Transmission Design at the National Level: Benefits, Risks and Possible Paths Forward

Future Grid Initiative White Paper

Power Systems Engineering Research Center

Empowering Minds to Engineer
the Future Electric Energy System

Transmission Design at the National Level: Benefits, Risks and Possible Paths Forward

Prepared for the Project
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White Paper Team

J. McCalley, Iowa State University
J. Bushnell, University of California, Davis
V. Krishnan, Iowa State University
S. Cano, Iowa State University

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Information about this white paper

For information about this white paper contact:

James D. McCalley, Harpole Professor of Electrical and Computer Engineering
Room 1115 Coover Hall
Iowa State University
Ames, Iowa 50011
jdm@iastate.edu, 515-294-4844

Your feedback on the white paper will be welcomed. Send your comments to Jim McCalley!

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For additional information, contact:

Power Systems Engineering Research Center
Arizona State University
527 Engineering Research Center
Tempe, Arizona 85287-5706
Phone: 480-965-1643
Fax: 480-965-0745

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Executive Summary

Today all areas of the contiguous U.S. are connected with one of the three U.S. transmission interconnections: Eastern, Western, and ERCOT, with each interconnection consisting of one (in the case of ERCOT) or more regions. The ability to move electric energy interregionally is limited to the capacity of the existing transmission system, a system designed largely to serve intraregional needs from fossil- and nuclear-based generation for which production costs are relatively flat from one region to another. In contrast, the levelized cost of energy production for renewables (e.g., wind, solar, and deep geothermal) varies dramatically from one part of the country to another. Furthermore, unlike energy in coal, natural gas, and uranium which may be moved electrically or in other ways (e.g., by rail and truck for coal, and by pipeline for natural gas), the only way to move renewable energy is by electric transmission. These two attributes of renewables, the heavy influence of location on their economic viability and their complete dependence on electric transmission for energy transfer, increases benefits derived from interregional transmission in future scenarios where renewables comprise an increased percentage in the national generation portfolio.

We define a national transmission overlay as a high capacity, multi-regional transmission grid spanning all three interconnections and designed as a single integrated system to provide economic and environmental benefits to the nation. This white paper's objectives are (1) to identify benefits to building a national transmission overlay, (2) to lay out essential elements to facilitate continued dialogue on this topic, and (3) to frame possible paths by which it could be realized. A preliminary study illustrated that a national transmission overlay, under a high renewable penetration and low CO_2 emissions scenario, could result in cost-reduction of between one quarter trillion and one-half trillion dollars over a 40-year period, while increasing infrastructure resilience and flexibility.

This white paper should not be perceived as either supporting or opposing development of a national transmission overlay, but rather providing objective information to use in further considerations. This information indicates that a national transmission overlay has potential to offer significant net benefits to the nation, while the political, regulatory, and procedural difficulties associated with initiating it are formidable. We conclude that development of a national transmission overlay merits further attention through discussion and analysis regarding benefits, issues and concerns, and possible paths forward. This paper can serve as a reference that gathers the essential elements to facilitate continued dialogue on this topic and to frame possible paths by which it could be realized. The next step in the effort will be to convene a group of experts spanning various dimensions of the issues who would expand and refine the work reported here and who would provide recommendations on the extent to which a national transmission overlay should be further pursued.

This version of the white paper will be revised in the coming weeks. Your feedback on the white paper will be welcomed. Send your comments to Jim McCalley at jdm@iastate.edu.

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1 Introduction and objective

The need to reduce greenhouse gas (GHG) emissions and other pollutants, coupled with aging infrastructure and corresponding retirements, is causing a shift from a fossil fuel-dominated generation portfolio to a renewable-dominated generation portfolio. This shift changes the nature of locational constraints encountered when siting generation. Locations for fossil-fueled generation are limited by air quality impacts and land availability, inhibiting the ability to locate fossil-fueled generation in or around urban centers. In contrast, locations for renewable generation are limited by the richness of the resource, inhibiting the ability to locate a given type of renewable generation within a region. The tendency of a renewable-dominated generation portfolio to be regionally constrained may result in significant disparity between renewable availability from one region to another. Although diversification of supply motivates continued presence of nuclear and clean-fossil generation within the national generation portfolio, today's cost projections suggest it likely that the nation's least-cost low-GHG electric supply strategy will favor heavy renewables, particularly inland wind, with significant transmission investment to move energy to regions having less renewable resources. This perspective is consistent with the 2008 U.S. Department of Energy (DOE) 20% by 2030 Report [1], which indicated 12,000 additional circuit-miles would be required if 300 GW of wind capacity were to be built by 2030.

Indeed, there is significant interest in building transmission in the U.S. today. The North American Electric Reliability Corporation (NERC) reports that from 1990 to 2010, the U.S. five-year rolling average of transmission constructed at voltage levels 200kV and greater averaged about 6000 circuit-miles per 5-year period, but they expect the 2010-2015 period to exceed 16,000 circuit-miles per 5-year period [2]. Yet, 50% of this transmission is motivated by reliability needs at the local or regional level. Of the 27% that is motivated by renewable integration, the average project length is 70 miles, with only 16 projects having length larger than 100 miles. NERC states that [2] "this is an indication that large, cross-Regional transmission lines are not being projected during the next ten years." Although this conclusion is certainly accurate with respect to the data reported by the industry during the 2010 year, it should not be understood to imply that the industry has never built or is not now exploring inter-regional transmission. For example, the Pacific AC and DC Interties, completed in 1970, and the Intermountain Power Project, completed in 1987, illustrate inter-regional transmission projects completed in the Western US. More recently, Title IV of the 2009 American Recovery and Reinvestment Act funded efforts to initiate and strengthen interconnection-wide planning in each of the three U.S. interconnections, with the awardees producing long-term resource and transmission planning for the Eastern Interconnection [3, 4], the West [5], and Texas [6].

However, transmission design spanning multiple regions at the national level which has resulted in actual construction has never occurred. Although there has been some recent conceptual proposals (see Appendix A1), we are not aware of engineering studies performed explicitly to design transmission at the national level. There are two basic reasons why this is the case. First, it has only been recently that the emphasis on renewables and consequent increased motivation for inter-regional transmission has become relevant. Second, building transmission of any distance is very difficult due to the needs to show transmission is the most economical alternative, perform cost allocation, obtain right-of-way, overcome technical challenges, and satisfy public opinion of its need. Building long-distance transmission multiplies each of these difficulties and incurs two more. First, long-distance transmission usually passes through the service areas of multiple electric industry organizations, each of which has interests to impose which result in increased project complexity. Second, long-distance transmission typically crosses state lines, and so regulators and agencies of multiple state governments, as well as the Federal Energy Regulatory Commission (FERC), must also become involved. These various challenges to long-distance transmission lead to a perception that building transmission at the national level would be an extremely complex undertaking. We endeavor to illuminate this perspective in this paper.

> **A national transmission overlay is a high capacity, multi-regional transmission grid, potentially spanning all three interconnections, designed as a single integrated system to provide economic and environmental benefits to the nation.**

> **The objective of this paper is to identify benefits to building a national transmission overlay, to lay out essential elements to facilitate continued dialogue on this topic, and to frame possible paths by which it could be realized.**

Although we identify potential merits and demerits of a national transmission overlay design, we provide only limited and preliminary quantitative evaluation, leaving that to be accomplished through future economic-engineering studies.

The paper is organized as follows. Section 2 provides essential background on load, generation, and transmission which support the remainder of the report and which should form the basis for continued dialogue on the subject. Section 3 reports benefits of high-capacity interregional transmission expansion based on preliminary study results using investment planning software. Section 4 identifies issues and concerns associated with building a national transmission overlay, and Section 5 identifies three types of "paths forward" which could lead to implementation of national transmission. Section 6 concludes.

2 Essential background on load, generation and transmission

This section provides information and perspectives on load, generation, and transmission which are central to consideration of a national transmission overlay.

2.1 Load centers and growth

One key to assessing the need for a national transmission overlay is the extent to which geographical variation in electric energy consumption changes relative to what it is today. Figure 1 [7] illustrates geographical variation in population density based on 2000 U.S. census data. If we assume that the population density is proportional to electric energy usage density in GWhrs/square mile, then Figure 1 provides a reasonable representation of relative electric energy consumption throughout the US, in which case it is easy to observe that most energy is consumed East of the Mississippi, in southeastern Texas, and on the West coast, with the most concentrated energy usage being along the Northeastern seaboard.

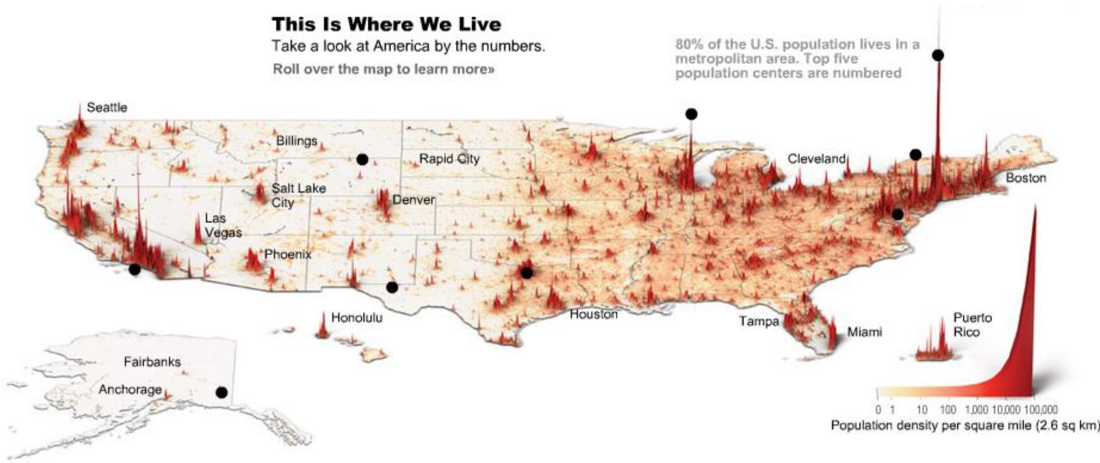

Figure 1: U.S. population density

Analysis of the 2010 U.S. Census data [8] suggests these observations about geographical variation in population density based on Figure 1 are reasonably applicable today as well, although there has been some population movement to the Southeast and to the Southwest between 2000 and 2010. The impact of major shifts away from this population distribution could affect assessment regarding the need for a national transmission overlay. Such shifts could occur, for example, as a result of variation in energy prices as energy-intensive industries move away from high-price regions into low-priced ones, or they could occur as a result of government incentives. We assume in this paper that we do not experience significant shifts of this nature, but we recognize that the robustness of a national transmission overlay's value should be studied relative to the uncertainty in this feature.

Population density is only a proxy for energy consumption and does not well capture the influence of each region's industrial base. Regions which have a significant penetration of high energy consuming industry will have higher per-capita energy use than regions which do not have high energy consuming industry. In addition, future electric use may change as new electro-technologies are implemented into industrial and transportation applications. For example, there is a trend towards replacing capacity in integrated steel mills by smaller, scalable mini-mills in remote areas. Exploring these types of developments on long-term electric load forecasting will be important in future planning studies. Annual energy consumption for each of the NERC regions can be ascertained from Figure 2 in the next section.

2.2 Generation investment

The motive for a national transmission overlay is ultimately driven by various policy drivers, particularly a perspective that it would facilitate reduction of GHG emissions at a lower cost (although an overlay is not necessary to reduce GHG emissions). GHG reduction motivates interest in a national transmission overlay because GHG reduction necessitates shifting some portion of the national generation portfolio from fossil-fueled generation technologies to low-GHG emitting generation technologies, the most promising of which include wind (inland and off shore), solar, (thermal and photovoltaic), geothermal, nuclear, clean-coal (integrated gasification combined cycle with carbon capture and sequestration), and ocean-based (wave, tidal, and ocean-thermal energy conversion). Of these, wind, solar, geothermal, and ocean-based technologies share the unique attribute that electric transmission is the only cost-effective way to move the associated energy. This is in contrast to coal, which may be moved also by rail, and natural gas, which may be moved also by pipeline.

Although nuclear and clean-coal are low-GHG generation technologies that may be transported in other ways beside electric transmission, it seems likely that cost, waste storage, and (in the case of nuclear) safety, will limit penetration of these two technologies. Although natural gas combined cycle (NGCC) plants are not low-GHG technologies, their emission rates are half that of pulverized coal plants [9] or less and will certainly play a significant role in future generation portfolios. Yet the fact that NGCC plants are significant GHG emitters and also that U.S. natural gas reserves are limited (reserve to production ratios range from 12 years [10] if unconventional gas, including shale gas, is not included to between 40 and 90 years [11, 12], if it is, depending on how much is assumed to be recoverable), suggests that the role of NGCC plants in the nation’s generation portfolio, other than perhaps replacing retiring coal plants, may decline over the next century. A reasonable conclusion is that the promising low-GHG technologies, as listed above, will comprise a large percentage of the overall national generation portfolio, a situation which means that the electric generation portfolio of the future will be dominated by technologies for which their energy may be moved only by electric transmission.

In summary, the following developments in generation will drive the need for a national transmission overlay:

- A very high percentage of future generation investment will be low GHG-emitting technologies;
- A significant portion of the low-GHG emitting technologies will be renewables (wind, solar, geothermal, biomass, hydro, tidal, wave, and ocean-thermal);

- Each renewable varies geographically in the cost of supplied energy;
- There is significant variation in the cost of supplied energy from one renewable to another.

The above developments may occur in combination with various growth levels of nuclear, clean-coal, and natural gas generation without significantly detracting from the benefits of a national transmission overlay, as long as renewables remain the dominant generation technologies of the future.

Although there are various attributes characterizing the future which influence the benefits of a national transmission overlay, there are two generation-related conditions which would significantly diminish the motivation for a national transmission overlay.

- High non-renewable growth: Should future generation portfolios be dominated by nuclear, clean-coal, and/or natural gas generation, so that that renewables are a relatively minor player, e.g., below 20%, then generation could be strategically sited to minimize the need for high-capacity transmission, and it would probably be economic to do so.
- High DG growth: Should distributed generation (DG) comprise a large part of future electricity supply, so that much electric load is met by co-located supply, then there would be diminished need for transmission.

These two conditions are further discussed in Section 4.

2.3 Transmission

2.3.1 Existing interregional transfers

We have used data from the North American Electric Reliability Corporation (NERC) [13] to compare, for each of the NERC regions, the amount of electric energy consumed in the region to that which is generated in the region. The extent to which these values differ provides an indirect indication of the extent to which electric energy is moved from one region to another. This information is illustrated for the year 2009 in Figure 2. For each plot, the vertical axis provides a scale of 0 to 4.5 Quads[1], the bar on the left indicates total generated energy with the portion in red showing how much of it is from renewables (hydro, wind, solar, geothermal) and the portion in green showing how much of it is from nuclear, and the bar on the right showing the energy consumed. It is clear from this plot that for all regions, the amount of energy generated does not significantly differ from the amount of energy consumed.

[1] 1 Quad=1×10^{15}BTU=293,080 GWhrs. To put into context, the nation produces about 13 Quads of electric energy each year.

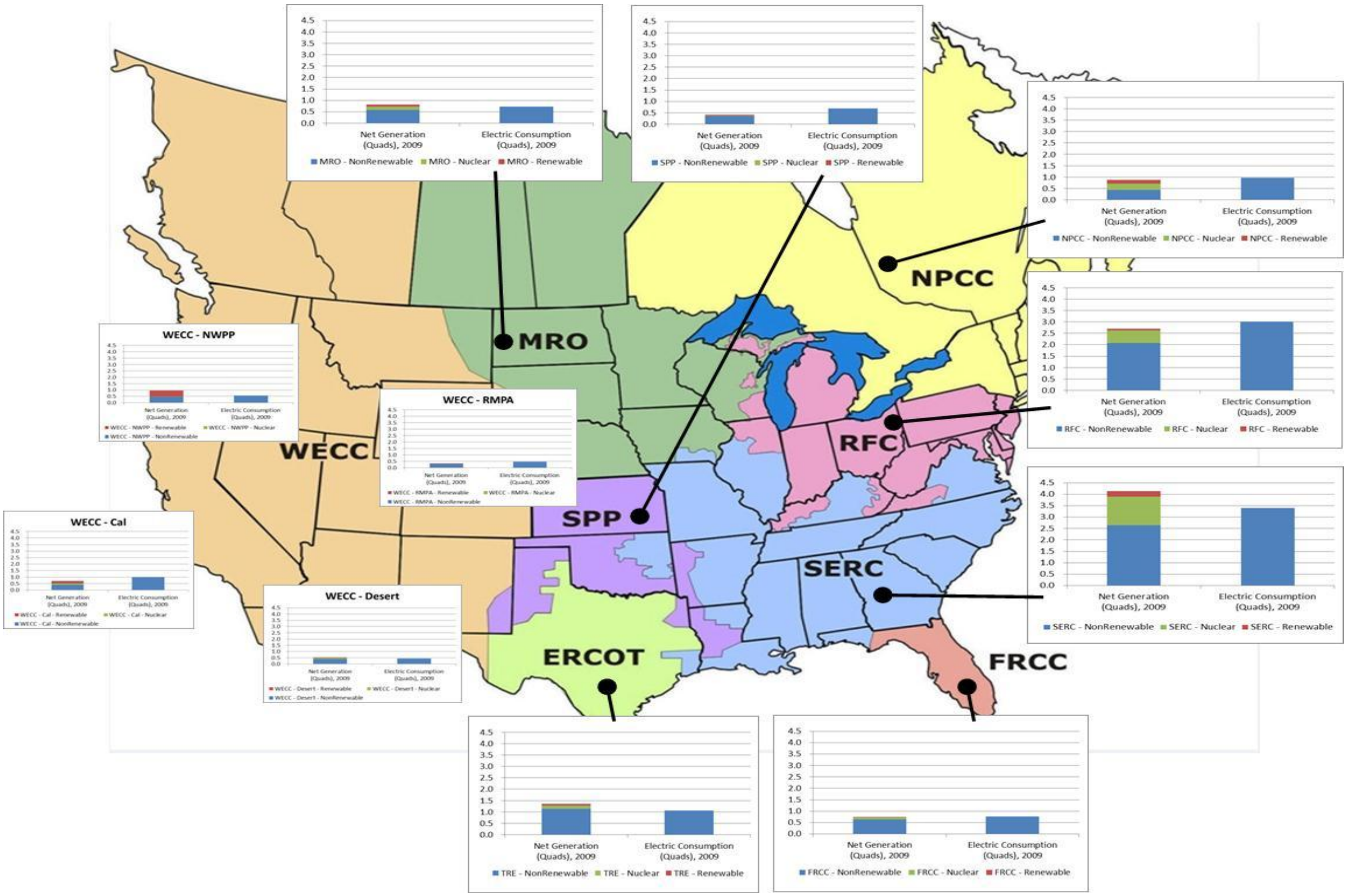

Figure 2: Regional energy consumption and generation (red is renewable, green is nuclear, blue is remainder) for 2009

2.3.2 DOE congestion studies

The U.S. Department of Energy (DOE) has conducted three major studies during the past 10 years to assess the U.S. transmission grid in an effort to understand the extent to which existing transmission is sufficient to meet the nation's needs (and a fourth one is ongoing at the time of this writing). The first of these was in 2002 [14], which resulted in a recommendation:

> "The National Energy Policy Development (NEPD) Group recommends that the President direct the appropriate federal agencies to take action that will remove constraints on the interstate transmission grid so that our nation's electricity supply will meet the growing needs of our economy. NEPD directs the Secretary of Energy to examine the benefits of establishing a national grid and to identify transmission bottlenecks and measures to address them."

This study resulted in identification of the twenty most congested paths in the Eastern and Western interconnections, major bottlenecks in both, and constraints based on transmission loading relief (TLR) events and high price differentials across an interface, as illustrated in Figure 3 [14]. This study also motivated consideration of developing similar studies periodically, which the 2005 Energy Power Act (EPA) affirmed by requiring them every three years. The 2005 EPA also amended the Federal Power Act to give authority for Secretary of Energy to designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects customers as a national interest electric transmission corridor."

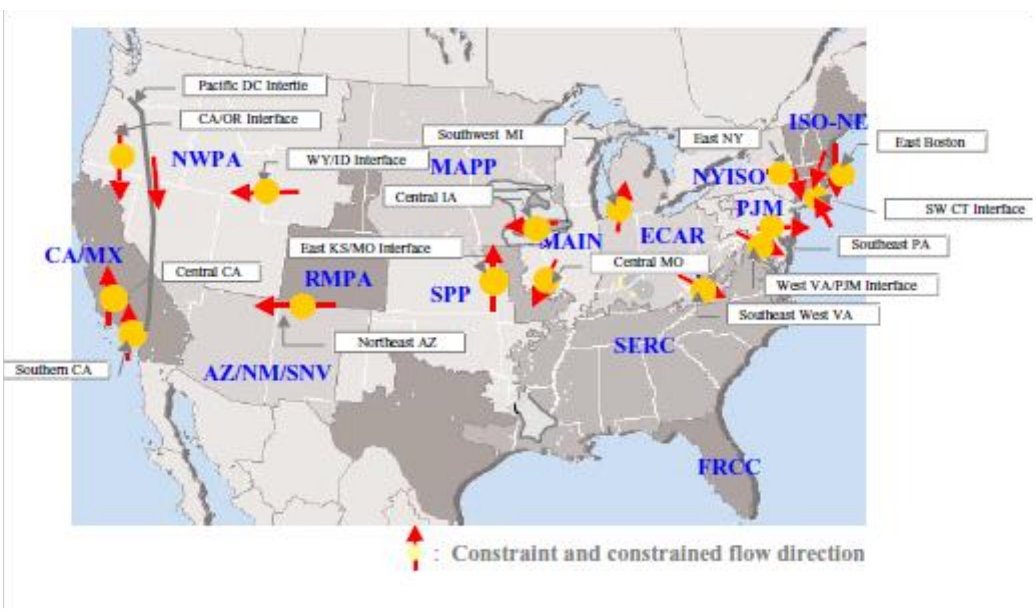

Figure 3: Identified transmission constraints in 2002

The second DOE study, in 2006 [15], indicated an intention "to open a dialogue with stakeholders in areas of the Nation where congestion is a matter of concern, focusing on ways in which congestion problems might be alleviated." It identified two *critical* *congestion areas*, the Atlantic coastal areas from metropolitan New York southward through Northern Virginia, and Southern California. It also identified *four congestion areas of concern*: New England, the Phoenix-Tucson area, the Seattle-Portland area, and the San Francisco Bay area. Finally, it identified five conditional congestion areas (areas were significant congestion would result if large amounts of new generation resources were to be developed without simultaneous development of associated transmission capacity): Montana-Wyoming (coal and wind); Dakotas-Minnesota (wind); Kansas-Oklahoma (wind); Illinois, Indiana and Upper Appalachia (coal); and the Southeast (nuclear). All of these areas are illustrated in Figure 4 and Figure 5 [15]. The 2006 DOE study concluded by saying,

> "DOE expects these planning efforts to be inter-regional where appropriate, because many of the problems and likely solutions cross regional boundaries. In particular, the Department believes that these analyses should encompass both the congestion areas and the areas where additional generation and transmission capacity are likely to be developed."

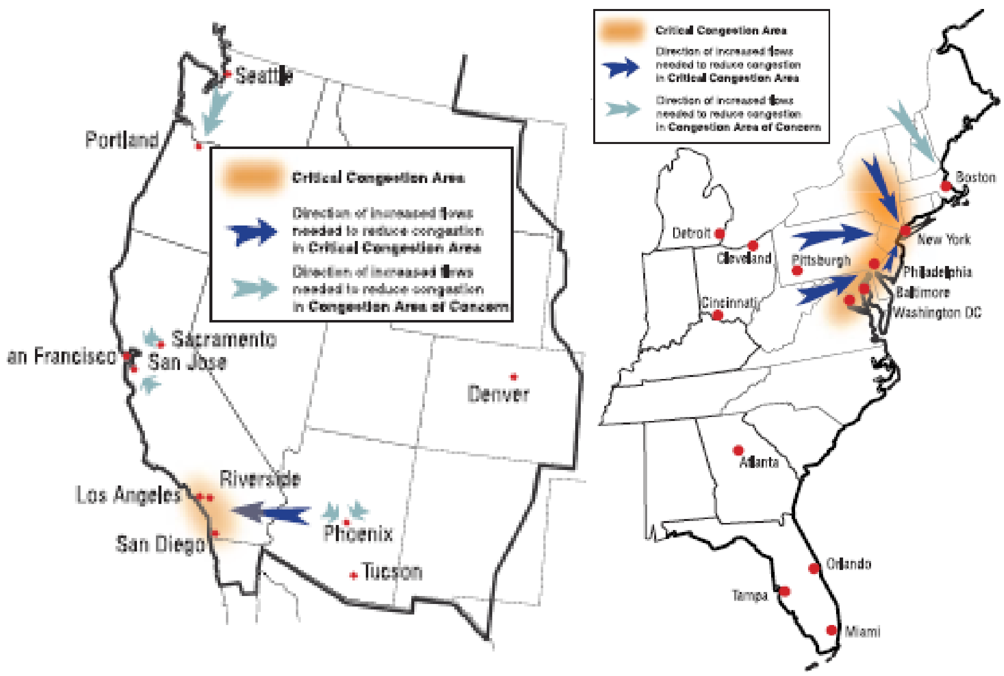

Figure 4: Critical congestion areas and congestion areas of concern

Figure 5: Conditional congestion areas

The most recent DOE transmission study was published in 2009 [16]. An important observation made in this study follows:

> "The 2009 study identifies regions of the country that are experiencing congestion, but refrains from addressing the issue of whether transmission expansion would be the most appropriate solution. In some cases, transmission expansion might simply move a constraint from one point on the grid to another without materially changing the overall costs of congestion. In other cases, the cost of building new facilities to remedy congestion over all affected lines may exceed the cost of the congestion itself, and, therefore, remedying the congestion would not be economic. In still other cases, alternatives other than transmission, such as increased local generation (including distributed generation), energy efficiency, energy storage and demand response may be more economic than transmission expansion in relieving congestion….Although congestion is a reflection of legitimate reliability or economic concerns, not all transmission congestion can or should be reduced or 'solved.'"[2]

The 2009 study retained Southern California and the Atlantic coastal areas from metropolitan New York southward through Northern Virginia as the only two *critical congestion areas*. Of the four *congestion areas of concern* identified in the 2006 study, it retained this status for the Seattle-Portland area and the San Francisco Bay area, but dropped New England and the Phoenix-Tucson area from the list citing additional transmission and generation development and implementation of demand-side resources.

