18. Revise Transmission Planning and Cost Allocation[1]

1. Profile

Transmission is an essential component of the modern electric grid, but one that is perhaps little understood by air pollution regulators, as the transmission lines themselves do not emit air pollution. This chapter explores a wide range of issues associated with transmission system planning and transmission cost allocation. These issues strongly influence how electric generating units are sited, built, and operated. Because electric generating units are the largest source of US greenhouse gas (GHG) emissions, public policies regarding transmission can facilitate or hinder GHG (and other air pollutant) emissions reductions.

As noted in Chapter 6, increasing the proportion of total electric generation that comes from zero-emissions resources can be a cost-effective way to reduce GHG emissions. In some cases, building new transmission lines and fairly allocating their costs is a necessary key to unlocking access to large quantities of low-cost, low-emitting resources. Lack of transmission can be a significant impediment to new, utility-scale renewable energy plants, because some of the highest quality renewable resources are located in remote areas, away from load centers. For example, Figure 18-1 shows how the best wind resources tend to be located in offshore areas and areas of the Great Plains that have relatively small population centers.

Clean energy resources that might be location-constrained but accessed by expanded transmission lines include wind, solar photovoltaic, solar thermal, geothermal, and biomass generating units. (The mature zero-emissions technologies of hydro and nuclear will continue to play an important role, but are unlikely to require any incremental transmission capacity in the near future.) It is important to address shortages in transmission capacity in the near term, because the development of new renewable energy plants takes only a few years, whereas transmission lines typically take seven to ten years to develop. In sum, transmission expansion that facilitates interconnection of cost-effective, low-emissions generation or that improves the energy efficiency of system operations is complementary to the resources themselves.

Transmission expansion can also support greater resource efficiency and lower carbon emissions by expanding the possibility of energy exchanges between regions. For example, regional exchange tools such as energy imbalance markets and dynamic transfers can facilitate the use of high-quality renewable resources with different production profiles (e.g., wind in Wyoming and Montana is a high-quality resource that produces wind at different times than West Coast wind).[2] Targeted transmission investment can increase the transmission capacity available for use and bring high-quality renewable energy into the mix of resources in a timely fashion. For example, as coal plants retire in the Midwest, additional firm transmission capacity is likely to be necessary to ensure wind resources can be delivered into load centers in the Northeast.

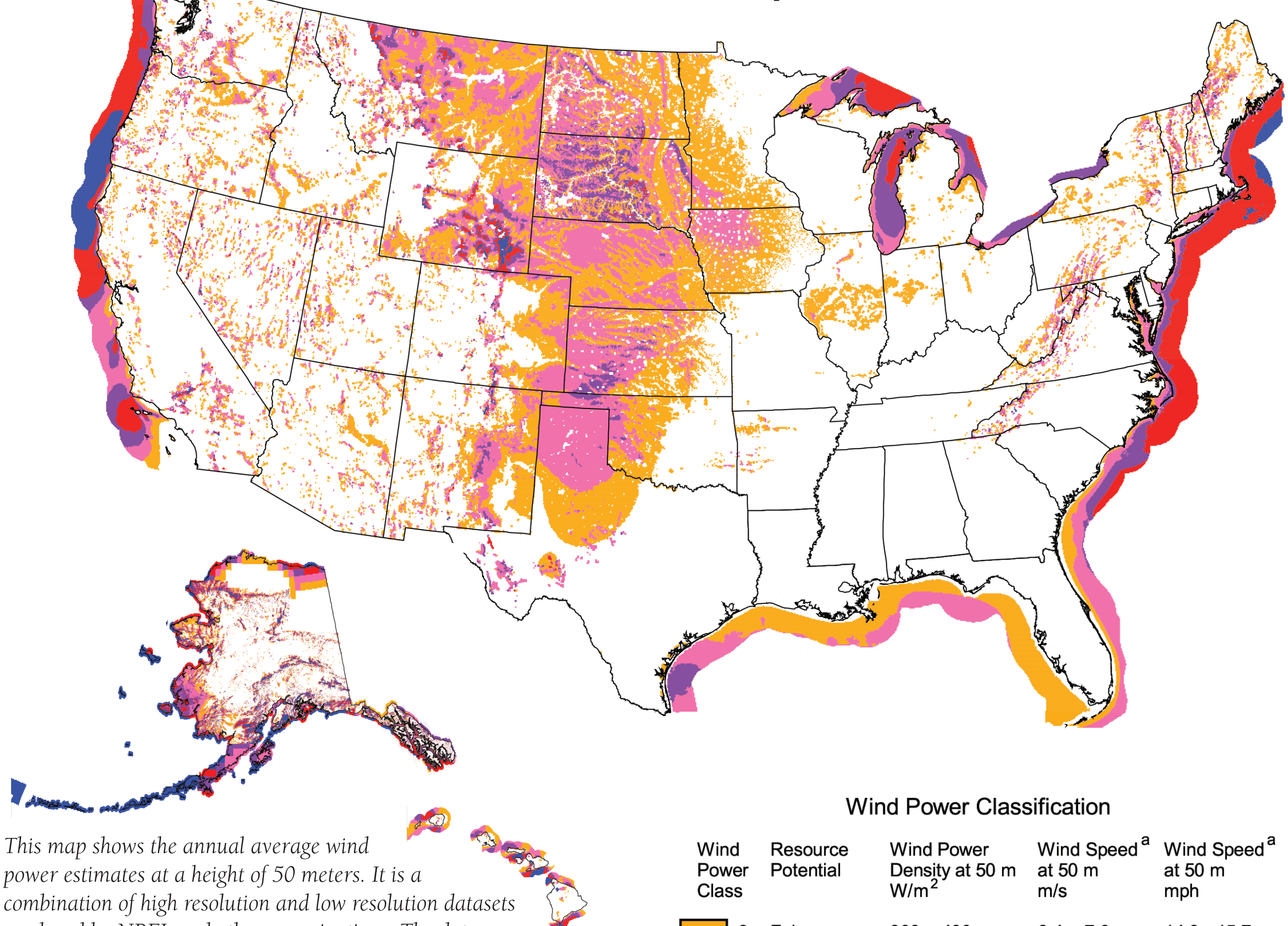
New transmission development has slowed in the United States over the last several decades, as the electric power industry has wrestled with much slower demand growth,

1 This chapter benefits from previous work done by Kevin Porter and Sari Fink (Exeter Associates), Philip Baker, and The Regulatory Assistance Project.

2 Normally, each balancing authority balances electricity supply and demand mostly by dispatching the least costly available resources on its own system to meet demand on its own system. In some cases, two balancing authorities may schedule a transfer of a known amount of electricity in advance (e.g., a day ahead). Dynamic transfers offer a way to transfer electricity from one balancing authority to another with little advance notice or when the amount of electricity to be transferred from a variable energy resource cannot be precisely predicted in advance. Doing so can provide reliability and economic benefits to both balancing authorities. Energy imbalance markets have been established in some locations to create a more formal, system-wide market mechanism for transferring electricity between balancing authorities on short notice.

Figure 18-1

US Wind Resource Map[3]



This map shows the annual average wind power estimates at a height of 50 meters. It is a combination of high resolution and low resolution datasets produced by NREL and other organizations. The data was screened to eliminate areas unlikely to be developed onshore due to land use or environmental issues. In many states, the wind resource on this map is visually enhanced to better show the distribution on ridge crests and other features.

