Chapter 4: Transmission Expansion

In this chapter, we consider regulatory policy affecting transmission expansion, with particular focus on the implications for transmission of the integration of large-scale renewable generation. Public policies aiming to access the best onshore wind and solar resources will require new transmission lines crossing state boundaries, independent system operator boundaries, and land managed by federal agencies. This chapter focuses on the transmission planning, business models, cost allocation, and siting challenges related to this expansion.

Section 4.1 provides background on the drivers and business models for transmission development in the U.S. A discussion of transmission planning follows. In Section 4.2, we highlight the importance of interregional and interconnection level transmission planning. We also find that existing data and planning methods are inadequate to meet the challenge of renewables integration and highlight transmission planning under uncertainty for complex networks as an important area for research.

Section 4.3 discusses transmission cost allocation, starting with a review of current practices in the U.S. We find that cost allocation should be intimately linked to transmission planning. We identify a set of core principles that should be followed as closely as possible to ensure that cost allocation is not a barrier to efficient and reliable network expansion.

Section 4.4 introduces challenges related to siting new transmission capacity. We find that current siting procedures are biased against approving interstate transmission projects and are a significant hurdle to efficient transmission expansion.

Section 4.5 provides our conclusions and recommendations. We first recommend the creation of permanent processes for conducting planning of interregional transmission projects at the interconnection level. We also recommend the compilation of detailed and comprehensive data on the U.S. bulk power system in order to support research on the methods that will be needed for effective interconnection level planning. We recommend the use of the cost allocation principles introduced in Section 4.3 as well as the adoption of a hierarchical approach to cost allocation that includes a single, uniform procedure for the allocation of costs between regions within each interconnection but allows individual regions to adopt their own internal cost-allocation procedures. Finally, we recommend that Congress grant the Federal Energy Regulatory Commission enhanced siting authority for interstate electricity transmission projects.

Several factors beyond normal growth in electricity demand will require new investment in transmission capacity in the next two decades. Perhaps the most important is the need to integrate large-scale renewable generation. The U.S. federal government and all state governments provide financial support for the use of renewable energy to generate electricity, and 29 states and the District of Columbia have enacted quantitative requirements.[1] These programs will spur growth in large-scale renewable generation, such as large wind farms, that will be connected to the high-voltage transmission system.

Also driving expansion, the recession-induced fall in electricity demand and the shale gas revolution have lowered electricity prices and adversely affected the economics of operating many older coal-fired units. A suite of new rules from the U.S. Environmental Protection Agency may provide further incentives for early retirement of those units. A number of recent studies have concluded that, as a result, significant early retirements are likely in the coming decade.[2] Early retirements and changes in dispatch will change the geographic pattern of generation and require new investment in transmission facilities.

In the reference case of its 2011 Annual Energy Outlook, for instance, the Energy Information Administration projects that 46% of the increase in total generating capacity in the electric power sector between 2010 and 2030 will be powered by non-hydro renewables, which accounted for only about 4.5% of 2010 capacity. Almost 90% of this increase is projected to come from growth in wind and solar capacity.[3]

Wind and solar generators have two characteristics that challenge transmission systems. First, even when fully functional, their available output can vary from zero to full capacity in relatively short times and is less predictable than output from other generation technologies. We discussed the implications in Chapter 3. The second characteristic, as noted in Chapter 1, is that many of the best onshore wind and solar resources are located far from major load centers and are, therefore, far from the existing transmission system. If they are to be tapped efficiently, 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. While some boundary-crossing lines have been built in the past, that experience underscores a number of obstacles such projects face.[4] As we discuss in Section 4.2, there is too little useful transmission planning at regional, interregional, or interconnection-wide levels; the costs of boundary-crossing projects can be allocated only through project-specific negotiations; and the need to obtain construction permits from multiple authorities makes it difficult to site and build boundary-crossing lines.

Some have argued that the best solution to this suite of problems is to construct a nationwide overlay or "super-highway" grid.[5] Others favor large, discrete transmission projects that connect sizeable renewable resources to major load centers.[6] Still others defend a more conventional buildup of transmission reinforcements—within regions and across multiple regional boundaries—and more use of local renewable resources.[7] We do not recommend or oppose any particular suite of investments. Given the complexity of transmission expansion and the many competing alternatives, this is a matter for careful decision-making by knowledgeable stakeholders. Only by unlikely coincidence will the public interest be served by transmission plans dictated by legislation or based on comprehensive visions devised from afar. Our focus is on the planning, cost allocation, and siting processes and criteria by which important transmission investment decisions should be made.

Consistent with this focus, the Federal Energy Regulatory Commission's (FERC) July 2011 Order No. 1000 required improved coordination in transmission planning and cost allocation procedures within planning regions and between neighboring regions.[8] (The Order does not define "region," but notes that planning regions are smaller than the two larger interconnections and larger than single utilities.) We believe the Order is a step in the right direction but that the public interest would be best served if affected parties went beyond the order's minimal requirements. Moreover, FERC's limited authority prevented it from addressing the problem of siting transmission facilities that cross state boundaries or federal lands. We argue that this process, too, needs reform.

4.1 TRANSMISSION DEVELOPMENT IN THE U.S.

Between 1980 and the late 1990s, annual investment in the U.S. transmission system declined in real terms, and many observers expressed concern that the system was becoming economically inefficient and unreliable.[9] A careful analysis of available data suggests that this concern was mostly unwarranted.[10] Transmission and distribution losses generally declined over this period (see Figure 1.4), and there is no quantitative support for assertions of diminishing reliability. Moreover, since the late 1990s, investment in transmission has increased considerably, and these earlier concerns are less often heard today.[11]

The transmission system is not broken, and there has been and continues to be substantial investment in system upgrades and new interconnections. Today's grid meets today's requirements, but new and different demands are driving the expansion and adaptation of the transmission grid and the evolution of its supporting institutions. The system can and will respond to the new forces, but effective response will require material changes in the regulatory and policy framework.

Drivers of Expansion

U.S. transmission projects traditionally have been categorized by the primary purpose they serve: reliability, economic efficiency, or generator interconnection.[i] Public policy purposes—for example, to meet renewable generation targets—have recently emerged as a fourth category, and they are explicitly recognized in FERC Order No. 1000. While these labels are common, in practice, increased transmission capacity will provide the system with multiple benefits that may change over time. While it has been convenient to label a transmission line according to its primary purpose, this convention is at odds with the new reality and could be both confusing and counterproductive. Any transmission line serves all these purposes to different degrees. In the future, coherent policy for analysis of costs and benefits should recognize and capture this interaction. Aggregation across the benefit categories should be the norm in evaluating transmission lines.

FINDING

Transmission lines routinely serve a variety of purposes with many categories of benefits. Aggregation across benefit categories should be the norm in evaluating transmission lines.

Reliability is the most common justification for transmission investment in the U.S. Transmission projects are developed either to meet reliability standards promulgated by the North American Electric Reliability Corporation (NERC) and regional reliability authorities or to accommodate uncertain future growth and development without violating those standards.[ii, 12] The benefits of reliability are difficult to quantify and are often asserted to be spread over relatively wide areas.

[i] As a general matter, it is important to recognize that non-transmission investments can sometimes serve the same purpose as transmission investments and that transmission investments do not always take the form of new towers and wires on new rights-of-way.[13]

[ii] A discussion of the reliability standards that are used to govern generation and transmission investment decisions is beyond the scope of this study. For the discussion in this chapter, we take them as given. However, the criteria underlying current reliability standards do not necessarily reflect rigorous cost–benefit analyses, an issue FERC is addressing.[14]

Only after reliability planning is complete do planners look for investments that would increase economic efficiency. Economic benefits include reduced network losses and mitigated or eliminated capacity constraints (generally termed "congestion") that prevent the use of the lowest-cost set of generators to meet demand. By strengthening the transmission network, these projects also allow wholesale electricity markets to expand geographically, which mitigates market power and may provide other benefits. Of course, lines justified by economic benefits generally improve system reliability and vice versa.[iii, 15]

Economic planning processes are generally not nearly as well developed as the procedures for reliability planning, and many regions are still in the process of completing their first studies of economic opportunities.

Recent years have seen very few transmission lines built that had been justified primarily on the basis of economic benefits.[16] The stringency of reliability requirements may ensure that most available economic benefits are captured by lines built primarily for reliability, and a persuasive economic case for investment is difficult to make in the current recession. In addition, while the most basic economic benefits are in principle easier to quantify than the economic value of reliability benefits, measuring them in practice is a challenging analytical task (see Box 4.1).[17] Economic planning processes are generally not nearly as well developed as the procedures for reliability planning, and many regions are still in the process of completing their first studies of economic opportunities.