The 2009 study also extended the concept of conditional congestion area from the 2006 study by distinguishing between a Type I and a Type II conditional congestion area:

[2] This quote essentially lays out the planning objective, which is to identify the solution that provides the most attractive long-term energy economics for the defined customer base. A key underlying issue today is to establish the "customer base." A necessary orientation for building a national transmission overlay is that the customer base must be viewed nationally.

- “A Type I Conditional Congestion Area is an area where large quantities of renewable resources could be developed economically using existing technology with known cost and performance characteristics—if transmission were available to serve them.”
- “By contrast, a Type II Conditional Congestion Area is an area with renewable resource potential that is not yet technologically mature but shows significant promise due to its quality, size, and location.”

Figure 6 [16] illustrates the various Type I and Type II conditional congestion areas identified in the 2009 study. This figure illustrates current understanding of where the nation’s most economically attractive renewable resources are located.

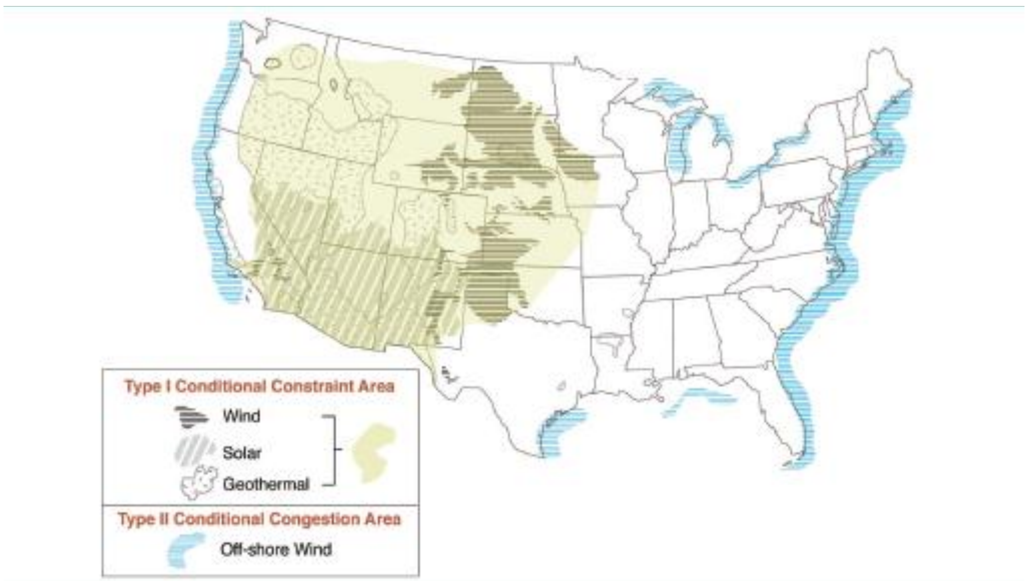

Figure 6: Type I and Type II conditional congestion areas

2.3.3 Existing inter-regional transmission capacity

We have identified three public sources for U.S. inter-regional transmission capacity. Data from these sources have been compiled and are summarized in Table 1. Data in the column labeled “NEMS” were obtained from [17] which was sourced from [18]; any values from area X to area Y in this column with an asterisk were not actually available from [18], and so the value from area Y to area X was used. Data in the column labeled “EPA” and “EPA2” were obtained from [19, Chapter 3], which is data used in the 2006 version of the U.S. Environmental Protection Agency’s “Integrated Planning Model” (IPM). The first of these, labeled “EPA1” indicates non-firm total transmission capacity (TCC), specifying the maximum power that can be transferred under normal operation (N-0). The second of these, “EPA2” indicates firm TTC, specifying the maximum power that can be transferred with acceptable contingency (N-1) performance. Data in the column labeled “LBNL” is data developed in a 2006 study performed by researchers at the Lawrence Berkeley National Laboratory [20]. Data in the column labeled “Other” is data obtained from a reliable source but one that cannot be identified in this document.

Data in the column labeled “Adopted” is data used in the study to be described in Chapter 3 of this report.

For each interregional interconnection, the capacity “adopted” was usually that given under the EPA1 column because the EPA source referenced NERC data as its source [21]. In a few cases, we adopted a different value than that given in the EPA1 column, usually based on subjective assessment of the other values given and some partial knowledge of the particular path given. The data used for existing interregional transmission capacity is also illustrated in Figure 7.

The capacities adopted in the study, as listed in Table 1, have not been verified beyond that described above. As a result, these data should be viewed as preliminary. If further efforts are made towards national transmission overlay design using the level of aggregation described here, then these data should be validated via discussions with NERC, the RTOs, and/or operating companies. In addition, regional boundaries should be updated, as indicated in the last paragraph of this subsection.

The acronyms representing the various regions in Table 1 are defined as follows:

1. ECAR: East Central Area Reliability
2. ERCOT: Electric Reliability Council of Texas
3. MAAC: Mid-Atlantic Area Council
4. MAIN: Mid-America Interconnected Network
5. MAPP: Mid-Continent Area Power Pool
6. NY: New York
7. NE: Northeast
8. FL: Florida
9. STV: Southern-Tennessee Valley
10. SPP: Southwest Power Pool
11. NWP: Northwest Power Pool
12. RA: Rocky Mountain Area
13. CNV: California Nevada

Some qualifying remarks follow regarding the regions summarized above and illustrated in Figure 7. These remarks are made necessary by the fact that the geographical boundaries of the regions and in some cases the regions themselves have evolved since they were used in the sources from which the related data were obtained.

- The regions of Figure 7 may not exactly correspond to the footprint of the actual region as it exists today. For example, SPP as illustrated is actually the SPP footprint plus the SERC Delta subregion which includes Entergy and Associated Electric Cooperative.
- Some regions indicated in Figure 7 like MAIN and MAPP no longer exist.

We are not aware, however, of any reason why the above qualifications and any inaccuracy in the interregional transfer capacities would qualitatively affect the general trends indicated in the study reported below, in terms of transmission needs and benefits.

Table 1: Existing inter-regional transmission capacity for U.S.

From area		To area		NEMS (GW)	EPA1 (GW)	EPA 2 (GW)	LBNL (GW)	Other (GW)	Adopted (GW)
Num	Name	Num	Name						
13	CNV	11	NWP	8.64*	8.325	8.275	7.3	8.58	8.325
13	CNV	12	RA	6.88*	8.315	7.116	1.2	7.70	8.315
1	ECAR	3	MAAC	7.50	9.500	3.699	3.40	7.02	9.500
1	ECAR	4	MAIN	3.69	13.138	8.164	3.9	6.50	12.619
1	ECAR	9	STV	6.89	8.582	4.627	5.4	5.62	8.582
2	ERCOT	10	SPP	0.97	0.979	0.979	0.7	0.80	0.979
8	FL	9	STV	2.10	2.000	2.000	2.70	2.10	2.000
3	MAAC	1	ECAR	7.5	8.008	3.298	4	7.95	8.008
3	MAAC	6	NY	3.42	3.435	2.706	3.3	4.74	3.435
3	MAAC	9	STV	4.47	2.600	2.600	4	0.81	2.600
4	MAIN	1	ECAR	3.69	12.619	3.946	3.9	5.87	12.619
4	MAIN	5	MAPP	1.62	1.500	1.500	2	3.62	1.500
4	MAIN	10	SPP	2.32	0.285	0.285	1.9	3.74	0.285
4	MAIN	9	STV	5.16	4.616	3.912	6	4.53	4.616
5	MAPP	4	MAIN	1.62	1.730	1.730	2.2	4.58	1.730
5	MAPP	11	NWP	0.20	0.200	0.200	0.10	0.20	0.200
5	MAPP	12	RA	0.35	0.310	0.310	0.3	0.51	0.310
5	MAPP	10	SPP	1.81	1.494	1.494	1.4	3.33	1.494
7	NE	6	NY	1.46*	1.596	1.453	1.5	2.16	1.596
11	NWP	13	CNV	8.64	9.180	9.140	8.1	10.27	9.180
11	NWP	5	MAPP	0.2*	0.150	0.150	0.2	0.20	0.150
11	NWP	12	RA	2.59	1.314	1.264	0.8	2.45	1.314
6	NY	3	MAAC	3.42*	3.385	3.325	4	3.71	3.385
6	NY	7	NE	1.46	1.886	1.886	1.5	2.51	1.886
12	RA	13	CNV	6.88	8.315	7.116	3.7	8.91	8.315
12	RA	5	MAPP	0.35*	0.310	0.310	0.3	0.51	0.310
12	RA	11	NWP	2.59*	1.335	1.335	0	5.12	1.335
12	RA	10	SPP	0.47*	0.400	0.400	0.4	0.61	0.400
10	SPP	2	ERCOT	0.97*	0.650	0.650	0.7	0.80	0.650
10	SPP	4	MAIN	2.32*	1.200	1.200	1.7	3.07	1.200
10	SPP	5	MAPP	1.81*	0.600	0.600	1.5	3.11	0.600
10	SPP	12	RA	0.47	0.400	0.400	0.6	0.63	0.400
10	SPP	9	STV	1.26*	12.775	3.570	1.1	5.93	5.614
9	STV	1	ECAR	6.89*	13.077	3.726	6.7	6.07	8.582
9	STV	8	FL	2.1*	3.600	3.600	4.6	3.70	3.600
9	STV	3	MAAC	4.47*	2.100	2.100	3.8	2.80	2.100
9	STV	4	MAIN	5.16*	2.460	1.690	5.6	1.18	2.460
9	STV	10	SPP	1.26	5.614	0.875	0.6	5.87	5.614

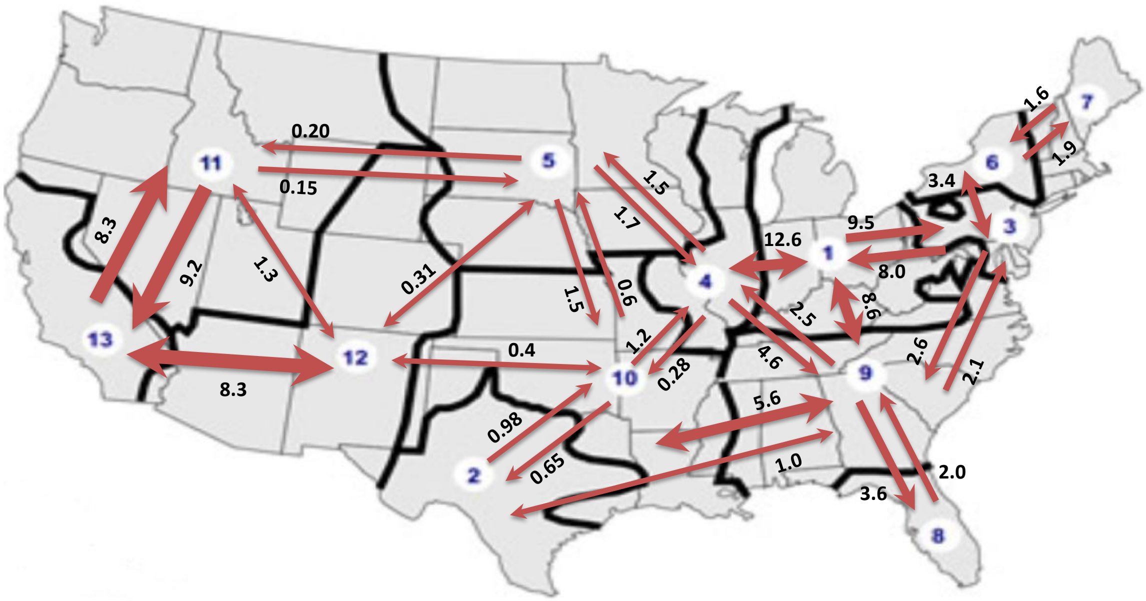

Figure 7: Existing interregional transmission capacities

2.3.4 Transmission technologies

Some of the information in this section is adapted from [22].

In planning for bulk transmission needs ranging from hundreds to potentially several thousands of miles, one can consider extra-high voltage AC (EHVAC), ultra-high voltage AC (UHVAC) or high-voltage DC (HVDC). EHVAC is generally defined as AC transmission having line-to-line voltage ratings between 300 kV and 1000 kV, whereas UHVAC is AC transmission having line-to-line voltage rating between 1000 kV and 1500 kV [23]. It is not clear there is a minimum voltage level specified by the term HVDC, although voltage levels for DC transmission lower than 200 kV are rare today. Although some use the term ultra-high voltage DC to refer to DC transmission at 600 kV and/or 800 kV, there is no IEEE standard which defines such terminology, and much of the literature refers to it under the umbrella term HVDC.

We review EHVAC options in Section 2.3.4.1 and HVDC options in Section 2.3.4.2. We describe use of superconducting transmission in Section 2.3.4.3.

2.3.4.1 EHVAC options

EHVAC solutions generally have lower investment costs than HVDC for distances less than about 400 miles. For EHVAC solutions, St. Clair curves [24, 25, 26] can be used to identify the appropriate design voltage based on MW-transfer requirements. High surge impedance loading (HSIL) designs for EHVAC lines are effective in reducing ROW requirements while also increasing SIL and reducing cost per MW-mile. HSIL is similar to compact line design in that phase separation is decreased. In addition, because

EHVAC lines require bundling to reduce corona effects, increasing the geometric mean radius of the bundle can further increase SIL.

EHVAC voltage levels in operation today within the U.S. include 345, 500, and 765 kV, and so equipment for any of these voltage levels can be easily obtained. Although there is one instance of a transmission line built at 1150 kV in Russia and another built at 1000 kV in Japan, both of the lines are now being operated at 500 kV [27]. Today, the only transmission operated above 765 kV is a 640 km, 1000 kV line in China which began commercial operation on January 6, 2009 [28]; it is illustrated in Figure 8.

Figure 8: 1000 kV transmission line in China

Underground gas-insulated transmission (GIL) uses a combination of sulfur hexafluoride (SF_6) and nitrogen (N_2) as the insulating medium, which gives it the ability to achieve much higher voltages within the relatively constrained space required for underground facilities. Because it is underground, there is no need to be concerned about strength as is necessary with overhead; therefore, the conductor can be manufactured based purely on its conductive properties (aluminum alloys are used). Relative to overhead lines, then, GIL is able to significantly diminish losses. Reduced losses not only decrease production costs, they also decrease heating, which is a significant issue for underground, where less natural cooling is available. However, GIL does not compete economically with overhead EHVAC and is of greatest interest in densely populated or environmentally sensitive areas where overhead transmission cannot be used [29].

2.3.4.2 HVDC options

HVDC first became a feasible transmission technology in the 1950s. Today, the highest-capacity projects have capacities between 3000 and 6400 MW at voltages of ±500, ±600, and ±800 kV [30]. Future HVDC appears likely at ±600 and ±800 kV, and some consideration has been given to the use of ±1000-kV. HVDC is well-known to be an attractive option for bulk power transmission in three types of applications:

1) interconnecting two asynchronous networks;
2) when the uninterrupted transmission distance exceeds about 600 km[3], either to move energy from a specific generation facility to a specific load center or to interconnect two areas of a single network;
3) for underground transmission.

We observe that most HVDC links between asynchronous networks in the US are of modest capacity. It may be particularly effective, in terms of economic benefit and in terms of transmission system performance, to interconnect asynchronous networks with long-distance, high capacity HVDC, which better utilizes the strength of HVDC.

The bipole configuration is the most common today. Its major advantage is that it can continue operating at a derated level when one conductor is lost. HVDC is an attractive option for long-distance underground bulk transmission because DC cables are less expensive than AC cables (but have higher termination investment costs and losses) and because DC cables do not suffer from high capacitive charging and therefore do not have a physical restriction limiting distance. A very recent proposal and an as-yet-unproven technology is the 800 kV HVDC electric pipe, which encases large-diameter conductors insulated with a nanocomposite reinforced cross-linked polyethylene (XLPE) cable within a fluid-filled pipe [31].

Reference [32] proposes a tripole arrangement with three conductors and one metallic return which provides for high utilization of the thermal conductors. For example [33], assume the continuous rating of an 800 kV HVDC terminal is 3600 MW, and the overload rating is 4500 MW for 22 minutes. If the system can be redispatched within the 22 minute interval, a tripole overlay on top of an AC system having a 1500 MW transfer capability (under N-1 AC contingency) would allow 2*4500+1500=10,500 MW of transfer, yielding 10,500/3=3500 MW/pole. This is 3500/3600=97% utilization of the tripole arrangement's continuous rating.

All HVDC systems built since 1975 use thyristor-based converters, with the exception of a few relatively low power (less than 350 MW) applications built after 2000 that use voltage source converters (VSCs) based on insulated gate bipolar transistors (IGBTs). The major difference between VSC-based and thyristor-based HVDC is that the latter is line-commutated (switched off when the thyristor is reverse-biased from the ac voltage), whereas the former is forced-commutated via control circuits driven by pulse-width modulation. This capability of VSC-based HVDC enables rapid control of both real and reactive power at both terminals (control which may be beneficial in handling real power variations from renewables). As a result, VSC-based terminals can be placed independently of network short-circuit capability, unlike thyristor-based terminals [34], which require adequate short-circuit capability for successful commutation. In addition, VSC-based HVDC offers flexibility regarding multiple terminals, which are unavailable

[3] The 600 km is a rough figure of merit, where, relative to equivalent capacity EHVAC and based on investment costs only, the additional converter costs of HVDC terminals can be balanced by the less costly HVDC line—in some cases, this threshold distance can be lower.

to thyristor-based HVDC. It is also significant that VSC terminal have much smaller space requirements, compared to thyristor-based line commutated terminals.

VSC has a number of other advantages [35], but it is limited to lower-capacity lines based on the lower voltage and power ratings of IGBTs relative to thyristors, although it is likely that these limitations will be mitigated as VSC technology matures. VSC capacity limitations have been mainly due to the limits on IGBT terminals, but it has also been affected by its design around cable capacity for underground transmission [36]. VSC can be used for overhead transmission also [37], although doing so incurs significantly increased fault protection requirements to protect the switching devices, based on the much higher probability of line-to-line and line-to-ground faults in overhead systems. VSC capacity is rapidly rising so that it is likely it will replace thyristor-based HVDC altogether.

HVDC lines lend themselves well to tolling arrangements whereby users subscribe transmission delivery services, and so cost allocation for HVDC may be less complex than for equivalent EHVAC. In addition, loading HVDC lines can be based entirely on price differences between the terminals, in contrast to AC lines which are based on angular spread. Furthermore, HVDC avoids loop flow issues. Operation of HVDC within or between LMP market regions does not yet seem to be well discussed in the literature with [38, 39] representing exceptions, and preliminary inquiry suggests existing HVDC schedules are not optimized within LMP markets, and they are not subject to congestion management practices.

2.3.4.3 Superconducting transmission

Superconductors are materials that, when operating at very low temperatures, exhibit zero resistance to DC and extremely high current densities. Superconducting transmission became more viable in 1986 when a ceramic "high temperature" superconducting (HTS) material was discovered that required cooling to only about 90 K (2183 8C), which can be accomplished with liquid nitrogen. Several AC prototypes are in operation today [40, 41], and underground superconducting DC has been proposed [42, 43].

Although superconducting transmission requires a refrigeration and pumping system for circulating the nitrogen coolant, it incurs no thermal (Joule or I^2R) losses. An advantage of the pumping "losses" is that they do not increase with power transfer as standard electric transmission does; yet, on the other hand, no-load losses are always present. One study indicates refrigeration stations can be spaced no greater than 9 to 15 miles to avoid sub-cooled boiling of the nitrogen [44]; reference [43] indicates that superconducting cables require refrigeration stations every 3 to 25 miles. In general, specific separation distances and refrigerator power requirements will depend on design factors including heat input, cable power, ac or dc operation, type of coolant, maximum allowable pressure, pipe diameter, and altitude changes between refrigerators. At the relatively low voltage of 200 kV DC, a superconducting "pipeline" can be coupled with VSC-based converters, thus reaping the benefits of multi-terminal flexibility while retaining the high power-transfer capability resulting from high currents allowed by superconducting transmission. For long distances, HTS lines must have multiple cooling facilities along the route, with auxiliary power provided from a low-voltage (480 to 4 kV) distribution system that is either already existing or installed new in the same trench as the superconducting cable. Redundancy in refrigeration equipment and cable design would accommodate intermittent power or equipment outages that may occur.

2.3.4.4 Underground transmission

Underground transmission has traditionally not been considered a viable option for long-distance transmission because it is significantly more expensive than overhead due to two main factors: construction costs and material costs. Higher construction costs result from the need to construct trenches, duct banks, and manholes every half mile or so. Increased material costs occur because underground transmission requires a conductor of much larger cross-sectional area than would an overhead conductor of the same ampacity, and because it requires insulation with relatively high dielectric strength owing to the proximity of the phase conductors with the earth and with each other. Because the insulation cost increases with higher voltage, the operational benefit to long distance transmission of increased voltage levels, loss reduction (due to lower current for a given power transfer capability), is, for underground transmission, partially offset by the significantly higher investment costs associated with the insulation.

The material cost of underground cabling is significantly higher than the material cost of the equivalent overhead conductors. However, because underground is not exposed like overhead, it requires less right-of-way. This fact, coupled with the fact that public resistance to overhead is greater than that for underground, can bring overall installation costs of the two technologies closer together. This smaller difference may be justifiable, particularly if it is simply not possible to build an overhead line, which is the case in some regions of European countries. The Netherlands, for example, imposed a cap on the total length of the overhead transmission and distribution network [45].

It is significant that the ratio of underground to overhead costs is declining; one manufacturer reports that [46] "Whereas the cost of a typical 100-km line using underground DC was about 20 times higher than an equivalent overhead AC line when the technology was first developed, it is now 4-6 times higher," and [47] "The conventional view that an underground link will cost 5 – 15 times its overhead counterpart must be revised. Depending on local conditions, it is realistic that the costs for an underground high-voltage line are equal to that of traditional overhead lines."

2.3.5 Transmission system costs

We review cost estimates for transmission from several sources in what follows with the following qualifications. First, these costs may not accurately reflect costs associated with construction work in progress (CWIP) [48], underlying system upgrades, and detailed routing efforts. Second, HVDC electric pipe and superconducting pipelines, addressed by one of the estimates, are relatively unproven technologies compared to conventional EHVAC and HVDC.

The Midwest Independent Transmission System Operator (MISO) has investigated relative costs for various HVDC options. Representative results are shown in Figure 9

[22]. Each point in this figure indicates, for a specific HVDC transmission technology, the cost per MW necessary to build 1200 miles of transmission to obtain the corresponding power transfer given by the point's horizontal coordinate.

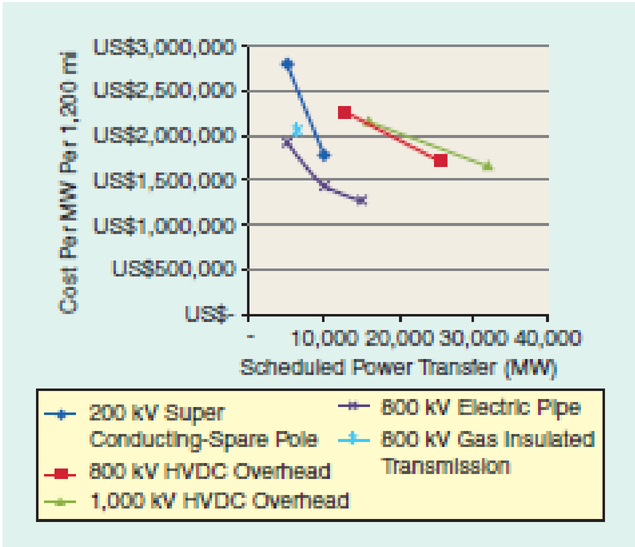

Figure 9: Cost/MW per 1200 miles for various HVDC options

Figure 10 [49] compares investment costs for obtaining 6000 MW of transmission capacity at three different distances, in terms of three EHVAC options and two overhead HVDC options. These estimates are based on initial capital costs only and do not reflect maintenance and replacement needs related to, for example, HVDC converters and controls, a point that speaks to the fact that conventional overhead EHVAC has a longer life than other options.

