

Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector

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ABSTRACT

Many governments, electric utilities, and large electricity consumers have committed to deep decarbonization of the electricity sector by 2050 or earlier. Over at least the next 30 years, achieving decarbonization targets will require replacing most fossil-fueled generators with zero carbon wind and solar generation along with energy storage to manage intermittency and for balancing more broadly. The best wind and solar resources are located in geographic areas that are often far from the locations of the legacy stock of generating plants and their supporting transmission infrastructure. Many studies have found that achieving decarbonization targets in a cost-efficient manner will require significant investments in new intra-regional and inter-regional transmission capacity. However, there are numerous barriers to planning, building, compensating, and financing this transmission capacity. They go beyond “NIMBY” opposition. These barriers are identified and potential reforms to reducing them are discussed here. The focus is on the U.S. and Europe. Comparing and contrasting U.S. and European responses to similar challenges yields suggestions for institutional, regulatory, planning, compensation and cost allocation policies that can reduce the barriers to efficient expansion of transmission capacity.

Key words: electricity, transmission, decarbonization, wind generation, solar generation, regulation

Introduction

It is now widely recognized that in order to meet governments’ deep decarbonization commitments for the electricity sector in a cost-efficient manner, very substantial investments in intra-regional and inter-regional transmission capacity will be required. The need for an expanded transmission infrastructure is driven by a number of factors. First, achieving decarbonization commitments on the order of 80% to 100% carbon free electricity by, for example, 2045² will in most countries require the virtually complete replacement of dispatchable fossil-fueled generators with large investments in wind, solar and energy storage capacity.³

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² For example, New York State has a commitment of 100% carbon free electricity by 2050, California by 2045, Virginia by 2050. The Biden administration has proposed a goal of 100% carbon free electricity by 2035. The UK and the EU have established the goal of moving their economies to “net zero” carbon emission by 2050.

³ The International Energy Agency (IEA 2021) study of a roadmap to global net zero emissions by 2050 projects that wind and solar generation will account for almost 70% of global electricity generation by 2050 (IEA 2021),

Second, the best sources of wind and solar resources are typically located in areas that are different from the locations of the legacy stock of thermal generating plants. They are also often more remote from demand centers. For example, in Texas, the demand centers are in the eastern part of the state and the best wind resources are located in the Texas Panhandle (northwest) and western areas of the state. On the other hand, the legacy stock of thermal generators⁴ has typically been located over many decades to optimize access to transportation of fossil fuels, cooling water, land availability, transmission costs, and proximity to demand centers (load centers). Natural gas can be transported by pipelines, coal by railroads and barges, and oil by pipelines, barges, and tankers, bringing these fuels to generator locations, but neither sun nor wind can be transported separately from one location to another for use to generate electricity remote from the wind and solar resources. Accordingly, in order to exploit the best wind and solar resources, generators must be located where the wind and solar resources are found and the electricity transported to supply consumers. Accessing and integrating the most attractive wind and solar locations requires significant expansion of transmission capacity to bring the electricity from where it is produced to where it is consumed. From this resource location perspective, the transmission needs are similar to those encountered in exploiting hydroelectric opportunities during much of the 20th century. Indeed, the earliest developments in high voltage transmission technology were associated with gaining access to “remote” hydroelectric locations (Hughes 1983, Chapter X).

Table 3.2). There are other zero or low carbon generating technologies that are potentially commercially viable, if not at large scale by 2050, then possibly later. Stored hydroelectricity is a dispatchable zero carbon technology, but resource limits, cost, environmental constraints and public opposition limit its expansion in most countries. Nuclear power is another potentially carbon free source of electricity that is at least partially dispatchable. However, in the U.S., some EU countries, and Japan, existing nuclear plants are slowly closing and high construction costs and/or public acceptance has severely limited construction of new plants in these regions. China has been expanding its fleet of nuclear plants for several years, though it is expanding more slowly than once projected. Current projections suggest that nuclear generation will be less than 20% of total electricity generation in China by 2050, while wind and solar generation is anticipated to account for most of the rest of its generation. Advanced flexible nuclear technologies are being developed but their wide commercial potential by 2050 is very uncertain. Carbon capture and storage technology and green hydrogen are not yet commercially viable and green hydrogen used in the electricity sector is best thought of as a storage technology. Other zero carbon technologies, such as the Allam cycle and net zero biofuels, are being developed as well, though their wide scale commercial viability by 2050 is uncertain. It should also be recognized that electrification strategies for transportation, buildings, and some industrial applications will lead to a significant increase in electricity demand by 2050.

⁴ Obviously, the location of hydroelectric generation depends on the locations of the necessary water resources.

Third, the output of wind and solar generating facilities is highly variable (intermittent) as it is driven by locational, hourly, daily, and seasonal variations in wind speeds, wind directions and of solar irradiation rather than economic dispatch instructions from the system operator (Joskow 2019). The costs of wind and solar generation can be reduced if they can be utilized over larger geographic market or dispatch areas to better exploit diversity on the demand and supply sides of bulk power systems. For example, if the sun goes down at 6:00 PM in Ohio, it will not go down for another hour in Nebraska. Solar generators in Nebraska can help to satisfy demand in Ohio, and when the sun goes down in Ohio, continue to satisfy demand in Nebraska, increasing capacity factors and reducing costs. Expanding transmission capacity not only increases access to the most attractive wind and solar sites but can also effectively reduce the system demand for electricity and increase generator load factors by aggregating system demands over larger geographic wholesale market or dispatch areas --- exploiting diversity. Of course, this requires more than just increases in transmission capacity. The geographic footprint of wholesale market and dispatch areas would have to expand as well, or actions taken to increase the coupling of proximate market areas with similar effects.

Fourth, transmission system operators need to be able to respond to rapid changes in the quantity and location of intermittent generation in order to balance supply and demand continuously while maintaining the network's essential physical operating reliability parameters (frequency, Area Control Error (ACE), voltage, stability, etc.). Today, many systems rely on fossil-generation to provide these system balancing and reliability functions. But in a deeply decarbonized system, conventional fossil generation will be sharply reduced, so energy storage and, when and where available, zero or low carbon *dispatchable* generation would provide these balancing and reliability function. The quantity of storage required to balance supply and demand can also be affected by the production attributes, locations, and the effective integration of wind and solar generators into larger geographic wholesale market or dispatch (control) areas. Expanding transmission to create larger wholesale market or dispatch areas makes it possible to utilize wind and solar generating capacity more efficiently, reduce curtailments of wind and

solar, decrease the quantity of generation needed to serve demand consistent with reliability criteria, and reduce the need for storage, reducing total bulk power system costs.⁵

Despite the potential advantages of expanding transmission capacity to improve access to and make more effective use of wind and solar resources, a number of barriers exist to expanding transmission capacity to exploit these opportunities to meet decarbonization commitments economically and without violating various power system reliability criteria. As a result, the necessary transmission investments are lagging in the U.S.,⁶ Europe,⁷ China⁸ and elsewhere. Many commentators have focused on stakeholder opposition to major new transmission projects due to real or imagined adverse visual impacts on them --- Not In My Back Yard --- or NIMBY. While NIMBYism is certainly an important source of opposition to permitting new transmission facilities or major enhancements to existing facilities, it is only one of several barriers to expanding transmission capacity. There are also stakeholders who are concerned about impacts on recreational values, economic impacts (e.g. fisherman for off-shore facilities), generators affected by increased supplies from competitors, stakeholders concerned about potential health effects from EMF, and stakeholders who simply see no benefits to them but are uncertain about potential negative impacts. Such stakeholders can and have organized to oppose transmission projects, leading either to construction permit rejections or long delays.

However, the barriers go well beyond these types of stakeholder opposition. There are organizational barriers resulting from excessively narrow transmission system planning protocols and the geographic expanses over which planning takes place. There are barriers created by considering too narrow a range of benefits associated with transmission capacity enhancements. There are barriers

⁵ Of course, expanding the geographic footprint of wholesale market or dispatch areas would likely reduce costs even absent decarbonization but the cost reduction potential is greater in a deeply decarbonized system dominated by intermittent wind and solar generation.

