Nation-wide transmission overlay design and benefits assessment for the U.S.

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HIGHLIGHTS

- Nation-wide transmission overlay—high capacity, multi-regional transmission grid.
- Promises economic and environmental benefits to the nation under high renewable.
- Objective—to identify benefits of building a national transmission overlay.
- Under high renewables, could result in cost-reduction of up to $0.5T over 40-years.

ABSTRACT

A U.S. nation-wide 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 and to lay out essential elements to facilitate continued dialog on this topic. A preliminary study performed on a national scale using a long term investment planning software illustrated that a national transmission overlay, under a high renewable penetration scenario, could result in cost-reduction of between one quarter trillion and one-half trillion dollars over a 40-year period, while promising to increase infrastructure resilience and flexibility.

1. Introduction

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. This tendency 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, 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 a recent Department of Energy (DOE) study (U.S. Department of Energy, 2008), which required 12 k additional circuit-miles if 300 GW of wind capacity were to be built by 2030.

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 200 kV and greater averaged about 6 k circuit-miles per 5-year period, but they expect the 2010–2015 period to exceed 16 k circuit-miles per 5-year period (North American Electric Reliability Corporation, 2010). About 50% of this transmission is motivated by reliability needs at the local or regional level, with 27% motivated by renewable integration. The U.S. industry in the past has built inter-regional transmission in the West (Pacific AC and DC Interties in 1970, and the Intermountain Power Project in 1987) and is currently exploring inter-regional transmission in the

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Eastern Interconnection (Eastern Interconnection States’), the West (Western Electricity Coordination Council), and ERCOT.

Although there has been recent conceptual proposals (Intermediate Transmission Vision for Wind Integration, 2007; Superconductor Electricity Pipelines, 2009; Joint Coordinated System Plan 2008, 2008; Eastern Wind Integration and Transmission Study, 2011; Order on application for authorization to sell transmission services at negotiated rates, 2010; Overbye et al., 2002; A 21st Century Interstate Electric Highway System, 2008), transmission designs spanning multiple regions at the national level has never resulted in actual construction. There are two basic reasons for this. First, only recently the emphasis on renewables and the 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 it as the most economical alternative, perform cost allocation, obtain right-of-way, overcome technical challenges, and satisfy the public. 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. Second, long-distance transmission typically crosses state lines, and so regulators and agencies of multiple state governments and the Federal Energy Regulatory Commission (FERC) become involved. These various challenges to long-distance transmission lead to a perception that building transmission at the national level is an extremely complex undertaking.

This paper is not intended to either support or oppose the development of a national transmission overlay, but rather it is intended to identify benefits of such a build-out using a systematic engineering study that facilitates continued consideration of this topic. The paper is organized as follows. Section 2 provides a background on past and future trend of load, generation, and transmission. Section 3 introduces a long term planning software, NETPLAN that co-optimizes infrastructure planning across the various energy industry sectors. Section 4 describes the study specifications, and Section 5 presents the results. Section 6 summarizes potential benefits, and Section 7 concludes.

2. Background and motivation

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. According to 2000 U.S. census data, about 80% of the U.S. population lived in metropolitan areas (http://www.time.com/time/interactive/0,31813,1549966,00.html), with the top five being New York, Chicago, Philadelphia (east of Mississippi), Dallas, and Los Angeles (west coast). Assuming that the population density is proportional to electric energy usage density in GWh/square mile, then it follows 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. The 2010 U.S. Census data (US Census Bureau Maps) suggests similar observations, with some movement to the Southeast and to the Southwest. Such shifts in population distribution, which could occur due to governmental policies or national economics, could affect assessment regarding the need for a national transmission overlay. We assume in this paper that we do not experience significant shifts of this nature.

Apart from population density, each region’s industrial base also serves as a proxy for ascertaining regional energy consumption. The Gross Domestic Product (GDP) data for 2011 published by U.S. department of commerce (U.S. Department of Commerce; U.S. Department of Commerce, 2011) indicates a flourishing industrial base in West Coast (in and around California), South-West (Texas), East (in and around New York), and least GDP in the North, and a moderate GDP in the Mid-west, a trend closer to population density. Regions with a significant penetration of high energy consuming industry will have higher per-capita energy use compared to other regions. In addition, future electric use may change as new electro-technologies are implemented into industrial and transportation applications, with an objective to achieve energy efficiency and demand side management. For example, there is a trend toward 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.