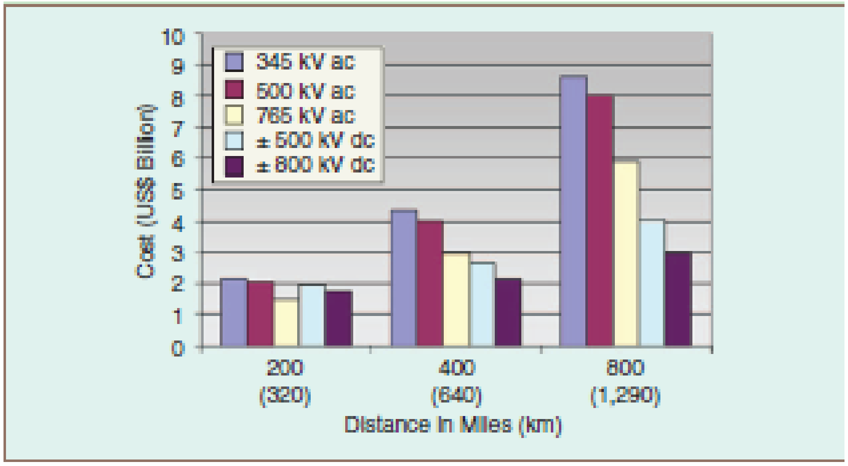

Figure 10: HVDC & EHVAC investment cost comparisons for 6000 MW of capacity

The Eastern Interconnection Planning Collaborative (EIPC) has recently published data characterizing transmission "base costs" for various transmission technologies [50]. These costs, summarized in Table 2, are paired with "multipliers" (not shown) to capture influences which increase or decrease these costs within a geographical area.

Table 2: Base costs for various transmission technologies

Voltage (kV)	# of Circuits	MW Capability	$/Mile
<230	1	300	$1,100,000
230	1	600	$1,150,000
230	1	900	$1,580,000
230	2	1200	$1,800,000
345	UG	500	$19,750,000
345	1	900	$2,100,000
345	1	1800	$2,500,000
345	UG	1800	$25,000,000
345	2	3600	$2,800,000
345	UG	3600	$28,000,000
500	1	2600	$3,450,000
765	1	4000	$5,550,000
HVDC	bipole	2400	$2,150,000
HVDC	bipole UG	2400	$7,500,000
HVDC Terminal (both ends)			$340,000,000

We have used a value of $1B/GW/1000miles in our basic analysis reported in Section 3, and we have performed a sensitivity analysis using a higher value of $1.5B/GW/1000miles.

This lower value is at the lower end of HVDC costs indicated by Figure 9, which is $1.25B/GW/1200miles, equivalent to $1.04B/GW/1000miles. The value provided in Figure 10 for 6 GW of capacity at 800 miles using two 765 kV single circuit lines is $1.25B/GW/1000miles, a value which includes the additional cost for measures to avoid loadability reduction due to distance for AC lines [51], including provision of intermediate substations every 200 miles together with series and shunt compensation.

Figure 10 also shows transmission cost for ±500 kV HVDC or ±800 kV HVDC would be $0.83B/GW/1000miles and $0.63B/GW/1000miles, respectively, values which, according to [49], include the costs of converter stations at the two terminals. These HVDC options would limit accessibility to only the terminals (increased accessibility could be provided but at significantly higher costs due to the need for multi-terminal DC lines). Limited accessibility may not be desirable for interregional transmission of low-GHG energy, where there are likely to be a large number of plants highly distributed throughout a region. Additional perspective on HVDC costs is provided in [52, 53].

From the data provided in Table 2, we compute the cost of an HVDC bipole (overhead) to be \$0.90B/GW/1000miles, and the cost of the 765 kV single circuit to be \$1.39B/GW/1000miles. These values do not include the costs of converter stations at the two terminals, estimated in the table to be \$340M.

Transmission costs would be higher if it is built underground. For example, according to Table 2, 2400 MW of underground HVDC capacity can be built at \$3.1B/GW/1000miles (plus the cost of the converter stations at the two terminals). Figure 9 indicates the cost per MW for underground DC superconductors at ±200 kV to be \$1.8M/MW/1200miles at the low end, and \$2.8M/MW/1200miles at the high end, equivalent to \$1.5B/GW/1000miles and \$2.3B/GW/1000miles, respectively, whereas reference [54] places cost for the same technology at about \$1.6B/GW/1000miles. Cost estimates related to superconducting transmission are highly sensitive to the assumptions made for the cost of the superconducting cable. For example, evaluations in [43] suggest that a 5 GW system would range \$1.9-2.2B/GW/1000miles if \$100/kW-meter is used as the superconductor cable cost, whereas the range would be \$1.4-1.7/GW/1000miles if \$50/kW-meter is used.

It is likely that long-distance bulk transmission design at the national level would necessarily include an integration of both HVDC transmission, to take advantage of its lower cost per MW-mile, and EHVAC transmission, to obtain the flexibility AC provides in facilitating the numerous interconnections of new generation projects and load centers, and that systems will be designed so that the two are complementary assets. This perspective is consistent with conclusions made in two recent studies [55, 56], which demonstrated that hybrid 500-765 kV AC and HVDC systems were effective solutions for a 20% renewable energy penetration in the Eastern Interconnection.

2.3.6 Other issues

There are a number of issues, in addition to cost, capacity, and accessibility, to be considered in the design of high-capacity transmission. Reference [49] provides a discussion of some of these issues on which we build in what follows.

2.3.6.1 Right of way (ROW)

ROW for a single circuit 765 kV AC transmission is often quoted at about 200 feet [27]. ROW for a single circuit HVDC line at ±500kV is 213 feet [57], ±600kV is 263 feet [57], and ±800kV has been specified at 246 feet [58], 295 feet [59] and 328 feet [57]. References [40, 42] indicate that superconducting HVDC transmission at ±200kV underground has a ROW requirement of only 25 feet. Table 3 adapts information from [49] and [58] to compare ROW requirements for providing about 6000 MW of capacity 800 miles. The 765 kV AC approach sites a substation every 200 miles to provide shunt capacitive and inductive compensation, but no series compensation. There is one application of double circuit 765 kV lines [60], with some data on that design available in [27].

Table 3: Comparison of 765 kV to HVDC options for ROW and capacity

Approach	No. of circuits	Circuits per tower	ROW (feet)	Per Circuit		Total capacity (MW)	Conductor		
				SIL (MW)	Capacity (MW)		Type	No. in bundle	Conductor area kcmil (mm^2)
765 AC	2	1	400	2400	3100	6200	ACSR/TW	6	957 (485)
±500 DC	2	1	426	N/A	3000	6000	ACSR	3	2515 (1274)
±600 DC	2	1	526	N/A	3150	6300	ACSR	3	?
±800 DC	1	1	246-328	N/A	6400	6400	ACSR	4	2515 (1274)
±200 DC	1	under-ground	25	N/A	5000	5000 or more	Super-conductor	2	700

2.3.6.2 Reliability

Reliability can be considered in terms of a particular circuit's unavailability, and in this sense, it is typical to quantify it using forced outages per 100 miles of circuit per year. Reference [61] indicates typical forced outage rates for 765 kV lines as 1.0 outage per 100 miles per year, with almost all of the outages being caused by single-phase faults. This same study shows that reliability is progressively better as the EHV voltage rises, i.e., 500 kV is better than 345 kV and 765 kV is better than 500 kV. In addition, 500 kV and 765 kV can (though often does not) use single-phase switching which further reduces permanent outages (only the faulted phase is interrupted, allowing power to continue to flow on unfaulted phases, followed by high-speed reclosing). Reference [49] reports outage rates for existing applications through ±600 kV to be under 0.5 per 100 miles per year, with almost all outages being single-pole, with availability of terminal equipment to exceed 98.5% (including both scheduled and forced outages). These data are provided here as representative, but comprehensive investigation has not yet been done.

Reliability may also be considered from a systems perspective. To this end, the Midwest ISO has advocated the so-called "Rule of Three" for economic choices when considering high-capacity overlays [62]. This rule is stated in [63] as follows:

1. If a transmission system is expanded by one line, generally the most economical line will be of the present voltages. Processes that approve one line at a time almost guarantee the selection of the present voltages.
2. If a transmission system is expanded by two lines, generally two higher voltage lines will be competitive with the lower voltage lines if they can be loaded to economic levels.
3. If a transmission system is expanded by three lines, generally the higher voltage lines will be the superior choice and for all expansions after that time.

This rule indicates that very high-capacity lines, (relative to the capacity of the underlying existing transmission system) can be economically justified when three or more of them can be built in parallel; building fewer lines requires that the loading restriction necessary to avoid overloads when one of the lines is lost will limit transmission capacity use to levels which inhibit cost justification. Appendix B develops this rule. The rule of three applies for high-capacity additions; it is not applicable for new transmission which does not significantly exceed that of the existing system.

2.3.6.3 Short circuit ratio

The short circuit current at a bus provides an indication of the network's voltage "stiffness" or "strength" at that bus. The higher a bus's short circuit current, the lower the impedance between that bus and current sources (generators), the less the variation in voltage magnitude will be to a given change in network conditions. The strength of the AC network at the AC side of a HVDC terminal is characterized by the short circuit ratio (SCR), defined as the relation between the short circuit level in MVA at the HVDC substation bus at 1.0 per-unit AC voltage and the DC power in MW [64]. The so-called "effective short circuit ratio" (ESCR) modifies SCR to account for the influence of shunt capacitors and harmonic filters on the AC side of the HVDC terminal.

A bus within an AC network can host a thyristor-based HVDC terminal without additional transient voltage control equipment if the ECSR exceeds 3. Buses having ECSR below 3 are usually not good candidates for hosting a thyristor-based HVDC terminal unless additional voltage control equipment, such as a static var compensator (SVC) is also provided at that bus [65, Chapter 8]. As indicated in Section 2.3.4.2, HVDC with voltage source converters can be located without concern about short circuit currents.

2.3.6.4 Controllability

The converters required at the terminals of an HVDC line provides control opportunities, many of which have been utilized for several decades and for which there is significant operating experience. HVDC offers at least four forms of useful control: steady-state, regulation and load following (slow), voltage control, and transient (fast). Steady-state control can be imposed by simply changing the flow on the HVDC line. It can be useful to do this in order to relieve congestion elsewhere in the network. Regulation may be obtained by using the DC line to follow part or all of the MW variability in one control area to ship to another control area [66]. This can be particularly useful when there is high penetration of variable generation in one area and available fast-ramping generation in another area. HVDC may also be used to mitigate voltage instability [67], to increase damping of interarea oscillatory modes [68], to enhance transient stability performance [69, 70], and to control subsynchronous resonance [71].

2.3.6.5 Transmission losses

Reference [72, Section 3] asserts, "The single greatest method to reduce transmission losses is to increase the voltage of the transmission system." Figure 11 [49] compares losses between various AC voltage levels and two DC voltage levels for a full load power transfer across a 6000 MW design using the respective technology. The indicated loss quantities include thermal losses (I^2R of the conductor) and, for HVDC, those due to terminal equipment. Thermal losses incurred in the line for DC are typically lower than those for an equivalent AC power transfer. For short lines terminal losses incurred by DC offset this advantage. Therefore Figure 11 indicates little difference between losses for the various technologies at 200 miles, but at 800 miles, the HVDC solutions incur significantly lower losses.

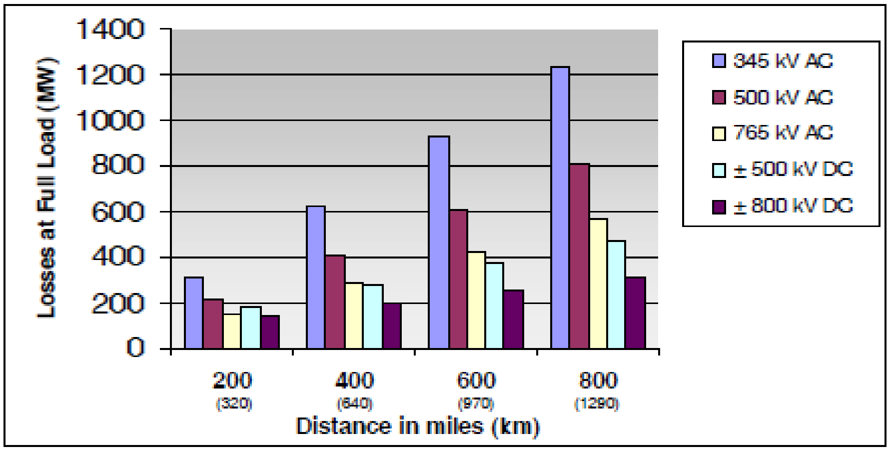

Figure 11: Loss comparison for a 6000 MW transfer

Although not included in Figure 11, reference [73] indicates for a 5 GW, 1500-mile transmission line the losses in a superconducting DC cable system are about 5% (250 MW); this includes VSC converter losses of 3%, such that the losses on just the line (due to refrigeration) are only 2%. These line losses are due to thermal heat load from the atmosphere and independent of the power transmitted. Thus, although no-load losses are always present, the more power that is transmitted the lower the percentage losses are for superconductors.

3 Benefits

In this section we report results of preliminary studies performed to illustrate the level of potential benefit from building a national transmission overlay. We used functionality within the long-term planning software application NETPLAN [17, 74, 75, 76, 77, 78], developed at Iowa State University. NETPLAN identifies optimal future (40 years) U.S. generation/transmission portfolios, accounting for variation in generation investment costs, production costs, and capacity factors by technology and by geographical region, and variation in transmission capacity and transmission investment costs between adjacent regions. The model has a variety of capabilities[4], but we have used only its core cost-minimization linear program in this work. The model used in this study represents the U.S. energy system (electric, natural gas, and coal) and the U.S. freight transportation system. The electric system uses one node for each of 13 regions. Although this is an aggregated model, it is sufficient to provide a high-level indication of benefits in terms of order of magnitude that may be gained from building a national transmission overlay.

The goal of these studies is to identify futures where a national transmission overlay provides benefit in terms of the net present worth of investment and production cost. We focus on what we think are “transmission-friendly” futures; if these futures do not show benefit, then it may be unlikely that less “transmission-friendly” futures would either. NETPLAN provides for imposing constraints on any particular technology, which we use to restrict non-renewable generation (coal, nuclear, natural gas) so that the most economic renewable technologies (wind, geothermal solar PV, and solar thermal) are favored. Because renewables have investment costs (for geothermal, due to drill depth) or capacity factors (for wind and solar, due to the quality of the resource) which are location-dependent, transmission enables renewables to be built in their most economic location. Transmission has much less effect in this way on non-renewable generation since their investment costs are not significantly affected by location and their production costs vary by location only to the extent that the transportation of the fuel varies by location (transportation costs for coal and natural gas are modeled within NETPLAN).

Installed reserve margin requirements were not imposed at the regional level. Although this allows that a region may have insufficient capacity to meet its own demand, it enables utilization of the least-cost generation resources on a national basis, thus providing a more “transmission-friendly” scenario, consistent with the overall study approach. The extent to which multi-regional reserve pooling can be implemented is a question that deserves discussion, as the answer affects the level of transmission which is cost-beneficial.

Four different sets of cases were studied, with each set distinguished from the other three sets based on which technologies were allowed to be considered in optimizing the generation portfolio. Geothermal investment was used as a variable to distinguish cases because among all technologies, its cost data was perceived to be the most uncertain. In

[4] NETPLAN has a cost-minimization linear program embedded as the fitness function within a multi-objective NSGA-II algorithm; it provides Pareto-optimal fronts of solutions (generation and transmission portfolios) that are “good” in terms of cost, sustainability (e.g., CO_2 emissions), and resilience.

all cases, offshore wind is an option for coastal regions but at a significantly higher investment cost assumed to also account for the necessary offshore transmission.

- Cases A1, B1, mostly renewable, geothermal light: These cases allow 520 GW of nuclear units to be built, with the rest inland wind, offshore wind, solar PV, solar thermal, and geothermal. Geothermal is built only in the west.
- Cases A2, B2, all renewable geothermal light: These cases allow only inland wind, offshore wind, solar PV, solar thermal, and geothermal to be built. Geothermal is built only in the West.
- Cases A3, B3, all renewable, no geothermal: These cases allow only inland wind, offshore wind, solar PV, and solar thermal to be built.
- Cases A4, B4, all renewable, geothermal heavy: These cases allow only inland and offshore wind, solar PV and thermal, and geothermal to be built. Geothermal may be built anywhere.

For each set, in case A, the interregional transmission is not allowed to grow and is therefore constrained to the 2010 levels throughout the simulation. In Case B, the capacity of each interregional transmission path is a decision variable within the optimization (generation and transmission are co-optimized); therefore, transmission capacity is grown as needed in order to minimize the 40-year investment and production cost. Therefore the difference in cost between each Case A and Case B provides a valuation of the interregional transmission that is built.

A CO_2 cost of \$30/ton[5] (2010 dollars) was imposed for all CO_2-producing generation. Inflation and (real) discount rates are assumed to be 2% and 7% respectively, resulting in a nominal discount rate of about 9%[6]. Load growth was modeled at 2%/year. Cost and capacity factor data for generation technologies are provided in Appendix C. These Appendix C data are rough estimates and may need refinement to appropriately characterize actual geographic influence. In all cases, a cost of \$1B/1000GW-miles (2010 dollars) was placed on interregional transmission (see discussion in Section 2.3.5). Therefore, transmission cost was determined by length, where length of each inter-regional transmission path was estimated based on distance between each regional geographical center. Also, losses were represented to a first order approximation as a linear function of loading and of distance, based on the data for an 800 kV HVDC line given in Figure 11. Initial (2010) capacity, losses, and investment costs for each interregional transmission path considered are provided in Table 4.

3.1 Results

Results are summarized in Table 5 where net present-worth and the annualized cost, with and without the transmission expansion are provided. When transmission is \$1B/GW/1000miles, the difference in present worth range from \$239B for the mostly

[5] Units of "tons" in this document is in short-tons, as opposed to metric tons. 1 short ton=0.907 metric tons.

[6] A significantly lower real discount rate may be used if the U.S. Office of Management and Budget figures are followed, based on interest rates on treasury notes and bonds, via Circular A-94, see www.federalregister.gov/articles/2011/02/11/2011-3044/discount-rates-for-cost-effectiveness-analysis-of-federal-programs.

renewable, geothermal-light case, to $492B for the all-renewable, geothermal-heavy case. When transmission is $1.5B/GW/1000miles, the difference in present worth is $206B.

Table 4: Transmission attributes

Transmission Lines	2010 Capacity (GW)	Losses (% / GWhr)	Distance (miles) & Investment Cost (M$/GW)
ECAR_MAAC	9.50	5.31	850
ECAR_MAIN	12.62	3.54	425
ECAR_STV	8.58	3.85	500
ERCOT_SPP	0.98	3.85	500
MAAC_NY	3.43	2.81	250
MAAC_STV	2.60	6.14	1050
MAIN_MAPP	1.50	4.48	650
MAIN_STV	4.62	5.10	800
MAIN_SPP	0.28	4.69	700
MAPP_SPP	1.49	5.10	800
MAPP_NWP	0.20	6.77	1200
MAPP_RA	0.31	6.35	1100
NY_NE	1.60	3.44	400
FL_STV	2.00	3.85	500
STV_SPP	5.61	5.02	780
SPP_RA	0.40	4.48	650
NWP_RA	1.31	5.94	1000
NWP_CNV	9.18	5.52	900
RA_CNV	8.31	5.73	950

Table 5: Summary of results

Cases	Case description	Transmission	Cost (Billion$)	
			Present worth (2010 dollars)	Annualized over 40 years
A1	Mostly renewable, geothermal-light	Fixed	5013.12	376.03
B1		Expanded	4773.96	358.09
		Difference	**239.16**	**17.94**
A2	All-renewable, geothermal-light	Fixed	5517.83	413.89
B2		Expanded	5059.38	379.50
		Difference	**458.45**	**34.39**
A3	All-renewable, no geothermal	Fixed	5328.11	399.66
B3		Expanded	5053.70	377.57
		Difference	**274.41**	**20.58**
A4	All-renewable, geothermal-heavy	Fixed	5457.63	409.37
B4		Expanded	4965.48	372.47
		Difference	**492.15**	**36.92**
B1-1.5T	Same as B1, but w/increased transmission costs	Expanded	4807.06	360.53
		Difference	**206.12**	**15.46**

Generation investments made for Cases A1 and B1, and for Cases A2 and B2, are illustrated in Figure 12. The decreased generation capacity of Case B1 relative to Case A1 shows that the expanded transmission of Case B1 enables use of wind with higher capacity factor relative to Case A1; a similar observation can be made in comparing Cases A2 and B2.

Transmission investments made for Cases B1 and B2 are illustrated in Figure 13 (Cases A1 and A2 were constrained to existing transmission capacity). This chart shows the additional transmission capacity developed over and above the existing transmission capacity, where it is clear that the largest investments are made for MAIN to ECAR, MAIN to MAPP, MAIN to STV, SPP to STV, and RA to SPP, with the investment being about 100 GW in both cases for MAIN to ECAR. Total invested transmission capacity is larger for Case B2 than for B1 because Case B1 was allowed to build some new generation that is not locationally constrained (nuclear) and was therefore built close to the load that it supplied, avoiding the need for transmission. In contrast, Case B2 was allowed to build only the locationally sensitive renewables; here it was more economical to build the more cost-effective but distant generation and required transmission than it was to build the less cost-effective generation close to the load.

Figure 14 and Figure 15 geographically illustrate, for Cases B1 and B2 respectively, the additional transmission capacity developed. Here, line thickness indicates capacity and arrows indicate the energy flow direction (bidirectional arrows indicate flows occur in one direction during some years and the other direction during other years). These figures also provide regional energy generation and consumption (in Quads[7]), where the energy generated by renewables is colored green. These figures indicate that the energy generally flows west to east, reflecting the facts that the most economical renewables are in the Midwest or West, and a high percentage of the load is in the East, particular in ECAR and STV.

[7] 1 Quad=1×10^{15}BTU=293,080 GWhrs. To put into context, the nation produces about 13 Quads of electric energy each year.