Wind Power Classification

Wind Power Class	Resource Potential	Wind Power Density at 50 m W/m^2	Wind Speed[a] at 50 m m/s	Wind Speed[a] at 50 m mph
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	800 - 1600	8.8 - 11.1	19.7 - 24.8

[a] Wind speeds are based on a Weibull k value of 2.0

generation overcapacity, designing and implementing wholesale markets, restructuring, and retail competition (in some US states). Additionally, transmission development in the United States from the 1950s through early in this century focused on delivering power from centrally located, baseload power stations, which were generally the most efficient and cost-effective sources of electric generation at that time. Because renewable technologies were immature, the need to access areas with high-quality renewable resources had not yet emerged. Developing transmission to location-constrained resources presents a "chicken-and-egg" problem: renewable resource developers cannot guarantee firm delivery from potential new projects without transmission, and transmission companies cannot develop transmission because of uncertainty about whether sufficient generating-plant development will occur. Uncertainties over transmission siting and cost allocation, especially for multistate transmission lines, can also be a barrier to new transmission that reinforces the chicken-and-egg dilemma.

Combinations of factors make transmission expansion more time-consuming than building new generation. A

3 National Renewable Energy Laboratory. (2009). *US 50m Wind Resource Map*. Available at: http://www.nrel.gov/gis/pdfs/windsmodel4pub1-1-9base200904enh.pdf

lack of flow control means that transmission is inherently a regulated network asset and not an individual, for-profit investment. Accordingly, transmission expansion decisions in the United States typically go through a public process involving the Federal Energy Regulatory Commission (FERC), state utility commissions, and stakeholders. This process can be lengthy; new transmission development often takes much longer than the construction of new generation facilities (which are usually not subject to direct federal regulation).[4] Compounding this problem is the high capital cost (and low operating cost) and long project life of transmission assets. Taken together, these issues require policymakers to make a difficult collective decision about the need for an asset up to 50 years in the future where virtually all the costs are incurred upfront. There are also very strong economies of scale, which, coupled with the long project life, makes coming to consensus even tougher.

Nonetheless, in recent years, state and federal regulators and transmission companies have increasingly engaged in regional transmission planning processes to determine how best to unlock areas of rich renewable resources. This trend has been driven in part by state renewable portfolio standard (RPS) policies, the emergence of offshore wind plants, and concerns over global climate change. Some experimentation with cost allocation policies is also taking place in an attempt to overcome the chicken-and-egg problem. These recent efforts are pointing toward some public policy approaches for transmission planning and cost allocation that can facilitate greater deployment and use of clean energy resources as a strategy to reduce GHG emissions.

2. Regulatory Backdrop

Transmission planning starts with identifying the need for new transmission. Establishing the need for transmission is essential to all regulatory decisions that follow. The determination of need justifies the use of land and natural resources, supports the allocation of costs, and motivates financing. Thus, the interests of a wide range of stakeholders are affected, and the regulators charged with guiding the transmission planning process must therefore ensure an open and transparent public process.

The responsibility for transmission planning is not uniform in the United States, but state and federal regulators are important participants in every venue. Transmission delivers wholesale electric power and FERC has jurisdiction over wholesale electricity markets, so FERC is integral to transmission planning and approval. However, states also get involved. Many states still have integrated resource planning requirements (refer to Chapter 22), and transmission projects are often offered to state regulators as a resource option to help meet an anticipated need for new energy or capacity. Even in states that do not have an integrated resource planning requirement, the state regulators often get involved in transmission planning and approval because costs are allocated to electric customers in each state that benefits.

FERC and state regulators oversee decisions regarding the determination of need, but the responsibility for formulating a transmission plan that becomes the basis for asserting need resides with different entities around the country. The responsibility for planning new transmission may reside with regional transmission organizations (RTOs) where they exist, regional transmission planning groups (particularly in the non-RTO regions of the West and the Southeast), and with individual transmission line owners. Individual transmission owners include investor-owned utilities, public power utilities, federal Power Marketing Administrations (the Western Area Power Administration, Bonneville Power Administration, and Tennessee Valley Authority), and independent transmission companies. Some of these entities raise financing and build transmission after a need has been identified. Others focus on identifying the need but depend on individual developers and transmission owners to finance and build needed projects.

There are different types of "needs" that motivate a transmission project, and who builds, finances, and pays for a project varies by the type of need. Projects generally fall into one of the following categories:

- *Reliability-based projects* are transmission upgrades and new transmission needed to ensure that the transmission system meets reliability criteria established and enforced by the North American Electric Reliability Corporation, particularly the expectation that the system will fail to meet customer demand no more than one day in every 10-year period.
- *Generation interconnection projects* are upgrades to transmission or new transmission assets needed

4 There are exceptions. Hydroelectric plants require an operating license from FERC, nuclear power plants require approval by the Nuclear Regulatory Commission, and generating units located on federal lands require approvals from one or more federal agencies.

to hook up generating projects that will be, or are expected to come, online.

- *Economic-based projects* are for new transmission or transmission upgrades aimed at some combination of reducing transmission congestion costs, accessing new generating resources, or making markets more competitive by accessing other markets or existing generating resources.
- *Customer-funded transmission projects* are those sponsored by transmission customers, such as within an RTO.
- *Merchant transmission projects* are privately owned transmission projects that are usually quite sizable and cross multiple states to transmit new generation and/or to arbitrage against differing prices in different regions.

Although state regulators may, and often do, become involved in evaluating the need for each of these categories of projects, FERC's jurisdiction over wholesale markets and interstate exchanges has made FERC the primary actor driving the regulatory context of transmission planning over the last decade. The remainder of this section focuses on explaining the regulatory foundation laid by FERC and concludes with a summary of the role that air regulators can play in these FERC-led processes.

FERC issued three orders that have shaped recent transmission planning activities in the United States. In July 2003, FERC issued Order No. 2003 directing transmission providers to revise their open access transmission tariffs to include the standardized Large Generator Interconnection Procedures contained in the Order. Included in Order 2003 are policies for how interconnection and transmission grid reinforcement costs should be allocated. The order identifies two types of construction costs that are associated with generation interconnection:

- *Direct connection facilities* — all equipment and construction required to connect the new generating facility to the first point of interconnection with the transmission grid.
- *Network transmission upgrades* — the equipment and construction required to reinforce the existing transmission system in order to accommodate the new generation project.

Under Order 2003, the generators are responsible for the cost of all direct connection facilities between the generator and the transmission grid. Generators must also provide the upfront funding for the cost of any network upgrades and new additions to the transmission network that are required as a result of the interconnection. However, Order 2003 states that generators should be fully reimbursed for the network upgrade costs by transmission providers within five years, with interest. The reimbursement can be in the form of credits against the costs of transmission service or, if available, financial transmission rights.

Order 2003 allows RTOs to propose variations to the interconnection policies and procedures contained in Order 2003.[5] Most of the nation's RTOs have gained approval from FERC to modify their large generator interconnection procedures. These modifications have included alternative cost allocation methodologies for transmission upgrades and for interconnecting new generators; increases to the initial study deposit amounts; inclusion of group studies; and adding requirements for generation developers to meet certain milestones prior to being able to proceed to subsequent study stages.