2.2. Generation investment

The motive for a national transmission overlay stems from various policy drivers, particularly from the prospect of reducing GHG emissions at a lower cost. This is because GHG reduction necessitates shifting some portion of the generation portfolio from fossil-fueled technologies to low-GHG emitting technologies, the most promising of which include wind (inland and offshore), solar (thermal and photovoltaic), enhanced geothermal, nuclear, clean-coal (integrated gasification combined cycle with carbon capture and sequestration), and ocean-based (wave, tidal, and ocean-thermal energy conversion). Among these the renewable technologies share the unique attribute that transmission is the only cost-effective way to move the associated energy. Although nuclear and clean-coal are low-GHG generation technologies that may be transported in other ways (rail) beside electric transmission, it seems likely that cost, waste storage, and safety factors will limit penetration of these two technologies. Although natural gas combined cycle (NGCC) plants will play a significant role in the near future, its use will eventually be constrained because (a) they are non-negligible GHG emitters (U.S. Environmental Protection Agency) and (b) the U.S. natural gas reserves are limited (US Natural Gas Reserves, 2011) (to between 40 and 90 years, depending on how much unconventional gas is assumed to be recoverable).

Traditionally large capacities of generation have been sited in a centralized manner. However, the future planning studies must also consider the possible penetration in distributed generation, as far as the economics and system operational (control and coordination) capability allows. Currently, the benefit on emissions front from renewables seems to come in an economical manner from centralized renewable resources.

2.3. Transmission

The U.S. 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. The first of these was in 2002 (U.S. Department of Energy, 2002), the second one in 2006 (U.S. DOE, 2006), and the most recent one was published in 2009 (U.S. DOE, 2009). The 2006 study introduced the concept of conditional congestion areas, later extended in the 2009 study, by distinguishing between a Type I and a Type II conditional congestion area, shown in Fig. 1:

- “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 technologi-
cally mature but shows significant promise due to its quality,
size, and location.”

Fig. 1 illustrates current understanding of where the nation’s
most economically attractive renewable resources are located,
i.e., in the West and Midwest. Considering that most U.S. electric
load is in the East, it is easy to understand the need for national
transmission in a high renewable future.

3. NETPLAN—introduction and formulation

The National Energy and Transportation Planning model NET-
PLAN (Ibanez, 2011; Ibanez and McCalley, 2011; Ibáñez et al.,
2010; Krishnan et al., 2012) is a software tool that models
the energy and transportation sectors of the U.S. as well their
interdependencies in order to perform national level long-term
multi-sector infrastructure planning. NETPLAN identifies co-
optimized infrastructure portfolios, including generation and
transmission, for the future (e.g., 40 years), accounting for vari-
ation in generation investment costs, production costs, capacity
factors by technology and region, variation in transmission
capacity and transmission investment costs between adjacent
regions, and variation in transportation costs of fuels transported
between source and generation plants. The model has a variety of
capabilities (Ibanez, 2011), but we have used only its core cost-
minimization linear program in this work, which is described in
this section with primary focus on the electric side.

A generalized network flow structure, depicted using nodes
and arcs as shown in Fig. 2, is used to model all the infrastructure
systems, wherein energy is considered as the commodity flowing
from source nodes to sink nodes via arcs. The energy system in
NETPLAN is represented with four different, but interconnected,
subsystems: coal, natural gas, electricity and petroleum. The unit
of energy flow is GWh for arcs representing the electric network
comprised of generation, demand and transmission, million cubic
feet for the natural gas network comprised of production (NP),
transshipment (NT) and storage (NS) nodes, million gallons for
liquid fuels such as gasoline and diesel, and it is thousand-short
tons for coal (production CP and transportation 1T nodes in Fig. 2).