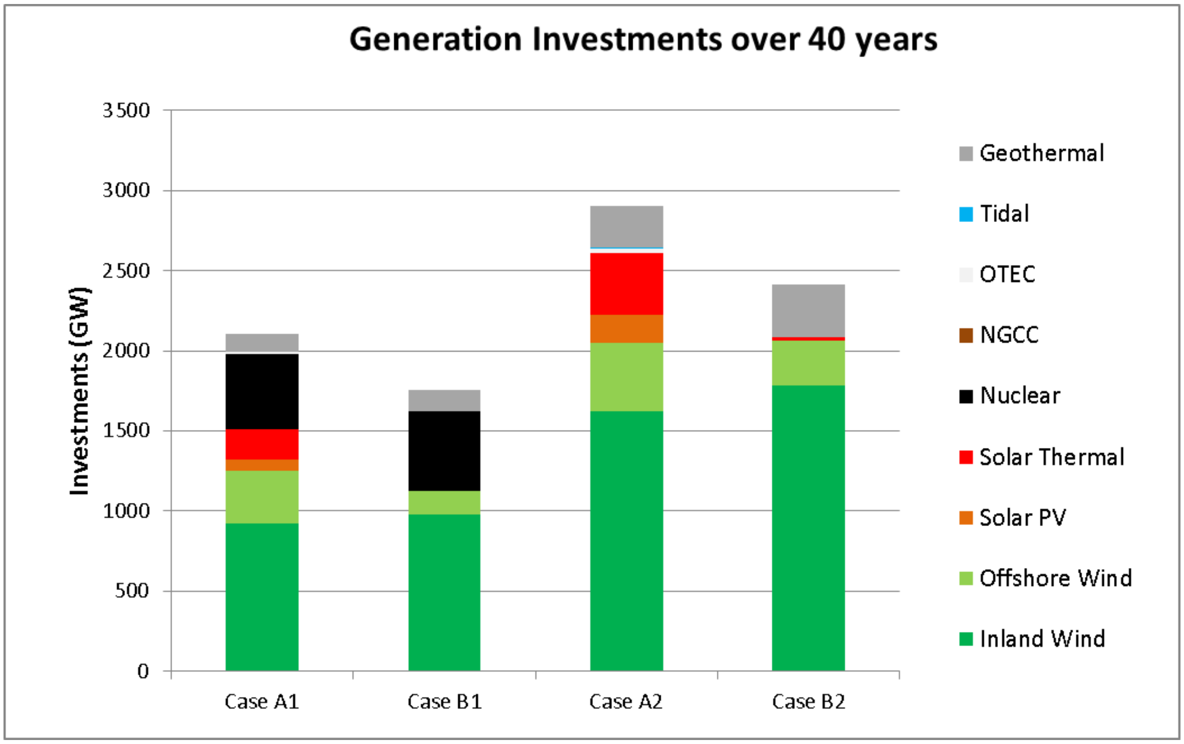

Figure 12: Generation investments over 40 years for Cases A1, B1 (mostly renewable, geothermal-light) & Cases A2, B2 (all-renewable, geothermal-light)

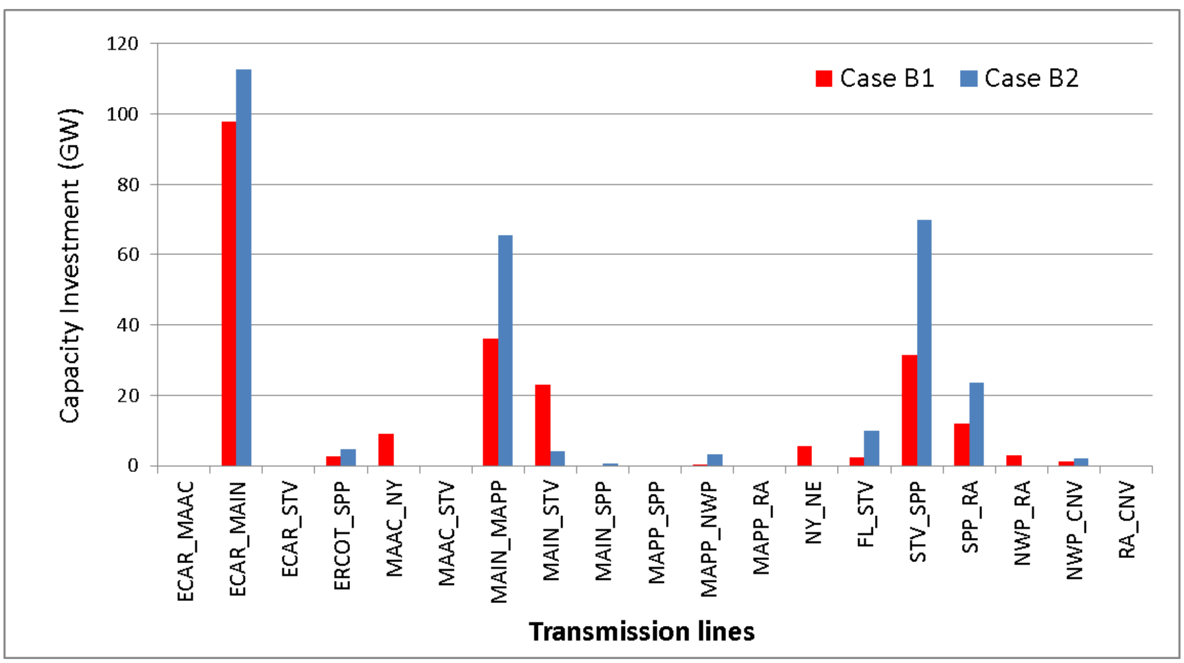

Figure 13: Transmission investments over 40 years: Case B1 (mostly renewable, geothermal-light) & Case B2 (all-renewable, geothermal-light)

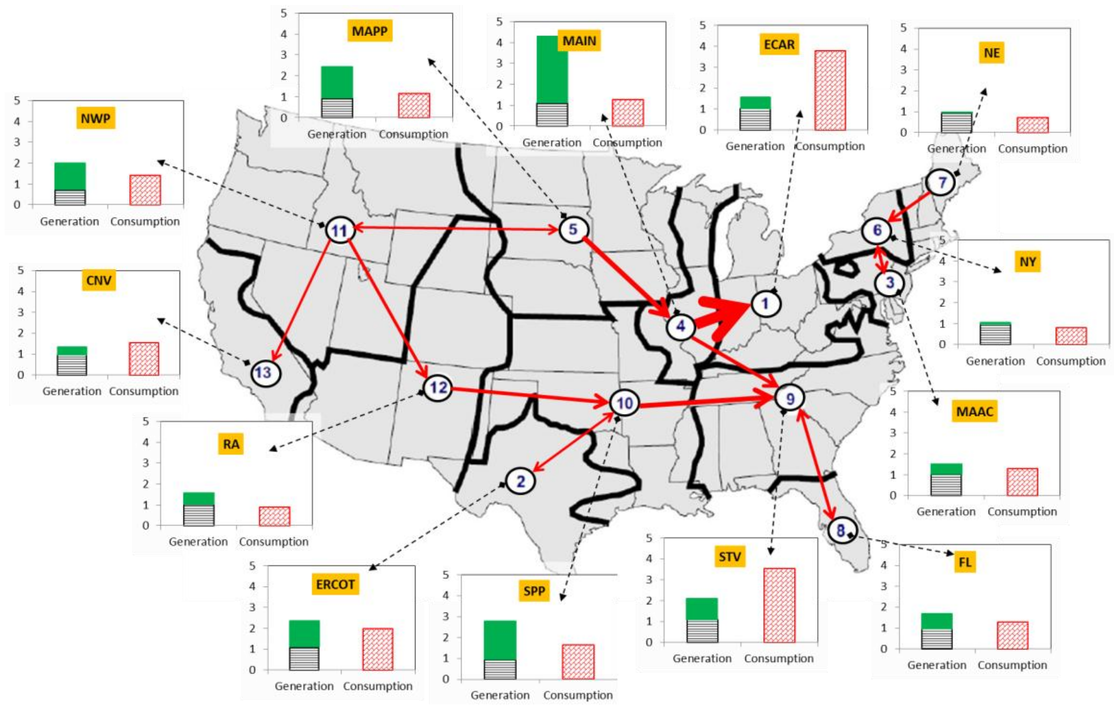

Figure 14: Generation mix and transmission investment over 40 years for Case B1 (mostly renewable, geothermal-light)

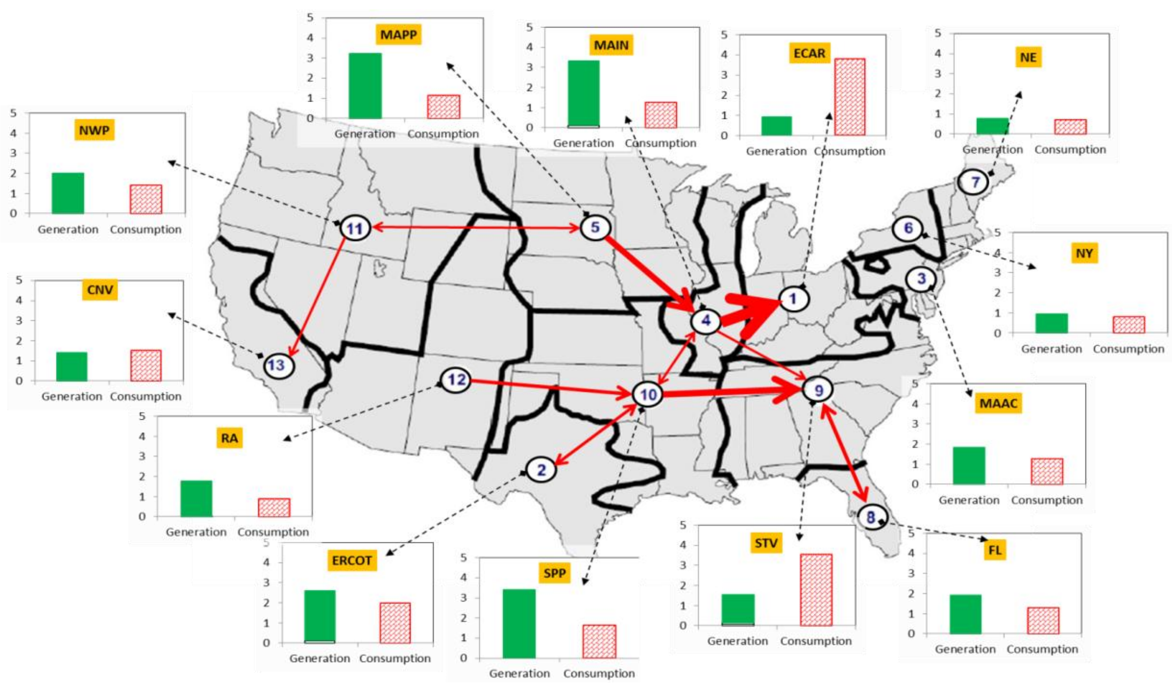

Figure 15: Generation mix and transmission investments over 40 years for Case B2 (all-renewable, geothermal-light)

Generation investments made for Cases A3 and B3, and for Cases A4 and B4, are illustrated in Figure 16. The decreased generation capacity of Case B3 relative to Case A3 shows that the expanded transmission of Case B3 enables use of wind with higher capacity factor relative to Case A3; a similar observation can be made in comparing Cases A4 and B4. Cases A4 and B4 show significantly less capacity than do Cases A3 and B3 because of the much heavier presence of geothermal in Cases A4 and B4 and because geothermal has a much higher capacity factor than wind.

Transmission investments made for Cases B3 and B4 are illustrated in Figure 17 (Cases A3 and A4 were constrained to existing transmission capacity). This chart shows the additional transmission capacity developed over and above the existing transmission capacity. The interregional corridors receiving the most transmission capacity investment for Case B3 are generally the same as for Cases B1 and B2 (MAIN to ECAR, MAIN to MAPP, MAIN to STV, SPP to STV, and RA to SPP), although the amounts are somewhat different for some corridors. On the other hand, the Case B4 transmission investment pattern was significantly different in that Case B3 invests in some transmission corridors that received little or no investment in other cases, including MAPP to NWP and NY to NE, while most other corridors received significantly less investment (e.g., MAIN to ECAR received only 40 GW as opposed to 100 GW or more in Cases B1, B2, and B3). This was because Cases B1, B2, and B3 constrained geothermal investment to be light and only in the West (Cases B1 and B2) or nonexistent (Case B3), whereas Case B4 allowed heavier geothermal investment in both West and East.

Total invested transmission capacity is significantly smaller for Case B4 than for Cases B1, B2, and B3 because Case B4 was allowed to heavily invest in geothermal in both the West and the East. The presence of the Eastern geothermal significantly relieved the need for transmission capacity which was otherwise required to move energy from the West and Midwest to the East. It is important to realize, however, that our cost assumptions regarding geothermal, expressed as a function of expected drill depth (see Appendix C), are more uncertain than cost assumptions for other technologies; it is not clear that Eastern geothermal investment can be economically attractive, a statement that is consistent with Figure 6.

Figure 18 and Figure 19 geographically illustrate, for Cases B3 and B4 respectively, the additional transmission capacity developed. Here, line thickness indicates capacity and arrows indicate the energy flow direction (bidirectional arrows indicate flows occur in one direction during some years and the other direction during other years). These figures also provide regional energy generation and consumption (in Quads or 1×10^{15} BTU), where the energy generated by renewables is colored green. It is interesting to observe that the flow direction for Cases B1, B2, and B4 (all of which have geothermal) is West to Midwest to East, whereas the flow direction for Case B3 (which has no geothermal) is Midwest to West and Midwest to East. This shows that, without geothermal, the Midwestern wind significantly increases its presence in supplying significant parts of the entire nation.

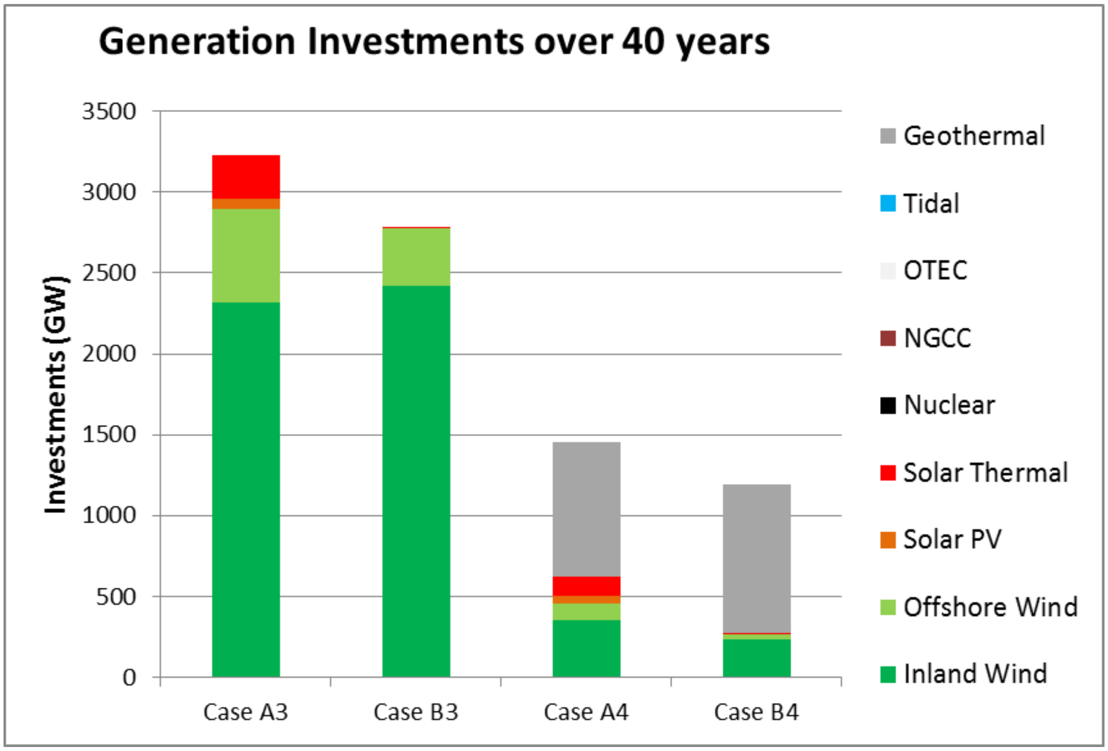

Figure 16: Generation investments over 40 years for Cases A3, B3 (all-renewable, no geothermal) and Cases A4, B4 (all-renewable, geothermal-heavy)

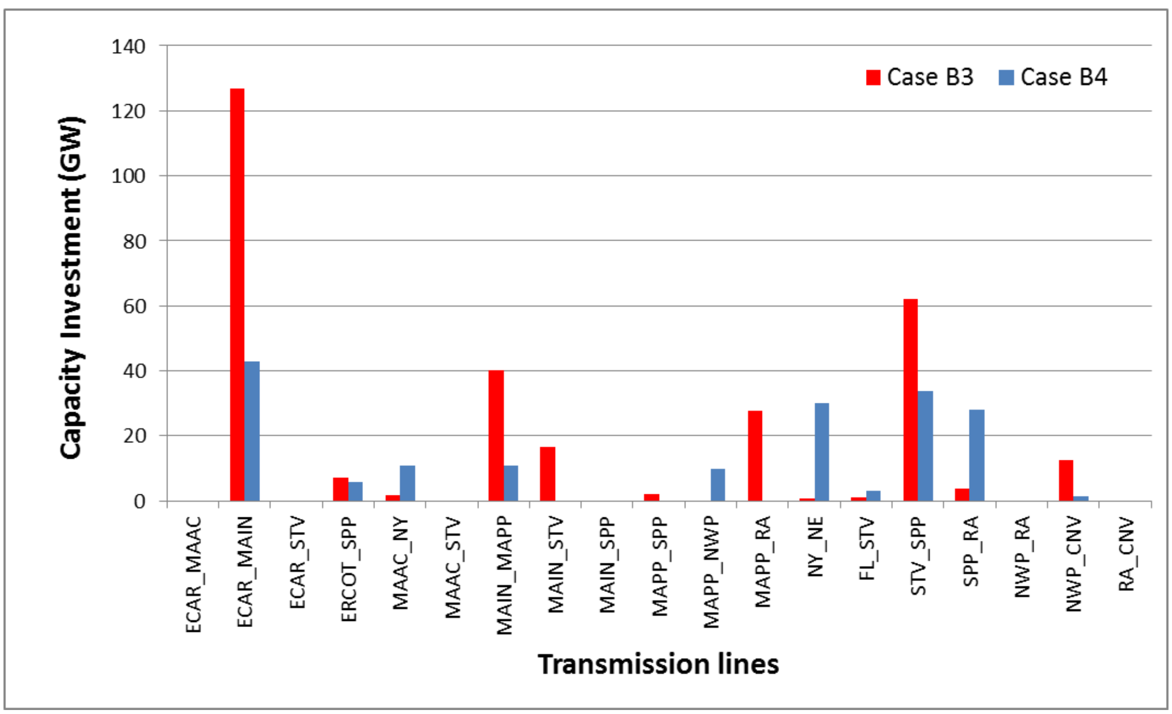

Figure 17: Transmission investments over 40 years for Case B3 (all-renewable, no geothermal) & Case B4 (all-renewable, geothermal-heavy)

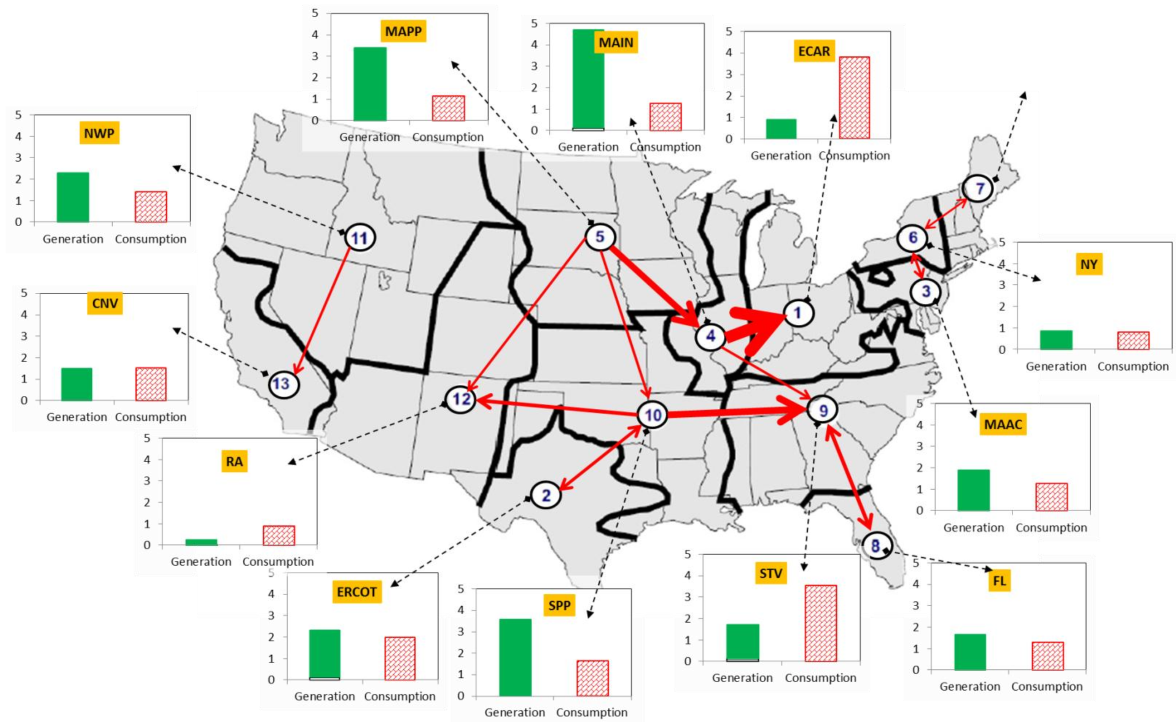

Figure 18: Generation mix and transmission investments over 40 years for Case B3 (all-renewable, no geothermal)

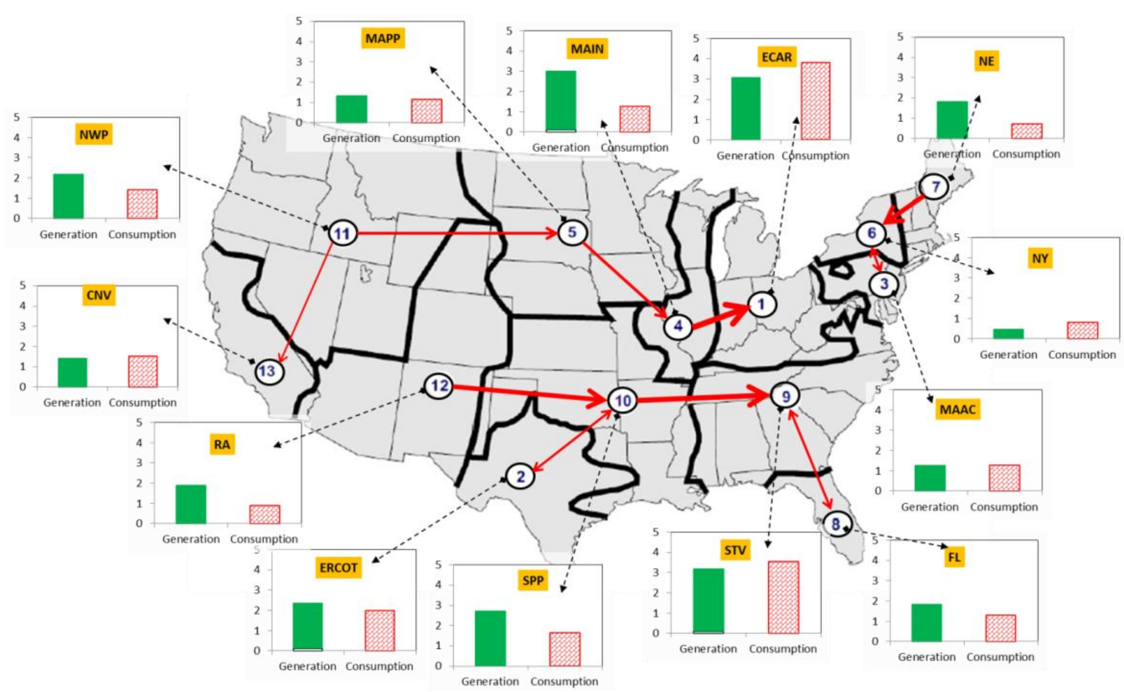

Figure 19: Generation mix and transmission investments over 40 years for Case B4 (all-renewable, geothermal-heavy)

To determine the sensitivity of results to transmission cost, case B1-2T was run, where transmission costs were increased from \$1B/GW/1000miles to \$1.5B/GW/1000miles. Otherwise, this case was the same as case B1.

Transmission investments made for Case B1-1.5T are illustrated in Figure 20. Total invested transmission capacity is smaller for Case B1-1.5T than for Case B1, an expected result given the doubling of transmission cost.

Figure 21geographically illustrates, for Case B1-1.5T, the additional transmission capacity developed. Here, line thickness indicates capacity and arrows indicate the energy flow direction (bidirectional arrows indicate flows occur in one direction during some years and the other direction during other years). This figure also provides regional energy generation and consumption (in Quads or 1×10^{15} BTU), where the energy generated by renewables is colored green. Comparison to Figure 14, which is the same information for Case B1 (with transmission cost at \$1B/GW/1000miles), indicates that the identified transmission topology is the same. This fact, together with the observation that the 50% increase in transmission cost only decreases net economic (present worth) benefit by 13% (of from \$B239 to \$206B - see Table 5), suggests the following conclusion:

The long-term benefit obtained from expanded transmission is not very sensitive to the cost of that transmission.

This conclusion makes sense: it is a confirmation of the well-known fact that the cost of transmission is generally a relatively small percentage of the composite long-term cost of building and operating power systems.