⁶ <https://energynews.us/2020/09/29/grid-congestion-a-growing-barrier-for-wind-solar-developers-in-miso-territory/>

⁷ <https://renewablesnow.com/news/analysis-we-need-to-talk-about-interconnectors-654352/>; Wettengle 2021a, 2021b .

⁸I will focus on the U.S. and Europe here. For a discussion of some of the barriers faced by the expansion of China's Ultra High Voltage Grid (>800Kv) see <https://chinadialogue.net/en/energy/untangling-the-crossed-wires-of-chinas-super-grid/> .

created by disputes over how the costs of these facilities will be allocated to users of the system. Finally, there are compensation (cost recovery) and associated financing barriers. .

The paper proceeds as follows. The next section discusses the locations of the most attractive wind and solar sites in the U.S., Europe and China. The second substantive section reviews the results of several modeling studies that examine the role that transmission expansion plays in meeting carbon decarbonization goals in a cost-efficient manner. The following section discusses the relevant attributes of transmission systems and transmission system operators in the U.S. and Europe. I then discuss five specific historical transmission project cases to provide a sense for the kinds of barriers and potential mitigating actions that new transmission projects frequently encounter or use. This section is followed by a broader discussion of the major barriers other than NIMBY faced by developers of new transmission projects and potential mitigating responses. NIMBY related issues are discussed in the final section of the paper.

I have chosen to focus on the U.S. and Europe for two primary reasons. First, I know the attributes of the electric power systems in these areas much better than I do for other areas of the world. Second, I think that there is much to learn by comparing and contrasting the responses to these barriers in the U.S. and Europe since the electricity sector decarbonization challenges they face are basically the same. I have also included some information for China since its energy transition is so important for meeting global carbon emission mitigation commitments and expanding China's transmission grid is essential for meeting its decarbonization commitments.

Location, Location, Location

The economic potential for wind and solar development varies widely due to geographic variations in the attributes of the primary wind and solar resources. Analyses of wind and solar potential in specific locations start with data on wind speeds and directions at various elevations and data on solar

irradiation at different locations and seasons.⁹ These data are widely available and maps of resource intensity help to visualize the major locational variations (e.g. from the National Renewable Energy Laboratory (NREL) in the U.S. (<https://www.nrel.gov/gis/solar.html> and <https://www.nrel.gov/gis/wind.html>), from the New European Wind Atlas (<https://map.neweuropeanwindatlas.eu/>) and from SOLARGIS in Europe (<https://solargis.com/maps-and-gis-data/download/europe>)). However, this information is just the starting point for assessing the economic potential of resources in these areas. Wind and solar development potentials are affected by factors like topography (e.g. hills and rolling terrain), elevation, land use restrictions (e.g. protected areas like state and national parks and recreation areas), urbanization, competing uses (e.g. recreation, oil and gas development, shipping, fishing), daily and seasonal variations in wind speeds and directions and solar irradiation, sea depths, distance to load centers, existing transmission infrastructure and of course, the cost of any new transmission infrastructure required to access the most attractive wind and solar resources.

For example, the Pacific coast of the United States exhibits very high offshore wind potential based on wind speeds at various elevations (Frontier Group 2021 <https://frontiergroup.org/reports/fg/offshore-wind-america>) . However, the ocean depth increases rapidly as one moves offshore along the Pacific coast and would require floating wind turbines to exploit. Indeed, there is substantial offshore wind potential in water deep enough to require floating wind turbines in several countries(e.g. Japan, Norway). However, floating wind turbines are still at early stages of development and not yet ready for widespread commercial deployment (<http://web.mit.edu/windenergy/windweek/Presentations/P6%20-%20Sclavounos.pdf>). In the long run there are important interactions between wind and solar *commercial* resource potential at different locations and technological innovation in wind and solar generating technology. For example, the typical turbine's generating capacity, blade length, and elevation have increased rapidly over time, making wind speeds at higher elevations more accessible and this creates opportunities to improve wind generation

⁹ e.g. Frontier Group (2021). <https://frontiergroup.org/reports/fg/offshore-wind-america>.

capacity factors and to reduce generating costs. Similarly, as this is written, the U.S. has only seven operating offshore wind turbines (5 off Block Island in Rhode Island and 2 off the coast of Virginia). However, there is much more substantial experience with offshore wind projects in Europe and that experience is being transferred to develop a great deal of offshore wind capacity along the northeastern coast of the U.S. from Massachusetts to North Carolina. As a result, it is difficult to generalize about the most attractive wind and solar development locations, though technological innovation and commercial development activity has tended to follow the most attractive locational wind and solar resource attributes.

In the U.S., the most attractive wind resources lie in the Great Plains and Eastern slope of the Rocky Mountains from the Canadian border to northern and western Texas, in areas of the far west, especially Wyoming, along the Atlantic coast from Maine to North Carolina, and a few smaller areas such as upstate New York, northern Maine, and portions of the Texas Gulf coast area (<https://www.nrel.gov/gis/wind.html>). The abundant wind resources located down the center of the U.S., in Wyoming, the Texas Panhandle, etc. are relatively distant from many urban load centers further to the east and are typically not near the bulk of existing generating plants and supporting transmission infrastructure. The offshore wind resources in the northeastern U.S. are located near major population centers but there is no existing offshore transmission infrastructure to support them. Moreover, the status of onshore interconnection and onward transmission capacity to receive and distribute the offshore generation varies considerably from one offshore wind development area to another. Retired power plant sites near the coast are favored interconnection locations for offshore wind developers because much of the needed interconnection and onshore transmission infrastructure is likely already to exist.

The best solar resources in the U.S. are in the southern areas of the country, especially the desert southwest and western Texas (<https://www.nrel.gov/gis/solar.html>). As a general matter, average solar irradiation increases as one moves from north to south, reflecting both the orientation to the sun at different latitudes, across seasons, as well as haze, clouds and other weather patterns. These resources too are distant from major load centers.

The EU exhibits similar variations in wind and solar resources. Wind resources are generally better as one moves north, especially offshore, while solar resources are better as one moves south (<https://www.wind-energy-the-facts.org/wind-atlases.html>; <https://www.ewea.org/fileadmin/files/library/publications/reports/EY-Offshore-Wind-in-Europe.pdf>; <https://solargis.com/maps-and-gis-data/download/europe>). North Africa has abundant solar resources creating an opportunity to expand transmission interconnections between Europe and North Africa to support access for development of solar generating facilities there to supply Europe (<https://solargis.com/maps-and-gis-data/download/middle-east-and-north-africa>). The UK has limited onshore wind potential but excellent offshore wind potential (<https://electricenergyonline.com/energy/magazine/936/article/Harnessing-UK-s-offshore-wind-potential.htm>) requiring new off-shore transmission infrastructure. The UK has relatively poor solar potential due to its northern location as well as land-use constraints; e.g. the UK electric power system has a winter peak at about 6:00 PM when it has long been dark there.

In China, the most attractive wind and solar resources are in the northwest and north (Inner Mongolia) (<https://aws-dewi.ul.com/assets/Wind-Resource-Map-CHINA-11x17-bleed1.pdf>; <https://solargis.com/maps-and-gis-data/download/china>), while load centers and existing power plants are more concentrated along or near the eastern and southern coasts. China is developing an ultra-high voltage “super-grid” to gain access to these resources (as well as to remote coal deposits around which future large coal-fueled generating plants may be developed to exploit the coal, though this may conflict with China’s carbon emissions commitments). (<https://spectrum.ieee.org/energy/the-smarter-grid/chinas-ambitious-plan-to-build-the-worlds-biggest-supergrid>)

The bottom line is that in the U.S., Europe and China the best wind and solar resources tend to be fairly remote from load centers, legacy power plants and/or existing transmission infrastructure. In order, to exploit these resources effectively significant investments in new intra- and interregional transmission capacity will be needed.