The objective function of the linear program is to minimize
operational and investment costs, as given in the following

\[
\text{Minimize } \sum_{t} \sum_{(i,j)} (1+r)^{-t} \; \text{CostOp}_{i,j}(t) \; e_{i,j}(t) + \sum_{t} \sum_{(i,j)} (1+r)^{-t} \; \text{CostInv}_{i,j}(t) \; eln_{i,j}(t)
\]

- \(e_{i,j}(t)\)—decision variable denoting energy flow in arc \((i,j)\)
- \(eln_{i,j}(t)\)—decision variable denoting investment in GW at
time period \(t\) for generation technology \(i\) in region \(j\) or for
transmission line connecting regions \(i\) and \(j\)
- \(\text{CostOp}_{i,j}(t)\)—operational cost of energy flow in \$/GWh through
arc \((i,j)\) at time period \(t\)
- \(\text{CostInv}_{i,j}(t)\)—investment cost of generation or transmission
line in \$/GW at time period \(t\)
- \(r\) is the discount rate

This paper considers only investments in generation and
transmission, though the model can include investments in
natural gas and transportation infrastructures as well. The total
operational cost in NETPLAN is comprised of generation produc-
tion cost, and fuel production and transportation costs.

Constraints are described in the remainder of this section. At
each node, the energy inflow and outflow must be such that the

![Type I Conditional Congestion Area](http://energy.gov/sites/prod/files/Congestion_Study_2009_ES.pdf)

See Figure E5-1. 2009 Type I and Type II Conditional Congestion Areas

Fig. 1. Type I and Type II conditional congestion areas.
nodal demand $d_j(t)$ must be met, as represented by:

$$\sum_i \eta_{i,j}(t) e_{i,j}(t) - \sum_j e_{j,i}(t) = d_j(t)$$

(2)

where $\eta$ is the arc efficiency parameter, which models capacity factor for generation arcs, loss for transmission arcs, and heat rate involved in energy conversion for arcs connecting fuel node and generation node. The generation production cost is computed based on the energy flow in generating arcs, subject to their mean capacity factor. Energy flow bounds on arcs are expressed by (3) and (4), where $lbe$ is the lower bound and $ube$ is the upper bound. The upper bound (total capacity) at time $t$ is a function of yearly capacity investments $elnv_{i,j}$ until time $t$. The yearly capacity investments are bound by $lbeinv$ and $ubeinv$ as given by (5).

$$e_{i,j}(t) \geq lbe_{i,j}(t)$$

(3)

$$e_{i,j}(t) \leq ube_{i,j}(t) + \sum_{z=0}^t elnv_{i,j}(z)$$

(4)

$$lbeinv_{i,j}(t) \leq elnv_{i,j}(t) \leq ubeinv_{i,j}(t)$$

(5)

4. System data and study specifications

The model used in this study represents the U.S. energy and the U.S. freight transportation system. The electric system uses one node for each of 13 regions as defined by the DOE Energy Information Administration (The National Energy Modeling System: An Overview, 2003), as shown in Fig. 3 (modified from The National Energy Modeling System: An Overview, 2003) p. 45 Fig. 10). 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. Fig. 3 shows the amount of electric energy generated and consumed in each of these regions in year 2010, which is the reference year for this study (NERC, 2010). The extent to which these values differ for each region provides an indirect indication of the extent to which electric energy is moved from one region to another. 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 and the bar on the right shows the energy consumed.

It is clear from this plot that for all regions, the amount of energy generated does not significantly differ from the energy consumed; thereby indicating a low level of inter-regional energy transfers. Fig. 3 also shows the available inter-regional transmission capacity at reference year using red bidirectional arrows, with the thickness proportional to the GW capacity given in Table 1 (Zip file, 2011; US Environmental Protection Agency, 2006; Gumerman et al., 2006). The investment and operational cost, emission and capacity factor data for generation technologies at reference year are provided in Tables 2 and 3 (Ibanez, 2011; Krishnan et al., 2012). Table 4 provides the regional generation production mix in meeting the average demand provided in Table 3 for the reference year.

The goal of these studies is to determine the potential level of economic benefit provided by a national transmission overlay in terms of the net present worth of investment and production cost over a 40 years period. We focus on what we perceive to be “transmission-friendly” futures; if these futures do not show benefit, then it is unlikely that less “transmission-friendly” futures would either. NETPLAN provides for bounding investment level on any particular technology, a facility we use to restrict non-renewable generation so that the most economic renewable technologies are favored. Because renewables have investment costs (for geothermal, due to drill depth) or capacity factors (for wind and solar) 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.

Therefore, Tables 2 and 3 indicate locational variability in capacity factor and cost for wind, solar and geothermal, which are unique by their inherent dependence on location (by virtue of their operation and installation). However, in future planning studies to continue the

\[ 1 \text{ Quad} = 1 \times 10^{15} \text{ BTU} = 293,080 \text{ GWh}. \]
dialog on this topic, it will be necessary to account for other external factors such as locational economics, policies, climatic conditions, regional generation mix, lower level transmission capacities, fuel and resource (land, water) availability; which contribute to locational uncertainties in all the generation technologies' parameters.

