other words, reductions in energy production costs may offset the cost of transmission expansion.

Notwithstanding the potential economic benefits of new transmission to consumers over a broad area, determining who pays for that transmission is a potentially significant barrier to its development. Methodologies that quantify the costs and benefits of a transmission line are relied upon to justify and authorize such transmission projects, but they are often inconsistent across areas, making cost allocation difficult. There is also a free rider issue where the beneficiaries of transmission have an incentive to avoid paying their share.

Where RTOs have authority, they often determine the cost allocation methodologies, while in other regions this task is delegated to individual states or utilities. In the latter areas, the lack of regional cost allocation methodologies and agreements not only complicates the planning and justification of interstate projects, but also creates a higher level of uncertainty and risk for investors. Such risks remain significant disincentives to project development, especially since the construction of large-scale projects can extend over a number of years with large capital investment.

In some jurisdictions, transmission are shared across all member companies 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 be engaged to encourage a shared approach for cost allocation for regional and interregional transmission facilities. An approach that enables regional and interregional planning will naturally encourage the design of transmission projects with widespread benefits. At the consumer level, sharing costs as broadly as possible reduces ratepayer impacts while enabling the robust infrastructure that also provides economic benefits through reduced congestion and lower energy production costs. With clear, established cost allocation methodologies, approval processes become much more efficient and the associated risk of uncertainty is minimized. This will encourage the adoption of prudent regional and interregional transmission projects and the investment needed to build them.

In addition to cost allocation, rate design has a profound effect on decisions to build high-voltage transmission. Timely recovery of transmission investment is a vital component in attracting sufficient investment. FERC’s current incentive rates rule to implement the Energy Policy Act of 2005 has already had beneficial effects and additional incentives, such as sharing the savings from relieved congestion. However, recovery of FERC-approved transmission costs is not necessarily guaranteed at the state level.

State regulators serving the needs of retail consumers have the obligation to ensure that transmission projects approved on economic grounds do not incur costs that exceed the bases for that economic determination. Further, they seek to avoid the institution of financial incentives that encourage utilities to propose unnecessary infrastructure investments simply to increase their rate base, or transmission projects more expensive than other alternatives. Thus, regulators and consumers alike remain concerned about the costs of many proposed transmission projects.

A middle-ground, between certainty of investment return and cost-accountability must be explored. While pass-through rates (state-approved mechanisms to allow automatic recovery of FERC-approved investments) help to bridge this gap and provide the certainty needed to stimulate major transmission investment, they will not be available in every circumstance. Reconciliation of federal and state incentives and cost recovery mechanisms to address both developer and consumer concerns will go far toward facilitating the construction of transmission lines.

Key Recommendations:

- FERC should engage RTOs and state and federal policy makers to develop a shared approach for cost allocation for regional and interregional transmission facilities.
- FERC should engage RTOs and state and federal policy makers to develop a middle-ground, between certainty of investment return and cost-accountability.

5. GRID OPERATIONS AND MANAGEMENT SHOULD BE ENHANCED

The existing grid is aging and its use is changing. The grid was largely developed from the 1950s through the mid-1970s with an aim to serve local utility needs. While some components last many decades with good maintenance, others do not last as long and need to be replaced. Much consumer load has also changed from “dumb” devices to a digital world that is not forgiving of even the slightest service deviation. More “reactive” power is being drawn from the grid for our motorized society, crowding out the ability to transmit “real” power long distances and increasing the construction of the development far from population centers. Optimization of these resources as well as the operation of the grid is needed now more than ever. Historically, resource dispatch was dependent on demand and the most cost effective generating plants that were nearby. Today resource dispatch is limited by congestion, weather (for renewable energy) and other factors. Significantly, higher renewable energy penetration will require better utilization of traditional supply side resources, new energy storage devices, and demand response to fill the gaps created by the variability of some renewable resources. Potential operating restrictions on the existing traditional generation plants to achieve air or water quality improvements may impact the viability of those resources to help integrate renewables, and could lead to major operational issues. In addition, the growing complexities and higher use of the grid, the long distances to renewable-rich resource areas, 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 controls are needed for the grid. Much capability of the existing grid is a result of well-engineered controls and communication systems. Without them, the capacity of the grid to transfer significant amounts of power while still meeting reliability criteria would be much diminished. But 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). 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 two 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 or "smart 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" makes 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. More flexible dispatch, shorter-term dispatch schedules (down to 5 or 10 minutes), better energy storage capability, and demand response over larger geographic regions can enable even more renewable generation and provide less 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.

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 attached to the grid using smart grid technology also have significant potential to provide demand-side flexibility in the future. This additional load is expected to increase off-peak demand, thus not requiring additional transmission unless penetration rates increase dramatically. However, it may require changes in how the transmission grid is operated and certainly calls for improved energy storage technologies, which in turn will affect grid operations.

New products and services could allow more efficient use of existing transmission infrastructure. The U.S. electric grid is sometimes highly congested, though typically in a few specific areas for limited times because congestion moves around depending on outage conditions, seasonal variation, and other factors. Thus, opportunities exist for transmission customers to use spare transmission capacity outside of congested times. Conditional firm transmission and generation redispatch are two flexible transmission services that offer innovative solutions to 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 they are during peak summer times, although they 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, significantly reducing the cost of reliably integrating new generation, and deferring or even obviating the need for new transmission infrastructure.