Model Assessments of Transmission Expansion to Support Deep Decarbonization Efficiently

There have been several assessments of the potential roles of future transmission configurations in supporting an efficient exploitation of wind and solar resources to meet deep decarbonization goals in the U.S. and Europe. These assessments typically rely on optimal long run system investment planning and dispatch models. Brown and Botterud (2021) examines the effects of expanding intraregional, interregional, and inter-synchronous network transmission capacity on the costs of supporting a zero carbon emissions U.S. electricity sector by 2040 using currently commercially available technologies.¹⁰ Expanding transmission capacity significantly reduces the costs of achieving a zero carbon U.S. electric power sector in 2040. These cost savings increase significantly as we move from expanding intra-regional, to inter-regional, to inter-synchronous network transmission capacity. The cost savings arise for two primary reasons in the analysis. First, expanded transmission capacity facilitates access to the most attractive wind and solar sites. Second, by expanding transmission capacity, the geographic expanse of electricity market areas where wind, solar, and storage can balance supply and demand also expands, allowing for more intensive use of wind, solar, and storage facilities to meet demand.

Nelson et. al. (2012) uses a different optimization model applied to the electric power systems in the Western U.S. and Canada to examine the most efficient configuration of wind, solar, storage, transmission and other generation sources assuming a \$70/ton price on CO₂ emissions, arguing that this price is consistent with a 450ppm CO₂ target. In their model, high voltage transmission is built primarily to bring high quality wind generation from the Rocky Mountain region to load centers. Li and McCalley (2015) simulates the effects of several national high voltage transmission overlay scenarios for the U.S. and finds that they provide cost, environmental and system performance benefits. MacDonald et. al (2016) finds that a national U.S. electric power system enabled by a national high voltage DC system

¹⁰ The U.S. has three synchronized AC networks --- the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT). These networks have very limited DC interconnections with one another and operate independently. The Eastern and Western Interconnections also encompass large portions of Canada. Patrick and Botterud (2021) defines 11 smaller planning areas (PA) or zones. Three of these PAs are in the Western Interconnection, one in Texas, and seven in the Eastern Interconnection. Except for Florida, Texas, and California, each PA contains multiple states.

linking regional systems can achieve an 80% reduction in CO₂ emissions compared to 1990 levels without an increase in the levelized cost of (generation + transmission) electricity.

In a widely circulated study, Bloom et. al. (2021) simulates the impact of adding various high voltage DC overlays connecting the Eastern and Western Interconnections in the U.S., co-optimized with both generation and AC transmission investments within each synchronous interconnection, under a wide range of cost assumptions. The benefit/cost ratios are as high as 2.89 and far exceed the Federal Energy Regulatory Commission's (FERC) benefit/cost threshold of 1.25 for regulated "market efficiency" transmission investments in all but one of 22 cases (where the B/C ratio is 1.22).

Optimization modelling and simulations for the EU yield similar results. Schlachtberger et. al. (2017) models and simulates a cost optimal system that allows for optimal DC transmission expansion to increase interconnection capacity between transmission systems¹¹ in the EU and to achieve a 95% reduction in CO₂ emissions from 1990 levels. The simulations yield an increase by a factor of 9 in flows between countries, requiring very large increases in transmission capacity. Restricting transmission expansion increases system costs by 30% and leads to changes in investments in wind, solar, and storage to meet the 95% CO₂ emission reduction constraint. However, allowing for transmission flows to be restricted to 44% of the optimal level (four times current flows) yields about 85% of the cost savings. Hagspiel et. al. (2015) models a 200-node system in Europe to achieve a 90% CO₂ emissions reduction and they find that the optimal system requires about double today's transmission capacity. Rodriguez et. al. (2014) finds that a least cost system with 100% CO₂ free electricity implies an increase in interconnector capacity by a factor of 11.5. However, most of the benefits can be achieved with an increase in interconnector capacity "only" 5.7 times current values. Horsch and Brown (2017) find that a least cost system that meets a 95% CO₂ emissions reduction implies an increase of a factor of 2-3 in intra-country and interconnector transmission capacity. Finally, Trondel et. al. (2020) finds that continental scale generation supply (copper plate) is the least cost way to achieve a 100% carbon free EU

¹¹ As discussed further below TSOs in Europe typically span a single country.

electricity system, but that it requires a large increase in transmission capacity. An alternative approach which relies on intra-regional generation investments but inter-regional balancing can be achieved with smaller expansions of transmission capacity with a modest cost penalty, though interconnector capacity must double from current levels.

These optimization studies rely on different optimization models, different cost assumptions, different demand growth assumptions, different levels of spatial and temporal resolution, different representations of transmission networks, different assumptions about topography and protected areas, and different CO2 emissions constraints. They do not model transmission networks, especially AC networks, in enough “electrical” detail to identify a specific portfolio of actual transmission projects. They do not, and, were not expected to, design specific transmission projects for potential development. However, the results of these analyses are indicative of what can be achieved by expanding transmission capacity to support deep decarbonization of electric power sectors.

However, the modelling results are consistent with the project specific studies done by ENTSO-E in the EU (https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2020/Foropinion/TYNDP2020_Main_Report.pdf) and with the “shovel ready” projects identified by Goggin, Gramlich, and Skelly (2021) in the U.S. Studies that look at much smaller geographic areas within the footprint of a single system operator are also consistent with the modelling results. For example, the New York ISO (NYISO) and the New York Public Service Commission (NYPSC) have identified and approved several transmission projects that would relieve congestion between upstate and downstate New York to increase access to renewable energy in northern New York and to Canadian hydro-power (https://www.nysrc.org/pdf/MeetingMaterial/ECMeetingMaterial/EC%20Agenda%20241/7.1.2%20AC_Transmission_PPTN_NYSRC-EC_2019-05-Attachment%207.1.2.pdf; <https://www.nypa.gov/power/transmission/transmission-projects>). The NYISO and NYPSC have also examined options to build new transmission capacity to connect offshore wind projects to the onshore network and enhancements necessary to accept and distribute this energy into the onshore AC grid

(<https://www.nyiso.com/documents/20142/1400973/OSW.pdf/c2ec9086-ea7b-f01c-66d6-ff4446a566fc>) .

As I will discuss further below, Texas developed about 18,000 MW of transmission capacity to connect Competitive Renewal Energy Zones (CREZ) primarily wind generation in the Texas Panhandle with load centers within Texas (<https://poweringtexas.com/wp-content/uploads/2018/12/Transmission-and-CREZ-Fact-Sheet.pdf>) . Germany has moved ahead with a major expansion of its transmission grids (more than one TSO in Germany). to meet its electricity sector decarbonization goals efficiently (Appunn 2018).

Planning, Operating and Investment Boundaries of Electric Power Systems

What do I mean by a “transmission system” and a “transmission system operator?” For the purposes of this paper I am referring primarily to the geographic boundaries of a transmission network within which a transmission system operator¹² has responsibility for balancing supply and demand continuously consistent with reliability criteria, managing wholesale markets where they exist, coordinating with proximate system operators which are often, but not always, part of the same larger synchronized AC network, managing transmission planning processes to meet reliability, economic and potentially decarbonization goals and other public policy goals, and managing transmission investment and cost allocation policies. At one extreme, system operators may own directly or indirectly through affiliates some or all of the physical generation, transmission and/or distribution assets within their systems’ boundaries. This is the case for some of the large remaining regulated vertically integrated utilities in the U.S. and Canada. At the other extreme, transmission system operators may be completely independent organizations owning no physical assets aside from control rooms, operating and planning software, etc. This is the case for the RTO/ISOs in the U.S. and Canada. Over the last 20 years, the restructuring and wholesale market development process has led policymakers to require many system operators to act independently without regard to who owns what, even if they are part of a company that

¹² The transmission system and the associated system operator are referred to by several different names. In the U.S., they may be referred to as Balancing Authorities (BA), Control Areas Operators (CAO), Independent System Operators (ISO) or Regional Transmission Organization (RTO). In Europe they are referred to as Transmission System Operators or TSOs.

owns generation, transmission, and distribution assets of their own (i.e. functional rather than ownership unbundling required).