In the end, clear technical procedures for justifying reliability investments have generally ensured that all the lines necessitated by reliability are built, while lines justified primarily by economic benefits are rare.[18] Yet we cannot identify specific situations in which lines with clear economic benefits were planned but could not be built, perhaps because economic benefits have been too narrowly defined.[19]

Generator interconnection lines allow generators to connect to the most appropriate point on the transmission system—usually the closest. Historically, such lines have been short and largely uncontroversial, and they have been included in proposals for new generating capacity. However, if companies develop large solar and wind plants at locations far from the existing network, the equivalent generator interconnection lines may be longer and more expensive than in the past. As a result, current treatment of these lines and required reinforcements elsewhere in the network may need revision.

Indeed, as renewables receive increasing amounts of attention in public policy debates, there is growing concern that current transmission development procedures may not adequately support their development. Reflecting this concern, the concept of including public policy purposes as a justification has emerged in some regions and has been endorsed in FERC Order No. 1000. California, Texas, Colorado, and Minnesota have already established practices that account for policy objectives, and California ISO, Midwest ISO, Electric Reliability Council of Texas (ERCOT), and Southwest Power Pool (SPP) have planning

[iii] This point is well illustrated by Midwest ISO's 2009 transmission expansion plan, which included $4 billion worth of exclusively reliability lines that were expected to provide nearly $3.4 billion in economic benefits.[20] Midwest ISO's systematic assessment of these investment benefits is unusual, though. The frameworks for assessing the economic value of these reliability upgrades tend to be either very weak or nonexistent in most regional transmission organizations.

BOX 4.1 THE CHALLENGE OF ASSESSING ECONOMIC BENEFIT

Justifying investment in transmission to improve the economic efficiency of the power system requires a calculation of the economic benefit of that investment. The separate but related problem of appropriate cost allocation also presents significant challenges for transmission expansion. Unless project proponents can persuasively argue that the benefits are likely to outweigh the costs, and the costs and benefits have been fairly apportioned among the affected parties, it will be difficult to move a project forward in the face of inevitable opposition in the siting process. Neither problem has a simple, one-size-fits-all solution, but as we discuss in subsequent sections, reasonable and workable solutions do exist.

At the most basic level, the economic benefit of any project is measured by the increase in consumer surplus plus producer profits from the project. In planning, this translates into forecasting future demand and finding the change in the least-cost way of reliably meeting that demand that the project would make possible. Allocation of project costs should be based on benefits to market participants—both consumers and generators. Note that these benefits will be negative for consumers in low-price areas who, unlike most residential and other small customers, face location-specific rather than area-average prices when transmission congestion isolating them is alleviated. Benefits are also, symmetrically, negative for generators in high-price areas when a new line increases the linkage with areas with lower electricity prices. A more comprehensive view of transmission-related benefits is given in the "Planning Criteria" section on page 87, where planning criteria are examined.

Benefits assessment is complicated in practice by the fact that transmission affects not only electricity prices, but jobs, local interests, and the environment. In addition, large transmission projects often add important flexibility to the system over the short and long term. Planners and stakeholders need to determine which benefits to consider, how to value some hard-to-quantify outcomes of transmission development, such as the economic value of reliability improvements, and what approach will be taken to determine the "optimal" solution.

Beyond the particulars of quantifying benefits, assumptions about future environmental policies, generation resource additions and retirements, technological change, and relative fuel costs are grounds for debate, a complication that is made all the more problematic by the long lives of the assets involved. To assess their benefits, new lines can be compared to a counterfactual situation in which the line or set of lines has not been built. This is not practical with lines that were built a long time ago because defining the counterfactual would require the hypothetical untangling of all the subsequent investments and assumptions regarding what would have been built instead of the line in question.

processes that allow for public policy benefits. FERC Order No. 1000 will require that all local and regional transmission planning processes include policy objectives. It also mandates that public utility transmission providers establish procedures to identify transmission needs driven by public policy requirements and evaluate alternative ways of meeting those needs.

Some projects to deliver renewable power will not increase reliability, nor will they necessarily bring economic benefits until state or federal policies sufficiently reduce the cost of renewables or increase the cost of fossil-powered generators. However, the policy dimension can be made commensurable with economic and reliability benefits for purposes of evaluating transmission investments.

Transmission Investment

During and following the processes of transmission planning, it is necessary to determine who will invest in and build the new line and how its costs will be recovered. These processes take place primarily at the state or regional level in coordination with the states' public utility commissions. FERC plays a role as well: electricity transmission is generally assumed by law to be in interstate commerce and thus subject to FERC regulation because it takes place in an interconnected high-voltage grid that crosses state lines.[iv]

Some projects to deliver renewable power will not increase reliability, nor will they necessarily bring economic benefits until state or federal policies sufficiently reduce the cost of renewables or increase the cost of fossil-powered generators.

In regions without an ISO, the local vertically integrated utilities will each centrally plan transmission expansion as part of an integrated resource planning process. Once the plan is approved by the relevant state utility commission, the utility builds and maintains the lines that have been proposed and recovers the total cost—including an allowed rate of return on the investment—through state-regulated retail rates. When lines connect two utilities, the division of costs between them is negotiated and, after approval by the state regulator or regulators, each recovers its share of costs through its own retail rates.

Regions with an ISO have more latitude for different investment schemes because multiple parties may own, build, and operate transmission assets. In most cases, utilities and ISOs identify needed network improvements, and a transmission utility builds and maintains the project. In some jurisdictions, the transmission builder is always an incumbent—a transmission company that already has a presence in the region. In others, non-incumbents may propose projects. The project costs are allocated to network users based on a wholesale transmission tariff, proposed by the ISO or utility and approved by FERC, and the corresponding retail tariffs. In other cases, the conditions are appropriate for voluntary or "merchant" transmission investment, in which costs are typically recovered through contracts between the transmission owner and specific users who benefit from the investment. Voluntary funding of large-scale transmission projects is uncommon, however. Tariff-financed projects undertaken by non-incumbents are also rare in the U.S., but this may change as the FERC implements Order No. 1000, which lowers barriers to their participation.[22]

The idea behind merchant investments is to create new transmission capacity where significant locational price differences or important network constraints exist that the new line will reduce or eliminate once it is in service.[v] Alternatively, investors may try to cover their costs by arbitraging the differences in the locational marginal prices between the two ends of the line. But because transmission investments are lumpy, respond to reliability

[iv] Alaska, Hawaii, and the ERCOT region of Texas are exceptions. In addition, about one-third of the high-voltage transmission system in the 48 contiguous states is owned by government enterprises, cooperatives, and other entities not subject to FERC regulation.[21] These entities have much higher shares in some regions. The legal and policy problem of harmonizing their behavior with that of the entities regulated by FERC is complex and important, but it is beyond the scope of our study.

[v] The corresponding contract rates may be similar to those that result from standard regulatory processes, although they also may be higher because merchant investors are not prevented from seeking a high rate of return when bargaining with beneficiaries.

criteria, and have scale economies, they tend to reduce price differences substantially, making it difficult for investors to cover their costs in this fashion.[23] Would-be merchant investors may find it difficult to reach an agreement with enough beneficiaries willing to help cover the cost of the line. The few merchant projects that exist or have been proposed are mostly sponsored by new entrants and generally involve high-voltage direct current (dc) technology (discussed in Chapter 2), which allows the owners of the facility to capture a larger portion of the line's benefits through their ability to control power flows, which makes it easier to define the beneficiaries.[24]

4.2 TRANSMISSION PLANNING

As noted in Appendix A, in the early years of the industry, transmission planning was the responsibility of vertically integrated utilities that met their native loads from their own generation. Some interconnection linking these utilities occurred before World War I, however, and interconnection accelerated thereafter. Today, about two-thirds of the U.S. load is served by large, regional ISOs that plan transmission to serve projected loads in their territories. The planning processes vary significantly among different ISOs and non-ISO regions, but they focus primarily on the objectives of maintaining a transmission grid that is reliable and, with lower priority, economically efficient.[25] ISOs, power marketing administrations, and vertically integrated utilities do little joint planning, though this is changing as interconnection increases over time. Because NERC regional entities (see Figure 1.3) are responsible for reliability throughout their geographic domains, individual vertically integrated utilities within the same NERC region tend to have similar planning processes.

The planning process in most ISO regions is significantly more difficult than within vertically integrated utilities because decisions about the installation of new generation are the result of market forces (modified by state and federal support for renewables and other policies) rather than centralized planning. Thus, transmission planning in these regions is subject to additional uncertainties about where future generation may locate and how power will flow around the network, especially when renewable generators are involved.[26] Magnifying this effect are uncertainties regarding future subsidies and requirements for renewable generation, because a painful fact of transmission planning is that it typically takes much longer to plan, get approvals, and build a high-voltage transmission line than a wind farm or solar generating facility. When generator build times are shorter than those for transmission, planners are forced to either anticipate new generation and build potentially unnecessary infrastructure or wait for firm generation plans before starting the process and thereby potentially discourage new generation investment.