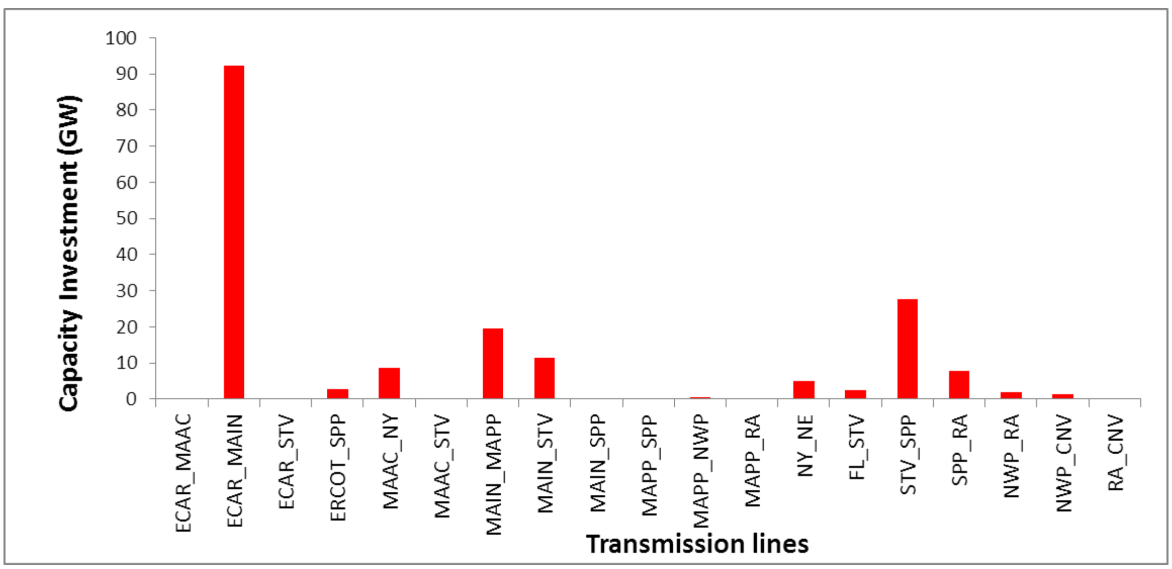

Figure 20: Transmission investments over 40 years: Case B1-1.5T (mostly renewable, geothermal-light, with increased transmission cost)

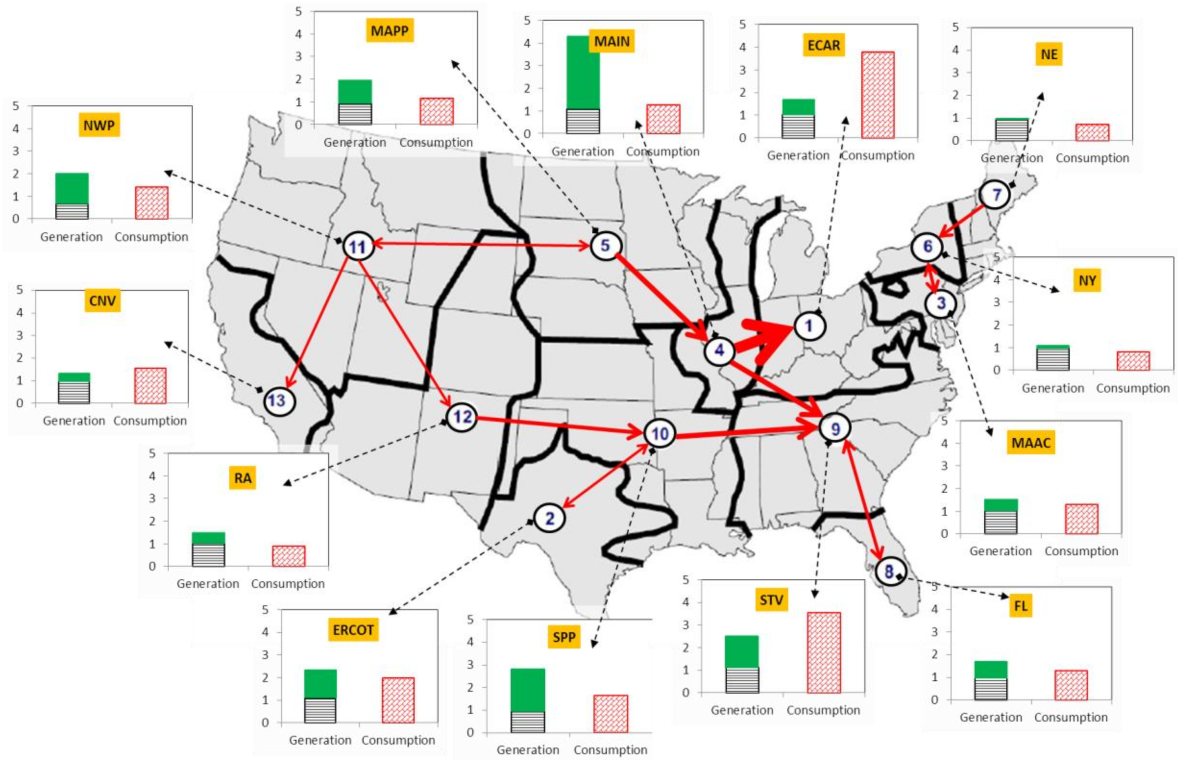

Figure 21: Generation mix and transmission investment over 40 years for Case B1-1.5T (mostly renewable, geothermal-light, with increased transmission cost)

3.2 Discussion

Relative to existing infrastructure, a national transmission overlay would have four main benefits which can be characterized as cost, sustainability, resilience, and flexibility. We describe these in the following four subsections.

3.2.1 Cost

For a given demand growth and a given emissions target, the minimum cost plan when transmission can be expanded will realize a savings over an extended period, say 40 years, relative to that of a minimum cost plan when transmission cannot be expanded. This savings can be observed in Table 5 as the difference between the net present worth of total costs (investment in generation and in transmission, plus production costs) with and without transmission expansion. For the four sets of cases run, this savings was $239B for Case B1, $274B for Case B2, $458B for Case B3, and $492B for Case B4. These savings account for the cost of the expanded transmission and indicate that it is better, from purely a cost basis, to build the transmission overlay than not, under the conditions characterizing the four futures analyzed. We provide four additional comments on these cost differences:

1. *Basis of comparison*: In each of our four sets of cases, we have compared two optimized solutions, one where transmission is a decision variable and one where it is not. Converting fixed values to decision variables within an optimization either does

not affect the objective function or improves it; thus, it is no surprise that we observe a cost savings when we expand transmission relative to when we do not. It might be asked, therefore, whether such a comparison is "fair." This is exactly the point, i.e., the overlay opens up cost-reducing opportunities that are not presently available, and this is a main reason why it is of interest. Alternatively, one might suggest that the transmission-expanded cases should be compared to cases where the transmission is allowed to expand at the lower, existing AC voltages. If this were done to accommodate the same level of interregional transfers as are accommodated in the transmission expanded cases, then it would be of much higher cost. On the other hand, if it were done to accommodate lower capacity intra-regional transfers, then it would not capture the benefit from locational variation in cost-effectiveness of renewables, which is the benefit that drives the cost savings in the four transmission-expanded cases.

2. *Transmission mileage*: A major impediment for building transmission is obtaining right-of-way. It is clear that building a national transmission overlay will require high transmission mileage. Yet, it is not clear how much lower-capacity transmission would be built without the national transmission overlay. For a high-renewable generation investment such as illustrated previously, it is possible that, without the national overlay, the mileage for the lower-capacity lines, which would be required to carry the same power as would the overlay should it be built, would be very high, likely exceeding that of the national overlay.
3. *Additional costs*: The evaluation does not include the cost of redesign that might be necessary within the underlying, existing transmission system to accommodate the overlay. However, if the overlay is built according to the "rule of three" (see Section 2.3.6.2 and Appendix B), and redesign of underlying transmission includes not only reinforcements (new lines) but also reconfigurations of existing transmission, then this reinforcement cost may not be very significant.
4. *Other benefits*: The cost savings, between a quarter and a half trillion dollars, though significant, may not be the most important benefit. Other benefits include emission reductions, resilience, and flexibility, as discussed in the following subsections.

3.2.2 Sustainability

The presence of a national transmission overlay will lower the cost per unit emission reduction over a given time frame. It is easy to understand why – transmission allows low-GHG technologies to be built in the regions where they are most effective in producing energy. Thus, for a given total cost over a given time frame, the national transmission overlay will enable greater GHG emission reductions. Alternatively, a national transmission overlay will allow a given GHG emission reduction over a given time frame at a lower total cost. We expect the benefit would be even more pronounced if the life-cycle GHG impact of a national transmission overlay is considered, since the amount of steel, concrete, aluminum, transportation, and construction would likely be less than alternative approaches.

3.2.3 Resilience

We consider resilience of the national energy system to be the ability to minimize and recover from the effects of an adverse event, whether natural or man-made, for a given state of the system [79], where here we consider events which are very large-scale and have catastrophic potential with respect to the energy system. The Katrina-Rita hurricanes of 2005 was such an event, where a large amount of natural gas production was constrained for several weeks simultaneous with significant reduction of Mississippi River barge traffic (important for coal transportation) and loss of many electric generation and transmission facilities in the area [76]. Other representative events that could be used to assess resilience of the energy system include [79];

1. 6 month loss of rail access to Powder River Basin coal,
2. Early retirement of 50% of U.S. nuclear fleet;
3. 6 month interruption of Canadian gas supply;
4. Earthquake in St. Louis [80] with major loss of transmission, rail, oil, and gas pipelines, and extended interruption to Mississippi River barge traffic;
5. 1 year loss of U.S. hydro resources due to extreme drought;
6. 50% reduction in annual wind farm capacity factor due to climate change effects;
7. Simultaneous failure of all power transformers throughout the East Central region of the country due to a geomagnetic storm or an electromagnetic pulse.

One may classify events useful for resilience assessment into technology events, geographical events, or combination of the two. Technology events reduce capacity of some particular technology – events 2, 5, and 6 in the above list are technology events. Geographical events reduce capacity of multiple technologies within a geographical area such as a region – the Katrina/Rita hurricanes and event 4 in the above list would be geographical events. Combination events affect a single technology within a single geographical region – events 1, 3, and 7 in the above list are combination events. Although sabotage (terror) has not been explicitly mentioned, it could play an initiating role in some of the aforementioned events, particularly 1, 3, and 7. Clearly, the above list could be extended; however, the intention in assessing resilience is not to be exhaustive in selecting events but rather to be representative in selecting extreme tests so that the performance under these tests of various designs may be compared.

The "ability to minimize and recover from the effects of an adverse event" can be measured in various ways. A common notion used within the electric industry is the time necessary for interrupted service to be restored. However, such a measure, important as it is, may not be effective in capturing the effects on resilience of infrastructure design attributes at the national level. An alternative measure is the system's operational cost for an extended time period following the event, e.g., several months to several years. The cost can be reflected locationally by the dual variables (Lagrange multipliers) corresponding to nodal energy balance constraints, referred to as locational marginal prices (LMPs) when the nodes are in the electric transmission system.

In Figure 22, we have illustrated by plotting the nodal price variation caused by a large-scale system disruption for a single node within the system. The resilience of this system corresponding to the location of the given node is characterized by the area between the nodal price variation with and without the disruption. The plot is from simulation which provides optimal operation of the energy (electric, natural gas, and coal) system. Therefore, the only effect influencing the nodal price is the system's ability to utilize its energy resources and corresponding infrastructure. Reference [76] uses this measure to assess resilience based on the effects of the 2005 Hurricanes Katrina and Rita.

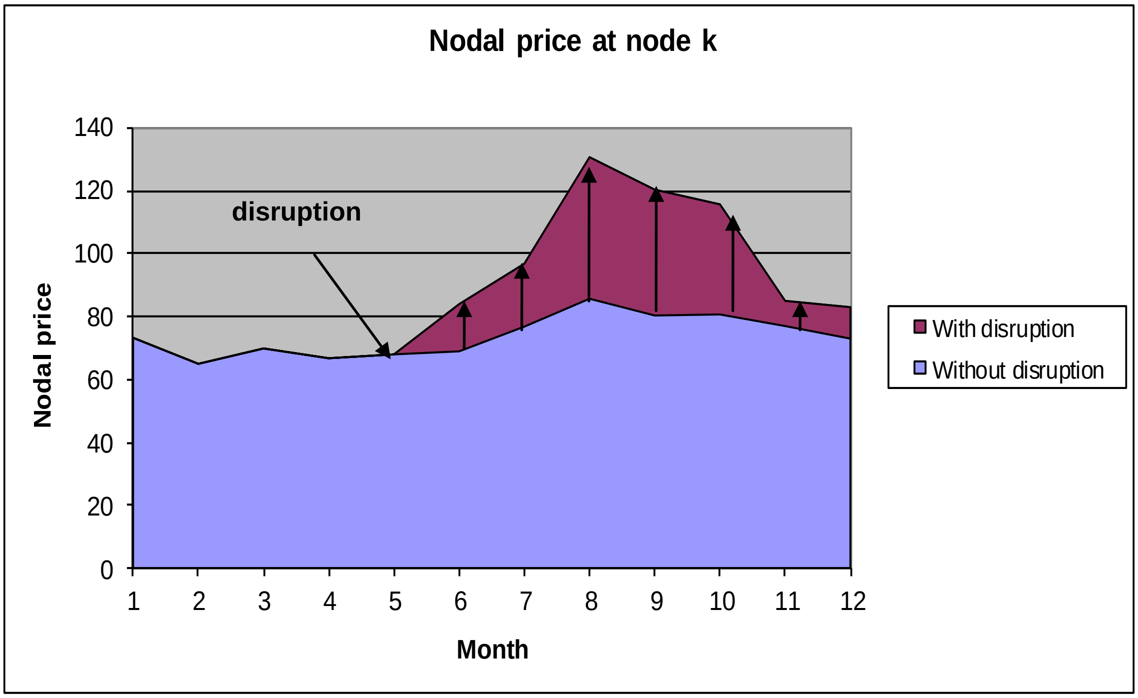

Figure 22: Price variation for Northeastern U.S. electric node following Katrina

Although a national transmission overlay would not eliminate cost increase due to disruptions, it would reduce it and therefore improve resilience as a result of the operational flexibility it provides. This overlay-related effect would be more pronounced for geographical events since it would provide the ability to compensate diminished generation capacity in one region with unused generation capacity in another region. This overlay-related effect would be less pronounced for technology events but would provide some benefit, to the extent that a technology event exhibits regional characteristics. As an enabling infrastructure that has very high availability compared to other bulk power system components, a high capacity transmission network can create significant value in operations.

3.2.4 Planning flexibility

Flexibility is the ability to effectively redirect, i.e., to implement cost-effective but new plans, following significant and unexpected events and trends which cause permanent changes in expected futures. Whereas a resilient system maintains reasonable operational cost for a short period following the event, the flexible system is able to change course quickly and pursue a new strategy which is as nearly as good as the previous one. Flexibility is important in a 40-year generation build-out, as shifts between favorability of resources occur over time. A transmission overlay would facilitate flexibility by increasing the number of options one might be able to consider in compensating permanent loss of significant resources.

4 Issues and concerns

Although there are many advantages to a large-scale coordinated inter-regional transmission network, the organization and governance of the US electricity industry has not produced one. The legacies of a system comprised of relatively small interlocking control areas, combined with a dominant role for state regulators, has created a "traditional" planning regime that is focused on identifying solutions that are local or regional but less so at considering interregional solutions.

There have been several studies citing various barriers to more extensive investment in inter-regional, particularly extra-high voltage, transmission projects. In its Order 1000, the Federal Energy Regulatory Commission cites planning processes that are still rooted in practices developed when the industry was dominated by a myriad of relatively small local utility control areas. In addition many, including FERC, cite current approaches to cost allocation as a large barrier to investment in inter-regional projects. Certainly larger scale projects create new challenges for cost allocation that are not of concern when investments are contained within a single state or even utility control area. In the following sections, we briefly discuss each of these issues.

4.1 Localized decision-making

Even after twenty years of FERC-led initiatives to stimulate competitive wholesale regional markets for electricity, most consequential resource decisions are made on a more local level. This has always been a concern with the organization of the U.S. electricity industry, but the shortcomings have become more acute as the industry has grown and demands on large regional interconnections have grown. The fact remains that a large share of the planning, funding, and particularly siting activity occurs in State-level proceedings.

4.1.1 Transmission between ISOs

The evolution of Regional Transmission Organizations and Independent System Operators has changed the dynamic somewhat. In regions such as New England and PJM, the multistate nature of the ISO/RTO has at least provided a forum in which competing State interests could be hashed out. Most of this progress has been limited to projects with benefits internal to ISOs. As Joskow notes of the northeastern ISOs [81] "Other than the opportunities for merchant investors to seek to expand inter-control area transmission facilities, there is no process in place in any of these areas systematically to evaluate opportunities to expand transmission capacity on both sides of the borders between them or to support beneficial projects with regulated transmission investments." More recent efforts to implement interconnection-wide planning are steps in the right direction, but these efforts are still in their infancy.

The concentration of transmission planning efforts at the State and Regional levels can also lead to more subtle distortions stemming from inconsistent policies across neighboring jurisdictions. For example, within ISOs, much of the impetus for transmission investment in the last decade is the need to accommodate and provide access for the nearly 200 GW of new generation that was built during this time. Unlike previous decades in which vertically integrated utilities dominated the industry, transmission planners have been placed in a position of having to "react" to interconnection requests by generation, rather than jointly plan network and generation investments.

4.1.2 RTO interconnection procedures

The decoupling of generation and transmission activities was undertaken with the hope for stimulating innovation and efficiencies through increased competition in the generation sector. At the same time, however, vertical dis-integration creates difficult new incentive and planning questions for the transmission sector. As we discuss below major transmission investments by RTOs can increase the value of generation in certain locations, and decrease it in others. This confounds the goal of keeping ISOs and RTOs "market-neutral" and leaving generation investment decisions up to market forces.

FERC orders 888 and 2000 require open-access to regional transmission networks, but there is still widespread disparity on how this is provided in practice. When a prospective new generation facility requests access to a network, there will be necessary network investments to physically connect that resource that are usually the responsibility of the generation asset. In addition, many such interconnections also spur a need, or desire, for "deeper" network investments that can simultaneously benefit other network users as well as facilitate interconnection.

The methods for sorting through and charging for such interconnections can create incentive problems. For example, a generation plant with no cost responsibility for the network investments necessary to relieve congestion created by its entry will not factor in those costs in its location decision. A series of generation facilities locating at the lowest cost (or most resource rich) areas for *generation* investment may then create a need for costly transmission investment. The net combined costs of transmission and generation may then in fact exceed the costs of locating generation in a more network-friendly location.

4.1.3 State-level policies

One last area where local decision-making has a strong interaction with transmission network needs and planning and is in the implementation of State-level utility and environmental policies, particularly renewable portfolio standards. One key element is the degree to which a State RPS requires either local production or delivery of the renewable energy. Here again there is a diversity of approaches, with some states allowing compliance through generic tradable Renewable Energy Credits while others, such as California requiring the bulk of the resources be physically connected with its local network. Still another factor is the degree to which distributed resources are emphasized relative to utility-scale renewable generation.

Varying application of interconnection rules, environmental policies, and siting standards across regions can therefore drive transmission investment in ways that a holistic regional "master-plan" never would. For example, regions with more generation friendly interconnection rules would incentivize more entry in places with more transmission needs than would arise in regions where generation projects carry more individual responsibility for network investments. Conversely regions that strongly favor distributed generation as an emphasis of their environmental policies may discourage investment as unnecessary or even conflicting with the goal of more "local" supply.

4.1.4 Influence of local economic development

Localized decision-making may also occur in the governor's office or the legislature of the state governments as they recognize the value of local generation siting to the economic development of their state. States on the sending end of transmission will experience increased generation facilities and the associated economic development that comes from the construction, maintenance, and operation of those facilities. States on the receiving end of transmission will not see this benefit and in fact may see reduced usage or even closure of some high-cost generation facilities, effectively transferring jobs to the sending end state. Of course, this influence is partly balanced with likely increases in energy prices for the sending end state and likely decreases in energy prices in the receiving end state.

4.1.5 Adequacy and reserves

Each state places requirements on maintaining adequate capacity reserves over peak demand. Obtaining economic benefits of a transmission overlay would require that reserve levels in some states be allowed to reduce while maintaining adequate levels of regional and multi-regional reserve levels. Individual states accustomed to maintaining their own reserve levels would need to develop willingness for depending on generation reserves in other regions and associated transmission. Reduced reserve requirements through pooling would be a cost benefit as long as deliverability and voltage support are ensured, but it could be a liability for a region if import contingencies become the largest single contingency.

4.2 Changes in planning approach

The underlying objective of transmission planning has been to identify new transmission which provides value to end-use customers while supporting state and federal policies, where value is a blend of low cost, reliable service, environmental considerations, and economic growth. It is important that that stakeholders participating in the planning process accept a common objective or set of guiding principles; otherwise the process may not converge. Design of a national transmission overlay can be done based on the previously stated objective; however, the means of achieving it may need to change relative to traditional planning procedures. This section identifies changes to the traditional planning approach necessary in order to implement a national overlay design appropriate for the nation. Clearly, one change is the perception of the "end-use customer," which, in the case of traditional planning, is the customer base of a localized geographical area or a region. Designing national infrastructure motivates a perspective of a national customer base, a perspective that has already been discussed in Section 4.1. Three additional changes are described in the following two subsections.

4.2.1 Transmission planning by portfolio design

Planners have traditionally developed transmission plans incrementally, just one or a limited number of projects at a time, an approach driven in large part by the tendency of state public utility commissions (PUCs) to approve in like manner. Incremental transmission planning and corresponding regulatory approval may inhibit the ability to plan and design at the interregional level. An approach that develops, studies, and assesses cost benefit and system performance of different portfolios of transmission projects, and ultimately undergoes regulatory review in this way, may better facilitate national transmission overlay development. There is movement in this direction at the regional level [82, 83].

4.2.2 Longer decision horizons

There is strong emphasis today by long-term planners on decision horizons that reach up to 20 years into the future, and it is infrequent that developers commit to constructing new facilities on the basis of needs that extend beyond this time frame. This is understandable because building significantly ahead of need can add expense due to the increased uncertainty of the longer time frame and the difficulty in convincing regulators to place economic burdens on current ratepayers for benefits enjoyed by future ratepayers. However, most of the investments have long lifetimes, some exceeding 50 and even 60 years, In addition, climate effects of GHG emissions are cumulative over multiple decades, so that response to GHG reductions are gradual and require long-term aggregation of measures to achieve them.

The benefits of a national transmission overlay, as they relate to reduction of GHG emissions, require taking a view of needs beyond the typical 20-year decision horizon of current planning cycles. This does not require that today's investment decisions address what is built 50 years into the future but rather, that today's investment decisions fit into a 50-year or more long-term plan, periodically adjusted to account for new information as it becomes available. To accomplish this, the industry will have to work with state and federal government at both the legislative and regulatory levels to improve its ability to balance short-term needs within a longer-term decision horizon. Doing so will require addressing the above-mentioned socio-economic issues. It will also require addressing technical challenges associated with the necessary software tools.

4.2.3 Resource forecasting

With the vertical separation of transmission and generation responsibilities in much of the country, the long lead-times for transmission investment create additional problems. Transmission planners face an uncomfortable conflict between trying to lead resource planning in what appears to be an optimal fashion and the possibility that, by getting out in front of generation development, transmission investments can strongly drive where and what kinds of generation are built.

In many regions, transmission planners are uncomfortable with speculating on the type and location of new generation resources. Transmission plans are rather initiated only after obtaining a strong signal in regards to new resource development, as expressed through interconnection requests and purchases of other transmission services. This approach is a type of resource forecasting, but it is one that attempts to build transmission so that it follows the generation resource market. Doing otherwise, planners argue, places them in positions of deciding which load serving entities and which generation developers will be "winners" and which ones will be "losers," thereby conflicting with the intention that transmission planning and operation be market-neutral.

Other regions, such as California, have been concerned that the time lags involved in transmission planning and construction require that transmission get "out front" of generation investment at least to some extent. The aggressive mandates for renewable purchases in several states have reinforced support for this view. The general approach, is to identify the areas with strong potential for building wind, solar, and geothermal generation as an equally strong signal in regards to new resource development, and forecast accordingly.

4.3 Cost allocation

The question of cost allocation is often cited as one of the greatest barriers to transmission investment. The FERC in its Order 1000 stated that "many cost allocation methods in place within transmission planning regions fail to account for the beneficiaries of new transmission facilities, while cost allocation methods for potential interregional facilities are largely nonexistent." Certainly in the most fundamental sense a process for recovering the costs of transmission investments must be in place for any entity to devote the capital required for such investments. A more subtle question is the degree to which the historical, regionally varying approaches inhibit or distort investment decisions.

Ironically, the industry's very focus on cost allocation has itself been a barrier to investment. Traditionally there has been an emphasis on the principle of "cost causation" in the allocation of the costs of new transmission facilities. This principle evolved into a related principle that "beneficiaries pay" for new investment. The notion that the main users or beneficiaries of facilities should bear cost responsibility has been viewed as important for both "fairness" and for enhancing support for investments. As FERC stated in Order 890 "[A] proposal that allocates costs fairly to participants who benefit from them is more likely to support new investment than one that does not. Adequate financial support for major new transmission projects may not be obtained unless costs are assigned fairly to those who benefit from the project."

However, the very process of determining who the beneficiaries of particular projects will be is fraught with uncertainties that provide the grounds for lengthy disputes. These disputes can greatly delay investments. As noted by in [84] "Even when the need for a particular transmission project has been established (*e.g.,* through a state or regional planning process), questions over who benefits and who pays remain perennial sources of dispute. Disputes over these types of issues often chill investment that might otherwise provide broad-based benefits to a large region over time. The uncertainty – and frequent disputes, procedural delays, and fights over cost recovery – has this chilling effect by raising the risk and uncertainty over transmission investment."

Frustration over the difficulties with predicting, measuring, and assigning the benefits of transmission projects have led many to call for some degree of "socialized" cost allocation. The general idea is to allocate investment costs pro-rata through a mechanism such as general grid access that would not distinguish between existing and new users or local and external users. In theory, a simple grid charge that funds a general investment pool could greatly streamline proceedings tasked with measuring and allocating costs and benefits of specific projects.

However, there are nuances even within the general approach of socialized costs. In particular, current disputes focus on exactly how broad a region such costs should be applied to. While the FERC had shown an interest in increased socialization of investment, the extent to which it may do so is still under dispute.[8] Critics of socialization argue that that it undermines regional cost advantages that might otherwise help to balance disadvantages an area may have in economic development. As discussed below, increased connectivity can hurt buyers of power in low-cost regions and sellers in high-cost regions. Even if the power can be put to more efficient use elsewhere, it is difficult to raise support for paying a share of socialized transmission costs for projects that yield no local benefits, and may even exacerbate local disadvantages. If market investment incentives were sufficient, such inter-regional effects would still arise, but could not then be attributed to a socialized charge.

4.4 Market impacts of transmission investment

One point often overlooked in the discussion of cost-allocation is the fact that the monetary cost of the transmission infrastructure is only one, often minority, aspect of the economic impact of large-scale investment. The impact of a major transmission project on energy prices in a local market can be far greater than simply the cost of building the transmission. When large exporting regions are connected with resource-constrained regions, prices rise in the exporting region due to the increase in demand for the local production, while prices fall in the importing regions.