Many of the challenges associated with efficient expansion of transmission networks to support deep decarbonization of electricity sectors are a consequence of barriers created by the diverse organizational arrangements, regulatory frameworks, political constraints, and geographic boundaries of legacy transmission systems. The diverse geographic boundaries of electric power systems, from the perspective of system operations, wholesale market coverage, planning, and investment in transmission facilities that we see today are a consequence of technological innovation, economics and, importantly, political forces over more than a century. In transmission systems whose operating and planning footprints include good wind and solar sites, intra-system transmission expansion will be needed to better exploit these resources for cost efficiency and to meet operating reliability criteria. However, in many cases economical transmission expansions will span at least two and potentially more legacy transmission operating, dispatch and planning system-areas. I will refer to former as “intra-regional” and the latter as “inter-regional” (or “interconnectors”) transmission projects below.

Transmission Systems and System Operators in the U.S.

The geographic footprints of transmission systems managed by individual system operators varies widely across the U.S., the EU, the UK, and in other countries. For example, as previously noted, the U.S. has three synchronized AC networks that also cover most of Canada. There are a few DC interconnections with very limited capacity between the three synchronized AC networks and from a physical and economic perspective they are presently independent synchronized networks. However, these synchronized networks are not transmission systems in the sense that I have in mind here. They are electrically synchronous AC electric power networks that support several individual transmission systems, their system operators, and a much larger number of transmission owners. Because they are part of larger synchronized networks, individual system operators responsible for portions of these networks must adhere to a strict set of physical operating rules to maintain operating reliability criteria across the entire synchronous network of which they are only a part.

For example, in the U.S. each synchronized network operates at a frequency of 60Hz with reliability criteria that allow very small upward or downward flexibility in frequency around 60 Hz (in Europe it is 50Hz). Each system operator has the responsibility to monitor and maintain their system's frequency at this level, to schedule operating reserves to respond rapidly to variations in supply and demand, to review whether sufficient investment in generation and transmission capacity is forthcoming to meet reliability criteria over up to a decade into the future, and to coordinate with other system operators to ensure that deviations from operating protocols do not occur --- e.g. managing deviations in power flows between interconnected system operators (Area Control Error -- ACE) --- and communicating with other system operators when abnormal conditions arise within their physical boundaries. In this regard, system operators on the same synchronized AC network cannot "do their own thing." Operating criteria and adherence to them are necessary for synchronized AC systems with multiple system operators to avoid free riding and actions that threaten the reliability of the larger synchronized network. These basic physical operating criteria for the synchronized networks in the U.S. are developed, monitored, and enforced by the North American Reliability Corporation (NERC) with regulatory enforcement support from FERC in the U.S. and by provincial regulators and the Canada Energy Board in Canada.

The U.S. has 66 "Balancing Authorities" (BA) which for our purposes are equivalent to system operators. They vary widely in size and organizational structure. At one extreme are Independent System Operators (ISO) and Regional Transmission Organization (RTO) which operate the system over specified geographic areas and coordinate with their neighbors. These include ISO-New England, New York ISO (NYISO), PJM, California ISO (CAISO), Midcontinent ISO (MISO), and the Southwest Power Pool (SPP). They do not own electric power assets, are non-profit, and have independent boards. They are responsible for operating their own short-term wholesale markets, coordinating operations with neighboring ISO/RTOs or BAs, generator and transmission interconnection policies, transmission planning, identifying needs for and responsibilities for expanding transmission within their geographic footprint to meet reliability criteria and since FERC Order 1000 issued in 2011 (subject to subsequent

compliance filings), inter-system transmission expansion. While the wholesale markets they operate have their own individual designs, they have many common attributes and efforts have been made to support participation by neighboring systems in each other's markets to at least a limited extent. These ISO/RTO footprints may cover a single state (e.g. New York, California) or multiple states (e.g. New England, PJM, MISO) and vary widely in geographic expanse.

ERCOT is an ISO covering about 90% of Texas. It is a synchronized network that is isolated from the Eastern and Western Interconnections, aside from a few DC links with very small capacities. ERCOT is regulated primarily by the Public Utility Commission of Texas (PUCT) rather than by FERC, though in most ways it is indistinguishable from the ISO/RTOs regulated by FERC. It manages a sophisticated organized wholesale market within its boundaries.

At the other extreme, are large traditional regulated fully or partially vertically integrated utilities which are system operators within their geographic footprints. The Southern Company¹³ is an example of a traditional regulated vertically integrated utility that is a large system operator. BC Hydro in British Columbia is another. These system operators do not manage the standard U.S. RTO/ISO organized wholesale markets but must adhere to various non-discriminatory transmission open access, planning, investment, and operating regulations specified and administered by FERC and NERC. In between are smaller vertically integrated utilities, some municipal or state-owned which are also system operators. The Los Angeles Department of Water and Power (LADWP) is a good example. LADWP is a large municipal transmission system operator in California and is partially vertically integrated through ownership of generating assets as well as long-term Purchased Power Agreements (PPA) with independent generators. It is separate from the California ISO. There are many more system operators, typically with much smaller geographic footprints that have not been or are only partially restructured, primarily in the Southeast, Florida, and the West outside of the CAISO.

¹³ The Southern Company is a holding company that owns regulated vertically integrated electric utilities in Georgia, Alabama, and Mississippi. It operates them as an integrated system. It also owns natural gas distribution, natural gas transmission, and other affiliates.

For my purposes here, an important feature of RTO/ISOs in the U.S. is that their missions include the design and operation of wholesale markets, transparent transmission planning processes, identification of transmission projects to meet reliability, market efficiency, and public policy goals and assignment of transmission investment obligations to existing or new transmission owners, almost entirely within their geographic boundaries. In the U.S., until relatively recently the RTO/ISOs focused only on investments to support transmission system reliability rather than on facilitating enhancements in market efficiency by mitigating significant and consistent network congestion at specific locations, or supporting public policy goals like aggressive decarbonization commitments made by the states they serve. Transmission projects approved and assigned by the ISO/RTOs are subject to FERC cost-of-service regulation, cost allocation rules approved by FERC, and ISO/RTO transmission tariff rules also regulated by FERC (except for ERCOT).¹⁴

TSOs in the EU, Baltic countries and the UK

Continental Europe has a large synchronous AC grid that stretches from Spain to Poland and western Turkey, covering all of continental Europe, and synchronized with Northern Africa via two AC links with Spain, with a third link under consideration (<https://www.pv-magazine.com/2019/02/20/spains-third-interconnection-with-morocco-could-be-europes-chance-for-african-pv-or-a-boost-for-coal/>). The Nordic countries maintain a separate synchronous AC grid (Nordic Grid) with DC interconnections with the Continental European Grid. The United Kingdom also has a separate synchronous network covering England, Wales and Scotland but has three DC interconnectors with the European Grid and three under construction, one with Norway (Nordic Grid). Ireland and Northern Ireland are not synchronized with either the European or UK grids but have DC interconnections with the UK grid. With some exceptions (e.g. Germany), each country has a single transmission system operators which covers physical operations, organized wholesale markets within its country's boundaries. This reflects the historical

¹⁴ Merchant projects that rely entirely on transmission contracts with shippers must apply to FERC for negotiated rate authority which applies criteria designed to ensure that the process for marketing transmission rights to shippers is competitive.

evolution of the electric power systems in each country and ongoing political considerations. Sweden also has a single transmission system operator --- Svenska kraftnät --- which is state-owned and serves as both the system operator and the owner of the transmission network.