Interregional Transmission Planning

Until recently, ISO regions and states had worked together to negotiate specific interregional projects but had not developed formal interregional planning processes. But the Eastern and Western Interconnections are becoming more tightly coupled, and considering interregional projects one at a time rather than as parts of an interconnection-wide plan is no longer sensible. Indeed, without such planning, problems could arise that would impede efficient expansion of renewables generation. The U.S. Department of Energy (DOE) Eastern Wind Integration and Transmission Study, which considered wind penetrations of 20%–30% in the Eastern

Considering interregional projects one at a time rather than as parts of an interconnection-wide plan is no longer sensible.

Interconnection, demonstrates that even in scenarios prioritizing local wind, transmission requirements span multiple operating regions.[27] Further, the study concludes that reaching very high penetration of renewables will require substantial use of local and remote wind resources, which in turn will require accompanying transmission development within and across multiple regions.

The scale and complexity of the Eastern and Western Interconnections are such that interconnection-wide planning requires a hierarchical approach encompassing bottom-up and top-down processes. Bottom-up planning is the process of integrating local or regional transmission plans that are based on detailed knowledge of local or regional conditions. Top-down planning involves a central body charged with identifying potentially desirable inter- and intraregional lines. Both have shortcomings: A solely bottom-up approach will fail to identify potentially desirable lines that traverse regional boundaries. To capture these potential investments, one needs top-down processes, performed as part of interregional, and perhaps interconnection-wide, planning exercises. But a purely top-down process may not be adequately responsive to regional issues or planning processes. A hierarchical hybrid of the two approaches has the potential to respect local and regional needs while still having vision broad enough to recognize interregional opportunities.

The Western Interconnection has long been a leader in wide-area transmission planning using a hierarchical approach. In the Western Interconnection, members of the Western Electricity Coordinating Council (WECC), the NERC regional reliability council responsible for the Western Interconnection, collaborate to model economic transmission expansion through the Transmission Expansion Planning Policy Committee (TEPPC), which spans the entire interconnection.[28] While TEPCC and its subcommittees model the strategic economic expansion of high-voltage lines, smaller subgroups model reliability and lower-voltage lines.[vi] With American Recovery and Reinvestment Act funds, the council also has recently started an electric transmission planning study for the entire Western Interconnection, although this research activity may or may not influence what actually gets built.

In the Eastern Interconnection, both the PJM Interconnection and SPP have bottom-up subregional planning processes to supplement their top-down regional planning processes.[29] In addition, the Northeastern ISO/RTO Planning Coordination Protocol among ISO New England, New York ISO, and PJM has been in effect since 2004. But, until recently, the East has not had an interconnection-wide institution comparable to the TEPCC in the West.

By comparison, the European Network of Transmission System Operators for Electricity (ENTSO-E) has been tasked with providing a 10-year pan-European transmission expansion plan and has recently finished its first preliminary report.[30] This plan is not mandatory, but a directive establishes that national plans should be consistent with the pan-European one. The newly created Agency for the Cooperation of

[vi] For example, to plan transmission for the state of Colorado, the Public Service Company of Colorado participates in TEPPC, the regional transmission planning group WestConnect, the Colorado Coordinated Planning Group within WestConnect, and state planning procedures.

Energy Regulators is responsible for supervising this consistency and for reporting any significant deviation to the European Commission. Recently ENTSO-E has started to develop a longer-term strategic plan that will provide a vision for how a pan-European power system could develop sequentially over a time horizon to 2050.[31]

FINDING

In the Eastern and Western Interconnections, interconnection-wide planning, which has become more important, requires a hierarchical approach encompassing both bottom-up and top-down processes.

Two recent developments may serve to expand the effective scope of hierarchical wide-area planning in the U.S. Title IV of the Recovery Act appropriated $80 million to establish interconnection-wide planning collaboratives with the goal of "facilitating the development of regional transmission plans" and providing assistance in the form of "modeling, support to regions and States for the development of coordinated State electricity policies, programs, laws, and regulations." The Office of Electricity Delivery and Energy Reliability at the DOE issued awards to five separate organizations, two each in the Eastern and Western Interconnections and one in ERCOT. These organizations are made up of regional planning authorities from across each interconnection, but their effectiveness and impact on what actually gets built remain to be determined. Moreover, because of the nature of their funding, the new collaboratives are only supported for a single round of analysis and may well disappear afterward.

FERC urges transmission facility owners not subject to its jurisdiction to participate in these interregional planning processes, though it cannot require them to do so.

In a second development, FERC's Order No. 1000 requires regional and interregional planning between adjacent regions.[32] "Region" is undefined in the order, but it is noted that a single utility cannot constitute a region for this purpose. There are no requirements at the interconnection level, however. FERC urges transmission facility owners not subject to its jurisdiction to participate in these interregional planning processes, though it cannot require them to do so.

While existing planning arrangements have enabled construction and ongoing expansion of a reliable and efficient transmission grid, extensive use of renewable resources distant from major load centers will require stronger, permanent interconnection-wide planning procedures, particularly in the East. The West has demonstrated that this can be accomplished collaboratively. It may not require another layer of authority or bureaucracy, though some central staff and modeling capability will presumably be required to perform the top-down analysis necessary to complement existing bottom-up processes, as well as an agreed-upon definition of planning criteria, a prescribed periodicity of the plan, transparency, and adequate stakeholder participation. In addition, problems of planning methods and data availability will need to be addressed. We discuss these next.

FINDING

Making more use of remote renewables in an efficient manner will require permanent planning processes at the interconnection level.

Transmission Planning Methods

Transmission planning involves discrete and long-lived modifications to complex networks in the face of an uncertain future. More technically, transmission planning is characterized by a large number of choices with multiple dimensions, a great deal of uncertainty, large investments, and long periods over which investments must be assessed. These characteristics are compounded and the challenges magnified when planning over larger areas and trying to achieve multiple objectives. The current state of the art in transmission planning is able to address power systems on an ISO level, including moderate levels of uncertainty on a scenario basis.[33] However, current methods have not dealt with planning over the larger geographic areas and with the increasing levels of uncertainty that must be considered to integrate substantial renewable generation efficiently.

Transmission planning is characterized by a large number of choices with multiple dimensions, a great deal of uncertainty, large investments, and long periods over which investments must be assessed.

Today, the transmission system is planned using expert judgment supported by technical models. The general procedure is to forecast demand 5–10 years into the future and simulate the system performance at that time. Complex simulations identify reliability issues and potential economic improvements. If the simulations indicate a problem, system reinforcements or other remedies are developed. Next, the simulations are re-run to ensure that the reinforced system meets the prescribed reliability requirements and delivered energy costs are reduced.

Because the transmission system is a complex network, many possible reinforcement options can resolve system concerns. In contemporary transmission planning, experts frequently define the set of possible reinforcements. Expert planners tend to consider one investment at a time, however, rather than focus on system outcomes. Some optimization techniques are in principle capable of producing system plans without this limitation, and they have been used in some systems for a long time, although they have limitations of their own.[34]

Restructuring and the ensuing separation of transmission and generation planning will increase uncertainty. As noted above, the impact of uncertainty surrounding plant location is often compounded by the mismatch between generation and transmission build times.[35] Moreover, because load characteristics and locations, fuel prices, environmental policies, and generation portfolios may vary substantially over the 50-year lifetime of transmission investments, the network must be designed to perform well under a variety of different conditions.

To evaluate a network design's robustness, planners perform multi-period analyses under uncertainty, which allow them to consider investments that may not be deemed prudent during short time frames but may enable the efficient evolution of the grid in the long term. Performing such analyses for a complex network subject to multi-dimensional uncertainty is a computational and conceptual challenge, however, and little work has been done to develop methods to support robust network planning. Forward-looking studies often consider only the design of networks for a static year and single scenario.[36] These analyses do not yield an optimal expansion path to the eventual desired network, nor do they consider robustness to situations in which the envisioned scenario does not unfold.

Scenario methods, which consider multiple futures, have been used in some cases.[37] But scenario methods may not identify important regulatory and other uncertainties regarding the availability of renewable resources.[38] Because increased uncertainty cannot always be dealt with adequately via deterministic or scenario processes, stochastic planning criteria, tools, and methods will need to be developed by the industry and the research community, and then employed.[39]

Finally, to improve planning methods for wide-area networks, detailed data used by transmission operators on real wide-area networks must be available to use for testing. For a variety of reasons, including security concerns, such data are not generally available for this purpose today.[40]

FINDING

Currently available data and planning methods are not adequate to support interconnection-level planning that takes appropriate account of uncertainty.