FERC Order No. 890, issued in February 2007, enhanced the stakeholder process for all public utilities by directing transmission providers to conduct local and regional level transmission planning in a coordinated, open, and transparent manner while allowing for regional differences.[6]

In July 2011, FERC issued Order No. 1000, which outlined several additional requirements for transmission planning and cost allocation. First, Order 1000 requires that transmission providers participate in regional planning processes that meet Order 890 requirements for transparency and stakeholder inclusion. Second, Order 1000 requires that these regional transmission planning processes consider transmission needs driven by public policy requirements established through state or federal

5 FERC: (2003, July 24). *Order No. 2003: Standardization of Generator Interconnection Agreements and Procedures;* (2004, March 5). *Order No. 2003-A;* (2004, December 20). *Order No. 2003-B;* and (2005, June 16). *Order No. 2003-C.* Available at: http://www.ferc.gov/legal/maj-ord-reg/land-docs/order2003.asp. FERC set out nine criteria for transmission plans: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.

6 FERC. (2007, February 16). *Order No. 890: Preventing Undue Discrimination and Preference in Transmission Service.* Docket Nos. RM05-17-000 and RM05-25-000. Available at: http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf

laws or regulations. These public policy requirements could include state energy policies, such as RPS requirements and energy efficiency resource standards, but could also include state air pollution policies, such as a state implementation plan for ozone or a GHG emissions policy. Third, as part of the planning process, transmission providers must consider non-transmission alternatives (NTAs) (e.g., energy efficiency, demand response, distributed generation, and so on) that can efficiently and cost-effectively satisfy reliability needs, as well as conventional energy supply and transmission projects. Finally, Order 1000 requires that neighboring transmission regions coordinate their planning processes to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

In addition to the transmission planning processes mandated by Order 1000, both the regional plans and the inter-regional plans must have a cost allocation method in place; otherwise, FERC will set the cost allocation method for them based on the case record. Participant funding (in which all transmission costs are assigned to participants in a transmission project, such as the transmission sponsors or generators) is allowed but not as the default regional or inter-regional cost allocation method. Interconnection-wide transmission cost allocation (in which all costs are allocated equally to all load) is not permitted.[7] Order 1000 prescribes six cost allocation principles for regions to consider:

- The costs of new transmission projects should be allocated to load-serving entities in a way that is "roughly commensurate" with the estimated benefits of the project to those entities.
- Those that do not benefit from transmission upgrades should not be required to pay for them.
- Project screening methods must not exclude projects with significant net benefits (i.e., benefits minus costs) even if the benefit-cost ratio (i.e., benefits divided by costs) is only slightly greater than 1.0.
- No allocation of costs outside a region unless the other region agrees.
- Cost allocation methods and identification of beneficiaries must be transparent.
- Different allocation methods could apply to different types of transmission facilities.[8]

In the context of Order 1000, air pollution regulators are "stakeholders" and they may be able to participate directly in regional transmission planning processes, to ensure that the costs associated with air pollutant emissions – which have historically been dismissed as "externalities" – are considered when the cost-effectiveness of various transmission and non-transmission alternatives is evaluated. Air pollution regulators can elevate awareness of key risks (e.g., the potential air quality impacts of diesel backup generators as an NTA) and opportunities (e.g., the potential multipollutant reduction benefits of energy efficiency as an NTA). Air regulators' participation in transmission planning processes can help guarantee appropriate consideration of these resources.

3. State and Local Implementation Experiences

States have demonstrated several possible paths for developing and implementing transmission plans to access renewable energy over the past ten years. In some cases, these efforts started with state-led initiatives, such as the Renewable Energy Transmission Initiative (RETI) in California and the Competitive Renewable Energy Zone (CREZ) efforts in Texas. Examples can also be found of similar, regional efforts, such as the Upper Midwest Transmission Development Initiative (UMTDI) and the Regional Generator Outlet Study (RGOS). All of those state-led renewable energy zone (REZ) projects are described in detail in this chapter. But more recently, comprehensive planning efforts in each of the interconnections have been driven primarily by FERC Order 1000 requirements. Compliance filings for FERC Order 1000 regional transmission plans were made in October 2012, and compliance filings for inter-regional transmission plans were made in May 2013. In November 2013, more than two dozen parties filed briefs with a federal appellate court challenging FERC's authority to require the filing of transmission plan cost allocation proposals.[9] But in August

7 Allocating costs "to load" means that the costs are apportioned to load-serving entities (utilities, or in some states, non-utility competitive retail electric service companies) in proportion to the amount of load they serve.

8 FERC. (2011, July 11). *Order No. 1000: Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities.* Docket No. RM10-23. Available at: http://ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf

9 Coalition for Fair Transmission Policy. (2013). CFTP Files Reply Briefs in US Court of Appeals Challenging FERC's Defense of Order 1000. [Press release]. Available at: http://www.prnewswire.com/news-releases/cftp-files-reply-briefs-in-us-court-of-appeals-challenging-fercs-defense-of-order-1000-232533521.html

2014, the US Court of Appeals for the DC Circuit affirmed the authority of FERC to implement Order 1000 in its entirety, including the cost allocation principles.[10]

Besides transmission planning as required by Order 1000, the US Department of Energy (DOE) issued grants to each of the three interconnections in the United States — Eastern, Western, and Texas — to devise an interconnection-wide plan. In December 2011, the Eastern Interconnection Planning Collaborative (EIPC) submitted its Phase One report to the DOE, which focused on the integration of regional plans and long-term macroeconomic analysis. EIPC submitted its Phase Two report to the DOE in December 2012. That report focused on transmission studies for three scenarios: a national carbon constraint with increased energy efficiency and demand response; a national RPS; and business as usual.[11] Also in 2011, the Texas Interconnection's Long-Term Study Task Force submitted to the DOE its interim status report for the Electric Reliability Council of Texas (ERCOT) Long-Term Transmission Analysis. ERCOT is the independent system operator serving most of the State of Texas. On October 2013, ERCOT's task force submitted its final report to DOE.[12]

The Transmission Expansion Planning and Policy Committee of the Western Electric Coordination Council (WECC) performed a comprehensive planning process in the Western Interconnection between 2009 and 2013 and produced 10-year and 20-year West-wide transmission plans to meet a wide range of scenarios.[13] All data in the plans were updated on a state-by-state, utility-by-utility basis so that, for the first time, the West has a consistent set of data vetted by diverse stakeholders that is suitable for planning. The data recognize all forthcoming approved plans. The planning tool developed by WECC staff and its consultants uses the data and future scenario assumptions to generate different generation futures for the West. A number of these futures are motivated by understanding what new transmission will be needed to achieve much lower carbon emissions in the West. For example, some futures investigate the transmission implications of using much more renewable energy and energy efficiency in place of coal generation. The planning process culminated in the production of a 2013 transmission plan for the Western Interconnection, and a 2015 planning process has now been initiated.

Renewable Energy Zones

To assist with transmission planning, a number of regions have initiated REZ activities in the last decade. These efforts begin with the identification of "renewable energy zones" that are rich in renewable energy development potential. Following identification of the zones, transmission plans are then drawn up to create the much-needed transmission infrastructure in order to facilitate renewable energy project construction in the zones.

In 2007, the California Public Utility Commission, the California Energy Commission, California Independent System Operator, and three publicly owned utilities[14] launched the California RETI. RETI is organized as a stakeholder collaborative to create support for the transmission projects that are needed to meet state RPS and GHG reduction goals. The first phase of the project identified several CREZs, both in and out of state, and then ranked them with respect to environmental impacts and development economics. In the second phase, a conceptual transmission plan was developed, including the outline of a plan designed to facilitate California meeting its RPS goal (33 percent by 2020). The plan consists of a set of transmission projects costing about $6.6 billion to access 82,739 gigawatt-hours of energy from 11 CREZs.[15] RETI was subsequently incorporated into the California Transmission Planning Group, which in February 2012

10 *S.C. Pub. Serv. Auth. v. Fed. Energy Regulatory Comm'n,* No. 12-1232. DC Circuit. (2014, August 15).