Five different sets of cases were studied, with each set distinguished from the others based on maximum allowable uncertainties in all the generation technologies' parameters.

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Table 1
Transmission attributes at reference year.

<table>
<thead>
<tr>
<th>Transmission lines</th>
<th>2010 capacity (GW)</th>
<th>Losses (%/GWh)</th>
<th>Inv. cost (M$/GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ECAR_MAAC</td>
<td>0.90</td>
<td>5.31</td>
<td>850</td>
</tr>
<tr>
<td>ECAR_MAIN</td>
<td>12.62</td>
<td>3.54</td>
<td>425</td>
</tr>
<tr>
<td>ECAR_STV</td>
<td>8.58</td>
<td>3.85</td>
<td>500</td>
</tr>
<tr>
<td>ERCOT_SPP</td>
<td>0.98</td>
<td>3.85</td>
<td>500</td>
</tr>
<tr>
<td>MAAC_NY</td>
<td>3.43</td>
<td>2.81</td>
<td>250</td>
</tr>
<tr>
<td>MAAC_STV</td>
<td>2.60</td>
<td>6.14</td>
<td>1050</td>
</tr>
<tr>
<td>MAIN_MAPP</td>
<td>1.50</td>
<td>4.48</td>
<td>650</td>
</tr>
<tr>
<td>MAIN_STV</td>
<td>4.62</td>
<td>5.10</td>
<td>800</td>
</tr>
<tr>
<td>MAIN_SPP</td>
<td>0.28</td>
<td>4.69</td>
<td>700</td>
</tr>
<tr>
<td>MAPP_SPP</td>
<td>1.49</td>
<td>5.10</td>
<td>800</td>
</tr>
<tr>
<td>MAPP_NWP</td>
<td>0.20</td>
<td>6.77</td>
<td>1200</td>
</tr>
<tr>
<td>NY_NE</td>
<td>1.60</td>
<td>3.44</td>
<td>400</td>
</tr>
<tr>
<td>FL_STV</td>
<td>2.00</td>
<td>3.85</td>
<td>500</td>
</tr>
<tr>
<td>STV_SPP</td>
<td>5.61</td>
<td>5.02</td>
<td>780</td>
</tr>
<tr>
<td>SPP_RA</td>
<td>0.40</td>
<td>4.48</td>
<td>650</td>
</tr>
<tr>
<td>NW_P_RA</td>
<td>1.31</td>
<td>5.94</td>
<td>1000</td>
</tr>
<tr>
<td>NW_P_CNv</td>
<td>9.18</td>
<td>5.52</td>
<td>900</td>
</tr>
<tr>
<td>RA_CNv</td>
<td>8.31</td>
<td>5.73</td>
<td>950</td>
</tr>
</tbody>
</table>

Table 2
Generation data at reference year.