Planning Criteria

As noted earlier, explicit criteria for transmission planning include NERC and state reliability standards and, in many regions, economic efficiency. In states or regions with requirements for renewable generation, public policy goals also play a formal role. Additional criteria are often left implicit and may include robustness and flexibility, expansion of wholesale markets and mitigation of market power, and the ease of constructing transmission in different localities.

In cases in which the criteria are unclear, conflicts can arise between system planning processes and policy requirements. The most obvious conflict today can occur in states with renewable portfolio standards but no transmission initiatives beyond the typical general requirement to provide transmission access. These states may fail to meet their renewables requirements for want of transmission, or they may meet them using unnecessarily low-quality, high-cost resources. Transmission to serve renewables will not materialize without appropriate policy requirements. Uncertainty regarding future support and requirements for renewables coupled with the mismatch between generation and transmission build times make such adverse outcomes more likely.

FINDING

States or regions with policies driving growth in renewable generation but that do not establish public policy goals as a clear criterion in transmission planning initiatives, may fail to meet their renewables requirements for want of transmission.

Some authorities have recognized this problem and established explicit transmission directives, such as the Renewable Energy Transmission Initiative (RETI) in California and the Competitive Renewable Energy Zone (CREZ) planning in Texas. In RETI, for instance, the criteria for assessing lines include the quality and quantity of the renewable energy resource accessed, the commercial viability of the renewable energy accessed, the environmental impact of a new line, and the proposed line's ability to bring renewable energy to market as opposed to relieving congestion. The RETI and CREZ criteria are detailed, which creates transparency and allows stakeholders to see why particular transmission expansions were studied and adopted.[41] These initiatives may be possible models for broader multistate or national initiatives.

4.3 TRANSMISSION COST ALLOCATION

As discussed earlier, cost allocation differs by market type. In regions served by vertically integrated utilities without organized wholesale markets, transmission costs are generally recovered across the utility's entire territory through regulated retail rates. The costs of lines that cross boundaries between regions are divided between the two regions in a manner negotiated specifically for each project.

But in ISO regions with wholesale markets, most transmission costs are recovered from network users through a separate charge. This shift from utility-by-utility allocation has severed what had been a clear association between specific transmission assets and the generators and loads they served. To date, the ISO regions have not yet converged on common principles of cost allocation, nor have they instituted consistent cost allocation procedures across or between regions.[42]

Even so, some generalizations are possible. In most ISO regions, regional cost allocation is performed differently for projects that serve primarily reliability, economic efficiency, and generator interconnection purposes. Costs of projects justified solely on reliability grounds are usually recovered on a uniform basis from electricity users. This general approach is commonly referred to as "socialization" of costs. Individual users' shares of total costs typically depend on total or peak consumption.

The costs of projects justified primarily on economic grounds are sometimes allocated in whole or in part to those end users who benefit most from their construction, and any remaining costs are socialized.

The generator involved tends to pay for generator interconnection projects. However, this is not done in a consistent fashion. Projects that are necessary to reinforce the network because a new generator is being connected may be allocated to loads and treated like reliability or economic upgrades. On the other hand, even the costs of radial lines connecting generators to the grid are often refunded to generators through regulated rates over time.

As we noted earlier, if intensive use is made of the best renewable resources, new generator interconnection lines and related system upgrades are likely to be more expensive on average than they have been historically. In addition, interregional lines probably will be more important. The corresponding cost allocation rules and processes will be under scrutiny and modification due to FERC's Order No. 1000 mandate that regional transmission planning processes must designate one cost-allocation method for all utility transmission providers and neighboring regions must have a common interregional method.[43]

Rather than proposing a specific cost-allocation method, we next lay out some fundamental principles that complement and extend the FERC order and then explore their application to the transmission planning process.

Principles of Cost Allocation

An important policy challenge is to develop principles and procedures for mandatory cost allocation. Participant funding for various forms of merchant lines or sale of capacity rights on large dc lines provide other cost allocation models. The common feature of these alternatives is that they are voluntary. Voluntary participant funding is desirable when it is workable. However, in many cases, the scale and scope of transmission investments can have a material effect on market conditions and create concerns over free-riding that would be impractical to overcome through strictly voluntary agreements. Thus, there is a requirement for regulatory approval and the associated mandatory rules for allocation of the costs.

None of the principles we present here conflicts with FERC Order No. 1000, but strict adherence to them would go beyond the order's requirements.

Principle 1. Costs should be allocated in proportion to benefits. This is the most fundamental principle. Each beneficiary's share of a project's costs should be as close as practical to its share of the project's total benefits.[vii] In principle, beneficiaries are any network users who see a change in their expected expenditures or profits as a result of the project, taking into account the value of increased reliability and any other benefits.[44] This so-called "beneficiary-pays" principle has been widely accepted in the U.S. and abroad. It stands at the core of FERC Order No. 1000, which in ¶585(1) states, "The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits." We see no principled reason not to take this one step further: the allocation of costs should be *exactly* proportional to those estimates if the planning process has produced a set of estimates of expected benefits. This stronger language would avoid an interpretation permitting cost allocations that depart materially from the pattern of estimated benefits.

A transmission project is economically justified if its benefits exceed its costs. By reducing or eliminating price differences, however, a transmission project could impose losses on generators in previously high-price areas or on load in previously low-price areas. In addition, these projects can affect the economic value of any existing transmission rights and contracts (see Box 4.2), and some entities might suffer losses because of environmental harm. Regulators can cut through this tangle of effects by approving any project with positive net benefits, even if it imposes losses on some entities. They should disapprove projects with gross benefits for some that exceed costs but with negative net benefits overall. This means turning down some projects for which those who receive benefits would be willing to cover the costs.

Dividing a project's costs among network users in proportion to their benefits is generally perceived as equitable. And if a project's benefits exceed costs, all beneficiaries will be better off and less likely to oppose progress on the project.[viii] Conversely, if a project's costs exceed its benefits, it will be impossible to

[vii] Large, discrete transmission investments can have a material effect on prospective market prices and the distribution of benefits, and the associated costs are largely fixed *ex post*. Rather than recover those costs through ordinary transmission tariffs, it is better to use a multipart charging mechanism that couples *ex post* efficient usage pricing (reflecting congestion and marginal losses) with fixed access charges, assigned to members of the coalition of putative beneficiaries in a way that preserves net benefits for being a member of the coalition.

[viii] In principle, if the project has positive net benefits, it is possible to compensate any losers for their losses and make all affected entities better off. In practice, this is complicated and seldom, if ever, done. It is generally argued that compensation is not deserved for the loss of economic benefits (high prices to generators, low prices to loads) that exist only because of network congestion, but major environmental impacts may raise more serious issues in the future. Such impacts might be claimed, for instance, if a proposed line would cross a particular state but confer no benefits on its residents.

BOX 4.2 FINANCIAL TRANSMISSION RIGHTS

In an electricity transmission network, the laws of physics dictate that power flows distribute across all possible paths between locations, approximately minimizing total system losses. This creates strong interactions between generators and loads. One implication is the need for a central system operator who oversees generator dispatch and maintains balance in the system while respecting the many transmission constraints. Another implication is that there is no workable definition of "physical" transmission rights that would allow for individual generators and loads to arrange their own trades and determine the final dispatch of the system.

Organized electricity markets overcome these problems and support competition by supplementing decentralized trading with a coordinated and centralized final dispatch built on the framework of bid-based, security-constrained, economic dispatch with locational prices. The prices reflect the locational marginal values of generation and load.[45] The difference in prices between any two locations is equal to the marginal cost of transmission between them.

This definition of the marginal cost of transmission does not require separating transactions to describe the complex physical flows between locations. The difference in locational prices is charged as the short-run price of transmission. Users of the transmission system pay this price for explicit bilateral transactions or implicit trades through the coordinated dispatch.

The difference in locational prices also provides a means to define an economic alternative to the missing physical transmission rights. This is the financial transmission right (FTR) that allows the owner to collect the difference in locational prices for a given volume between two points. Users of the system pay, and owners of the FTRs collect. The economic effect is the same as would be true if it were possible to define and use separable physical rights. But the integrity of the FTR does not depend on the actual use of the system corresponding to the distribution of FTRs. In effect, the set of FTRs operates as though there were a set of fully tradable and reconfigurable physical transmission rights.

For a given transmission grid, if all the FTRs awarded are simultaneously feasible, the revenues collected from the system users will be sufficient to cover the payments to the holders of the FTRs. This is an inherent property of economic dispatch and the related locational prices.[46] For transmission expansions, the simultaneous feasibility rule applied to the existing plus incremental FTRs awarded with the expansion would guarantee the same property going forward.

An inferior but commonly used alternative to the beneficiary-pays principle is the socialization of cost, which spreads it uniformly throughout a region.

allocate costs in such a way as to make all entities better off. Thus adopting the beneficiary-pays principle helps with decisions about what should be built, as well as determining who should pay for what is built. Fairness is important, but support of consistent incentives for investments is the key reason for embracing this principle. Of course, failure to recognize all beneficiaries—the generators, in particular—could cause a beneficial project not be built because not enough of the benefits have been captured to cover the costs.