11 EIPC. (2012, December). *Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios.* Available at: http://eipconline.com/uploads/20130103_Phase2Report_Part1_Final.pdf

12 ERCOT. (2013, October). *Long Term Transmission Analysis 2010-2030 Final Report. ERCOT Interconnection, October 2013. Long-Term Transmission Analysis 2012-2032 - Volume 1* [online]. Available at: http://www.ercot.com/content/committees/other/lts/keydocs/2013/DOE_LONG_TERM_STUDY_-_Draft_V_1_0.pdf

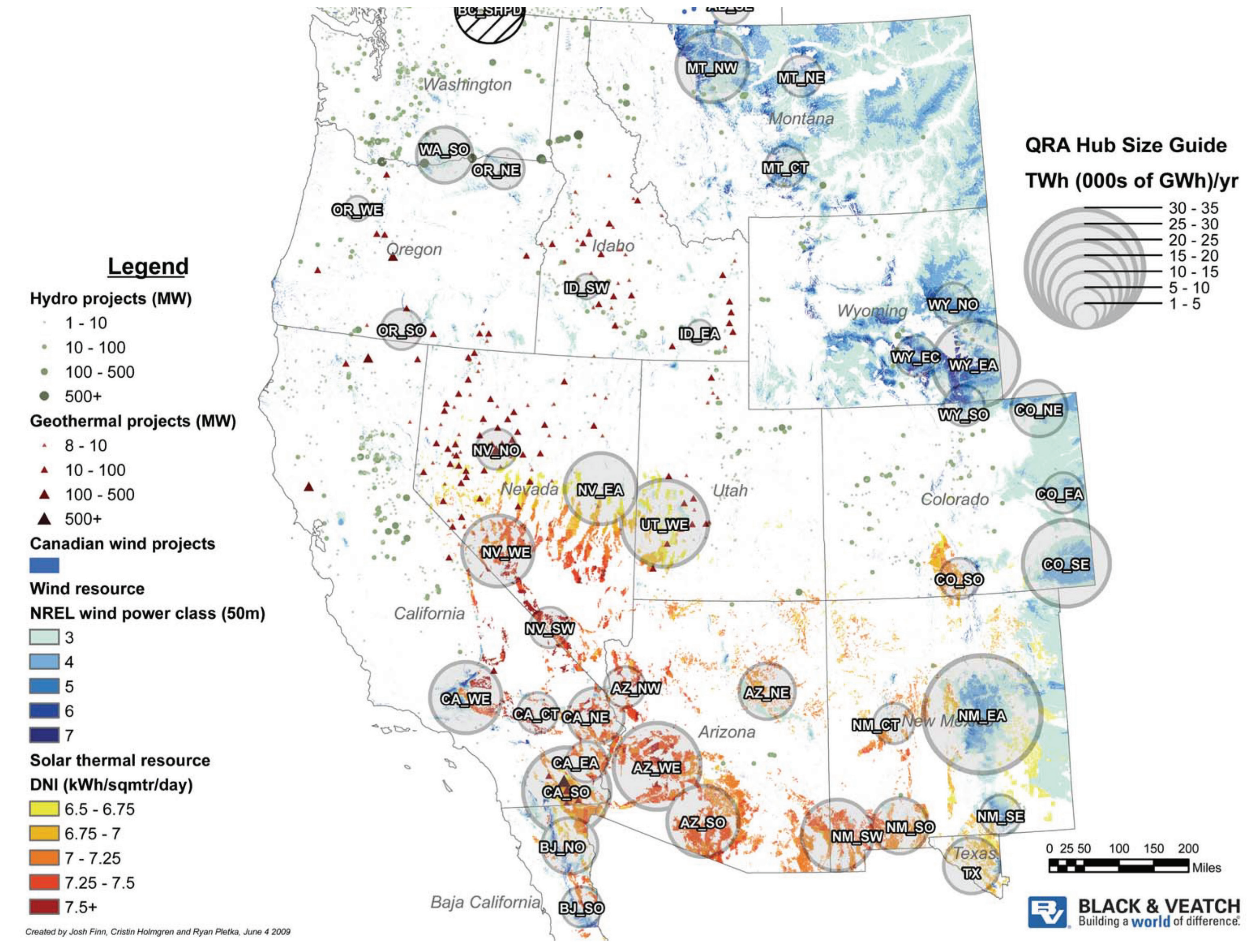
13 The WECC common case transmission plan for 2022 can be found at: https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/TEPPC_2022_StudyReport_PC1%20Common%20Case.docx&action=default&DefaultItemOpen=1; and the 2032 scenarios are described at: https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Scenario-Planning.aspx

14 Sacramento Public Utility District, Southern California Public Power Authority, and Northern California Power Agency.

15 CPUC RETI website. Available at: http://www.energy.ca.gov/reti/index.html

Figure 18-2

Qualified Resource Areas Identified in WREZ Phase I[16]



issued its final comprehensive Statewide Transmission Plan.[17] Environmental and land use approvals are key to getting transmission approved in environmentally sensitive areas, and so California followed up the RETI process with a detailed look at the desert regions of California. The Desert Renewable Energy Conservation Plan is identifying transmission paths for accessing high-quality renewables in the desert region of the state.[18] The set of transmission segments that accesses about 4000 megawatts (MW) of wind and solar in the Tehachapi region in California was a notable success of the RETI initiative.

In recognition of RPS adopted in California and other western states, the Western Governors Association obtained funding from the DOE to characterize REZs across the western United States. The initiative is referred to as the Western Renewable Energy Zone (WREZ) initiative. The WREZ initiative leveraged work from the RETI process in California and hired Black & Veatch to perform a renewable energy characterization study for the footprint of the

16 Western Governors' Association & US Deparment of Energy. (2009, June). *Western Renewable Energy Zones – Phase 1 Report.* Available at: http://www.westgov.org/component/content/article/102-initiatives/219-wrez

17 California Transmission Planning Group website. Available at: http://www.ctpg.us/index.php?option=com_content&view=article&id=4&Itemid=4

18 A description of the Desert Renewable Energy Conservation Plan activities and the Draft conservation plan can be viewed at: http://www.drecp.org/