It is important to emphasize that in market-oriented regions, this effect can be much more pronounced than simply the change in the production costs in a given region, particularly if congestion risk is not hedged. This is because markets will settle, either directly or indirectly, at the offer (willingness to sell) of the last, or marginal seller. In a perfectly competitive market, this will be the marginal cost of the most expensive unit operating in the dispatch order. In LMP based markets this is an explicit calculation made by an ISO, however even in markets that are not operated by ISOs but instead feature a mix of vertically integrated investor-owned and municipal utilities and co-ops, there is still a substantial amount of wholesale trade, and these trades adjust to a market-clearing price in a more decentralized fashion.

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[8] An important test case has been a proposal by PJM to recover costs for high-voltage investments through socialized cost recovery, via "postage-stamp" charge collected pro-rata from all regions of the PJM interconnection. A decision by Seventh Circuit U.S. Court of Appeals determined that PJM and FERC did not satisfactorily demonstrate that a postage-stamp rates meet the just and reasonable standard (*Illinois Commerce Commission, et al. v. FERC*, Nos. 08-1306, et al, (7th Cir. (Aug. 6, 2009)).

One result of a large-scale transmission project, therefore is to raise sale prices for all market participants in exporting regions and lower them for all participants in purchasing regions. In the jargon of economists or policy-makers, the effect of a price change on pre-existing production is not an efficiency gain, it is simply a transfer of revenues from buyers to sellers - or vice-versa. The efficiency gains arise from changes in production or consumption, but these incremental changes are usually small compared to the pre-existing quantities. Because these are not reductions in costs or increases in efficiency per-se, most transmission planning processes do not even consider transfers. However, they can be an order of magnitude larger than the underlying physical costs or benefits of a given project.

Whenever there are large transfers at stake, there can be large winners and losers to a given project. Sellers in exporting regions benefit from increased access to new markets, but buyers in those regions no longer enjoy the supply from relatively low-cost resources that are ``trapped" in a relatively local market. The opposite applies to importing regions. Finally, when congestion is relieved or eliminated, those entities earning congestion payments on those lines experience a large reduction in revenues. Because of this, the stakes involved from large scale projects can go far beyond the question of who pays for the steel, engineering services, and rights-of-way for a new line. The magnitudes of such effects are illustrated in Awad, et al., [85] in their 2006 study of an upgrade of Path 26, a major interface between northern and southern California. Table 6 illustrates their estimated 2013 impacts of a Path 26 upgrade, assuming that all actors in the market were perfectly competitive.

Table 6: Decomposition of benefits of path 26 expansion - perfect competition

Perspective	Consumer Benefit (Mill.$)	Producer Benefit (Mill.$)	Trans. Owner Benefit (Mill.$)	Total Benefit (Mill.$)
WECC wide	1.6	1.0	-2.1	0.5
CAISO Ratepayer	-0.8	1.0	-0.8	-0.6

The transfers and benefits listed in Table 6 assume a perfectly competitive market. In restructured markets, transmission can play an important role in increasing competition, and more subtly, reducing reliance on relatively heavy-handed local market power mitigation by ISOs. Importantly, these benefits may not be highly correlated with the actual ex-post usage of facilities since the *threat* of increased competition can be enough to induce behavior that prevents the need for increased imports. A simple model developed by Borenstein, Bushnell, and Stoft [86] illustrates this point. Consider two identical markets each served by monopoly suppliers. If these markets are connected by a large transmission line, the two markets would be effectively merged and prices in both markets would fall from monopoly to duopoly levels. However, because both markets were identical and symmetric, this price reduction would arise despite the fact that there would be no flow on the line connecting the two, formerly monopoly, regions.

In practice, this pro-competitive effect can be substantial but extremely hard to quantify ex-ante. The California ISO's TEAM methodology described in [85] applies a specific oligopoly model, of which there is a myriad to choose from. As seen in Table 7, the effects of potential market power dramatically increases the implied transfers of the Path 26 expansion.

Table 7: Decomposition of benefits of path 26 expansion: imperfect competition

Perspective	Consumer Benefit (Mill.$)	Producer Benefit (Mill.$)	Trans. Owner Benefit (Mill.$)	Total Benefit (Mill.$)
WECC wide	34.4	-25.8	-6.6	2.0
CAISO Ratepayer	11.1	-4.0	-0.9	6.2

Both of the above tables provide excellent examples of two large economic issues confronting inter-regional transmission projects. First, as evidenced by the difference across the rows of these tables, the impacts on consumers, transmission owners, and on "society" depends upon *which* consumers, transmission owners, etc., are considered. In Table 6, the large winners from this project are consumers located outside of California, in part because relaxing this California constraint allows for more robust trade throughout the WECC region. Consumers in California, however, benefitted from this constraint keeping western flows "inside" the CAISO during some constraint periods. One contentious aspect of the CAISO planning process at the time was the attempt to draw boundaries around whose benefits should count for California decision making. Second, as one compares benefits across columns, it becomes clear how much the "benefits" to one party come at the expense of another.

These factors illustrate both the challenges of and need for a regional, or even national perspective in transmission planning. There are instances where projects produce only local benefits at the expense of other participants outside the region making a decision. In other cases, a project may produce an increase in benefits as a whole, but still constitute a negative impact for some particular group or region that may have veto power over a projects approval.

4.5 Uncertainty in policy

One of the most significant uncertainties faced by planners has been the extent to which government would create policy to influence the relative costs and benefits of different planning alternatives. It is commonly argued that there is need to creating certainty in this arena by creating long-term policy that is stable and consistent, particularly in regards to subsidization of various technologies and fuels, renewable portfolio standards, and environmental requirements including implementation of economic penalties for CO_2 emissions through taxation or a cap and trade system. On the other hand, many states have renewable portfolio or electricity standards or goals that effectively drive policy on renewables and CO_2, notwithstanding the EPA rules (i.e., the Cross-State Air Pollution Rules, or CSAPR) which seem destined to have serious impacts on existing coal and gas-fired generation. In terms of transmission, it may be best to act based on these certainties.

There is a cost to the do-nothing option as well, and it also has the unintended consequence of limiting future options because of the long lead-time for transmission which tends to constrain supply options and alternatives for future plans. There may be need to identify plans and move them forward, accepting that plans need to evolve as key factors become known.

4.6 Difficulty in obtaining right-of-way

It has become increasingly difficult over the past several decades to obtain right-of-way (ROW) for electric transmission usage. This difficulty may become even more severe if a portion of the public perceives such transmission as being merely “pass-through,” i.e., both the generation and the demand served by the transmission are located in states which are remote from the line. It was mentioned in Section 2.3.4.4 that underground transmission, although more expensive than overhead, might reduce the public resistance to transmission siting. In addition, it is possible that public resistance may be decreased if the transmission is perceived to facilitate renewable generation. Also, there may be benefits to considering models for compensating landowners alternative to the traditional one-time payment. Finally, ROW considerations should include opportunities brought about by aging infrastructure and the need to replace or upgrade existing EHV transmission facilities. Nonetheless, the level of public resistance to provision of right-of-way for a national transmission overlay poses an uncertain but likely significant impediment.

4.7 Future scenarios less dependent on transmission

We have made the case in Section 3 those future scenarios having a high level of bulk renewable electric energy resources will benefit from investment in high-capacity transmission, since the lowest-cost renewables are location-constrained and can only be moved by transmission. Yet, there are at least two other future scenarios for which a national transmission overlay may be less beneficial and perhaps even detrimental in terms of minimizing total investment and production costs. These are described in the following two subsections.

Other attributes important to the future scenarios are load growth and the retirement rate for existing plants. However, unless load growth is negative and/or generation is never retired, these attributes mainly affect the timing of building interregional transmission; they affect much less the extent to which it is attractive to do so. (The analysis of Section 3 covers 40 years, so that the aggregate results presented are unlikely to be significantly affected by changes in load growth and/or retirement rates.) On the other hand, either high DG penetration or high non-renewable penetration have potential to qualitatively change the benefits of a national transmission overlay and are therefore further discussed in the following two subsections.

4.7.1 High DG and/or storage penetration

IEEE Standard 1547 [87] defines distributed resources (DR) as “sources of electric power that are not directly connected to a bulk power transmission system,” which includes both storage facilities and DG. Distributed generation (DG), a subset of DR, is defined as “electric generation facilities connected to an Area electric power system through a point of common coupling," where an "Area electric power system" is essentially a distribution system. A 2007 DOE report [88] defines DG as "electric generation that feeds into the distribution grid, rather than the bulk transmission grid, whether on the utility side of the meter, or on the customer side." A 2004 California Energy Commission report [89] defines DG as "electricity production that is on-site or close to the load center and is interconnected to the utility distribution system."

As stated in [88], DG typically includes at least three types of generation facilities:

- "On-site DG: includes photovoltaic solar arrays, micro-turbines, and fuel cells, as well as combined heat and power (CHP), which are installed on-site, and owned and operated by customers themselves to reduce energy costs, boost on-site power reliability, and improve power quality.
- Emergency power units: are installed, owned, and operated by customers themselves in the event of emergency power loss or outages. These units are normally diesel generation units that operate for a small number of hours per year, and have access to fuel supplies that are meant to last hours, not days.
- District energy systems: are installed, owned, and operated by third parties, utility companies, or customers. These systems are often used in municipal areas or on college campuses. They provide electricity and thermal energy (heat/hot water) to groups of closely located buildings."

DG has the essential features of being connected (a) to the distribution system and (b) close to the load. As a result, DG generally serves the load to which it is closely connected. Energy produced by DG is generally not intended to be moved via transmission because it would incur losses of the distribution system to which the DG is connected, the distribution to transmission transformer, and the transmission system, significantly more than the losses incurred by for transmission-connected generation. Therefore, in a high-DG future scenario, transmission becomes less beneficial.

There are three features to assess when considering the relative benefits of centralized versus distributed generation: cost, resilience, and sustainability. In regards to cost, the issue is whether the economies of scale which have heretofore driven the preference towards large, centralized power stations, have now changed. Regarding resilience, the issue is whether distributing the generation resource from a few very large units to many smaller units enhances the ability to avoid large-scale events and the ability to continue performing well when such events do occur.

It is strongly argued in [88, Chapter 7] that DG significantly enhances resilience of the electric infrastructure, and there is clearly a basis for this line of reasoning. Yet there is a another kind of resilience offered by a high-transmission capacity future scenario in that it facilitates the nation's ability to shift from a generation resource in one region to a generation resource in another region. Although this has always been recognized from an operational perspective, it is also true from a long-term infrastructure investment perspective. This can be important when the "events" of concern have sustained, long-term consequences.

In regards to sustainability, a key question is what technologies would dominate in a high DG future scenario? If microturbines (which use natural gas) and diesel turbines dominate, it is not clear that this would necessarily lead to a very sustainable future, as would be the case if photovoltaics and biomass-based CHP dominate. It is also possible that large-scale deployment of storage could offset the need for additional transmission investment.

The above considerations must receive more attention before firming conclusions regarding a national transmission overlay.

4.7.2 High non-renewable penetration

Another future scenario which may also diminish the value of a national transmission overlay is if nuclear, coal, and gas dominate the generation portfolio, under the assumption that the investment and operational cost of these technologies are not very sensitive to location. This assumption holds for these technologies only insofar that the transportation cost for the raw fuel (uranium, coal, and gas) is much less than the cost of the fuel itself, which is generally the case. Under this assumption, then, it is possible to locate such generation almost anywhere without changing the investment or operational cost. Therefore the main driver of generation location is the need to minimize transmission investment and losses, resulting in generation locating close to the demand which it serves. Therefore, less transmission gets built in this scenario.

4.8 Dependence on technology improvement

The likelihood that future scenarios occur which would benefit from a national transmission overlay versus the likelihood that future scenarios occur that would not depends to a significant degree on the how investment and production costs of each technology changes over time. This feature has been captured by the advancement (maturation) rates and the "learning by doing" rates of technology [90, 91]. The maturation rates depend heavily on the research efforts that are made to enhance the technology. A large change in the maturation rates of one or more key technologies could have dramatic effects on development of the U.S. generation portfolio.

4.9 Lack of long-term congestion hedging products

A major impediment for securing long distance imports which is inhibiting wind development today is the lack of congestion hedging products to support long-term power purchase agreements (PPAs). Some load-serving entities (LSEs) embrace a business model which depends on securing 10-20 year PPAs, a business model which wind developers find attractive, but long-term congestion hedges are not typically available. The problem may be that interregional transfer capability is unavailable; it may instead or also be that local transmission in the host balancing authority is congested. Therefore, the benefits of interregional transmission capacity may be dramatically diminished if congestion cost exposure in the local transmission system cannot be hedged. This motivates the need to design transmission collection networks in resource-rich regions to ensure adequate delivery from resources to the high-capacity overlay.

4.10 Resource collection networks

High penetrations of renewables cannot be moved from resource to load with the conventional low-voltage collection network at the plant level (often 34.5 kV) and high-capacity transmission only. There is also need for an intermediate stage of what we might call in the case of wind energy a multi-farm collection network. This would generally be at an intermediate transmission voltage level of 69 kV to 345 kV and would collect the energy produced from multiple plants for transmission along a backbone system (the national transmission overlay). This conceptualization, as illustrated in Figure 23, provides for a 3-level network hierarchy:

<u>Level 1</u>, turbine collection network, typically at 34.5kV
<u>Level 2</u>, multi-farm collection network, typically at 69-345kV
<u>Level 3</u>, backbone transmission, 345kV-765kV, or HVDC.

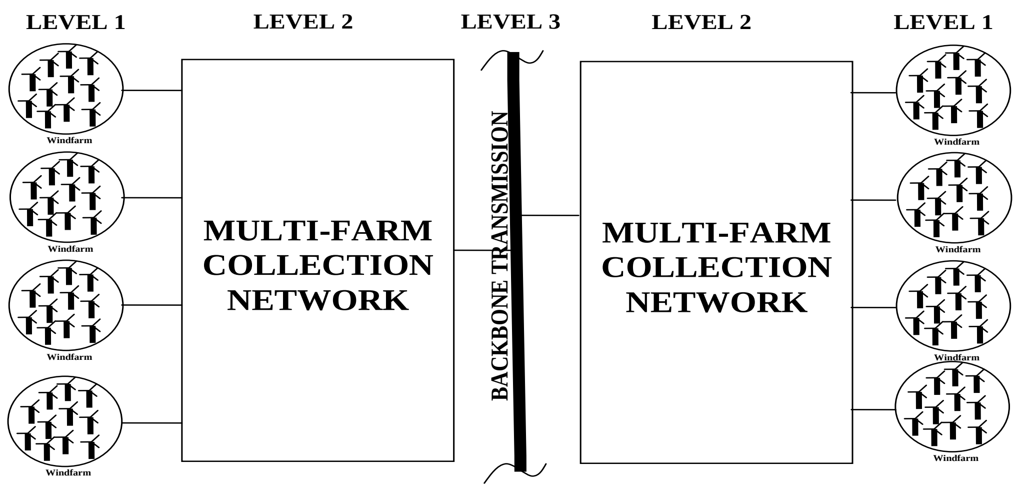

Figure 23: Conceptualization of three-level transmission hierarchy

To date, most renewable resources have been interconnected to the transmission system on a case-by-case basis. In designing a national transmission overlay, it will be important to also develop network topologies at Level 2 which balance low investment costs with low losses and high reliability for high renewable penetrations.

4.11 Selective interregional transmission

The orientation of this document is towards a national transmission overlay which, as defined in the introduction, "is a high capacity, multi-regional transmission grid, potentially spanning all three interconnections, designed as a single integrated system to provide economic and environmental benefits to the nation." This definition is intentionally defined to embrace a system-oriented national view, as opposed to an approach whereby selected interregional transmission investments are developed one-by-one, in order to avoid the piecemeal transmission development and fully capture the benefits of designing the overlay as a "single integrated system." Yet, there exists graduations between these two approaches where two or more regions within the nation may work together to design a multi-regional overlay that stops short of being national. Indeed, we refer to this as the "interregional collaborative approach" in the three possible "paths forward" described in Section 5.

5 Possible paths forward

We have analyzed the potential benefits of coordinated investment in large-scale, inter-regional transmission projects, and discussed the many drawbacks and barriers to such coordinated investment. We now turn to a very exploratory discussion about the possible ways forward for achieving such a set of investments. We should again emphasize the key assumptions we have made in developing estimates of the benefits of such a network. These include a national commitment to renewable energy on a large scale, either through direct mechanisms such as renewable portfolio standards or indirectly through climate policy.

We also have focused on the "national" aspects of a national transmission backbone. In so doing we have made the assumption that regional planning will proceed in a fashion that is able to take proper advantage of the inter-regional investments.

With these caveats in mind, we now explore three very broad frameworks for investing in transportation networks, and discuss their relative "fit" to the task of building a national transmission backbone. These frameworks are, a.) market driven investment, b.) federal driven investment, c.) coordinated regional partnerships.

5.1 Market driven investment

There are at least two reasons to discuss market driven investment in this context. The first is that many national transportation and distribution networks, including natural gas, petroleum products, rail transportation, and telecommunications today feature substantial market driven investment. It is true that in many of these industries regulation plays an important role, but for the most part large capital investments are made without a guarantee of recovery of those costs under rate-of-return regulation. The second is that the relatively rare instances of merchant transmission investment (or proposals) in this country and others tend to arise in the context of connections (usually DC) between regions that also experience large cost or price differences. This may be further evidence of the fact that the current regulated regional planning processes are far more effective at building intra-regional projects than inter-regional projects.

The FERC and various ISOs have spent considerable time developing frameworks that could accommodate merchant transmission investment, which we will define as investment made without a rate-based cost recovery. The general framework first provides a review of proposed projects that needs to meet a lower bar for approval than a rate-based project. The review involves establishing that new projects do not create new congestion or reliability concerns in other parts of the network, but does not require an economic or reliability-based determination of need. Upon construction the owners of the facility, in addition to enjoying the benefits of reduced congestion that are shared by everyone else in the network, may select an allocation of financial transmission rights (FTRs). The FTRs provide both near-term revenues and a longer-term hedge against future entrants who may cause the new interface to become congested at some later date.

Merchant transmission is an accepted term used in reference to the situation where an entity constructs, owns, and operates electric transmission within the service area of another organization. As indicated in [92], "…merchant transmission providers are distinguished from other transmission providers by the fact that they do not serve captive retail customers and assume all market risk of a transmission project." Furthermore, "Unlike traditional public utilities, merchant transmission providers assume all of a project's market risk and have no captive pool from which to recoup project costs." And more recently, "…merchant transmission projects are defined as those for which the costs of constructing the proposed transmission facilities will be recovered through negotiated rates instead of cost-based rates" [93].

In 2009, FERC made a significant change in its policies associated with merchant transmission, via its ruling on the Chinook and Zephyr transmission projects, which was reinforced in March 2010 via its ruling on the Tres Amigas project. The Chinook and Zephyr argument was motivated by difficulties in early financing of their respective projects, resulting in the proposal to utilize an "anchor customer" (a large wind developer) to share development costs [92], to whom they would subscribe 50% of the transmission rights. The remaining 50% would then be auctioned in an open season. The argument was that the 50% level balances the need for the project to be economically viable while still providing customers an opportunity to bid for capacity in the open season [92]. In accepting this argument, the FERC established criteria referred to as the "four factor test." These factors are well described in [92], from which the following are paraphrased:

1. <u>Justness and reasonableness of rates</u>:
    a. Whether the merchant transmission owner assumed full market risk and is not building within the region of its own or affiliate's transmission system (this assures there are no captive customers to subsidize the project);
    b. Whether the merchant transmission developer
        i. already owns transmission facilities in the region where the project is to be located and what alternatives customers have;
        ii. is capable of erecting barriers to competitors' entry;
        iii. would have any incentive to withhold capacity.
    c. Whether the rates are commensurate with rates of alternative transmission based on cost-of-service and/or with the difference in energy prices at the line's terminals.

2. <u>Potential for undue discrimination</u>:
    a. The merchant transmission provider's open season, which must be fair, transparent and non-discriminatory, with post-open season reports filed with FERC;
    b. Its OATT commitments (or, commitment to turn operational control over to the RTO/ISO, assuming the project is within an RTO/ISO area).

3. <u>Potential for undue preference, including affiliate preference</u>: This may occur when the merchant transmission owner is affiliated with anchor customer, an open season participant, and/or customers who take service on the merchant transmission facility.

4. Regional reliability and operational efficiency requirements: A merchant transmission owner must comply with NERC criteria, both planning and operating criteria, just as any other transmission owner must and should participate in regional planning processes. Merchant transmission owners may cede some of these responsibilities to the RTO.

While many of the procedural questions concerning market driven investment have been resolved, merchant transmission investment remains a much more challenging undertaking than market driven investment in other industries. These problems have been discussed in detail elsewhere [94, 95], but we summarize some of the issues here.

First, the large economies of scale associated with investment ensure that most new projects, particularly the kind of large inter-regional projects we are discussing here, create large changes to existing locational prices. Therefore current price differences can be a bad indicator of the potential congestion rents earned by a new project as the project itself will likely greatly reduce congestion. This fact lies at the heart of the well-known view that congestion rents alone are insufficient to fund investment in transmission [96]. Since the value of ex post congestion is not sufficient to fund investment, the value instead has to come from the benefits the project bestows on market participants. For example, buyers of power reap potentially large benefits from expansion of import capabilities into their regions. However, under open-access regimes these benefits are shared by all buyers, not just those that fund the transmission line. (Although HVDC lines require special treatment within market clearing systems [38, 39], they also provide this beneficial effect on buyers). Therefore participant funds must be concentrated, either through the concentration of the market participants (e.g. buyers, generators into large firms) or through cooperative agreements between participants. Consolidation of firms to the scales required would threaten the competitiveness of restructured markets, while cooperative agreements can be very difficult to forge, given the incentive to free ride on the investments of other parties.

These factors have influenced the types of merchant projects that have been proposed. These tend to be relatively smaller scale direct connections between markets that feature large and persistent price differences. These characterize the small subset of projects for which congestion revenues alone may prove sufficient for a decent return.

It is possible that a strong Federal mandate for renewable energy could spur larger differentials in the prices of either energy or renewable energy credits between regions. This would in turn increase interest in interregional trade and possible investment. However, the generation investment necessary to create such large price differentials could quite possibly be held up in anticipation of the future of transmission investment. Relying primarily on market incentives for both generation and transmission investment in this context would increase the risk of both, quite possibly leading to the construction of neither.

5.2 Federal initiative

At the opposite extreme in terms of philosophical approaches – if not in plausibility – is a top-down planning and financing process pushed from the Federal level. Many invoke the federal interstate system as an example for such a federal transmission network, and it is interesting to compare and contrast the two situations. Reference [97] provides some initial perspective towards this end[9].

> "One of Eisenhower's top priorities upon becoming President was to secure legislation for an interstate highway system…. On June 26, 1956, both the Senate and the House gave final approval to the compromise version and sent it to Eisenhower….There, he signed the Federal-Aid Highway Act of 1956 privately, without ceremony, on June 29, 1956….The interstate system now comprises 46,876 miles. The completion of the system, at a cost of $129 billion, was a cooperative federal-state undertaking. Each state transportation department managed its own program for location, design, right-of-way acquisition, and construction. The states also were responsible for the ownership and maintenance of the system, and in 1981, they began receiving federal funds for maintenance….Congress provided revenues from the federal gasoline tax to provide 90 percent of the cost of the construction of the interstates with the states picking up the remaining 10 percent. The technical standards for the highways were highly regulated—lanes had to be 12 feet wide and shoulders 10 feet wide, the bridges had to have 14 feet of clearance, grades had to be less than 30 percent, and the highway had to be designed for travel at 70 miles an hour. The most notable attribute of the system is the limited access concept. The 42,000-mile system only has approximately 16,000 interchanges….While created in part to help defend the nation in the event of an emergency, the interstates, with limited access and many lanes, have also spurred and speeded the development of commerce throughout the country and abroad. Trucks move quickly from one region to another, transporting everything from durable goods and mail to fresh produce and the latest fashions….And they have increased the mobility of all Americans, allowing them to move out of the cities and establish homes in a growing suburbia even farther from their workplaces and to travel quickly from one region to another for vacation and business."

Although the above description proclaims the merits of the interstate highway system, it is interesting to note that the interstate program was not without its critics, many of whom link it to the demise of local and regional commuter rail. While there has not been much

[9] The analogy to the interstate highway system is provided to illustrate one procedural means of building infrastructure which has national benefits and which geographically spans the nation. However, there are at least two important differences which inhibit carrying the analogy too far. Firsts, whereas the interstate highway system offers a service (decreasing travel time) which is inherent to the highway itself, the service provided by the electric transmission system (access to cheaper, more reliable, and/or cleaner energy) depends on the generation to which it provides access, an additional infrastructure. This difference results in a higher degree of difficulty in assessing and maintaining the value of transmission, relative to the value of interstate highways. Second, interstate highways tend to facilitate economic development throughout its path. High capacity transmission, particularly if it is built using HVDC, may not benefit so-called "pass-through" regions as much as those regions at the terminals.

concrete discussion about how such a process would work in electricity, we can sketch out the steps it would have to take.