An inferior but commonly used alternative to the beneficiary-pays principle is the socialization of cost, which spreads it uniformly throughout a region. Socialization eliminates locational signals, reducing the system's ability to promote investment in the best locations. For instance, all else equal, socialization would always favor the best wind or solar resources, regardless of their location and impact on transmission costs. Additionally, spreading costs too widely may reduce cost discipline and eliminate the incentive to consider economic alternatives to transmission expansion.[47] One solution might be to socialize the costs of the alternatives, too, but doing so would call for significant changes in decision-making in the electric system and put many important investment decisions into the hands of regulators. Finally, uniform region-wide cost recovery can provoke substantial public opposition to even highly beneficial new investments if some parties are forced to shoulder costs that significantly exceed the benefits they realize.[ix]

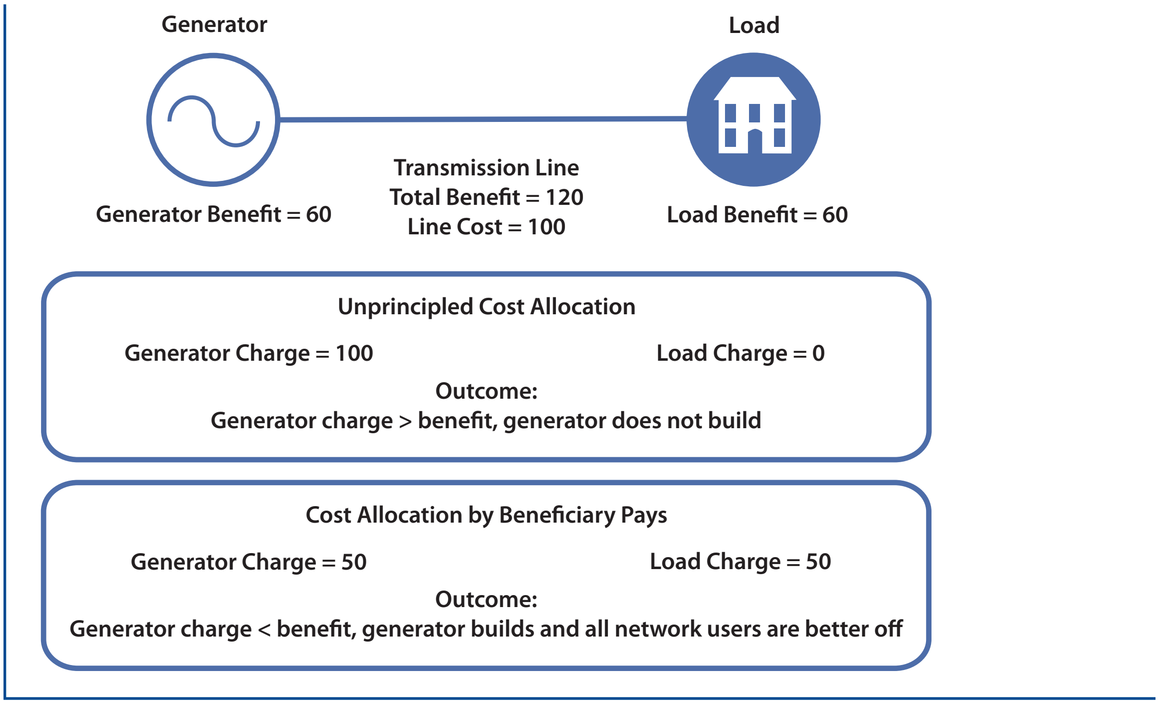
It is sometimes argued that cost socialization is a workable approximation when much uncertainty exists in the estimation of beneficiaries, or when the investment impacts several regions. However, this argument misleads. Great uncertainty about benefits and beneficiaries generally implies that expected benefits are widely distributed. The beneficiary-pays principle is still applicable, even though it might produce a cost allocation similar to direct socialization. But this would not be the same as abandoning the principle, nor would it produce the same result in the more common cases where significant uncertainty about some beneficiaries is accompanied by less uncertainty about others.

Where there are wholesale markets for electricity, generation and load generally are both beneficiaries of new transmission capacity. Generators use the transmission system to deliver their product, benefit financially from doing so, and should therefore be responsible for paying for a fraction of the network costs. Load also benefits from new transmission through reduced energy costs, increased reliability, or both. Cost-allocation procedures should seek to apportion the costs of a line to generation and load proportional to aggregate economic benefits realized by the two groups. As in any highly competitive market, if wholesale markets are highly competitive and there are no special opportunities for any generator to capture extra rents, all costs levied on generators will end up being passed on to load via wholesale electricity prices, either in the short or in the long term. This is true even if network charges are levied as an annual lump sum or on a per megawatt basis rather than per megawatt-hour of produced energy. In some markets, however, some generators may enjoy unique location-specific or other advantages, so they will retain benefits from transmission that is built to these locations. Moreover, not all generators operate in highly competitive environments, and changing market conditions typically provide multiple opportunities to generators to enjoy short-term rents (and suffer short-term losses), so these generators can be charged transmission costs without any anticipated pass-through to consumers.

If regulation fails to allocate costs according to benefits generated and, for instance, the cost of long interconnection lines is charged 100% to the generators involved, socially beneficial investments in generation could be abandoned, as shown by the illustrative example in Figure 4.1. Likewise, allocating too much of the transmission cost to load would eliminate locational signals to generators, especially for renewables that require costly transmission investments. These signals help to ensure that the most economically sensible sites are chosen for generator development.

[ix] This danger is illustrated clearly by PJM tariff submissions, which show a divergence as large as $1.2 billion in cost-allocation outcomes of a specific project for socialization compared to the PJM DFAX flow-based method.[48] While DFAX is not a perfect application of the beneficiary-pays principle, it does employ one commonly employed proxy for benefits. The Florence School of regulation has provided a useful comparative analysis of cost allocation methods.[49]

Figure 4.1 Illustrative Example for Generator Cost-Allocation Outcomes



All this stands in contrast to some current procedures, in which, for instance, generators are at least initially responsible for the entire cost of radial interconnection lines, while load entirely bears the cost of other network reinforcements. Regulators should be aware of the link that exists between the economic value of any subsidy to renewables and the decision of how much to charge these generators as a function of their economic benefits.

Any transmission planning exercise should look for investments with the largest margin of aggregated benefits (or reduction in system costs) over additional network costs. A sound planning process must provide sufficient information on the identities of the beneficiaries of proposed transmission investments to enable those proposals to be evaluated. Conceptually, this information can be used to allocate costs according to the beneficiary-pays principle. Transmission is inherently about moving electric power between locations, and the analysis of the value of such investment requires calculation of locational impacts on generation and load. A consistent parsing of the benefits, with careful consideration of the geographic scope of benefits from increased reliability, allows for estimation of cost shares that make the beneficiaries better off while respecting the principle that those in regions who do not benefit do not pay. This approach can yield a workable approximation to a beneficiary-pays allocation and make cost socialization a last resort.[50]

Principle 2. Transmission charges should be independent of commercial transactions. Regardless of any specific, pre-arranged commercial electricity trades, the physical flows on the network will remain unchanged, and loads will always be served by the least-cost set of available generators that does not violate any network constraints. Because commercial transactions have no influence on the physical network flows, charges for network use should not depend on individual commercial transactions. Instead, transmission charges should depend only on the location of the network users within the system and on when and where power is injected and withdrawn from the system.[51]

According to this second principle, a generator located in a region A that trades with a load-serving entity in a region B should pay the same transmission charge as if, instead, it were contracted to supply a neighboring load sited within its own region—and vice versa. The existence of any contracts voluntarily signed by any agents should not affect application of this principle because they should modify neither the physical real-time efficient dispatch of generation nor the pattern of demand. This second principle is not tantamount to socialization of network costs; as indicated before, transmission charges should depend on the location and the timing of network utilization.

When planners fail to separate transmission charges from commercial transactions, the result can be pancaking, a situation in which network users are required to pay accumulating fees in every region their power is deemed by contract to pass through, regardless of actual power flows. As a result, transmission charges depend on the number of administrative borders between buyer and seller. Such pricing tends to stifle trade and prevent buyers from accessing low-cost sellers. Furthermore, linking benefits calculations and contracts creates perverse incentives for entering into contracts to avoid cost allocations. This could lead to inefficient transmission investments and would significantly complicate operations in networks. The U.S. and the European Union have recognized that pancaking is undesirable; in response, FERC issued Order No. 888 providing open access to the transmission system and the EU developed a standardized mechanism for accessing and paying for the transmission system.[52] Today, transmission charges generally are independent of commercial transactions within U.S. ISOs, but not in inter-ISO transactions. This principle should also be applied in inter-ISO transactions.