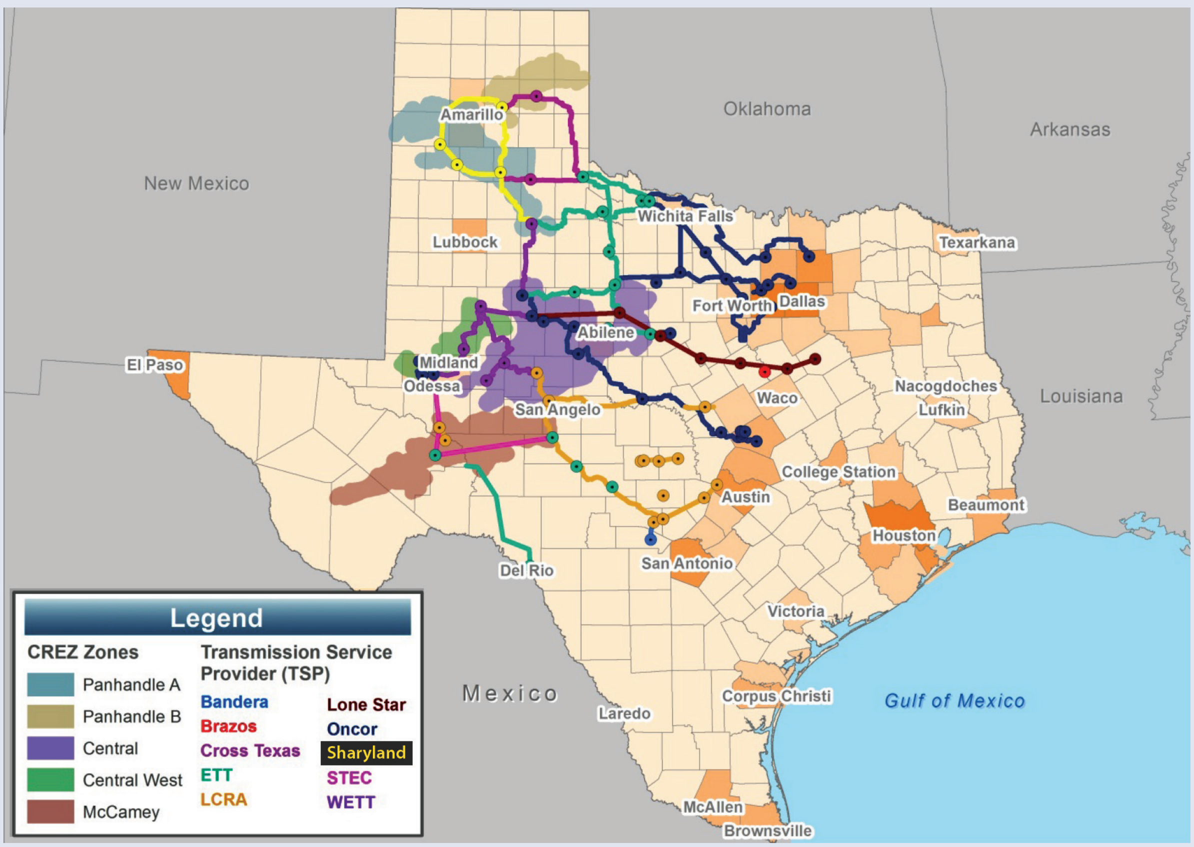
Western Interconnection. The resulting map of Qualified Resource Areas is depicted in Figure 18-2. Additional work in characterizing environmental, land, wildlife and cultural resources in the West to follow up the WREZ work is being conducted by the Environmental Data Task Force at WECC, with federal funding from the American Recovery and Reinvestment Act of 2009.[19] Several transmission projects being designed to deliver power from Arizona, Wyoming, Colorado, and New Mexico have benefitted from the WREZ resource characterization and subsequent conceptual transmission planning process.

Perhaps the most successful transmission initiative to date was launched in Texas in 2005, when the legislature authorized the creation of CREZs in that state. In 2007, ERCOT submitted a report to the Public Utility Commission of Texas identifying five CREZs in the Texas Panhandle, West Central Texas, and the McCamey area, as well as four different wind energy and transmission development scenarios. The Public Utility Commission of Texas chose to grant approval for development of a scenario that included up to 18,456 MW of wind power, along with an extensive transmission development plan estimated to cost about $4.93 billion.[20] A total of 186 CREZ transmission projects were ultimately proposed. As of October 2013, 139 have been completed, 15 have been canceled, and 32 are still in progress, as shown in Figure 18-3.[21]

The UMTDI was started in September 2008 by the Governors of Iowa, Minnesota, North Dakota, South

Figure 18-3

Texas CREZ Project Status as of October 2013[22]



19 For more information, see Western Electricity Coordinating Council, Environmental and Cultural Considerations webpage. Available at: https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Environmental-and-Cultural-Considerations.aspx

20 ERCOT. (2008, April 15). *CREZ Transmission Optimization Study Summary.* Presentation by Dan Woodfin to the ERCOT Board of Directors. Available at: http://66.128.17.81/content/meetings/board/keydocs/2008/B0415/Item_6_-_CREZ_Transmission_Report_to_PUC_-_Woodfin_Bojorquez.pdf

21 RS&H. (2013, October). CREZ Progress Report (October Update). Prepared for the Public Utility Commission of Texas. Available at: http://www.texascrezprojects.com/page29605445.aspx

22 Ibid.

Dakota, and Wisconsin. The objective of the project was to promote renewable energy development, primarily wind projects, by identifying REZs within the footprint of the Midwest Independent System Operator (MISO),[23] determining transmission needs to access those REZs, and proposing an equitable cost allocation formula for those transmission projects. The UMTDI project identified 20 REZs and six transmission corridors in the five-state region that could deliver as much as 15 GW of wind capacity. The cost of building the necessary transmission lines was estimated to be approximately $3 billion.

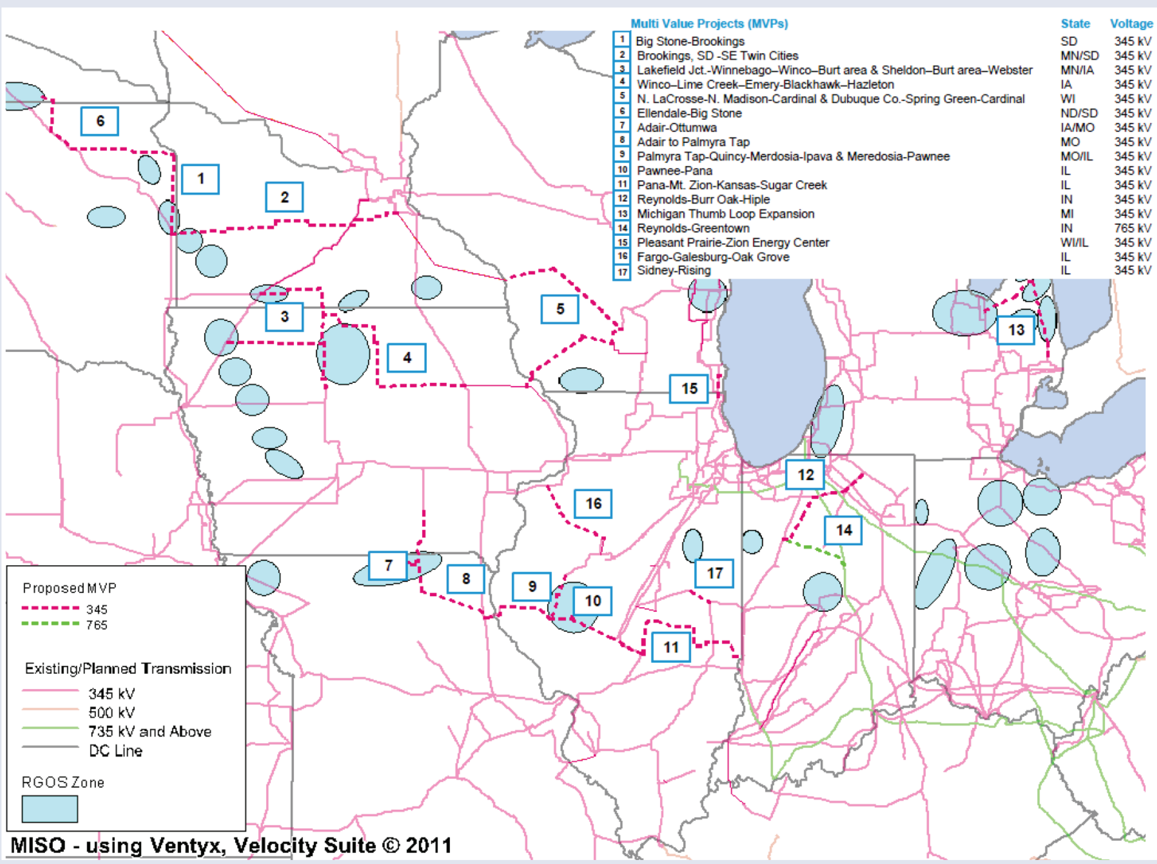
The UMTDI project provided policy direction for a similar but broader planning effort undertaken by MISO called the Regional Generator Outlet Study, or RGOS. The objectives of RGOS included:

- Analyzing and planning for each state's RPS;
- Setting goals for meeting load-serving entities' RPS;
- Balancing distribution of wind zones to consider local desires, optimal wind conditions, and distances from load;
- Providing consumers with energy solutions at the least possible cost; and
- Identifying transmission expansion starter projects.