<table>
<thead>
<tr>
<th>Generation technology</th>
<th>Capacity factor</th>
<th>Investment cost (M$/GW)</th>
<th>Lifespan (years)</th>
<th>Operational cost (M$/GWh)</th>
<th>CO2 (Short ton/GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>0.95</td>
<td>3156</td>
<td>60</td>
<td>0.002349</td>
<td>8.51</td>
</tr>
<tr>
<td>Coal</td>
<td>0.85</td>
<td>1788</td>
<td>40</td>
<td>0.002404</td>
<td>919.35</td>
</tr>
<tr>
<td>IGCC</td>
<td>0.85</td>
<td>2673</td>
<td>40</td>
<td>0.002159</td>
<td>865.1</td>
</tr>
<tr>
<td>IPCC</td>
<td>0.85</td>
<td>3311</td>
<td>30</td>
<td>0.011884</td>
<td>–</td>
</tr>
<tr>
<td>NGCC</td>
<td>0.61</td>
<td>827</td>
<td>30</td>
<td>0.002591</td>
<td>407.07</td>
</tr>
<tr>
<td>Oil</td>
<td>0.85</td>
<td>1655</td>
<td>30</td>
<td>0.003048</td>
<td>808.1</td>
</tr>
<tr>
<td>CT</td>
<td>0.2</td>
<td>551</td>
<td>30</td>
<td>0.003654</td>
<td>555.69</td>
</tr>
<tr>
<td>PV solar</td>
<td>0.1–0.25</td>
<td>4603</td>
<td>30</td>
<td>0</td>
<td>–</td>
</tr>
<tr>
<td>PV thermal</td>
<td>0.15–0.32</td>
<td>3617</td>
<td>30</td>
<td>0.001</td>
<td>–</td>
</tr>
<tr>
<td>Wind</td>
<td>0.1–0.5</td>
<td>1150</td>
<td>25</td>
<td>0.000268</td>
<td>–</td>
</tr>
<tr>
<td>Offshore</td>
<td>0–0.4</td>
<td>2662</td>
<td>25</td>
<td>0</td>
<td>–</td>
</tr>
<tr>
<td>Geothermal</td>
<td>0.9</td>
<td>3149–7747</td>
<td>50</td>
<td>0</td>
<td>123.57</td>
</tr>
<tr>
<td>OTEC</td>
<td>0.3</td>
<td>6163</td>
<td>50</td>
<td>0</td>
<td>–</td>
</tr>
<tr>
<td>Tidal</td>
<td>0.3</td>
<td>18,286</td>
<td>50</td>
<td>0</td>
<td>–</td>
</tr>
<tr>
<td>Hydro</td>
<td>0.5</td>
<td>4594</td>
<td>100</td>
<td>0.002835</td>
<td>–</td>
</tr>
</tbody>
</table>

- Cases A1, B1, mostly renewable, geothermal light: these cases allow 520 GW of nuclear units to be built, with the rest being inland wind, offshore wind, solar PV, solar thermal, and geothermal (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 (only in the West) to be built.
- Cases A3, B3, all renewable, no geothermal: these cases allow only inland wind, offshore wind, solar PV and thermal.
- Cases A4, B4, all renewable, geothermal heavy: these cases allow only inland and offshore wind, solar PV and thermal, and geothermal. Geothermal may be built anywhere.
- Cases A5, B5, business as usual: these cases allow both renewable and non-renewable anywhere, without carbon costs. These cases are simulated to keep the estimated benefits of transmission overlay under the above four “transmission friendly” scenarios in perspective with the contemporary scenario.

In case A, the interregional transmission is not allowed to expand and is therefore constrained to the 2010 levels of Table 1 throughout the simulation. In Case B, the capacity of each interregional transmission is a decision variable in the optimization; therefore, transmission capacity is grown as needed in order to minimize the 40-years investment and production cost. Therefore the difference in cost
between each Cases A and B provides a valuation of the transmission built.

A CO₂ cost of $30/short ton (i.e., 0.907 metric tons) was imposed for all CO₂-producing generation. Inflation and (real) discount rates are assumed to be 2% and 7% respectively, resulting in a nominal discount rate of about 9%. Load growth was modeled at 2%/year. In all cases, a cost of $1B/GW/1000 miles (2010 dollars) was placed on interregional transmission (expansion was only considered for adjacent regions), and we also performed sensitivity analyses using values of $1.5B/GW/1000 miles and $2B/GW/1000 miles respectively. No effort was made to account for variation in transmission cost based on location or any cost for upgrading underlying transmission. Initial (2010) capacity, losses, and investment costs for each interregional transmission path considered are provided in Table 1. Transmission cost between regions was determined by 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 data for an 800 kV HVDC line (Fleeman et al., 2009).

5. Numerical results

5.1. Case studies

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/1000 miles, the difference in present worth range from $239B for the “mostly renewable, geothermal-light” case to $492B for the “all-renewable, geothermal-heavy” case.

Generation investments made for Cases A1 and B1, and for Cases A2 and B2, are illustrated in Fig. 4. 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 Fig. 5. 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 (these names, corresponding to the regions illustrated in Fig. 3, were used for our modeling but do not necessarily correspond to the names used by organizations representing parts or all of those regions today). 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 some of the transmission need observed in Case B2. 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 to build the less cost-effective generation close to load.

Figs. 6 and 7 geographically illustrate the additional transmission capacity for Cases B1 and B2 respectively. These figures also provide energy generation and consumption (in Quads). 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, particularly in ECAR and STV.

Fig. 8 shows generation investments for Cases A3, B3, A4 and B4. Similar to Fig. 4, we observe a decrease in generation capacity due to expanded transmission using lower cost renewables. Also, because of the much heavier presence of geothermal, Cases A4 and B4 show significantly less capacity than do Cases A3 and B3, since geothermal has a much higher capacity factor than wind.