One possible argument for pancaking is that it can enable compensation to some losers from a transmission project. Consider a line connecting regions A and B that crosses region C but provides no benefits within it. The generators and consumers in A and B who benefit from the line should pay for it. One might argue that residents of C will bear the environmental impact of the line and thus are entitled to charge for the transmission of electricity through it. While one can argue that compensation is justified in this case, that argument does not rationalize the wholesale distortion of transmission charges that pancaking implies.

Transmission charges should depend only on the location of the network users within the system and on when and where power is injected and withdrawn from the system.

Principle 3. The allocation of costs should be established *ex ante*, before the project is built. Once costs have been allocated on the basis of anticipated benefits, that allocation should be left in place for the life of the project—or at least a long period on the order of a decade. There is no reason to update a long-term price signal soon after a project has been completed because that project's investors have already responded to the signal and committed to action. The possibility of future updates adds uncertainty and raises capital costs.

Moreover, it is possible and necessary to evaluate a transmission investment *ex ante*, defining the net benefits as the difference in expected benefits with and without the investment, but there is no comparable method for *ex post* evaluation of benefits. A feature of network interactions is the strong interdependence of power flows. After projects A, B, and C have been built in order, for instance, it makes no sense to consider benefits *ex post* in a hypothetical network with B and C but without A because as a general matter the presence of

A will have affected the designs of B and C as well as the decisions to build them. *Ex ante* calculation of expected benefits is necessary for analyzing a decision to go forward with an investment, and the same calculations can support *ex ante* cost allocation. By contrast, *ex post* calculation is neither easy nor required for sunk investment decisions, nor is there a principled framework for parsing benefits in an interconnected grid.

Applying this principle sometimes requires judgment, as when significant uncertainty about future benefits is expected to be resolved in the relatively near term. For example, the imminent location of a large generating plant might have a material impact on the expected distribution of benefits. In such cases, it may be most sensible to allocate cost after the uncertainty is resolved rather than risk imposing costs well in excess of *ex post* benefits on some parties. Current transmission cost-allocation methods in some interregional markets, such as in Central America and the EU, have adopted this approach.

Once costs have been allocated on the basis of anticipated benefits, that allocation should be left in place for the life of the project—or at least a long period on the order of a decade.

Applying these principles perfectly is difficult in practice. But unless one begins with sound principles and departs from them only to the extent required by practical considerations, the final system of cost allocation will lack coherence, and the resulting pattern of investments is likely to be inefficient.

FINDING

To achieve an efficient and reliable network, three cost allocation principles should be followed as closely as possible:

- **Costs should be allocated in proportion to benefits.**
- **Transmission charges should be independent of commercial transactions.**
- **The allocation of costs should be established *ex ante*, before the project is built.**

Cost Allocation in Practice

In practice, the process of determining who benefits and how much they benefit is analytically complex, especially because of uncertainty regarding future benefits.[53] In addition, the lumpiness and economies of scale of transmission lines means that it is often sensible to build facilities with excess capacity in anticipation of future needs. This may provide economic justification for at least partial socialization of many projects during the early years of their operational lives, when they are not operating at full capacity. If a portion of capacity is put in place to serve potential future users, it may be sensible to socialize the costs for the early years of operation until those users appear.

Cost-allocation procedures are only workable if they are roughly compatible with voluntary agreements by the parties involved. The three principles of cost allocation form a sound foundation on which mutually beneficial agreements can be constructed. Recognizing that the first of them—the beneficiaries-pay principle—can have somewhat different operational meanings in different settings, we present some very general guidelines for allocation of intraregional transmission network costs:

- Maintain current transmission network charges for existing lines, and apply the cost-allocation method only to new or recently built lines.[x]

- For any new potential generator, estimate the benefits of recently built lines and lines that are scheduled to enter in service shortly. Any existing transmission capacity expansion planning procedure should be helpful in the evaluation of the benefits of new transmission facilities, and generators that have been built recently or are planned to be built soon have an impact on the network expansion plans.

- Use this information to compute the transmission charges for recently installed and prospective generators and loads, as well as for the remaining network users.

Even gradual implementation of these guidelines should move transmission tariffs toward a more cost-reflective—and thus more economically efficient—structure.[54]

Cost-allocation procedures for interregional, interconnection-wide, and renewable generation projects are even less developed than those for intraregional projects. But they will become more important in the future if large-scale renewable generation is substantially expanded.

Interregional or Interconnection-Wide Cost Allocation. FERC's Order No. 1000 calls for the development of standardized interregional planning and cost-allocation procedures. The result could be either common interconnection-wide procedures or a set of bilateral or multilateral cost-allocation agreements within each interconnection.

The former might emerge from discussions among planning regions or be imposed by FERC. An interesting example of such a procedure is the European Inter-TSO Compensation Mechanism.[55] This mechanism uses network flows as a proxy for benefits and deals only with the allocation of costs between regional system operators (TSOs in European terminology). Planners first employ flow-based methodologies to determine how much external agents use the network of each region. Then they calculate the costs associated with that usage and allocate them to the corresponding external regions. The net balance is credited or charged to each region, and its network users pay based on that region's chosen tariff method. This hierarchical scheme provides a workable (if imperfect) interregional cost-allocation system anchored in beneficiary-pays logic and leaves each regional operator free to define its own system for intraregional cost allocation.

On the other hand, it may be difficult as a practical matter for the many regional authorities involved in both the Eastern and Western Interconnections to reach agreement on this or any other common interregional approach. The alternative is a set of bilateral or multilateral cost-allocation agreements. This outcome would obviously lead to processes that would be more sensitive to regional differences, but such a system would be less adept at dealing with multiregional problems involving, for instance, loop flows. In this case, FERC might consider developing default procedures for multiregional issues in the absence of prior agreements among all affected parties.

[x] Our major concern is the allocation of the costs of new transmission investments. Transmission charges for the existing lines to new network users are of lesser importance to this study, but some practical implementation guidelines can be found in the literature.[56]

From these considerations emerge broad guidelines for sound interregional transmission cost-allocation procedures. Ideally, they should be applied globally within each interconnect:

- Apply cost-allocation method only to new transmission projects.
- Whenever possible, use an estimate of the project's benefits to allocate costs among the regions involved; if this is not possible, some measure of network usage might be used as a proxy for benefits.
- Use this information to compute the fraction of the cost of the project to be covered by each involved region.
- Allow each region to allocate the cost it must cover to its network users according to its own internal procedures, which should be built on the three basic principles presented here.

Remote Renewable Generators. When all generators were built by vertically integrated utilities, lines connecting the generator to the transmission grid were treated as (a generally small) part of the cost of the generator. Transmission cost differences were thus automatically taken into account in making locational decisions, but only in unusual cases, like mine-mouth coal plants, did they have much of an effect on those decisions.

In contrast, different entities may now build and own generation and transmission facilities, and the cost of interconnection lines and other required transmission network upgrades may represent a significant fraction of the cost of the remote, large-scale wind and solar plants that may be developed in the future. Under the traditional approach, the generator would pay the full project cost. But in the case of remote renewables, this is likely to represent a significant departure from the beneficiary-pays principle. That principle should be applied to determine cost allocations for interconnections of major system upgrades between major load centers and remote renewable generators just as for other transmission projects.

Two other issues associated with renewables development deserve mention. First, wind and solar power plants are often built in relatively small increments of several tens to a few hundred megawatts, typically substantially less than the standard sizes of conventional thermal power plants. This is true even in areas with good resources that may ultimately support many such plants. High-voltage transmission lines, however, are often most efficiently constructed at scales designed to serve a gigawatt of capacity or more. The effect of this mismatch is that large amounts of transmission capacity may not be used until more generation comes online in an area, which could take years. In the meantime, a relatively small generator could face the cost burden of oversized, underutilized transmission system upgrades.

A second problem emerges because many of the best wind and solar resources are far from the existing transmission system. Transmission utilities have little interest in building capacity to remote areas far from the existing infrastructure, since it is generally unclear under current tariffs who would pay for such lines. As a result, transmission utilities would like to wait for generators to build first so that they can then finance the transmission upgrades necessary to accommodate these resources. Of course, generators will not build if their plants have to sit idle for years before they can interconnect to the grid and start to sell their power.[57] This is the classic chicken-and-egg problem with transmission.

There are creative approaches to address both problems. Initially, regions could allocate the cost of new transmission projects in remote areas where wind or solar development is anticipated to load. Then, as generators come on-line in these areas, they would assume their pro rata share of the transmission costs, even paying back consumers if appropriate. Eventually, if generators come on-line as forecast, the proper costs would be allocated to all parties, but costs would shift over time to ensure that initial financing challenges do not prevent utilities from building a beneficial line at efficient scale. In this way, planners can reduce the financial risk to transmission developers, and a lack of available transmission would not force generation investors to inaction. A risk is that the forecast is wrong, new generation does not appear, and the loads subsidize the costs. This is not strictly compatible with *ex ante* cost allocation, but it does involve a process that would be put in place *ex ante*, with well-defined steps.