MISO used the results of the UMTDI and RGOS studies to identify and initiate several near-term, "multi-value transmission projects" (MVPs) designed to simultaneously address current state RPS needs and regional reliability needs, shown in Figure 18-4. As of December 2014, 1 of the 17 MVPs was complete, 5 more were under construction, and 5 others had all of the necessary regulatory approvals.[24] MISO estimates

Figure 18-4

Multi-Value Projects Selected by MISO[25]



23 MISO later changed its name to *Midcontinent ISO* after adding parts of Arkansas, Louisiana, Mississippi, and Texas to its territory.

24 Refer to MISO's MVP dashboard. Available at: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=181351

25 MISO. (2012). *Multi Value Project Portfolio – Results and Analyses*. Available at: https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MVP%20Portfolio%20Analysis%20Full%20Report.pdf

that when fully implemented, these 17 MVPs will enable access to 2230 MW of additional renewable capacity and 41 million megawatt-hours of annual renewable generation to serve future renewable energy mandates.

Cost Allocation

As noted earlier, FERC's Order 1000 dictates that the costs of new transmission projects should be allocated to load-serving entities in a way that is "roughly commensurate" with the estimated benefits of the project to those entities. Socializing all of the costs of transmission equally to all load is not an acceptable default solution. However, this question of "who benefits and how much" is a controversial one (see text box), and does not lend itself to a simple and universal answer.

Without question, transmission cost allocation methods can influence whether transmission to facilitate renewable energy development is built. If a transmission project will benefit a large number of load-serving entities, its costs can be shared among a large customer base, and the impacts on any individual load-serving entity and its customers' bills may be acceptable. On the other hand, if a project is deemed to benefit only a small subset of customers, the impact on their bills could be large and they may oppose the project.

FERC has approved a variety of transmission cost allocation methods for different regions of the country. The MISO MVPs provide an interesting example. MISO argued that all customers would benefit from these carefully selected projects, and developed a tariff spreading the costs of those projects equally among all load. Some utilities opposed the tariff, claiming that they and their ratepayers were not beneficiaries and thus the tariff did not comply with Order 1000 principles for cost allocation. However, FERC sided with MISO and approved the tariff for MVP projects, and FERC's decision was upheld in subsequent legal challenges.

NTAs are seriously disadvantaged by current cost allocation methods, and this is perhaps one reason NTAs are generally not being included in transmission plans (despite the Order 1000 requirement to consider them). Because NTAs are by definition not transmission, the costs of implementing them are not recovered through regional transmission tariffs. Even if an NTA (e.g., an energy efficiency project that is targeted to defer the need for a new transmission line) costs less to implement than a new transmission line, it may be that the costs of the NTA are allocated entirely to the customers of a single utility while the costs of the transmission line would be spread across multiple utilities. In this example, the customers that would be asked to pay for the NTA will often be better off paying for a share of the transmission line than paying for all of the NTA – and thus the NTA is never implemented.

Who Benefits From Transmission Investments?[26]

The parties that benefit from transmission upgrades or new transmission lines depend on the perspective from which the question is viewed. On a general level, beneficiaries can be defined as users of the transmission system who actually affect flows on a particular transmission facility in service. From a transmission power flow perspective, generators and loads can be identified as impacting flows on various transmission facilities through distribution factors. From this perspective, beneficiaries may be seen as "cost causers" – the parties using the facility are causing the costs on that facility.

In identifying beneficiaries as those affecting flows on transmission facilities, it can be argued that it is these parties who are enjoying the majority of the reliability and/or monetary benefits of the new transmission assets. Beneficiaries can be identified through power flow studies and market efficiency analyses that are used in transmission planning.

Yet another perspective is that beneficiaries may also be defined more broadly. There may be benefits that accrue to all parties connected to the transmission system regardless of impacts on power flows, such as enhanced reliability, reduced impact of fuel price and fuel market variations, reduced opportunity for market power, and the ability to better meet public policy goals. These beneficiaries cannot be identified through power flow studies or market efficiency analyses; rather, they are one or more steps removed from transmission planning analyses.

26 PJM. (2010). *A Survey of Transmission Cost Allocation Issues, Methods and Practices.* Available at: http://ftp.pjm.com/~/media/documents/reports/20100310-transmission-allocation-cost-web.ashx

Lessons Learned From Good Transmission Planning Exercises

States, regions, or countries can adopt policies that encourage transmission planners to consider how to access larger quantities of cost-effective, low-carbon resources. These policies and the resulting planning processes should include all of the following elements:

- Conduct renewable energy mapping exercises that identify regional, low-cost resources that can replace higher-emitting fossil resources.
- Participate in regional transmission planning and cost allocation problem-solving exercises to identify the beneficial transmission projects that could unlock large quantities of low-emitting resources.
- Institute clear criteria for siting transmission and for the entities that evaluate and rule on applications for transmission. Ensure that a wide range of stakeholders and members of the public can participate in the transmission siting process.
- Support making the data and assumptions used in transmission planning as transparent and open as possible.
- Reduce transmission project uncertainty and mitigate potential delays in transmission construction by opening up the transmission planning process to include state and/or federal regulators, independent transmission and generation project developers, utilities, technology companies, environmental advocates, and consumer advocates.
- Support the acquisition of data, modeling tools, and forecasts necessary to complete regional transmission planning exercises.
- Ensure that NTAs are evaluated comparably against transmission to ensure that a least-cost portfolio of local and regional resources are chosen to meet emissions reduction targets.
- Support transmission plan periodic updates, such as annually, biennially, or triennially, to ensure plans are updated to reflect advances in technologies and discoveries of new resource zones.
- Support clear transmission cost allocation policies that implement "beneficiary pays" principles in light of the full range of local and regional costs and benefits, including reliability benefits, market development benefits, public policy compliance benefits, consumer benefits, and environmental, land, wildlife, and cultural benefits.
- Recognize that building transmission to access prospective renewable resources may require broad sharing of transmission costs in order to make projects economically feasible.
- Consider oversizing new transmission facilities to support least-cost development of low-emitting resources over a 20-year time horizon and to mitigate the need for additional transmission corridors in the future.