While the TSOs in Europe share with U.S. RTO/ISOs the responsibility for real time wholesale market operations, system operations, transmission grid and congestion management and planning functions, they also typically own and can invest in the transmission network. They are also typically for-profit entities. For example, the French TSO – RTE --- is the system operator for France and owns and operates the French transmission system. It is also partially owned by Electricité de France and is a for-profit entity. The TSO in the UK is National Grid ESO which is the system operator for the transmission grid in England and Wales, offshore transmission networks, and also operates the two transmission networks in Scotland. It is part of the National Grid Group, though it is legally separate and functionally independent. It is a for-profit organization. In Spain, the TSO is Red Electrica. It is the system operator, owns, operates and invests in Spain’s transmission network. It is a for-profit company and its primary shareholders are Spanish utilities. The Italian transmission system operator is TERN and it is responsible for market and physical operation of the Italian grid, planning, development and investment in new transmission facilities and is a for-profit entity.

Another difference between the RTO/ISOs in the U.S. and the TSOs in Europe is their involvement in organizing and managing wholesale power markets. U.S. RTO/ISOs operate integrated day-ahead, adjustment, and real time energy and ancillary services markets (co-optimized) and rely on security-constrained bidding and dispatch mechanisms to manage and price congestion simultaneously with generation supplies to yield different hourly and real time prices at each node when there is congestion on the network ((Locational Marginal Prices---LMP). In Europe, independent power exchanges operate day-ahead and intra-day adjustment markets for generation supplies, yielding market clearing prices and schedules. They then “give” the schedules to system operators which must dispatch the resources and balance the system in real time to take account of feasibility, transmission congestion, and ancillary services needs --- typically relying on pay as bid markets to redispatch, acquire ancillary

services, and balance the system in real time. Locational price differences in Europe are much less granular than in the U.S., reflecting granularity at the “zonal” (redispatch) level, though the principles establishing zones vary from country to country. For example, Germany has two wholesale pricing zones (Northern and Southern), Italy has six intra-country pricing zones, and England and Wales has one energy price zone. Interconnectors between transmission systems are also typically pricing and scheduling points.

Forty-two TSOs representing 35 European countries have joined together to create the European Network of Transmission Operators Organization (ENTSO-E). ENTSO-E is responsible for facilitating the cooperation of European TSOs, establishing protocols to ensure the reliable operation and optimal functioning of the European Grid, and supports the development of interconnected electricity markets, including organizing planning of transmission facilities and supporting their development. It fulfills various mandates given to it by EU regulatory authorities, including supporting the transition of the EU to become carbon neutral by 2050.

ENTSO-E has taken on many of the functions fulfilled by NERC in the U.S. However, as I discuss further below, its mandate is much broader than developing, applying, and monitoring operating reliability criteria and protocols. It also has responsibility for working with all of the TSOs to better integrate wholesale markets, to expand transmission capacity, especially interconnectors, to facilitate greater market coupling and to support the EU's decarbonization and associated transmission expansion goals.

Transmission Project Case Studies in the U.S. and Europe

To motivate the discussion of barriers to transmission expansion and potential approaches to reducing them, I start by discussing five brief case studies of major transmission projects in the U.S. and Europe. The successful development of long-distance transmission facilities has never been easy, reflecting a variety of organizational, compensation, financing, cost and benefit allocations, and NIMBY opposition.

The Pacific Northwest-Southwest AC/DC intertie, which was designed to facilitate access to cheap hydroelectric power in the northwest by electric utilities and their customers in the southwest is a case in point. The idea of building transmission lines to bring hydroelectric power from the Pacific Northwest to supply electricity to California and Arizona was first advanced in 1919.¹⁵ It took 45 years to come to fruition. In the 1930s, Franklin Roosevelt supported the development of federally owned transmission facilities connecting the Northwest and Southwest as a complement to the creation of the Bonneville Power Authority (BPA) and the construction of hydroelectric facilities by the federal government along the Columbia River. The BPA and its hydroelectric facilities went forward but not the transmission links to the Southwest. Disputes about hydro-electric resource allocations between the U.S. and Canada, concerns among northwestern states that “their” cheap hydroelectric power would be siphoned off by population centers in the southwest, investor-owned utility concerns about competition from government-owned utilities, permits needed from several states and federal agencies, cost recovery and financing issues, and other factors complicated moving forward. Power shortages in California in 1948 led to renewed interest in the idea, but the controversies continued and the project languished during the 1950s. President Kennedy directed the Secretary of the Interior to do what was necessary to move the project forward after he became president in 1961. Acts of Congress supporting the development of the intertie were passed in 1964 and 1965. The project ultimately involved the construction of four major transmission links, one HVDC and three AC, and multiple smaller supporting AC transmission upgrades by a group of investor-owned, municipal utilities, state power authorities, and federal agencies, across multiple states in the West. Portions of the project were first energized in 1968.¹⁶

A more recent example was the development of the Phase 2 of the HVDC link between Quebec and New England that was energized in 1990 (Swain 2019).¹⁷ Again, two countries, several states, many

¹⁵ Based on <https://www.nwcouncil.org/reports/columbia-river-history/intertie>

¹⁶ A map of the Pacific AC/DC Interties can be viewed at https://en.wikipedia.org/wiki/Pacific_DC_Intertie

¹⁷ Maps of the Hydro-Quebec Phase 2 HVDC project can be viewed at <https://www.energy.gov/sites/prod/files/2015/06/f24/EIS-0129-FEIS.pdf> and at https://www.ieee-pes.org/presentations/gm2014/Sandy_Pond_Terminal.pdf

utilities, but this project went much more smoothly than the Pacific Intertie. In the late 1970s and early 1980s, interest in New England in accessing hydroelectric power was driven by the high cost of oil which at that time was the primary fuel used to generate electricity in New England and growing environmental constraints on emissions from oil and coal plants (The new England utilities also pursued the development of several jointly owned nuclear power plants for the same reasons, many of which are now closed). Quebec was interested in the economic opportunities to supply electricity to New England from potentially enormous hydroelectric resources near James Bay in northern Quebec. The New England utilities and Quebec adopted an economic framework that minimized conflicts between the multiple New England utilities, six states, and Quebec. Basically, all of the costs of the new transmission capacity located in the U.S. were shared by the then regulated U.S. utilities in proportion to their allocations of power supplied from Quebec. Regulatory cost recovery using traditional rate base, rate of return cost of service regulatory principles was approved by FERC. (One state negotiated a larger share of the power supplied under the contract with Hydro-Quebec in return for approving a small portion of the project that went through the state.) The costs of the new transmission facilities in Quebec were the responsibility of Hydro-Quebec, the Crown Corporation that supplies electricity in Quebec and is the Quebec system operator. Hydro-Quebec got an 11-year purchased power agreement --- PPA (followed by subsequent PPAs). The project was first energized in 1990.

The major obstacle to this project was local opposition to new transmission lines along the route of the project. The project maximized the use of existing rights of way, avoided densely populated areas, engaged local authorities along the line in planning and construction, and provided various incentives to the towns from which approvals were required. Swain (2019) concludes that all of these actions collectively contributed to the project being completed on time and on budget. The more recent experience with another HVDC link with Quebec has been more troubled.