California has instituted procedures of this sort, called location-constrained resource interconnection pricing, in its processes for developing in-state renewable resources.[58] Texas is using its CREZ planning, which involves socialized regional cost recovery, to address this issue.[59] The New York ISO also has dealt with this issue in its interconnection procedures by initially using a "class-year" allocation process to share the costs of transmission upgrades among numerous generators and establishing a headroom account whereby future developers reimburse the developer who has initially paid for the transmission upgrade. Yet another alternative approach is the coordinated procurement, or anchor tenant, model that the New England states are discussing.[60]

4.4 SITING NEW TRANSMISSION CAPACITY

When a developer attempts to build a transmission line, it must acquire necessary siting permits from some set of states, localities, and federal authorities to build the facility. During the siting process, projects are most vulnerable to challenge and litigation by parties who are not satisfied with the project for any reason. Shortcomings in planning or cost allocation can compound intrinsic difficulties with siting, such as NIMBY ("not in my backyard") complaints. Conversely, progress on transmission planning and cost allocation should serve to reduce disputes about cost allocation that surface in disguise during siting proceedings. A major test of this hypothesis would follow from implementation of the new planning and cost-allocation proposals in FERC Order No. 1000. It is hard to imagine, though, that siting will ever become routine: local protests and logistical troubles will undoubtedly persist to some extent.[61]

State laws and regulations primarily govern the approval process for siting transmission, though in some states, city and county authorities also may be involved. While recent decades have seen a steady movement toward greater transmission grid interconnection and regionalization, siting regimes have not kept up with this expansion in scope. The rules in one state may specify requirements different than in another that affects the same investment—e.g., requiring a specific route in Iowa and a set of alternatives in Illinois. And as Ashley C. Brown and Jim Rossi note, "There is a powerful economic incentive to be parochial in siting decisions."[62] This mismatch in scope compounds siting difficulties. If one hopes to build a line across multiple states or utility systems, limited provisions are in place to recognize the benefits of transmission that may accrue to neighboring systems.[63] This basic conflict is not unique to the U.S.; it appears in other large, hierarchically organized power systems.[64]

During the siting process, projects are most vulnerable to challenge and litigation by parties who are not satisfied with the project for any reason.

The current siting landscape in the U.S. encompasses a complex system of many stakeholders and administrative processes, each with its own interests and rules.[65] The plethora of authorities involved in transmission siting is well illustrated by a 2006 memorandum of understanding on transmission siting signed by five executive agencies, two regulatory bodies, the Council on Environmental Quality, and the Advisory Council on Historic Preservation.[66] Within the federal executive agencies, an additional 12 major subagency organizations are also cited as playing a significant role in the process.

At the local level, challenges take the form of individuals or communities objecting to the aesthetic or perceived health or environmental impacts of transmission infrastructure. NIMBY opposition has grown over time as concerns for fragile ecosystems, recreational land, and scenic or historic trails and parks have intensified. Nationally, the federal government controls about 30% of land in the U.S. and higher percentages of several western states. Obtaining approval to build a transmission line across federal land is never an ordinary commercial transaction, and federal agencies with a conservation mandate can strongly resist the construction of high-voltage transmission facilities. Even on land that is not federally controlled, projects to build new lines must undergo federal and state environmental reviews adhering to the National Environmental Policy Act, the Endangered Species Act, the Migratory Bird Treaty Act, and other laws.

Challenges can take years to resolve. In March 1990, American Electric Power announced its intention to build a 765 kilovolt line between Virginia and West Virginia that would pass through the Jefferson National Forest. Largely because of opposition by the U.S. Forest Service, final approvals were not received until December 2002. The line was energized in June 2006.[67] Another example is Public Service Electric & Gas Group's proposed Susquehanna–Roseland project, which would link Pennsylvania and New Jersey. The utility proposed a route in August 2008 after a detailed study and public workshops. New Jersey and Pennsylvania regulators have approved the project, but as of September 2011, the National Park Service has not.[68]

Siting permits and environmental reviews often have a limited shelf life and thus may lapse if other complications cause delays. In other cases, approval timelines for certain sections of a right-of-way may exceed those for others because of the differing siting authorities. Groups opposing a project can exploit the mismatch between processes.[xi]

Perhaps more than anything else, securing an authorization for a transmission project hinges on the determination of need, because state regulators are often required by political reality—and sometimes by law—to focus exclusively on in-state costs and benefits in making decisions.[69] The requirements to give priority to local need can be problematic even when there are stakeholders in a state that might benefit from the local development and tax base of the new transmission investment. For instance, in May 2007, Arizona regulators unanimously rejected Southern California Edison's proposed Devers–Palo Verde 2 line, which one commissioner described as "a 230-mile extension cord" pulling energy from Arizona to California.[70] They found that California ratepayers would benefit from access to Arizona's generating capacity, while Arizona rates would increase as a consequence of the increased demand. The increased cost for some due to expanded interstate commerce is a normal consequence of trade. Even without

[xi] The U.S. Chamber of Commerce maintains a useful resource that describes many of these challenges and includes a list of active transmission projects facing major hurdles (http://www.projectnoproject.com/category/project/transmission/).

affecting electricity prices, the focus on local need is an obstacle to development. For example, a transmission line that crossed a state like Arkansas without local interconnections might make sense, but the absence of local service could preclude a required demonstration of meeting a need under state law. If national policy is best implemented by bulk transfer of renewable power across long distances and across state lines, the existing state-centered siting procedures will likely prove to be a significant impediment.

Despite these impediments, many transmission projects have been planned, sited, and built in recent decades. Many of these do not cross state lines, and state authorities are responsible for approving them. ISOs' planning processes have also been successful in facilitating multistate lines that are justified by reliability considerations, simply because reliability problems will tend to affect all states within a region. Problems arise when projects serve economic or public policy goals and involve costs and benefits in multiple states or regions.

As regional institutions and processes have grown in importance, some states have gradually taken action to ease the siting process for lines that serve interests in multiple states. They have employed several mechanisms, including interstate cooperatives and joint transmission studies. For example, the Western Governors Association established a protocol in 2002 to set forth procedures for collaboration between siting agencies in the Western Interconnection. While this agreement did not contain specific siting provisions, it may serve as a basis for more detailed and binding future steps. Although differing in their details and execution, similar organizations exist in the Midwest ISO, SPP, and PJM with the purpose of understanding and coordinating transmission siting processes across the different states involved. These regional efforts are still works in progress, and being voluntary present real problems of fashioning agreements that compromise different interests of competitors.

If national policy is best implemented by bulk transfer of renewable power across long distances and across state lines, the existing state-centered siting procedures will likely prove to be a significant impediment.

At the federal level, the Energy Policy Act of 2005 empowered groups of states to form interstate compacts for transmission siting, though no such compacts have been formally recognized yet. More notably, this act also added the new §216 to the Federal Power Act, which gave FERC authority to issue permits for facilities in areas experiencing capacity constraints or congestion and designated by the Secretary of Energy as a National Interest Electric Transmission Corridor (NIETC). These permits would confer rights of eminent domain if a state commission or other entity with authority to approve siting has "withheld approval for more than one year after the filing of an application seeking approval."

However, subsequent Circuit Court decisions made §216 effectively irrelevant, ruling that FERC cannot act if a state simply rejects rather than withholds approval of a project it opposes and that the process to designate NIETCs was flawed.[71] In 2009 the House of Representatives passed a bill with a provision that would have empowered FERC to consider interstate projects rejected by state regulators, though only in the Western Interconnection.[72] A bill reported out of the Senate Committee on Energy and Natural Resources contained a broadly similar provision that would have applied in both Eastern and Western Interconnections.[73] Neither provision became law, and even if FERC had meaningful backstop authority within NIETCs, there now exist no legally designated NIETCs within which it could exercise that authority.

FINDING

Current siting procedures make it easier to obtain permission to build a transmission project located in a single state that does not cross federal lands than one that requires the approval of more than one state or a federal agency.

A range of other measures has been proposed to streamline the siting process and lower unnecessarily high barriers to transmission development:[74]

- Articulate best practices for reviewing siting proposals.
- Examine state legal frameworks to identify legislative language that may inhibit siting coordination and how that can be remedied.
- Broaden the definition of need that state commissions use to include energy efficiency, public policy, and out-of-state benefits.
- Develop common review processes between local, state, and federal authorities, including coordination of requirements and potentially a centralized siting agency.
- Coordinate and speed federal agency reviews. The interagency memorandum of understanding signed in 2006 is an example of action in this direction, as is the recently announced formation of an interagency Renewable Energy Rapid Response Team to ensure timely review of proposals to site transmission facilities on federal lands.[75]
- Increase regulation of the time allowed for permitting reviews at all levels.
- Establish or use existing regional institutions to facilitate interstate siting and standardize siting procedures.