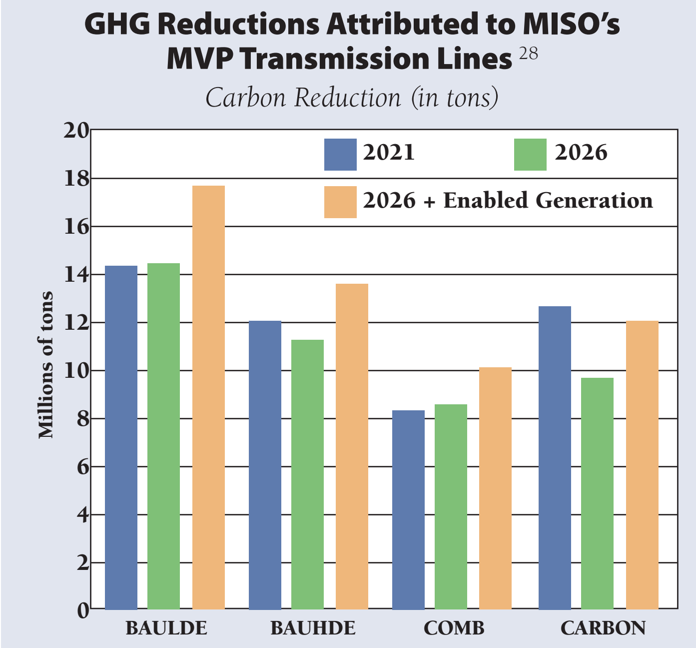
4. GHG Emissions Reductions

Transmission planning and cost allocation policies are complementary to other GHG emissions reduction policies. As previously noted, transmission improvements can facilitate the interconnection of new, low-emitting but location-constrained resources, such as wind, solar, geothermal, and biomass generating units. In addition, transmission expansion can support greater regional exchanges of energy and more efficient use of dispatchable generation assets. Curtailments of existing zero-emissions resources, which sometimes must occur when their potential output exceeds local energy demand, can also be reduced by increasing the capacity to transmit electricity to more distant load centers. Planning processes that consider energy efficiency as a transmission alternative can also help to reduce system-wide emissions by reducing demand for electricity.

The potential GHG emissions reductions that can be achieved through greater deployment of clean energy technologies are detailed in Chapters 6, 16, and 17. The potential GHG emissions reductions associated with energy efficiency are detailed in Chapters 11 to 15. Effective transmission planning and cost allocation policies will increase the likelihood that the full potential of those strategies is reached, even though the transmission policies will not, in and of themselves, reduce GHG emissions.

Quantitative data showing the impact of transmission system improvements on GHG emissions are scarce. However, MISO included an assessment of the GHG emissions reductions that could be attributed to full implementation of its 17 MVP transmission lines in a 2012

Figure 18-5



report, as shown in Figure 18-5.[27] As the figure shows, the reductions attributable to building those transmission lines depend on assumptions about future electricity demand and future energy and climate policies. The "BAULDE" scenario considered "business as usual" (BAU) with "low" demand for energy; "BAUHDE" considered BAU with "high" demand for energy; "CARBON" considered BAU energy policies but with a hypothetical national carbon cap; and "COMB" considered a hypothetical federal RPS and other energy policy changes along with a national carbon cap. In every scenario, these 17 carefully selected transmission lines are estimated to support at least ten million tons of GHG emissions reductions from 2026 onward.

5. Co-Benefits

The co-benefits that can be realized by increasing renewable generation and energy efficiency are identified and explained in detail in Chapters 6 and in Chapters 11 to 17. Those benefits include potentially significant reductions in criteria and hazardous air pollutant emissions. Transmission planning and cost allocation policies that enable and facilitate increased renewable generation and energy efficiency enable and facilitate a greater level of those same co-benefits. In fact, in some cases the potential co-benefits of renewable generation simply can't (or won't) be realized unless appropriate transmission planning and cost allocation policies are in place.

Table 18-1 summarizes the most likely co-benefits associated with revised transmission planning and cost allocation policies. Obviously, some of these benefits do not derive from the policy or process itself, but rather from the fact that it results in increased deployment of

Table 18-1

Types of Co-Benefits Potentially Associated With Revised Transmission Planning and Cost Allocation

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Maybe
Avoided Production Energy Costs	Maybe
Avoided Costs of Existing Environmental Regulations	Maybe
Avoided Costs of Future Environmental Regulations	Maybe
Avoided Transmission Capacity Costs	Maybe – if NTAs are identified
Avoided Distribution Capacity Costs	Maybe – if NTAs are identified
Avoided Line Losses	Maybe – if NTAs are identified
Avoided Reserves	Maybe – if NTAs are identified
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Maybe
Other	

27 Supra footnote 25.

28 Ibid.

renewable generation or energy efficiency. However, transmission planning is a useful tool for enhancing electric reliability and capturing other utility system benefits, even if the emphasis is not on policies to facilitate renewable generation or energy efficiency.

6. Costs and Cost-Effectiveness

The costs and cost-effectiveness of renewable generation vary by category of technology, geographic regions of the United States, and pre-existing state and federal support for these initiatives, and were identified in Chapter 6. State RPS requirements and other mandatory renewable procurement policies were described in Chapter 16, along with an assessment of the costs of such policies. But the key point in this current chapter is that the cost of delivering energy from renewable resources, and the cost of meeting states' renewable energy and climate goals, can be reduced through transmission system improvements. Without such improvements, states will be limited in what they can achieve by the capacity and capabilities of the existing transmission system, and they will need to rely disproportionately on intrastate resources even if lower-cost renewable resources are available elsewhere.

If a transmission project can provide GHG reduction benefits by accessing renewable energy or by improving system efficiency, then it should be considered as a potential vehicle for reducing GHG emissions. But once again, it should be noted that transmission does not by itself reduce emissions. Instead, it enables additional options for reducing emissions that would not be possible absent a strong transmission system, and it facilitates greater potential reductions at lower costs than would otherwise be possible. Therefore, the question of cost-effectiveness turns on the incremental costs incurred to garner any incremental GHG reduction benefits. For example, imagine two transmission alternatives, Alternative A and Alternative B, either of which is sufficient to meet a demonstrated transmission need. Although Alternative A costs more than Alternative B, it might provide more GHG benefits. The incremental costs and benefits of Alternative A could be compared to the costs and benefits of other GHG emissions reduction strategies to determine if this option is cost-effective in light of GHG policy goals.

If a project is cost-effective without considering GHG reduction benefits and if the project facilitates GHG reductions that would not be possible absent the project, then the incremental GHG reductions are essentially "free." Any cost-effective project providing these "free" incremental GHG reductions should factor into a state's GHG emissions reduction strategies. However, if the project is not cost-effective absent the incremental GHG reduction benefits, the analysis is more complicated. One needs to consider the cost of the project, the non-incremental GHG benefits produced by the project, and the incremental GHG benefits of the project to determine whether the project is a cost-effective strategy for reducing GHG.

The first step in such an analysis is to determine the incremental GHG benefits accruing from the project in question, the second step is to determine the project cost, and the third is to account for all non-incremental GHG benefits of the project. With these three sources of information, an evaluation of cost-effectiveness relative to other GHG reduction strategies is possible. Establishing the incremental GHG benefits is self-explanatory, but assessing the other two steps requires some explanation.

Transmission projects differ substantially in their costs and in the benefits they deliver, thus generic statements using average numbers are meaningless. The cost of building or upgrading transmission lines is extremely variable, based on terrain, population density, and other factors. A decade ago, it was common to assume that a transmission project would cost $1 million per mile of transmission, but many projects built over the last decade exceeded that cost by five times or more. One can easily understand why the costs of building a transmission line in New York City, northern Alaska, or rural Kansas would be considerably different. Thus, simply quoting an average cost per mile is not particularly relevant to this document, but establishing the cost of a specific project relevant to your state's compliance strategy is important.