In 2018, the state of Massachusetts selected Northern Pass Transmission, a subsidiary of Eversource, a distribution and transmission utility with subsidiaries in Massachusetts, Connecticut, and New Hampshire, as the winner of a competitive solicitation for clean energy bundled with new

transmission facilities supported by long-term PPAs for both power and transmission.¹⁸ Northern Pass was selected to help to meet Massachusetts electricity decarbonization commitments. Its winning bid proposed to build a 192 mile HVDC transmission line to connect the Hydro-Quebec network with the New England network, along with a converter station, AC transmission facility and substation upgrades elsewhere in New England, to support the delivery and distribution of 1,090 MW of hydroelectric power produced by Quebec Hydro to Massachusetts distribution utilities.¹⁹ Northern Pass would have been compensated for the costs of these transmission facilities through a FERC regulated tariff meeting criteria, including cost containment and performance commitments, specified in its winning bid. This transmission tariff would have been separate from ISO-NE's regulated open access transmission tariffs to "protect" the rest of the region from paying for any of the costs of this project developed to meet Massachusetts' decarbonization goals. The HVDC portion of the project was to be located entirely in New Hampshire, though none of the clean energy supplied by Hydro-Quebec would have been credited to utilities or consumers in New Hampshire since the counterparties to the contract with Hydro-Quebec and the costs of the transmission facilities and power supply contract were to be credited to and paid for by Massachusetts consumers.

There was substantial public opposition to the project in New Hampshire primarily on visual, recreational, and environmental impact grounds since a large portion of the project went through protected recreational areas, especially the White Mountain region. The developer of the project responded to expected concerns about adverse impacts by placing a portion of the project underground. However, opposition in New Hampshire persisted and a permit for the HVDC portion of the Northern Pass project was subsequently rejected by a regulatory agency in New Hampshire. That decision was affirmed by the New Hampshire Supreme Court in mid-2019 and the project was abandoned.

¹⁸ A map of the proposed Northern Pass transmission project can be viewed at <https://forestsociety.org/map-northern-pass-proposed-route>

¹⁹ <http://www.northernpass.us/project-overview.htm>; <http://www.northernpass.us/facilities-equipment.htm>.

An alternative HVDC project through Maine to connect with Hydro-Quebec to access the contracted hydroelectric power--- New England Clean Energy Connect²⁰ --- that scored well in the original Massachusetts competitive solicitation, was then selected as the winner of the Massachusetts RFP. This project involves building 145 miles of new HVDC line, new AC lines, upgrades to existing AC lines throughout New England, a new substation, and a converter station.²¹ The developer of this project is Central Maine Power (Avangrid), part of the Iberdrola Group, but the costs (and most of the clean energy benefits in the form of renewable energy credits) of the project will be allocated to Massachusetts retail customers. As with the terminated Northern Pass project, the costs will be allocated to them through regulated transmission tariff charges, separate from ISO-NE's regulated open access transmission tariff. Responding to opposition to the project in Maine, the developers emphasized the economic development benefits of the project in Maine and the indirect benefits of lower wholesale electricity prices in the region resulting from the increased supplies from Hydro-Quebec. About 2/3 of the project uses existing rights of way to mitigate additional adverse impacts. Opponents endeavored to use a ballot initiative to block the project, but the Maine Supreme Court blocked the ballot initiative in 2020. The project received all regulatory permits and construction began in early 2021 with a target completion date of 2023, though I am told that opponents are trying again to use a ballot initiative to block completion of the project.

Turning now to a couple of case studies in Europe. The first example is the development of additional transmission capacity between France and Spain. Prior to 2015, Spain had only 1200 MW of transmission capacity with France and through France to the rest of Europe. A new transmission link between France and Spain was first proposed in the 1980s (Ciupuliga and Cuppen 2013). The project was initially proposed as an extra high voltage double circuit overhead AC link going through the Pyrenees-Orientales region. A companion contract to supply electricity by France to Spain was

²⁰ <https://www.necleanenergyconnect.org/project-overview>

²¹ A map of this project can be viewed at https://www.masslive.com/news/2018/02/maine_transmission_line_will_c.html

negotiated in 1984. The project met with substantial opposition on environmental, adverse economic impact (tourism), and NIMBY grounds. The initial project was effectively abandoned but a new project proposal was made in 2003, again for a two-circuit overhead AC link, but it too attracted substantial public opposition, especially in France (Ciupuliga and Cuppen 2013). With the project stalled, in 2006 France and Spain requested that a European Coordinator be appointed by the European Commission to help to move the project forward. The coordinator discussed project alternatives with the French and Spanish TSOs as well as with other stakeholders in both countries. In 2008, a new agreement was negotiated for a new HVDC link that would be entirely in two underground tunnels.²² The project was developed by a joint 50/50 venture between the TSOs in France and Spain, with a grant from the EU and a loan from the European Investment Bank, accounting for about 82% of the estimated cost of the project. The project was completed in 2015 and reached commercial operation in October 2015, roughly 30 years after an additional link between France and Spain was first proposed. Of course, many things have changed in 30 years. Spain is now fully integrated into the EU, the EU has adopted electricity market and transmission interconnection guidelines and goals, and deep decarbonization is now a fundamental EU policy goal. Unlike the 1984 proposal, this project expects power supplies to move both to and from Spain and France, and to advance security of supply, decarbonization, and market coupling goals in both countries.

The examples presented so far all involve multiple states (in the U.S.) and multiple countries (in the EU and the U.S.). However, challenges to building transmission facilities to support decarbonization goals are not limited to these situations. A case in point is transmission development to support Germany's Energiewende policy (Appunn 2018). The German decarbonization policy relies on a shift from fossil-fueled power generation to zero carbon renewables, taking into account Germany's decision to retire all of its nuclear plants by 2022. The most attractive wind sites are in the north of Germany, and

²² A map of the project can be viewed at <https://www.eib.org/en/infocentre/stories/all/2015-february-02/connecting-france-and-spain.htm>

an efficient transition depends on moving a significant amount of that generation to the south. Today, there is significant congestion between the north and the south and imbalances between the north and the south are expected to continue to grow as wind generation expands to meet decarbonization commitments. Such imbalances will increase the costs of decarbonization, primarily in the south, and may create operating reliability issues due to intermittency of wind generation. Accordingly, the German TSOs and the federal government have endeavored to build additional transmission lines (4,600 miles of lines) to remove the bottlenecks, including an “overlay” of four new HVDC links, with a completion goals of 2025.²³

In Germany, it takes on average ten years for a large transmission line to go through the planning, approval, and construction process (Appunn 2018). There has been significant opposition by German stakeholders to the new north/south HVDC transmission links, especially in areas near where new links will be built, and this has led some German states to support the projects in theory but to slow-walk the projects in practice. There have also been objections about the “excessive” financial returns that the grid operators will receive. The TSOs are apparently guaranteed a fixed return on their investments and the projects did not go through a competitive procurement process to select projects and agree on the terms and conditions for cost containment and compensation (Appunn, page 6). Others have argued that the transmission expansion plan is excessive and that more reliance could be placed on distributed resources closer to load centers. As the completion of these projects by 2025 seems increasingly doubtful, other short-term solutions, including “smart grid” solutions are being considered. At the same time, grid operators argue that substantial additional north/south transmission capacity will be needed by 2030 and 2035 to meet Germany’s decarbonization and supply security goals (Wettengle 2021b).

²³ A map of these four projects (along three corridors) can be viewed at <https://spectrum.ieee.org/energy/renewables/germany-takes-the-lead-in-hvdc>

Barriers to Major Transmission Projects other than NIMBYism

There are several barriers that must be managed to accelerate the build-out of transmission facilities to support efficient decarbonization programs. While opposition to permitting new transmission projects is often attributed primarily to “NIMBY” considerations, I believe that this is only one part, perhaps a very important part, of a longer list of barriers to developing and completing major intra- and inter-regional transmission projects. In this section I will discuss a larger set of barriers and potential approaches to reducing them. The U.S. and Europe have faced similar barriers and it is useful to compare and contrast how they have endeavored to manage them. I will leave “NIMBY” opposition to permitting and potential responses to it until the next section of the paper.

Transmission planning and “attention” geographic areas are too small and there is inadequate coordination of planning and development between TSOs, especially in the U.S.