Because existing transmission siting procedures are widely recognized as a hurdle to development, some of these reforms may be realized, at least in part. However, they are relatively modest and unlikely substantially to reduce obstacles that arise because responsible state agencies serve the interests of their in-state constituents at the expense of others and federal agencies pursue mandates that give little weight to an efficient and reliable bulk power system. State and federal agency officials may be doing their assigned jobs well yet acting against the broader national interest. This structural problem is unlikely to be solved without effective structural change.

An analogous problem arose within states in the early years of the grid's development.[76] The early technology for electric transmission emphasized local development of generation and limited (or no) longer-distance interconnection. Local authorities held sway over need determination and the siting process. As conditions changed and the impact of transmission grew to cover larger areas and loads, state governments began a slow and incomplete process of centralizing decisions within the state and preempting local authorities, all in pursuit of the broader state-wide interest. The same technical process continues with longer-distance transmission, increasing interconnection and even broader regional and national goals—but now the role of individual states, not to mention local governments, has changed against the backdrop of this broader reach of proposed transmission investments. The parochial interests of the states and localities, which are easy to understand, do not naturally encompass the broader interests of larger regions or of the nation as a whole.

The parochial interests of the states and localities, which are easy to understand, do not naturally encompass the broader interests of larger regions or of the nation as a whole.

We have also seen this process before in the case of natural gas. In 1938, Congress recognized that a similar structural problem could substantially retard the development of interstate natural gas pipelines and passed the Natural Gas Act. Section 7(h) grants FERC authority to evaluate proposals for such pipelines. Since a 1947 amendment to this Section, if the FERC approves a proposed pipeline, the company building it receives the right to acquire the necessary property by eminent domain if it cannot acquire it on negotiated terms.[77] While this procedure may not be optimally designed or perfectly administered, it does not generate either intense controversies or unreasonable delays compared to the analogous challenges of electricity transmission expansion.

The problem of siting interstate electric transmission facilities was not important in 1935 when the Federal Power Act was passed, and it was not addressed in that legislation. It is important now and, as we have argued, in large part because of the growing importance of remote renewables, it will likely become more important in the future. Improving regional, interregional, and interconnection-wide analysis and planning would help. Implementing a workable, beneficiary-pays cost-allocation procedure within each interconnection would help. But even with perfection in these reforms, the competing interests of states would affect electricity transmission in the same way that conflicting state interest could have affected natural gas pipelines and other forms of interstate commerce. In the end, hoping that obvious structural problems will not retard desirable investment is not enough.

The simplest and most elegant solution to the problem of interstate transmission siting is to give FERC authority over significant interstate projects or those requiring land managed by another federal agency. One might want to depart from the natural gas model by limiting FERC's authority to projects that have emerged from regional, interregional, or interconnection-wide planning processes, as appropriate. Yet eliminating states' roles entirely has a variety of disadvantages given their superior knowledge of local conditions. Thus a workable alternative would be to amend §216 of the Federal Power Act to give the FERC effective backstop authority over these projects, anywhere in the U.S. This would involve eliminating the conceptually and administratively troublesome notion of NIETCs, allowing FERC to consider reliability, as well as economic and public policy benefits, while specifying that a state's denial of approval of a multistate project should serve as a trigger to FERC consideration.

While one can debate the merits of these alternative approaches—and we have done so within our study team—we agree that either the natural gas model or the FERC backstop approach would serve the national interest much better than the status quo.

4.5 CONCLUSIONS AND RECOMMENDATIONS

The current system for governing and financing transmission expansion has served the U.S. electric power industry well. However, this system likely will not be adequate in the immediate future, when large deployment of grid-scale wind and solar generation is anticipated and the transmission grid becomes more interconnected across state and regional boundaries. Because some of the best wind and solar resources are located far from major load centers, their efficient utilization will require permanent, effective interconnection-wide transmission planning processes.

These processes and associated institutions could be required by federal legislation, or FERC could extend the planning requirements in Order No. 1000 from regional and bilateral interregional levels to the interconnection-wide level, leaving the details of procedures and organization to internal industry agreements. Alternatively, the industry could see the logic and value of a broad, comprehensive approach to planning and voluntarily go beyond the order's minimum requirements.

RECOMMENDATION

To support the integration of large-scale wind and solar resources, improve system reliability, and increase efficiency, permanent hierarchical and collaborative processes should be established for conducting planning of interregional transmission projects at the interconnection level.

Unfortunately, however, available data and planning methods do not yet support rigorous interconnection-wide planning that adequately accounts for uncertainty, particularly in the more complex Eastern Interconnection.

The first need is to develop the necessary data and make them available to those who can use them constructively. This does not require the creation of a new agency; NERC's mandate could be broadened to include this function. Making detailed network data widely available would obviously raise security concerns, but in recent years the Census Bureau and other federal agencies have developed protocols for making highly confidential data available to researchers without compromising security. We believe similar protocols can be devised for bulk power system data.

RECOMMENDATION

A responsible entity should develop detailed and comprehensive data on the U.S. bulk power system and make them available to researchers and others under procedures that satisfy security concerns.

While we believe the development—and utilization—of better planning methods is important and an attractive area for academic research, we do not believe the necessary research is likely to be expensive by the standards of federal energy research and development projects. It could be funded by industry contributions to the Electric Power Research Institute, an ad hoc industry coalition, or a public-private partnership involving DOE.

RECOMMENDATION

The industry, the federal government, or both should support research to improve hierarchical, robust methods for wide-area transmission planning under uncertainty over multiple time periods.

To produce coherent outcomes, transmission regulation has to be a conceptually integrated system. Planning, business models, cost allocation, and siting are all interrelated, and a consistent approach to all is required to produce stakeholder support for an efficient and reliable system. In particular, as FERC Order No. 1000 recognizes, the criteria and decision-making process that are adopted for transmission planning need to be closely coupled to the subsequent cost-allocation process.

RECOMMENDATION

In the interest of producing reliable electric power at least cost, particularly while integrating large-scale renewable generation, transmission cost-allocation methods should abide by three basic principles:

- **Costs should be allocated as closely as practical in proportion to benefits.**
- **Transmission charges should be independent of commercial transactions.**
- **The allocation of costs should be established *ex ante*.**

Implementation of these principles will be a challenge, but the challenge can be met through application of the same tools used to perform cost–benefit analysis in transmission expansion planning. FERC's Order No. 1000 sets out the core principles. Those responding with compliance filings should apply the same information used to calculate expected benefits to the task of displaying the expected distribution of benefits that are inherent in the analysis of transmission projects, and the allocation of costs should in principle be exactly proportional to the expected distribution of benefits. While intraregional cost-allocation methods may differ somewhat, they should be compatible with these three principles.

Currently, rules for interregional network cost allocation do not exist. Thus, to accommodate renewable generation and the growing interconnectedness of the transmission system, it is important to develop an agreed-upon procedure for allocating the costs of projects that cross regional boundaries or have a significant impact on interregional trade. Ideally, each interconnection would have a single procedure rather than a maze of bilateral or multilateral agreements.

RECOMMENDATION

A hierarchical approach to interregional transmission cost allocation should be developed that uses a single procedure, respecting the three principles of the preceding recommendation, to allocate costs between regions. Each region then can cover the costs allocated to it using its own internal cost-allocation procedure, also in agreement with the three principles.

Like the first recommendation, this goes beyond the requirements of FERC's Order No. 1000. Federal legislation or a new FERC order could mandate this approach. Or the industry could see the advantages of having a single interregional cost allocation procedure and establish one voluntarily.

If investments in the transmission grid are to advance overall system efficiency and efficient integration of large-scale renewables, planning criteria, decision-making procedures, and cost-allocation methods must enable transmission projects that have justifications other than reliability to be built under appropriate business models.

Siting transmission facilities will always be a complex issue, but sound approaches to planning and cost allocation will make it easier. Even with these improvements, however, there are strong incentives for state agencies to ignore out-of-state interests and for managers of federal lands to give inadequate weight to the health and efficiency of the bulk power system. These incentives constitute barriers to siting interstate transmission facilities that serve the broader national interest, in particular by providing for the efficient integration of large-scale wind and solar generation.

RECOMMENDATION

The federal government should grant FERC enhanced siting authority over interstate electricity transmission projects or those that cross land managed by another federal agency. Such authority could broadly parallel its authority over interstate natural gas pipelines, or §216 of the Federal Power Act should be amended to give the FERC effective backstop siting authority anywhere in the U.S.

As we have discussed above, these two approaches have different strengths and weaknesses, but either would be a significant improvement over the status quo.

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