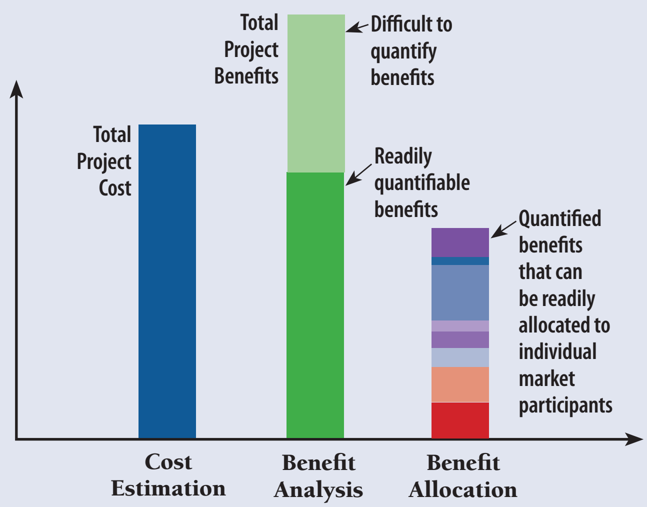
Similarly, transmission projects differ considerably in the benefits they deliver, and accounting for the full range of benefits is a technically challenging exercise. A recent report by the Brattle Group enumerates the sources of benefits arising from a new transmission project and provides guidance on how the benefits should be calculated.[29] Figure 18-6 illustrates the challenge in

29 Chang, J., Pfeifenberger, J. P., & Hagerty, J. M. (2013, July). *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments.* Brattle Group for WIRES (Working group for Investment in Reliable and Economic electric Systems). Available at: http://www.wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf

identifying the net value of a transmission project – the benefits can be substantial, but many benefits are difficult to quantify, and many benefits do not accrue to separable beneficiaries. If the project benefits fall short of the project cost, then the incremental cost attributable to the incremental GHG benefits is the difference between these costs and non-incremental GHG benefits.

Figure 18-6

Importance of Considering All Economy-Wide Benefits When Evaluating Cost-Effectiveness of Transmission Projects[30]



Examples that illustrate how such an analysis might be undertaken exist, although not in the narrow context of incremental GHG improvement. For example, in 2012, MISO published an assessment of the costs and benefits of the MVPs it selected to simultaneously address current state RPS needs and regional reliability needs.[31] Overall, MISO found that the MVPs would provide electricity system benefits in excess of the costs under a variety of future policy and economic assumptions (including scenarios in which a cost was assigned to emitting carbon dioxide). The net benefit of these projects over their expected lifetimes was estimated to fall between $8 billion and $104 billion (net present value in 2011 dollars), with a benefit/cost ratio between 1.8 and 5.8, depending on the scenario. The MVPs were thus cost-effective under every scenario considered and supporting a project like this one on the basis of incremental GHG improvement would thus be straightforward if incremental GHG benefits are in fact produced.

In addition to facilitating the deployment of renewable generation, good transmission planning processes can reveal the value of incremental energy efficiency. FERC Order 1000 mandated that transmission planners *consider* NTAs, such as energy efficiency, but those alternatives will not be included in transmission plans and implemented unless they lower transmission system costs. The only real issue with NTAs is not whether they will be cost-effective, but whether potentially cost-effective NTAs will be ignored in favor of more expensive solutions because of the discouraging approach to cost allocation that was explained in section 2.

7. Other Considerations

In addition to facilitating increased deployment of renewables, transmission system improvements directly address one of the greatest concerns associated with reducing power sector GHG emissions: reliability. Although some transmission projects may be primarily motivated by economic considerations or, as noted herein, by public policy considerations, they all make the grid more resilient and promote greater reliability.

As a practical matter, the costs, cost-effectiveness, and emissions savings associated with low-emissions sources of generation should also account for the costs of system integration, including transmission needs. These costs are not unique to low-emissions resources. Integration costs are also an issue with more traditional forms of generation, which, owing to size and inflexibility, may impose additional costs on the system. Most integration studies performed to date on renewable energy have focused on wind turbines, as wind has been the predominant variable renewable energy technology to date. Many global studies suggest that the costs are between $1 and $7 per megawatt-hour for the relevant study ranges of 10- to 20-percent penetration of variable renewable energy technologies.[32] Higher penetrations of variable renewables lead to higher costs, but experience is limited with high penetrations, and time and experience with integration techniques are likely to bring down the costs. State-specific and utility-specific studies in the United States show considerable variability in

30 Supra footnote 29.

31 Supra footnote 25.

32 International Energy Agency. (2011). *Harnessing Variable Renewables: A Guide to the Balancing Challenge*. Available at: http://www.iea.org/publications/freepublications/publication/Harnessing_Variable_Renewables2011.pdf

these integration costs, again based on the increasing wind penetration.

Job creation is often mentioned as an additional consideration of transmission system improvements. Transmission construction projects are often very large in scale and may last for several years. There is some evidence that, for each million dollars of investment in transmission, local investment increases an additional $0.2 million to $2.9 million, and employment increases by somewhere between 2 and 18 job-years.[33]

As is the case with almost all large infrastructure projects, the siting of a transmission line is often very controversial, irrespective of the technical merits of the project. Projects are often opposed by local landowners because of aesthetic and natural resource impacts, property value concerns, and other reasons. Regulation over transmission siting may be fragmented and involve multiple federal, state, and local governmental agencies, making transmission siting both time- and resource-intensive.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on transmission planning and cost allocation.

- Chang, J., Pfeifenberger, J. P., & Hagerty, J. M. (2013, July). *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments.* Brattle Group for WIRES (Working group for Investment in Reliable and Economic electric Systems). Available at: http://www.wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf
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- National Renewable Energy Laboratory website on Transmission Grid Integration Projects. Available at: http://www.nrel.gov/electricity/transmission/projects.html
- E3G, ECN, RAP, and ECF. (2010). *Roadmap 2050: A Practical Guide to a Prosperous Low-Carbon Europe. Policy Recommendations.* European Climate Foundation. Available at: http://www.roadmap2050.eu/attachments/files/Volume2_Policy.pdf

33 Pfeifenberger, J. P., & Hou, D. (2011, May) *Employment and Economic Benefits of Transmission Infrastructure Investment in the US and Canada.* The Brattle Group for WIRES. Available at: http://www.wiresgroup.com/docs/reports/Brattle_WIRES_JobsStudy_May2011.pdf

9. Summary

Transmission lines don't directly reduce GHG emissions, but they make many of the options that can potentially reduce GHG emissions more reliable and more cost-effective.

Some of the low-emissions generation technologies, like wind, solar, and geothermal technologies, are already cost-effective (compared to fossil fuel generation technologies) when sited in optimal locations. However, if those optimal locations are far from load centers, transmission is a necessary complement to developing these resources. In some cases, the best sites for these technologies simply cannot be developed at all unless new transmission lines are built. And in other cases, improvements to the transmission system are necessary (or will be) to enable grid operators to integrate more and more variable energy resources while maintaining system reliability.

Transmission planning processes can identify the best options for tapping the potential of low-emitting electric generation resources, while maintaining reliability and containing costs. A variety of federal and state regulators are likely to be involved in overseeing these processes, and the policies that those regulators choose to make and enforce (including cost allocation policies) can strongly influence the outcomes.

Some transmission options that facilitate GHG emissions reductions will make economic sense even if those reductions are not needed or are considered to have no value. But other options may only be considered cost-effective when the value of GHG emissions reductions is considered along with all other relevant costs and benefits. Good planning processes will not only consider all of the costs and benefits of transmission, including GHG benefits, but will allocate costs fairly to all beneficiaries. Good planning processes will also identify the potential to meet customer demand through NTAs, such as energy efficiency, that also reduce GHG emissions but may be more cost-effective.