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 throughput. In addition, the use of HVDC to complement today's AC network can also be used to control the network, provide more connectivity across the three U.S. grids, and mitigate the spread of blackouts.

Building upon lessons learned, 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 DOE is encouraged to review the status of each of them carefully, assess what else must be done, and determine how DOE can help advance them. In addition, in Europe, they have successfully integrated over 50GW of wind. We can learn from their lessons learned as they have successfully dealt with the variability of wind resources.

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 our grid and energy future.
- FERC should encourage coordination/consolidation of balancing authorities to improve integration of variable resources and further the benefits of smart grid technologies and demand response.
- FERC should encourage development of market-based tools for improved generation dispatch and system flexibility for our grid and energy future.
- DOE should assess the implementation of the recommendations of the 2003 Blackout Report and direct actions if not implemented successfully.

6. CONTINUE MANDATED RELIABILITY COMPLIANCE

The Energy Policy Act of 2005 enabled FERC to mandate reliability compliance standards. Congress largely acted on this issue as a result of the 2003 blackout in the Eastern U.S. This area is very important to our energy security and FERC has done an admirable job developing and enforcing these standards, directly and in concert with the delegation to NERC and its regional entities. Utilities responsible for compliance are responding to FERC's lead.

Key Recommendation:

- FERC should continue its efforts to refine and enforce reliability compliance standards.

7. TECHNOLOGICAL INNOVATION SHOULD BE INCENTED

In transmission, R&D efforts are needed in three broad areas: (i) achieving more effective use of existing right-of-way (ROW), (ii) application of improved system and equipment controls for managing ever-changing energy portfolio and grid complexity, and (iii) advancing smart grid concepts to facilitate a self-healing grid and energy use management.

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 both investment in unnecessary infrastructure and environmental impacts. But R&D leadership is needed. The industry is highly fragmented with over 500 transmission owners and over 3000 distribution owners and R&D expenditures totaling less than 1% of revenues.

Costs to develop and implement a new technology can be substantial, and even if the project proves successful, little or no benefit might flow to its owners. FERC has encouraged development of advanced technology through incentives under the Energy Policy Act of 2005. [GIVE AN EXAMPLE OF FERC INCENTIVES? INCREASED RATE OF RETURN?] However, these incentives are subject to regulatory barriers at the state level, and cost recovery or its timing is not assured. [IF THIS IS THE CASE, EXPLAIN HOW STATE DECISIONS IMPEDE THE FERC AWARDED INCENTIVES]

Investment will occur only when regulatory policy provides reasonably certain cost recovery and a reasonable rate of return commensurate with risk. Also, mandatory reliability standards may suppress innovation if undue penalties are levied for good-faith R&D efforts that might fall short of expectations.

Timely introduction of novel technologies can only be accomplished in the industry with leadership and direct involvement of DOE in collaboration with entities such as the Electric Power Research Institute (EPRI). Elements of such a futuristic grid have been articulated through various industry initiatives, including DOE Smart Grid, EPRI IntelliGrid and National Energy Technology Laboratory (NETL) Modern Grid. However, the current Office of Electricity Delivery and Energy Reliability R&D budget is far lower than any other energy research area. A significant increase in DOE R&D funding 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 reflect federal leadership.

DOE's prior commitments to partner with the private sector in demonstrating advanced technologies can serve as a model for the new collaboration. With input from stakeholders, DOE can and should build an R&D portfolio, formulate an R&D roadmap, provide seed funding, and engage willing participants in joint efforts to develop and/or demonstrate new technologies.

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.
- FERC should support continued incentives for technology development and encourage state regulatory bodies to support cost recovery of transmission R&D investment.
- DOE should collaborate with EPRI and other private and public organizations to leverage R&D resources.

8. 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 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, in which their investment would be at risk and their return not capped. 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 cases. 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.

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 constructed expeditiously because they are required to meet NERC criteria or to "keep the lights on." Transmission dependent utilities (TDUs) and consumer advocates frequently express concerns that incumbent utilities can continue to exercise market power by delaying "economic" projects through the request for repeated feasibility and cost-benefit studies and other delaying tactics. 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 TDUs, system robustness, and consumer prices.

Seams are the borders between RTOs, as well as between utility control areas. Coordinating transmission projects across such seams is increasingly important to bring renewable energy to customer loads, as well as to improve 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. RTO boards of directors should be encouraged to develop processes for dealing with these types of projects and facilitating independent transmission company participation and utility partnerships in "bidding" for construction rights.

While increased participation is encouraged, it is equally important to avoid complications to system operations and jeopardizing reliability that could arise with a larger number of transmission owners. Expanding transmission infrastructure with increased participants and jointly-owned transmission facilities must be accompanied by legally binding agreements to merge system operations for such facilities. Increased consolidation and coordination of system operations improves reliability, enables the integration of variable resources, and prevents conflicting control issues that could negatively impact reliability. However, incumbent utilities should not be looked upon as operator, maintainer, and restorer of last resort, with reliability compliance responsibilities, without some financial reward beyond coverage of costs.

Key Recommendations:

- DOE and FERC should support reduced barriers for transmission investors and new transmission ownership structures, while ensuring that more fragmented ownership does not jeopardize operations.
- FERC should encourage states and RTOs 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 TDUs, system robustness, and consumer prices.

- FERC should promote the development of seams agreements between RTOs and other jurisdictional authorities for planning and allocating costs of interstate transmission facilities.
- FERC should encourage operating agreements for jointly-owned transmission projects to maintain fewer transmission operators.

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