First there would need to be a process for identifying projects for investment. There are several models for this, including the current process for distributing capital from the Federal highway trust fund raised by the national gasoline tax. This approach is highly politicized and, through the political process, results in a “sharing of the wealth” of investment across most districts of the country. While allowing for a sense of more equitable distribution, this process is not well positioned to prioritize the set of projects that would led to the largest aggregate social benefit if such projects involve disproportionate spending in a given region. This and other criticisms have led to calls for restructuring the allocation process and creation of new mechanisms such as a national infrastructure bank.

A more centralized approached to identifying projects would be to build upon the existing studies periodically performed by the DOE for the purposes of identifying corridors of national interest and measuring and highlighting bottlenecks in the national network. This process is already somewhat politicized and would no doubt become much more so if billions of dollars of investment were dependent upon its results. However, there is enough precedence and expertise within Federal agencies to form the backbone of an expanded, integrated, study process. The process would attempt to identify the set of infrastructure investments that would help achieve a stated national goal (e.g. 20% of energy from renewable sources, or 15% reduction in CO_2 emissions, increased reliability, and lower average wholesale prices) at minimum costs. While it seems almost certain that final project decisions would be subject to some amount of political negotiation, these negotiations would at least be framed by the results of the study process.

Second, a method for cost allocation would have to be determined. In keeping with the theme of centralized, top-down policy with this option, a straightforward but no doubt controversial mechanism would be to establish a flat Federal grid charge, along the lines of grid management charges collected today by ISOs, on each kWhr consumed to generate an investment pool. This would constitute complete socialization of the investment costs, with no explicit attempt to measure and allocate costs associated with the benefits of the investments.

There are many barriers to such an approach. If revenues were raised under the auspices of the FERC, areas not regulated by FERC such as ERCOT and the federal Power Marketing Administrations would likely claim to be exempt. A new framework for collecting such a fee on a national basis would be necessary. Second, there is still great political and possibly legal resistance to completely socialized cost. In fact, a socialized cost mechanism, akin to the Federal gas tax, could create more pressure for the spending of the funds to reflect the sources of the contributions thereby making it more difficult to concentrate investments on a small number of large inter-regional projects, rather than on the kind of more regional projects funded in transportation.

The alternative would be to attempt to measure benefits on a regional basis and adjust the grid charges dedicated to transmission investment accordingly. In order to do this, there will have to be decisions made about what kinds of benefits would be counted and which ones would not. Reliability benefits should be monetized in some way to make them comparable to economic benefits. However, some reliability benefits will be local, while many others are shared in ways that can be difficult to quantify. National environmental goals could be thought of as benefitting everyone, but the local economic benefits of such goals will not be distributed evenly. Increased high-voltage capacity could lower production costs everywhere, but market prices will also reflect the adjustment of increased imports or exports to different regions. Thus prices could go up in some regions as a result of increased exports. Last, there could be regions, such as those along the corridors themselves, who view their own benefit as negative. Grid charges that vary by region could allow for compensation of such areas.

Even if reasonable agreement can be reached on the definition, forecasting those benefits will be a challenging task. Because of the long-lived nature of these assets, they continue to generate value more than 20 or 30 years after construction. Forecasting of economic and technological conditions even ten years out is imprecise to say the least. Another controversial aspect is whether to consider the construction costs of generation assets in a benefits calculation. These costs will not need to be recovered through a grid charge, but the generation investment decisions are certainly endogenous to the transmission decision. If one assumes that 10 GW of wind will appear in the plains states at no cost, then the building of transmission there looks very economic. However, explicit consideration of generation and transmission costs takes the planners down a road of least-cost vertical planning that was largely abandoned in restructured regions.

A third element of a Federal system will have to be siting. This would perhaps be the most challenging step of all, as currently almost all siting power, with the exception of federal lands, rests with state and local jurisdictions. An attempt by a Federal process to impose large high-voltage structures on local jurisdictions will be problematic, particularly if there is significant local hostility to the process. Section 1221 of the Energy Policy Act of 2005 (which added Section 216 to the Federal Power Act of 1935) [98] gave FERC authority to site interstate transmission lines in a designated national interest corridor if a state fails to act on or cannot approve a transmission siting application, effectively providing FERC the ability to preempt a state's decision not to issue a transmission construction permit. Yet, there have been rulings from the courts which challenged procedures and criteria for identifying national interest corridors [99] and FERC's authority over siting permits previously denied by a state [100]. Both of these rulings have diminished FERC's authority to site transmission, essentially maintaining this authority with the states. In addition, FERC has received only one transmission siting application since 2005, and that one was subsequently withdrawn [101], and so FERC has not yet utilized this authority.

On the other hand, FERC's recent Order 1000 [93, 102] has (among other things) eliminated rights of first refusal of incumbent transmission providers to construct transmission facilities, an action which may increase the number of siting applications from merchant transmission providers. Because such providers may not meet the definition of "public utilities," state public utility commissions may not have authority over their proposed transmission projects, effectively ceding that authority to FERC [103]. Nonetheless, it seems at this point that absent further legislation granting Federal authorities with stronger siting authority, a collaborative process may be inevitable for making progress on actual construction.

5.3 Interregional coordination

A third approach would be one that encourages an expansion of the current local and regional planning processes toward a focus on large interregional projects. This approach may be less effective at building a national network but much more likely to be adopted. Such collaboration would also be likely to lead to policy developments which would facilitate and rationalize high-capacity interregional transmission investment, including

- A process to standardize definitions and benefit calculations of reliability-based investments.
- A formulaic mechanism for distributing the costs of inter-regional projects, including potential compensation for "through-way" regions.
- Consistent standards and policies for the planning for, and cost recovery of, transmission investments driven by the interconnection of new generation.
- Replace local piece-meal renewable initiatives with a regional or super-regional standard that accommodates the trade of renewable energy and renewable energy credits.

It is certain that such a collaborative process would necessarily need participation from industry, state governments, and advocacy groups. There are three recent indications that such coordination is growing. The first is, as already mentioned in the introductory Section 1, Title IV of the 2009 American Recovery and Reinvestment Act funded efforts to initiate and strengthen interconnection-wide planning in each of the three U.S. interconnections, with the awardees producing long-term resource and transmission planning for the Eastern Interconnection [3, 4], the West [5], and ERCOT [6]. The interconnection-wide planning efforts are relatively new for the Eastern Interconnection, and although interconnection-wide planning is more familiar in the West and ERCOT, these funds are strengthening those processes.

The second indication that coordinated planning is growing is activities of two regional governors associations. The Midwest Governors Association has participation from Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Ohio, South Dakota, and Wisconsin, and is co-sponsored by the American Wind Energy Association (AWEA), MidAmerican Energy, ITC Transmission, Xcel Energy, and the Midwest ISO, and they indicate on their webpage that "The Midwest has made steady progress in planning for the transmission needs of the future. Midwestern governors have been actively engaged in this process to ensure collaboration and progress among the many regional stakeholders" [104]. The Western Governors' Association, with participation from 19 states, also has strong interest in promoting transmission as indicated by their participation in various transmission planning efforts among which is the DOE-sponsored interconnection-wide planning project [105] mentioned in the last paragraph.

The third indication that coordinated planning is growing is from the recent FERC Order 1000 in 2011 which requires transmission planning at the regional level and also that each pair of neighboring regions must coordinate to determine if more efficient or cost-effective solutions are available [93, 103]. It is important to note that FERC Order 1000 requirements regarding interregional planning should be considered as minimum, not absolute, requirements by adjacent regions if broader interregional planning makes sense, which can be expected in almost all circumstances.

Although the U.S. has never built a national interregional transmission grid, interregional transmission does exist today, although generally at relatively low capacities, as illustrated in Figure 7. But there are some isolated exceptions with relatively high capacity transmission interconnecting two regions. Some examples have already been mentioned in the introduction, e.g., the Pacific AC and DC Interties, and the Intermountain Power Project, and to these we should add the 765kV grid within the AEP area. Although AEP's 765kV grid was not exactly an interregional planning effort in the sense of separate companies or regions planning it, it was a region-wide effort across five subsidiary AEP companies. These transmission projects were all built based on a model having characteristics of interregional collaboration. To further develop the interregional coordination approach to developing a national transmission overlay, it would be prudent to study the processes and procedures that were implemented when these other transmission projects were built.

6 Conclusions

In this white paper, we described a number of essential elements necessary to the consideration of building a national transmission overlay. These include the locations of future generation and load centers, technologies likely to dominate future generation portfolios, and existing interregional transmission capacity and congested locations. These also include transmission technologies and attributes which characterize them including cost, accessibility, right-of-way requirements, reliability, required short-circuit ratios, controllability, and energy efficiency. We identified benefits to building a national transmission overlay as long-term cost savings, resilience of energy prices to large-scale events, emissions reduction, and the future flexibility of the energy system. We used investment planning software and data aggregated to the regional level characterizing today's U.S. electric system to illustrate the cost benefits for what we perceive to be "transmission-friendly" futures where generation is dominated by renewables. We have also identified a number of issues and concerns in regards to building a national transmission overlay, including the high influence of localized interests and the tendency of each state to focus on its own economic development, changes necessary to planning, the difficulty in allocating costs, market impacts of transmission investment resulting from transfer of surplus between market participants, uncertainty in policy, the difficulty of obtaining right-of-way, the potential of evolving scenarios which will be less dependent on transmission, dependence on technology improvement, lack of long-term congestion hedging products, the need for mid-level resource collection networks, and selective interregional transmission.

In the last chapter, we described three distinct paths that could be pursued to realize a national transmission overlay: market driven investment, federal initiative, and interregional coordination. There are elements of each of these three approaches ongoing today. The market-driven approach has appeared via several recent efforts towards building merchant transmission, and in several recent FERC rulings on such proposals. An initial movement towards the federal initiative approach can be observed in Section 1221 of the Energy Policy Act of 2005 giving some authority to FERC to site interstate transmission lines, although no transmission siting applications have yet to be approved as a result of this authority. Interregional coordination is ongoing via the DOE-funded interconnection-wide planning efforts, and these kinds of activities are receiving support from at least two governor's associations as well as the recent FERC Order 1000.

This white paper should not be perceived as either supporting or opposing development of a national transmission overlay but rather providing objective information to use in further considerations. This information indicates that a national transmission overlay has potential to offer significant net benefits to the nation, while the political, regulatory, and procedural difficulties associated with initiating it are formidable. We conclude that development of a national transmission overlay merits further attention through discussion and analysis regarding benefits, risks and impediments, and possible paths forward. This paper can serve as a reference that gathers the essential elements to facilitate continued dialogue on this topic and to frame possible paths by which it could be realized. The next step in the effort will be to convene a group of experts spanning various dimensions of the issues who would expand and refine the work reported here and who would provide recommendations on the extent to which a national transmission overlay should be further pursued.

Appendix A: Literature review

A.1 National or interconnection-wide transmission overlays

- Conceptual 765 kV interstate transportation system

American Electric Power (AEP), working at the request of, and in partnership with, the American Wind Energy Association (AWEA), develops a conceptual 765 kV interstate transportation system that encompasses major portions of the United States connecting areas of high wind resource potential with major load centers, as it is shown in Figure A1.

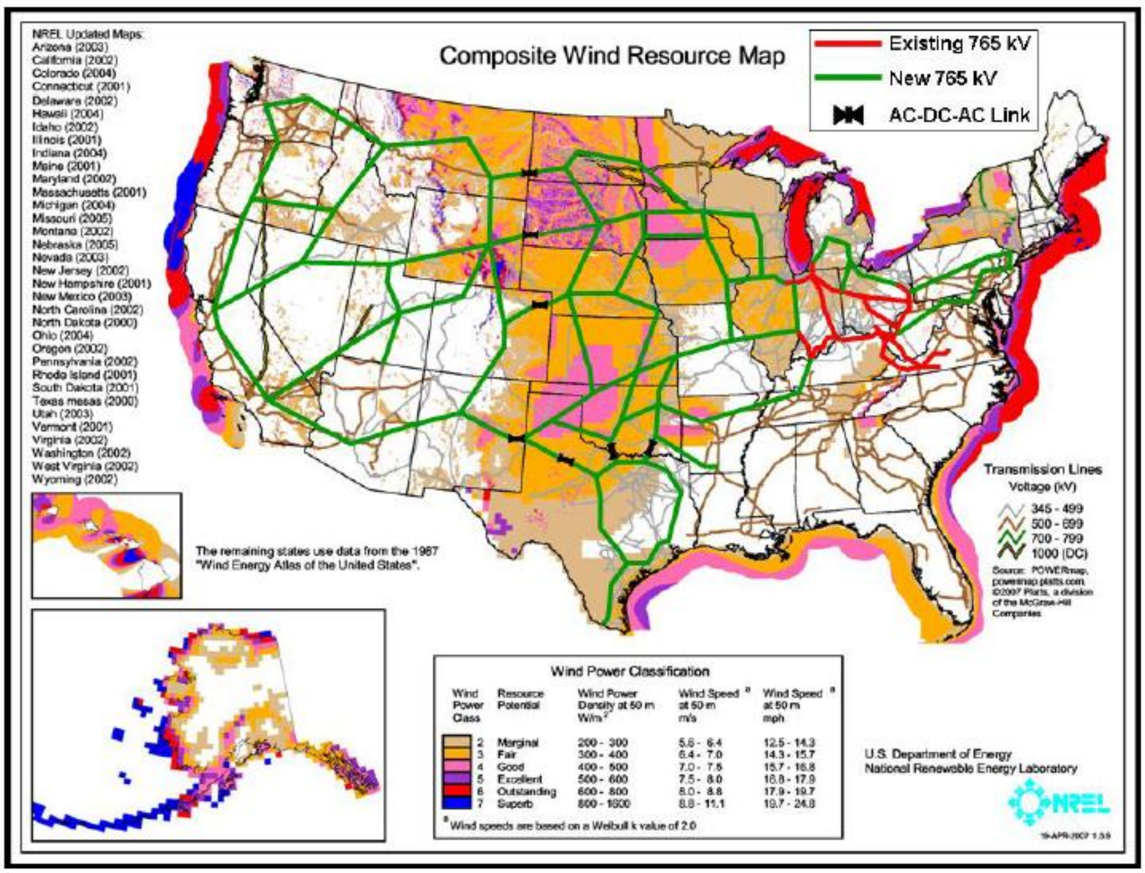

Figure A1: Conceptual 765 kV backbone system for wind resource integration

This proposal is a derivative effort associated with a joint study involving AWEA, U.S. Department of Energy (DOE), and National Renewable Energy Laboratory (NREL), which is committed to developing an implementation plan that would enable AWEA's proposal to provide up to 20% (approximately 350 GW) of the nation's electricity from wind energy.

The conceptual 765 kV overlay consists of approximately 19,000 miles of new transmission lines and a total capital investment of $60 billion (2007 dollars). It is expected that could provide enough capacity to connect up to 400 GW of generation.

Source:

“Interstate Transmission Vision for Wind Integration” Published by American Electric Power (AEP). March 2007. (Accessed: September 22, 2011) Available at: <http://www.energycentral.com/reference/whitepapers/102686/>

- Superconductor Electricity Pipelines

American Superconductor develops a theoretical interstate transportation system using Superconductor Electricity Pipelines. This alternative is proposed as a response to the challenges that could limit the use of high voltage overhead lines to move electricity from the renewable resource rich parts of the country to population centers. Figure A2 shows possible paths for a Superconductor Electricity Pipeline, and its potential discrete points of connection to the pipeline.

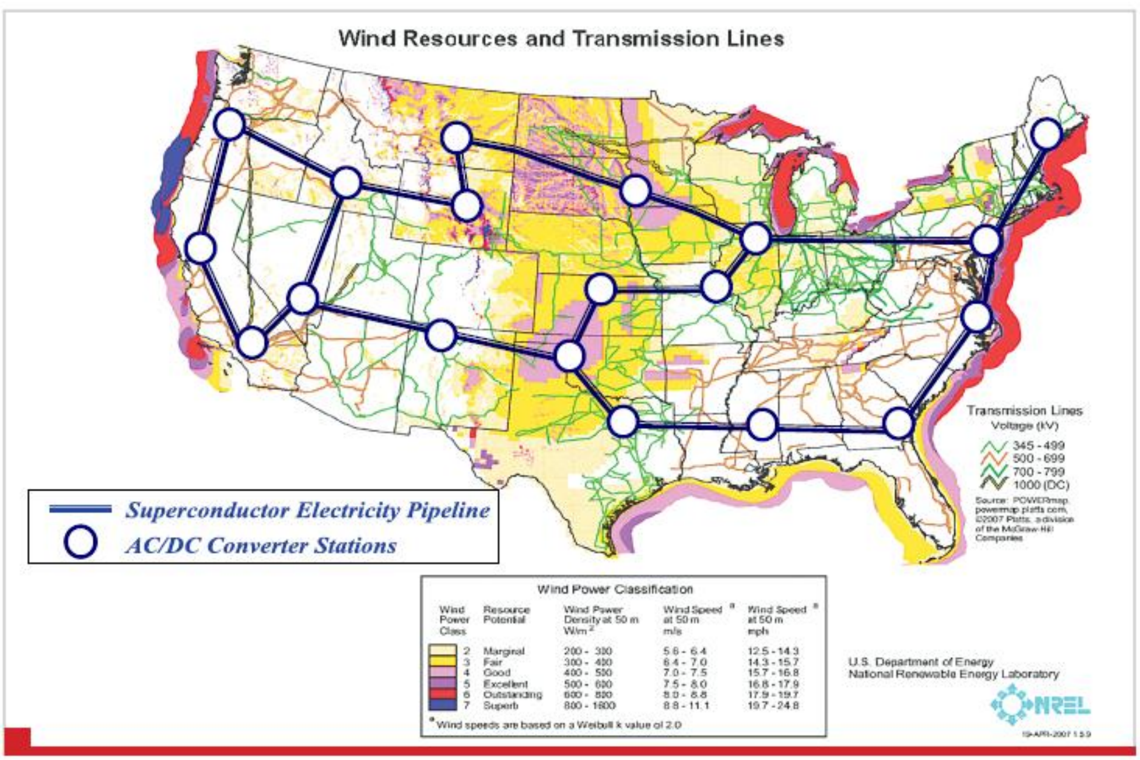

Figure A2: Potential superconductor electricity pipeline system to connect renewable power

This technology combines conventional underground pipeline construction techniques with two highly complementary electric power options: superconductor cables and multi-terminal (voltage-source converter-based) DC power transmission, resulting in a high-capacity electric transmission “pipeline” that could carry many GWs of power efficiently.

Finally it allow to improve aesthetics, reduce power losses, simplify cost allocation, and increase security compared with an EHV or HVDC transportation system, at a similar cost to overhead lines for long distances projects.

Source:

"Superconductor Electricity Pipelines - Carrying Renewable Electricity across the U.S.A. Out of sight and Out of Harm's Way - White Paper." American Superconductor, November 2009. Available at: <http://www.amsc.com/products/powerpipelines/index.html>

- Joint Coordinated System Plan 2008.

The Joint Coordinated System Plan 2008 Study developed and analyzed the costs and benefits of conceptual transmission overlays for two scenarios, to serve a total of 745,000 MW of coincident peak load in the Eastern Interconnection, except Florida, in 2024.

The Reference Scenario assumes that the existing laws and policies governing generation resource choices remain in place. Under this scenario there will be about 60,000 MW of new wind developed by 2024, along with 75,600 MW of additional base load steam generation, and would add 10,000 miles of new extra high voltage transmission at an assumed cost of approximately $50 billion (2024 dollars). The approximate locations for the new transmission are shown in Figure A3.

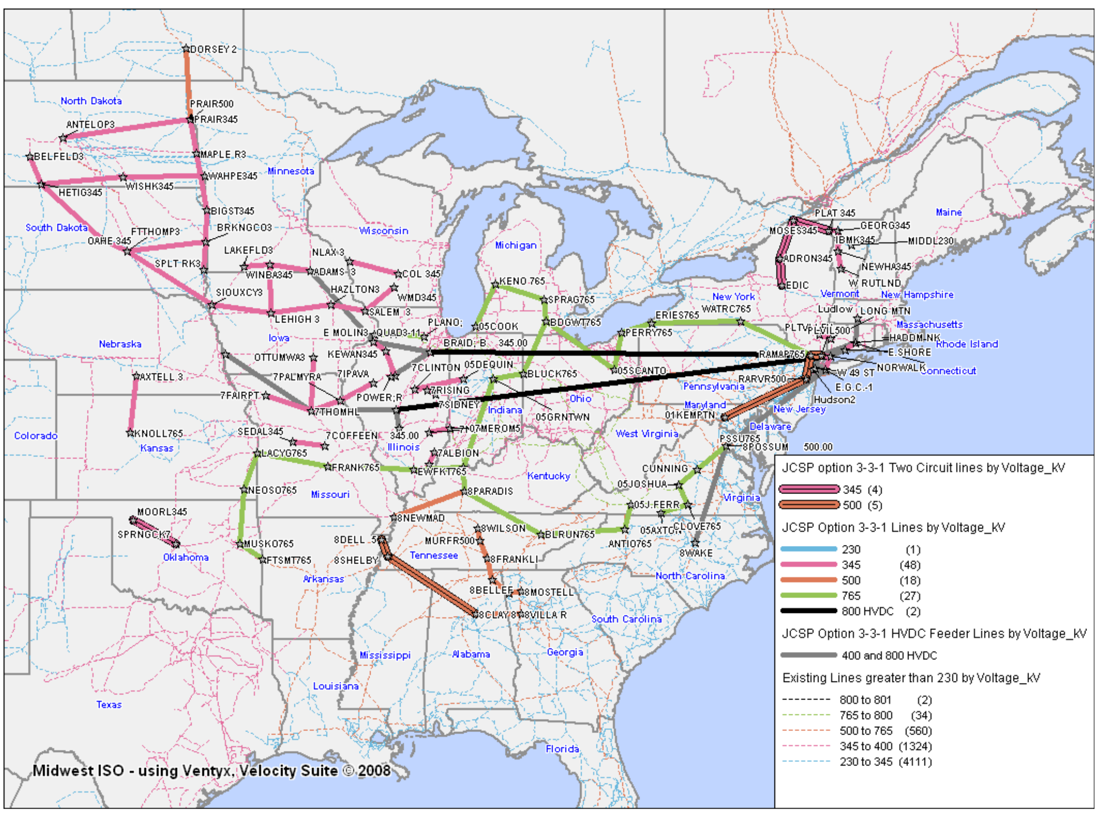

Figure A3: Reference scenario - conceptual transmission overlay

The second scenario (20% Wind Energy Scenario) assumes that the entire Eastern Interconnection will meet 20% of its energy needs using wind generation by 2024. This scenario assumes that 229,000 MW of new wind capacity will be built by the year 2024, with 36,000 MW of new base load steam generation, and would add 15,000 miles of new EHV transmission at an assumed cost of approximately $80 billion (2024 dollars). The approximate locations for the new transmission are shown in Figure A4.

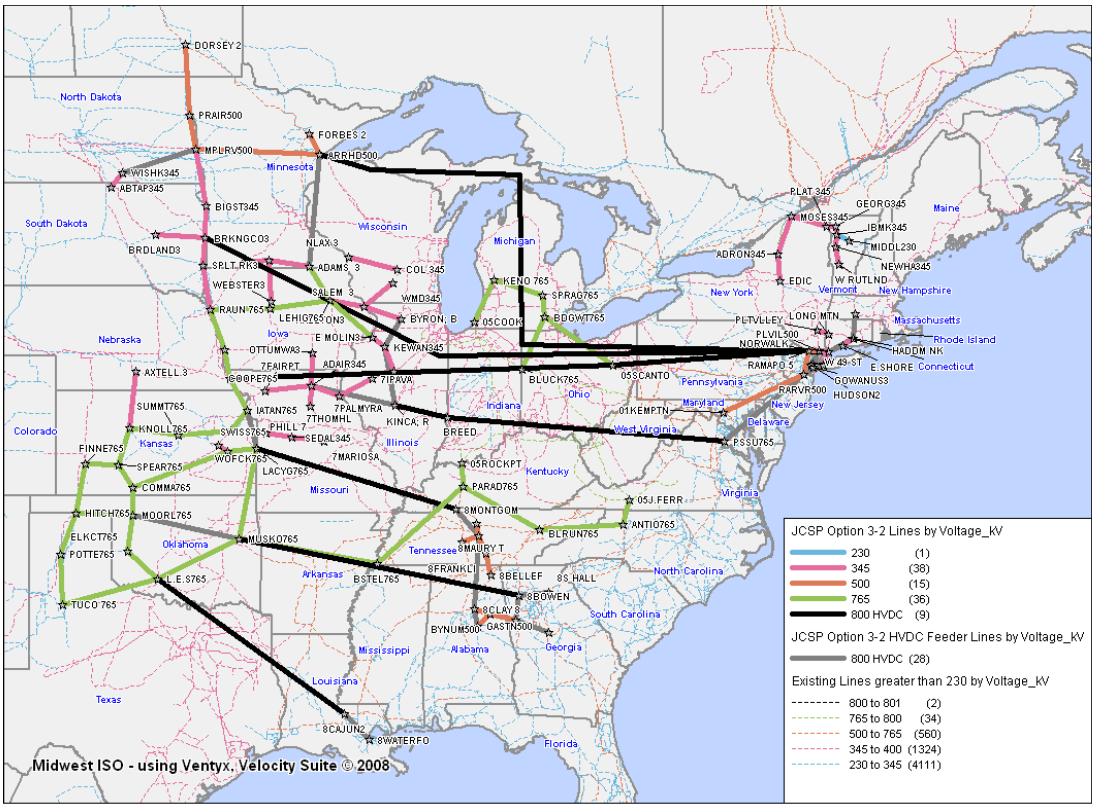

Figure A4: 20% wind energy scenario - conceptual transmission overlay

Source:

"Joint Coordinated System Plan 2008" A joint publication of most of the major transmission operators in the Eastern Interconnection, 2008 (Accessed: September 26, 2011). Available at: <https://www.midwestiso.org/Planning/Pages/StudyRepository.aspx>

- DOE - 20% Wind Energy by 2030 transmission requirements.