Transmission system operators naturally focus on the transmission development needs within the boundaries of their own transmission systems and, where applicable, their own wholesale market areas. Of course, they must cooperate with other TSOs on the same synchronous network and adhere to the associated operating reliability criteria for this synchronous network. But expanding transmission capacity between TSOs and better integrating their wholesale markets has historically been given much less attention than transmission planning and wholesale market design within their geographic footprints. This is why interconnections to neighboring TSOs have historically often been quite limited.²⁴ However, as discussed above, the transmission capacity enhancements needed to access and effectively utilize wind and solar generation resources, as well as storage, often span the geographic footprint of two or more TSOs. The European Transmission Development Plan (TYNDP), to be discussed further presently, identifies many specific transmission (154) and storage (26) projects that involve multiple TSOs on and between the continental European, Nordic, UK, Irish, and North African grids (<https://tyndp2020-project->

²⁴ The EU has set minimum interconnector capacity targets of at least 10% by 2020 and 15% by 2030 for each TSO. https://ec.europa.eu/energy/topics/infrastructure/electricity-interconnection-targets_en. This is not the case for all TSOs in Europe or in the U.S. For example, California has extensive interconnections with the rest of the U.S. Western Interconnection and Switzerland has extensive interconnections with the rest of Europe.

platform.azurewebsites.net/projectsheets). In the U.S., some of the transmission enhancements analyzed by Patrick and Botterud (2021) and Bloom et. al. (2020) span two or three synchronous networks as well as multiple transmission system/wholesale market boundaries. The U.S. has no established planning organization that is responsible for identifying inter-network transmission projects for development.

In the U.S., post-restructuring, transmission planning, development, and cost allocation protocols within the RTO/ISOs initially focused on interconnections of new generators and new loads and intra-system enhancements motivated by projected violations of intra-system reliability criteria. Core RTO/ISO planning procedures originally did not focus on transmission enhancements to improve market efficiency within their boundaries or on projects to support public policy initiatives such as decarbonization. Little attention was paid to projects to expand interregional transmission capacity that could enhance reliability, market efficiency, or to support decarbonization or other public policies. It was as if FERC decided that once the ISO/RTO wholesale market systems produced the right locational marginal prices and associated transmission congestion contracts, then “the market” (read merchant projects) would take care of the rest of the transmission expansion opportunities. This assumption is neither correct theoretically (Joskow and Tirole 2005) nor as a practical matter.

Moreover, to get the full benefits of transmission expansion to access the most economical wind and solar opportunities, further market integration across the footprints of multiple transmission system operators would be necessary. Presently, the geographic boundaries of wholesale markets are historical legacies that reflect the limited transmission interconnections between many transmission systems when sector liberalization began in the late 1990s. As transmission interconnections expand and generating capacity is distributed further from traditional transmission system planning areas, additional market integration (or the European term “market coupling”) over wider geographic areas would reduce generating capacity needs, reduce storage needs, reduce operating costs, and increase reliability (e.g. Yuan, M., K. Tapia-Ahumada and J. Reilly 2021).

FERC has gradually enhanced the required components of core transmission planning processes to require ISOs to consider market efficiency projects within their footprints, applying benefit/cost criteria

to market efficiency projects --- $B/C > 1.25$, though very few such projects have gone forward to date. In Order 1000, FERC required TSOs to develop cooperative arrangements to identify opportunities to expand interregional transmission capacity, noted its transmission cost allocation principles, eliminated incumbent federal rights of first refusal on transmission enhancements, required policies be adopted to accommodate public policy transmission projects (e.g. to support decarbonization), and promoted the use of competitive bidding to select developers and define performance-based cost recovery principles for projects selected through competitive procurement. FERC also requires RTO/TSOs to develop beneficiary pays principles to transmission cost allocation.²⁵

Order 1000 was issued ten years ago and in my view has not yet realized its promise. In particular, in the multi-state ISOs there is little if any consideration of decarbonization benefits in their core transmission planning and cost allocation processes. The RTO/ISOs and planning regions in the Eastern Interconnection have taken steps in the right direction through bilateral agreements and the creation of Eastern Interconnection Planning Collaborative (EIPC) (<https://www.pjm.com/planning/interregional-planning>). And as far as I can tell few if any interregional projects have come out of these cooperative interregional planning processes so far. Moreover, the EIPC would likely not examine opportunities to add interconnections between the Eastern and Western interconnections, such as those analyzed by Bloom et. al. (2021) and Patrick and Botterud (2020) because its scope is limited to the Eastern Interconnection. Several projects specifically designed to increase access to wind and solar resources that are in the design, development, permitting, and financing stages are one-off “private initiative” projects (pure merchant projects or projects that expect to be compensated through some form of regulatory cost recovery) that were not developed and coordinated as part of the core RTO/ISO transmission planning processes.²⁶ While there has been progress toward market

²⁵ Hogan (2018) provides a very useful primer on transmission benefit and cost allocation. Similar principles can be applied to perform social welfare analyses of potential transmission projects as discussed below for the development of ENTSO-E’s transmission plan and for the valuation of “regulatory route” interconnectors in the UK.

²⁶ The SOO Green HVDC project will be underground, utilize existing railroad rights of way and would connect MISO and PJM. <https://www.soogreenrr.com/about/>

expansion, especially in the western United States where there is only one ISO (California), it has focused on short-term trading of energy imbalances across the region, internalizing only a very small set of the responsibilities of an RTO/ISO. It has been suggested that an RTO/ISO covering the entire western interconnection would save up to \$2 billion per years and expand access to low-cost wind and solar resources. Similar discussions to create an energy imbalance market in the southeast, where there are also no ISO/RTO, are ongoing as this is written.

There are useful lessons to learn from the initiatives taken in Europe to identify and ultimately the development of new transmission projects that have reliability, market efficiency, decarbonization, and other public policy benefits. As discussed above, Europe, including the UK and the Nordic countries, has roughly 40 TSOs, each which typically covers an entire country. The individual TSO footprints are still too small to fully internalize renewable energy opportunities to minimize the costs of meeting EU and country-specific decarbonization plans. In 2013 the “Regulation on Trans-European Energy Networks” (TEN-E) was passed by the European Commission. “The Regulation has helped achieve the EU's energy policy objectives: ensure the functioning of the internal energy market and security of supply in the Union; promote energy efficiency and energy saving and the development of new and renewable forms of energy; and promote the interconnection of energy networks.”

(https://ec.europa.eu/commission/presscorner/detail/en/IP_20_2394) It was revised in 2020 “...to better support the modernization of Europe's cross-border energy infrastructure and achieve the objectives of the European “Green Deal” https://ec.europa.eu/commission/presscorner/detail/en/IP_19_6691. Europe's progress towards a climate neutral economy powered by clean energy requires new infrastructure adapted to exploit wind, solar and storage technologies. The TEN-E policy supports this transformation through projects of common interest (PCI), which must contribute to the achievement of the EU's emission reduction targets for 2030 and carbon neutrality by 2050. The revised TEN-E Regulation will continue to ensure that new projects respond to market integration, competitiveness and security of supply objectives.” (https://ec.europa.eu/commission/presscorner/detail/en/IP_20_2394).

The EU's TEN-E regulations go well beyond what FERC Order 1000 envisions, let alone has accomplished. Pursuant to the TEN-E regulations, the TSOs through ENTSO-E and with the cooperation of national regulatory authorities (NRA) and the Agency for the Cooperation of Energy Regulators (ACER) develop a Ten-Year Network Development Plan (TYNDP) to identify a large set of specific "Projects of Common Interest" (PCI). The most recent 2020 plan released in January 2021 (https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2020/Foropinion/TYNDP2020_Main_Report.pdf). The EU also provides financial support for some of PCIs identified as well.