Transmission investments made for Cases B3 and B4 are illustrated in Fig. 9. The interregional corridors receiving the most transmission investment for Case B3 are generally the same as for Cases B1 and B2, although the amounts are somewhat different for some corridors. On the other hand, Case B4 invests in some 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., 40 GW in MAIN to ECAR as opposed to 100 GW or more in other cases). This was because geothermal investment was constrained to be light and only in the West (Cases B1 and B2) or nonexistent (Case B3), whereas Case B4 allowed geothermal investment in both West and East. Also, the total invested transmission is significantly smaller for Case B4 than others due to the presence of the geothermal in the East that relieved part of the need for transmission that was otherwise required to move energy from the West and Midwest to the East. However, the cost assumptions for geothermal, function of expected drill-depth, are uncertain, and so it is not clear that Eastern geothermal investment can be economically attractive, a perspective underlying the lack of Eastern geothermal in Fig. 1.

Figs. 10 and 11 geographically illustrate the additional transmission capacity for Cases B3 and B4 respectively. It is interesting to observe that the flow direction for Cases B1, B2, and B4 (with geothermal) is West to Midwest to East, whereas the flow

<table>
<thead>
<tr>
<th>Cases</th>
<th>Case description</th>
<th>Transmission</th>
<th>Cost (Billion$)</th>
<th>Present worth (2010 dollars)</th>
<th>Annualized over 40 years</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1</td>
<td>Mostly renewable, geothermal-light</td>
<td>Fixed</td>
<td>5013.12</td>
<td>376.03</td>
<td></td>
</tr>
<tr>
<td>B1</td>
<td>Expanded</td>
<td>4773.96</td>
<td>358.09</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Difference</td>
<td>239.16</td>
<td>17.94</td>
<td></td>
<td></td>
</tr>
<tr>
<td>B1-1.5T</td>
<td>Same as B1, but w/1.5 times transmission costs</td>
<td>Expanded</td>
<td>4807.96</td>
<td>360.53</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Difference</td>
<td>205.16</td>
<td>15.46</td>
<td></td>
<td></td>
</tr>
<tr>
<td>B1-2T</td>
<td>Same as B1, but w/2 times transmission costs</td>
<td>Expanded</td>
<td>4835.29</td>
<td>362.69</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Difference</td>
<td>177.83</td>
<td>13.34</td>
<td></td>
<td></td>
</tr>
<tr>
<td>A2</td>
<td>All-renewable, geothermal-light</td>
<td>Fixed</td>
<td>5517.83</td>
<td>413.89</td>
<td></td>
</tr>
<tr>
<td>B2</td>
<td>Expanded</td>
<td>5059.38</td>
<td>379.50</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Difference</td>
<td>458.45</td>
<td>34.39</td>
<td></td>
<td></td>
</tr>
<tr>
<td>A3</td>
<td>All-renewable, no geothermal</td>
<td>Fixed</td>
<td>5328.11</td>
<td>399.66</td>
<td></td>
</tr>
<tr>
<td>B3</td>
<td>Expanded</td>
<td>5053.70</td>
<td>377.57</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Difference</td>
<td>274.41</td>
<td>20.58</td>
<td></td>
<td></td>
</tr>
<tr>
<td>A4</td>
<td>All-renewable, geothermal-heavy</td>
<td>Fixed</td>
<td>5457.63</td>
<td>409.37</td>
<td></td>
</tr>
<tr>
<td>B4</td>
<td>Expanded</td>
<td>4965.48</td>
<td>372.47</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Difference</td>
<td>492.15</td>
<td>36.92</td>
<td></td>
<td></td>
</tr>
<tr>
<td>A5</td>
<td>Business as usual</td>
<td>Fixed</td>
<td>4655.70</td>
<td>349.22</td>
<td></td>
</tr>
<tr>
<td>B5</td>
<td>Expanded</td>
<td>4650.10</td>
<td>348.80</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Difference</td>
<td>5.60</td>
<td>0.42</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
direction for Case B3 (with no geothermal) is Midwest to West and Midwest to East. This shows that, without geothermal; the Midwestern wind significantly increases its presence in supplying parts of the entire nation.