One of the main issues that DOE studied in the report "20% Wind Energy by 2030" were the transmission and grid integration requirements associated with a 20% Wind Scenario.

This study uses the NREL's Wind Deployment System (WinDS) model to determine distances from the point of production to the point of consumption, as well as the cost-effectiveness of building wind plants close to load or in remote locations and paying the transmission cost, finding that it would be cost-effective to build more than 12,000 miles of additional transmission, at a cost of approximately $20 billion (2008 dollars).

The transmission required for the 20% Wind Scenario can be seen in the red lines on the map in Figure A5. The existing transmission grid is illustrated by green lines.

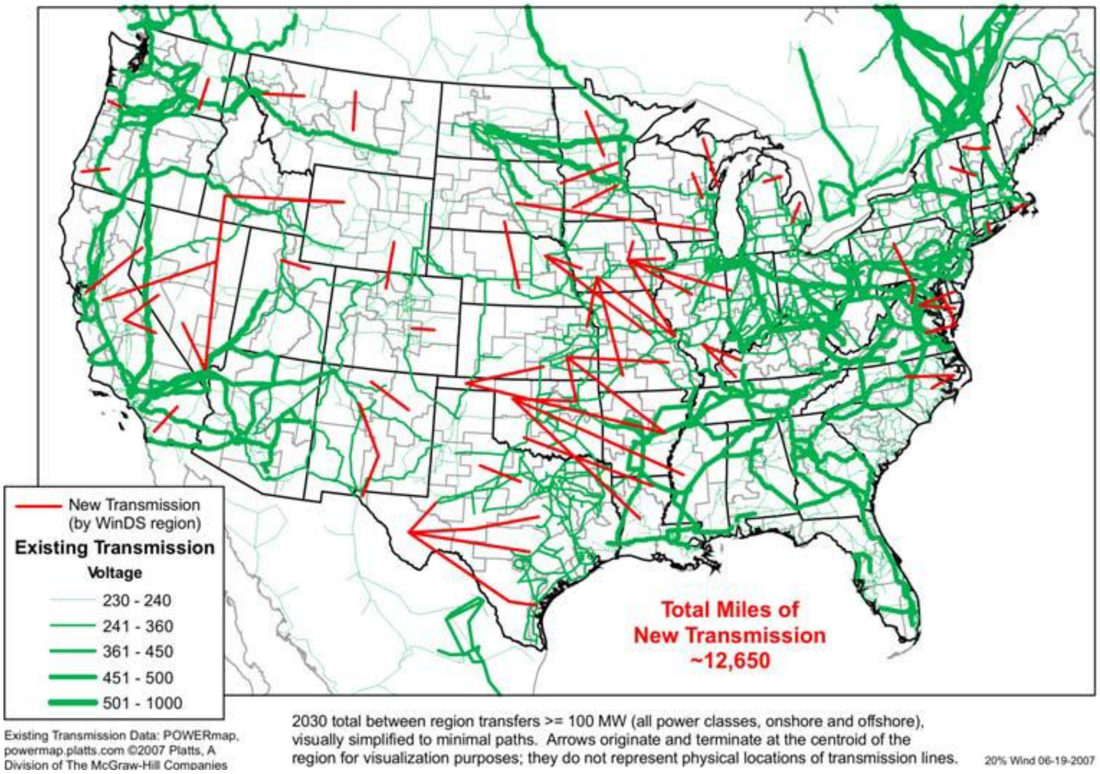

Figure A5: DOE's 20% wind energy scenario conceptual transmission overlay

Source:

"20% Wind Energy by 2030 - Increasing Wind Energy's Contribution to U.S. Electricity Supply" DOE/GO-102008-2567, July 2008 (Accessed: September 22, 2011). Available at: <http://www.nrel.gov/docs/fy08osti/41869.pdf>

- Eastern Wind Integration and Transmission Study

The Eastern Wind Integration and Transmission Study (EWITS) was commissioned by DOE through its National Renewable Energy Laboratory (NREL) to examine the operational impact of up to 20% to 30% wind energy penetration on the bulk power system of the U.S. Eastern Interconnection. Four scenarios were studied, three at 20% wind penetration and one at 30%. Of the three 20% scenarios, Scenario 1 emphasized high capacity factor onshore wind generation, mainly in the U.S. Great Plains, and is the most economical. Scenario 2 was a hybrid scenario in that it moved some wind generation eastwards, including some East Coast offshore wind generation; it might be called the political, economic development solution. Scenario 3 was high off-shore; it moved more wind generation eastward, including a high amount of offshore wind. Scenario 4 represented aggressive on- and off-shore wind to meet the 30% wind energy penetration level. Four “conceptual” transmission overlays were developed consisting of multiple 800 kV HVDC and EHVAC lines, as shown in Fig. A6.

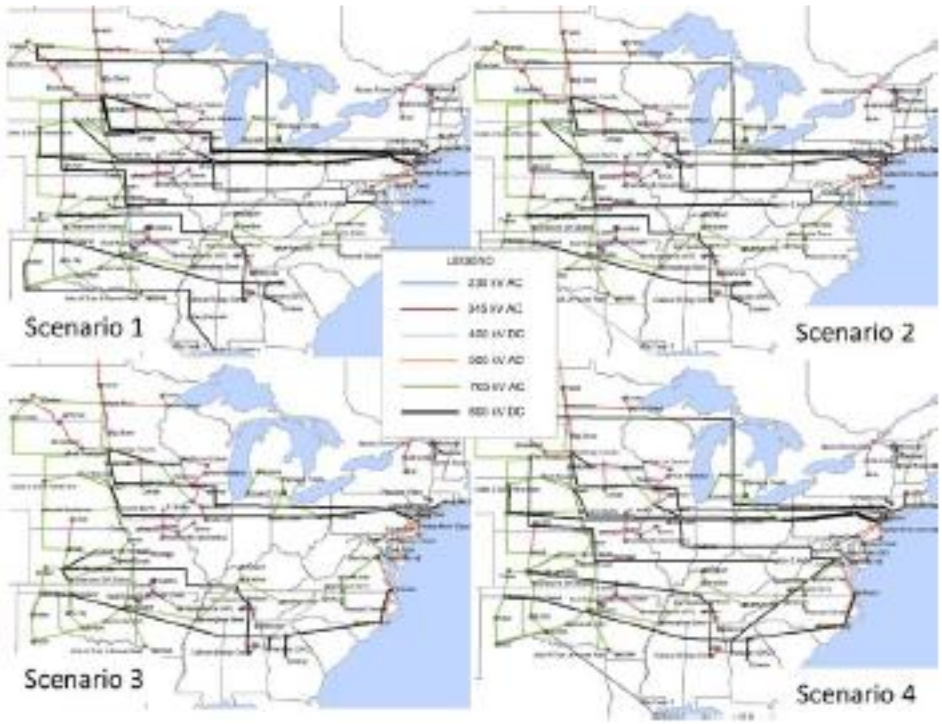

Figure A6: EWITS transmission designs for four scenarios

Source:

“Eastern Wind Integration and Transmission Study,” January 2010, revised February 2011, Available at: <http://www.nrel.gov/wind/systemsintegration/ewits.html>

- Tres Amigas Project

Tres Amigas project will provide a high-capacity link between the three U.S. interconnections (East, West, and Texas). The initial plans for the project are to handle approximately 5 GW of transfers between terminals, and be capable of expansion up to 30 GW. Figure A7 illustrates the project which was proposed by the private developer Tres Amigas LCC.

Actually, connections between any two of the grids are limited, and in no place are all three grids connected currently. Tres Amigas project will build a three-way AC/DC transmission superstation in eastern New Mexico that will be designed to eliminate the market separation between the three asynchronous interconnections in the continental United States.

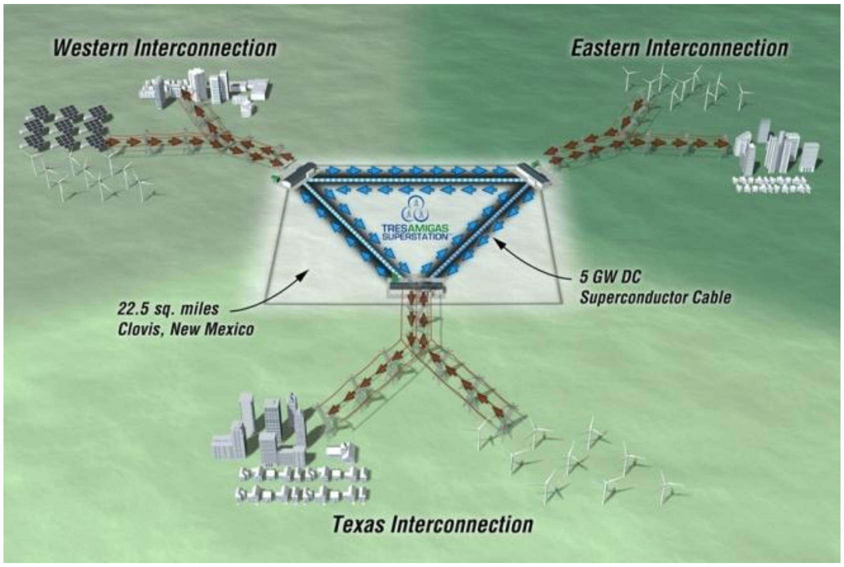

Figure A7: A depiction of the proposed Tres Amigas Superstation

Source:

"Order on application for authorization to sell transmission services at negotiated rates", U.S. Federal Energy Regulatory Commission, March, 2010. Available at:

<http://www.ferc.gov/whats-new/comm-meet/2010/031810/E-12.pdf>

- 2011 WECC 10-Year Regional Transmission Plan

The 2011 WECC 10-Year Regional Transmission Plan is a product of WECC's Regional Transmission Expansion Planning process that is funded, in part, by a U.S. Department of Energy grant provided through the American Recovery and Reinvestment Act. The plan provides credible information regarding the future of the transmission system in the Western Interconnection. It facilitates the development of transmission in infrastructure needed to maintain electric grid reliability and to increase access to renewable and other low-carbon generation resources throughout the region. Figure A8 illustrates the major transmission additions in the WECC through 2020.

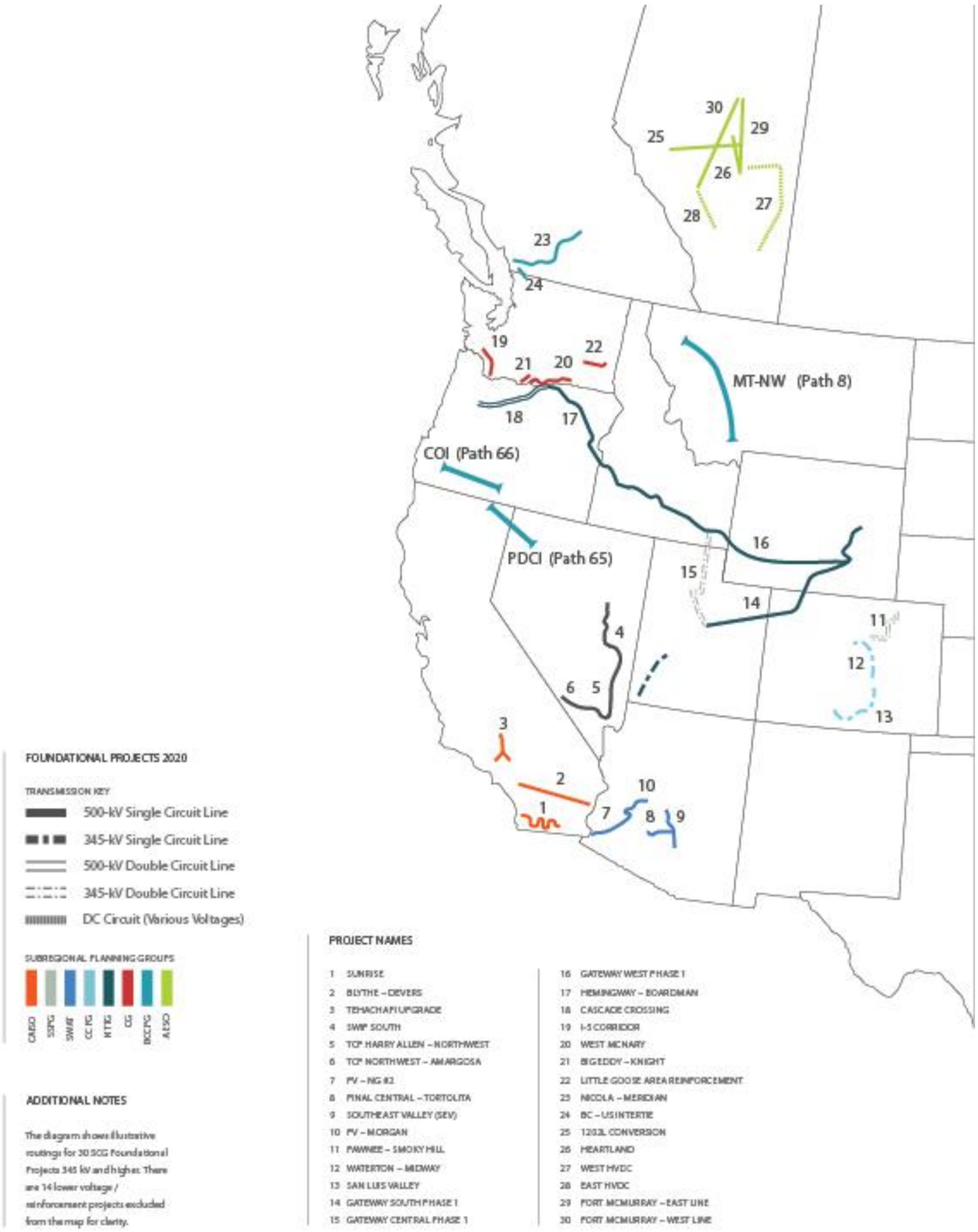

Figure A8: Major transmission additions in the WECC through 2020

A.2 Other literature

- T. Overbye, C. Starr, P. Grant, T. Schneider, "National Energy Supergrid Workshop Report," November 6-8, 2002, Available at

  <http://energy.ece.illinois.edu/SuperGridReportFinal.pdf>

  This report summarizes the results of the University of Illinois at Urbana-Champaign (UIUC) sponsored National Energy Supergrid Workshop, which was held on November 6-8, 2002 in Palo Alto, California. The purpose of the workshop was to investigate the technical feasibility of a proposal developed by Chauncey Starr, founder and emeritus president of EPRI, for the creation of a "Continental SuperGrid" to meet the nation's energy needs in the mid to latter half of the 21st Century. In brief, Dr. Starr's proposal calls for the creation of an Energy Supergrid, delivering both electricity and hydrogen. The electric portion of the grid would use superconducting, high voltage dc cables for power transmission, with liquid hydrogen used as the core coolant. The electric power and hydrogen would be supplied from nuclear and other source power plants spaced along the grid. Electricity would exit the system at various taps, connecting into the existing ac power grid. The hydrogen would also exit the grid, providing a readily available, alternative fuel, for perhaps fuel-cell based automobiles.

- "21st Century Transmission Planning: The Intersection of Engineering, Economics and Environment" Gutman, R.; Wilcox, E.R. Integration of Wide-Scale Renewable Resources into the Power Delivery System, 2009 CIGRE/IEEE PES Joint Symposium, August 2009. (Accessed: September 27, 2011) Available at:

  <http://xplorebcpaz.ieee.org/Xplore/dynhome.jsp>

  Taking into account that during the last decades, economic and environmental pressures, as well as short – term vision planning, have delayed the development of the overall transmission system, the authors calls on the need to build a robust transmission infrastructure that can harvest renewable and clean energy generation and deliver those resources to a multitude of load centers.

- "A 21st Century Interstate Electric Highway System – Connecting Consumers and Domestic Clean Power Supplies" A report by Analysis Group. Prepared for AEP – Transmission. October 2008. (Accessed: September 22, 2011) Available at: < http://www.analysisgroup.com/publishsearch.aspx?author=Tierney+S>

  This paper calls on the need to face the new century challenges and requirements for clean, reliable and affordable electricity supplies with a new National Extra-High-Voltage Transmission System, just as it was adopted the National Interstate Highway System 50 years ago, to usher in a new era of mobility, interstate commerce and economic development.

- “AEP Interstate Project: 765 kV or 345 kV Transmission” Published by American Electric Power (AEP). April 2007. (Accessed: September 22, 2011) Available at:

  <http://www.docstoc.com/docs/36779143/AEP-INTERSTATE-PROJECT-765-kV-or-345-kV-Transmission>

  This paper highlights the advantages of EHV 765 kV technology for use in a modern interstate transmission system compared to 345 kV transmission and traditional DC. Particularly, it develops an exhaustive comparison between 765 kV and 345 kV technologies for a particular transmission project, in terms of loadability, reliability, electrical losses, right of way requirements, visual impact and costs.

- “A National Electrical Superhighway: How Extra-High Voltage Transmission can enable National Energy Security and Environmental Goals” A report by Anbaric Holding, April 2008 (Accessed: September 22, 2011). Available at:

  <http://greenlineproject.com/news/industry/>

  This paper provides a holistic assessment based on American society’s needs from broad regional and national perspectives, and explores how it will has to adapt the existing transmission system to help achieve these broad policy objectives.

- "EHV AC and HVDC Transmission working together to Integrate Renewable Power" Fleeman, J.A.; Gutman, R.; Heyeck, M.; Bahrman, M.; Normark, B. Integration of Wide-Scale Renewable Resources Into the Power Delivery System, 2009 CIGRE/IEEE PES Joint Symposium, July 2009. (Accessed: September 27, 2011) Available at:

  <http://xplorebcpaz.ieee.org/Xplore/dynhome.jsp>

  This paper outlines strengths and complementary features of Extra-High-Voltage Alternating Current (EHV AC) and High Voltage Direct Current (HVDC) transmission systems and advocates a hybrid approach, tailored to integrating renewable sources.

- “Financing a National Transmission Grid: What are the Issues?” Metcalf, G. E; Center for Energy and the Environment. Energy Policy & the Environment Report. No. 5. September 2010. (Accessed: September 27, 2011) Available at:

  <http://www.manhattan-institute.org/html/eper_05.htm>

  This paper investigates the infrastructure needs and the barriers that stand in the way of transmission infrastructure investment. In particular, it reviews the actual available options to finance that investment and the role that the government should play to improve them.

- “Green Power Superhighways - Building a Path to America’s Clean Energy Future” A joint publication of the American Wind Energy Association and the Solar Energy Industries Association. February 2009. (Accessed: September 22, 2011) Available at:

  <http://www.nrel.gov/wind/systemsintegration/news/2009/671.html>

This paper highlights the barriers that hinder investment in transmission infrastructure, and proposes an interconnection – wide transmission planning, an interconnection – wide transmission cost allocation and certainty of cost recovery and a reform of the transmission siting process like potential policy solutions to overcome them.

- "Study Roadmap towards Modular Development Plan on pan – European Electricity Highways System" Draft 3P – Document for Public Consultation. European Network of Transmission System Operators for Electricity (ENTSOE). May 2011. (Accessed: September 22, 2011) Available at:

  <https://www.entsoe.eu/resources/consultations/archive/study-roadmap-modpehs/>

  The European Network of Transmission System Operators for Electricity (ENTSO-E) association proposes a roadmap with the future main drivers necessary to enable the development of a pan-European electricity highway system that allow the integration of renewable energy sources, improves further market integration and maintain the security of electricity supply.

- "The Role of Transmission in the Clean Energy Economy" Public Service Enterprise Group, Inc. (PSEG). Fall 2009. (Accessed: September 27, 2011) Available at:

  <http://www.pseg.com/info/media/pdf/clean_energy_wp.pdf>

  This paper questions the premise that there is a vast renewable resource – including wind in the Midwest and solar in the deserts – that is trapped and needs to get to East and West coasts, to finally conclude that the development of a national transmission superhighway could impede renewable growth, while yielding expensive and inefficient transmission expansion.

Appendix B, Development of "rule of three" for high-capacity overlays

The essence of the "Rule of Three" can be illustrated as follows. Consider that *n* lines each of capacity *C* will be built in parallel with an existing corridor of capacity C_0 (typically the underlying path, of lower capacity, where $C>C_0$). Assume each new line and the existing path has its loading restricted to only *p* percent of the line's or path's respective capacity. If the system is to satisfy N-1 security, i.e., if loss of any one high-capacity line cannot overload any of the remaining lines or paths, then the pre-contingency flow must not exceed the post-contingency capacity, i.e.,

$$pnC+pC_0 \leq (n-1)C+C_0 \qquad \text{(a)}$$

where it is assumed each line and the existing path are of equal impedance. Equation (a) can be manipulated to obtain:

$$C/C_0 \leq (1-p)/(np-n+1) \qquad \text{(b)}$$

assuming $np-n+1>0$ or $p>(n-1)/n$. Equation (b) imposes tradeoffs between limits on investment economics *C* and *n* and operational economics *p* in that we need to make *nC* large enough to obtain sufficient transfer capability and we need to make *p* large enough to be able to use that transfer capability. For example, if we want to be able to load the paths to 70% of their rating, then (b) requires that capacity *C* of an $n=1$ additional line be limited to 42.9% of the existing capacity C_0, capacities of each of $n=2$ additional lines be limited to 75% of the existing capacity, and capacities of each of $n=3$ additional lines be limited to 300% of the existing capacity. If we want to capture more operational benefits and so be able to load the paths to 75% of their rating, then (b) requires that capacity *C* of $n=1$ additional line be limited to 33% of the existing capacity C_0, capacity of each of $n=2$ additional lines be limited to 50% of the existing capacity, and capacities of each of $n=3$ additional lines be limited to 100% of the existing capacity. Loading the paths to 80% of their rating requires that capacity *C* of $n=1$ additional line be limited to 25% of the existing capacity C_0, capacities of each of $n=2$ additional lines be limited to 33% of the existing capacity, and capacities of each of $n=3$ additional lines be limited to 50% of the existing capacity.

Appendix C: Data used in studies reported in Section 3

Table C- 1: Data for generation technologies represented

Generation Technology	*Capacity Factor*	*Investment Cost (M$/GW)*	*Lifespan (years)*	*Operational Cost (M$/GWh)*	*CO_2 (Short ton/GWh)*
Nuclear	0.95	3156	60	0.002349	8.51
Coal	0.85	1788	40	0.002404	919.35
IGCC	0.85	2673	40	0.002159	865.1
IPCC	0.85	3311	30	0.011884	-
NGCC	0.61	827	30	0.002591	407.07
Oil	0.85	1655	30	0.003048	808.1
CT	0.2	551	30	0.003654	555.69
PV Solar	0.1-0.25	4603	30	0	-
PV Thermal	0.15-0.32	3617	30	0.001	-
Wind	0.1-0.5	1150	25	0.000268	-
Offshore	0-0.4	2662	25	0	-
Geothermal	0.9	3149-7747	50	0	123.57
OTEC	0.3	6163	50	0	-
Tidal	0.3	18286	50	0	-
Hydro	0.5	4594	100	0.002835	-

Table C- 2: Regional data

Region, j	*Base Demand (GW)*	*Inland Wind CF*	*Offshore Wind CF*	*Solar PV CF*	*Solar Thermal CF*	*Geothermal investment cost ($/GW)*
1- ECAR	75.90865	0.3	0	0.15	0.22	5426.167401
2- ERCOT	39.61863	0.4	0.2	0.2	0.25	4514.472362
3- MAAC	25.73917	0.3	0.4	0.15	0.22	7747.659574
4- MAIN	25.32782	0.5	0	0.15	0.22	5601.56682
5- MAPP	23.00705	0.5	0	0.15	0.22	5352.181425
6- NY	16.4444	0.3	0	0.15	0.22	7558.14433
7- NE	14.04696	0.3	0.4	0.15	0.22	5281.016949
8- FL	25.81881	0.3	0.4	0.22	0.27	6203.554377
9- STV	70.62432	0.1	0.4	0.2	0.25	5547.272727
10- SPP	32.72866	0.4	0	0.2	0.25	4238.181818
11- NWP	28.25084	0.4	0.4	0.1	0.15	3149.20354
12- RA	18.12711	0.2	0	0.25	0.32	3714.545455
13- CNV	30.61133	0.3	0.3	0.22	0.27	4020

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