Fig. 12 shows the generation production mix for the reference year (from Table 4), Cases B1 and B5 over all the 40 years. The 100% of pie-chart for Cases B1 and B5 represents about 2.2E8 GWh of production over 40 years. The reference year portfolio is much dominated by coal generation, followed by nuclear and natural gas. Based on the current cost assumptions, the business as usual case directed the future portfolio much toward nuclear and coal. It is observed from Fig. 12 and Table 6 that Case B5, dominated by nuclear
and coal units that are relatively much less location-dependent compared to renewables, allows for very less investment in transmission overlay (in GW-Miles) compared to transmission friendly Case B1 with higher penetration of wind and geothermal. This is also reflected in Table 5, where it shows that the cost benefits of a national transmission overlay under Case B1 is highly promising compared to Case B5.

On the other hand, Table 6 shows that the total cost of Case B5 is about $123.86B lesser than Case B1. However, assuming a carbon cost of about $30/Short ton, Case B1 promises a carbon credit of about $1245B (10 times the cost difference between the portfolios) by virtue of its low CO2 emitting portfolio. Interestingly, Table 6 also shows that the cost to build out the transmission overlay in Case B1 is about 1.3% of the composite long-term cost of infrastructure building and operating power systems.

5.2. Sensitivity studies

To determine the sensitivity of results to transmission cost, Cases B1—1.5T and B1—2T were run, where transmission costs were increased to $1.5B/GW/1000miles and $2B/GW/1000miles respectively. The transmission topology identified was almost similar compared to Case B1 as seen from Fig. 13, with changes in the capacity investments across various corridors. As the transmission cost increases, there is decreasing investments in North-West to Mid-West (NWP to MAPP and NWP to RA) and Mid-West to East (MAPP to MAIN, MAIN to STV, MAIN to ECAR) corridors, and increase in South-West to East corridors (RA to SPP and SPP to STV). This is because the increase in transmission cost mainly spurred increase in geothermal generation investments in South-West while decreasing wind investments in North-West to achieve an overall cost-effective portfolio. Fig. 14 indicates an overall increase and decrease in geothermal and

![Generation Investments over 40 years](image)

**Fig. 8.** Generation investments over 40 years—Cases A3, B3 and Cases A4, B4.

![Transmission Investments over 40 years](image)

**Fig. 9.** Transmission investments over 40 years—Case B3 and Case B4.

![Generation mix and transmission investments over 40 years](image)

**Fig. 10.** Generation mix and transmission investments over 40 years—Case B3.
wind representations respectively in the portfolios with increasing transmission cost.

Also, 50% and 100% increase in transmission cost only decreases net economic benefit by about 14% and 25% respectively (i.e., from $239B to $206B, and $239B to $178B respectively per Table 5). These observations suggest that the long-term benefit obtained from expanded transmission is not very sensitive to the transmission cost. This is a confirmation of the well-known fact that the transmission cost is generally a relatively small percentage of the composite long-term cost of building and operating power systems, as also seen from Table 6.

6. Discussion

We identify four types of potential benefits associated with deploying a national transmission overlay:

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**Fig. 11.** Generation mix and transmission investments over 40 years—Case B4.

**Fig. 12.** Generation production mix—(a) Reference year, (b) Case B1 (over 40 years), and (c) Case B5 (over 40 years).

**Table 6**

Summary of results.

<table>
<thead>
<tr>
<th>Cases</th>
<th>Case description</th>
<th>Transmission (Billion$ (GW-Miles))</th>
<th>Cost (Billion$)</th>
<th>CO₂ emission (short ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>B1</td>
<td>Mostly renewable, geothermal-light</td>
<td>63.09 (126,045.9)</td>
<td>4773.96</td>
<td>1.75E + 10</td>
</tr>
<tr>
<td>B5</td>
<td>Business as usual</td>
<td>5.23 (7167.8)</td>
<td>4650.10</td>
<td>5.90E + 10</td>
</tr>
<tr>
<td>Difference</td>
<td></td>
<td>57.86 (119,778.1)</td>
<td>123.86</td>
<td>-4.15E + 10</td>
</tr>
</tbody>
</table>
Transmission investments over 40 years—Cases B1, B1-1.5T and B1-2T.

Fig. 13. Transmission investments over 40 years—Cases B1, B1-1.5T and B1-2T.

Generation investments over 40 years

Fig. 14. Generation investments over 40 years—Cases B1, B1-1.5T and B1-2T.

6.1. Cost

For a given demand growth and emissions target, the minimum cost plan with transmission expansion will realize a savings over an extended period, say 40 years, relative to that without transmission expansion. This savings is observed in Table 5 as the difference between the net present worth of total costs (generation and transmission investments, plus production) with and without transmission expansion. These savings account for the transmission expansion cost and indicate that it is better, from purely a cost basis, to build the transmission overlay than not, under the high renewable conditions characterizing four out of five futures analyzed.

(1) Basis of comparison: In each of our sets of cases, we have compared two optimized solutions with and without transmission as a decision variable. Converting fixed values to decision variables within an optimization either does not affect the objective or improves it. The results indicate an overlay opens up cost-reducing opportunities that are not evident otherwise.

Alternatively, the transmission-expanded cases could 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, the benefit that drives the cost savings in all the four cases.

(2) Transmission mileage: A major impediment for building transmission is obtaining right-of-way. It is clear that building a national overlay will require high transmission mileage. Yet, it is not clear how much lower-capacity transmission would be built without the overlay. For a high-renewable generation investment as illustrated previously, it is possible that, without the 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” (The 2008 Midwest ISO Transmission Expansion Plan (MTEP08)), 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.

6.2. GHG emissions

Table 7 shows the net CO2 emissions over 40 years under Cases 1, 3 and 5, where it is seen that building a national transmission overlay apart from promising economic benefits as per Table 5, also promises overall reduction in CO2 emissions. From Tables 5 and 6, it can be inferred that the presence of a national transmission overlay will lower the cost per unit emission reduction over a given time frame. Transmission allows low-GHG technologies to be built economically, and thus, for a given total cost over a given time frame, the overlay will enable greater GHG emission reductions. Alternatively, the overlay will allow a given GHG emission reduction over a given time frame at a lower total cost, which is observed both in Tables 6 and 7. We expect the benefit would be even more pronounced if the life-cycle GHG impact of an overlay is considered, since the amount of steel, concrete, aluminum, transportation, and construction would likely be less than alternative approaches.

6.3. Resilience

We consider resilience of the national energy system to be the ability to minimize and recover from the effects of an adverse event (Ibanez et al., in press), that are very large-scale and have catastrophic potential. One may classify events useful for resilience assessment into technology events, geographical events, or their combination. Technology events reduce capacity of a particular technology, e.g., early retirement of 50% of U.S. nuclear fleet. Geographical events reduce capacity of multiple technologies...
within a geographical area-Katrina/Rita hurricanes (Gil and McCalley, 2011; St. Charles County). We use the system's operational cost for an extended time period following the event, i.e., several months to years (Gil and McCalley, 2011), as a measure of resilience. The operational cost with and without the event reflects the system's ability to utilize its energy resources.

Totally 13 geographical events were simulated, wherein each event is defined by 50% capacity outage at year 25 in all the technologies in each of 13 areas respectively. The average of operational cost increase at year 26 under all the 13 events is used as resilience metric. Although an 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. The results showed compared to Case A1 with a resilience metric of $3116.3B, in Case B1 the resilience metric reduced to about $2945.7B, an improvement by about 5.4% ($170.6B savings). 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 capacity in another region. It will be less pronounced for technology events but would provide some benefits; to that extent the event exhibits regional characteristics.

6.4. 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 causing permanent changes in expected futures. Flexibility is important in a 40-years generation build-out, as over-time shifts between favorability of resources occur. An overlay would facilitate flexibility by increasing the number of options one may be able to consider in compensating permanent loss of significant resources.

7. Conclusions

This paper presents the concept of a national transmission overlay as a high capacity, multi-regional transmission grid, and discusses the system futures that may motivate such a deployment. The paper presents an engineering study to identify benefits to building such a national transmission overlay under certain “transmission-friendly” scenarios, using a tool named NETPLAN that co-optimizes national level long-term expansion of generation and transmission. A preliminary study indicates that a national transmission overlay has potential to offer significant net benefits to the nation in terms of total production and investment costs, while also promising to offer system emission and resilience related benefits. While acknowledging the formidable challenges in political, regulatory, and procedural fronts, one of the main objectives of the paper is to lay out essential elements to facilitate a continued dialog on this topic of developing national transmission overlay, which merits further attention through discussion and analysis regarding benefits, issues and concerns, and possible paths forward.

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