More importantly, the EU has created an umbrella transmission planning organization --- ENTSO-E --- that covers and includes all of the TSOs that operate on the European synchronous grid and interconnections with neighboring TSOs. ENTSO-E is an EU organization that includes all of the TSOs in the region (<https://www.entsoe.eu/>). Among other things, it engages in comprehensive transmission planning activities to identify potential transmission projects that can support security of supply (reliability), integration (market coupling), of the individual TSO wholesale markets by relieving transmission constraints, as well as decarbonization and other public policy goals. ENTSO-E performs detailed cost-benefit analyses of potential transmission projects which include multiple factors in addition to cost savings and reliability considerations.²⁷ Its cost benefit analyses follow guidelines reviewed and approved by the Agency for Cooperation of Energy Regulators (ACER--- <https://www.acer.europa.eu/en/Electricity>), an official EU organization, and by the European Commission. ENTSO-E's 2020 Ten Year Development Plan evaluated 180 transmission and potential storage and transmission projects, mostly interconnectors between TSOs, that were identified across the region to support these goals (<https://tyndp.entsoe.eu/>). Stakeholders other than the TSOs are engaged in

²⁷ ENTSO-E's project evaluation and cost/benefit guidelines can be found at https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/2020-01-28_3rd_CBA_Guidleine_Draft.pdf and https://eepublicdownloads.azureedge.net/tyndp-documents/TYNDP2022/210601_TYNDP%202022%20Draft%20Guidance%20for%20Promoters%20for%20Consultation.pdf.

this process, including developers, individual country electricity regulators, and ACER. The ENTSO-E managed transmission assessments include evaluations of detailed operating criteria, (e.g. voltage and frequency control). The assessment process produces a cost-benefit analysis for each project. The process encompasses the entire European system and neighboring TSOs. The 2020 transmission plan includes interconnections with North Africa, additional interconnections with the UK and with Ireland, additional interconnections with the Nordic networks, extensive development of transmission facilities in the North Sea, projects inside Italy, the UK, Ireland, Norway, Germany, etc. (<https://tyndp2020-project-platform.azurewebsites.net/projectsheets/transmission>).

Some of the projects identified through this process are now completed, some in development, some in permitting, and some for developers and TSOs to mull over. Of course, ENTSO-E cannot approve projects, compensation arrangements, including cost allocations, or take projects through the permitting process. This remains the responsibility of TSOs, potential developers, national regulatory authorities, subject to EU regulations. However, the process identifies the best transmission expansion opportunities for TSOs and developers to pursue further and by working with National Regulatory Authorities and ACER can deal with regulatory and financing issues more effectively (e.g. ENTSO-E's work on transmission remuneration frameworks. https://eepublicdownloads.entsoe.eu/clean-documents/mc-documents/210414_Financeability.pdf)

The U.S. (and the rest of North America) would benefit from more ambitious enhancements to existing transmission planning institutions to better serve reliability, market efficiency, and decarbonization goals. Specifically, the U.S. needs a new umbrella organization like ENTSO-E with comprehensive planning and project identification and evaluation authority, using state-of-the art cost-benefit analysis, power system and economic modelling, that covers the entire country (perhaps plus the portions of Canada and Mexico that are synchronized with the Eastern or Western Interconnections or, in the case of Mexico, has small DC links with ERCOT). Let's call this organization the North American Transmission Planning Organization (NATPO). One approach might be to expand the roles of the North American Electric Reliability Corporation (NERC) from assessing regional reliability based on

exogenous developments in the reliability regions and sub-regions, to take on this kind of North American umbrella transmission infrastructure assessment and potential inter-regional and inter-network transmission project identification process from the perspective of North America rather than the much smaller individual transmission planning areas. It could do its evaluations by placing a range of values for accessing and integrating renewables and storage to meet decarbonization goals, in addition to any reliability and market efficiency benefits or costs, and other public policy goals.

The FERC Order 1000 planning regions could all be members of NATPO, perhaps along with the TSOs in Canada and Mexico, and representatives of stakeholder groups. Their active participation in the assessments would be critical both because of their expertise and because they will ultimately play an important role in identifying the most attractive projects and deciding whether and how to move them forward. This organization would examine and assess transmission expansion opportunities over a much larger geographic footprint than is covered by any transmission system operator in the U.S. today. It would follow comprehensive evaluation guidelines such as those that guide ENTSO-E. NATPO's project identification and assessment procedures would identify a portfolio of specific candidate transmission projects for consideration by transmission system operators, developers of merchant projects, state and federal policymakers. The North American project assessments could then be used by the individual planning regions, including the ISOs, potential developers, and regulators to decide what to do with the information about the attributes of the transmission projects identified and which would be priorities for development.

Transmission system planning fails to take all benefits into account: reliability, market efficiency, decarbonization, especially in the U.S.

In the U.S., most core transmission planning processes do not explicitly include valuations of carbon free resources to meet decarbonization commitments, focusing on traditional reliability and (reluctantly) internal market efficiency (e.g. congestion mitigation) opportunities. Nor do they take

account of potential reliability or security of supply benefits²⁸ that may result from “public policy” projects that seek to improve access to wind, solar, storage, and other carbon-free generators (Single state ISOs in California and New York are a partial exception within their footprint).²⁹ Unless the direct (decarbonization) and indirect benefits (reliability, market efficiency) of expanding access to and integration of zero or low carbon resources are included in the core transmission planning process, potential transmission projects to support access to and integration of these resources will not be identified and efficiently integrated into the core transmission plan except by accident.³⁰

In single state ISOs with deep decarbonization commitments (e.g. California and New York), identification of transmission projects to support access to and integration of zero carbon resources is now included directly in the planning process, at least within the footprint of each ISO, including potential interconnections with neighboring TSOs, through the FERC-created “public policy” transmission category, or by accommodating a variety of variations of merchant or “private initiative” projects developed outside of the NYISO planning process. This can be accomplished because the state public utility commissions and the ISOs can work together to pursue common goals. The recent transmission upgrades approved by the New York ISO as “public policy” transmission projects to reduce congestion from upstate to downstate in order to facilitate access to zero carbon resources in upstate New York and in Canada are good examples. The NYISO and the New York Public Service Commission worked together to identify these opportunities

<http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=12-T->

²⁸ Any reliability costs would be identified through interconnection studies and the costs of mitigating any reliability mitigation costs assigned to the project.

²⁹ The Midcontinent ISO (MISO) has had a “multi-value” transmission line category since roughly 2012 that uses both quantitative and qualitative measures of benefits, including carbon reduction, and includes cost allocation principles. <https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf> ; https://docs.misoenergy.org/legalcontent/Schedule_39_-_Multi-Value_Project_Financial_Obligations_and_Cost_Recovery.pdf; This approach could be adopted more broadly if FERC encouraged it.

³⁰ The SOO Green merchant project being developed to connect MISO with PJM in order to facilitate bringing wind energy from MISO (Iowa) to PJM recently filed a complaint with FERC regarding what it called an excessively long interconnections process and requested being included in PJM’s core transmission planning process called the RTEP. “Complaint and Request for Waiver of SOO Green HVDC Link ProjectCo, LLC,” FERC Docket No. EL21-85-000, June 18, 2021.

[0502&submit=Search](#)). Even here, however, proposed merchant or private initiative transmission projects are not fully integrated into the core ISO planning process (<http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=10-T-0139&submit=Search>) but are effectively considered as if they were merchant generating plants seeking interconnection rights and, if and when completed, operated by the NYISO. The Champlain Hudson HVDC project in New York (merchant) and the Clean Energy Connect Project in New England (private initiative or “elective” project with a regulated transmission tariff), as discussed above, are examples (<https://chpexpress.com/>; <https://www.necleanenergyconnect.org/>).

Obviously, if transmission system planning does not take the benefits of decarbonization into account, project evaluation and selection will be distorted away from supporting decarbonization goals. Once decarbonization is added to the more traditional benefits associated with short-term and long-term reliability, congestion management, market efficiency, etc., the benefits and costs of potential transmission projects to support integration of wind, solar, and storage can be expected to lead to a different menu of potential transmission projects (Olmos, Rivier and Perez-Arriaga 2018). The only reason not to include decarbonization benefits in the analysis in the U.S. is that the U.S. does not have a national decarbonization policy, while several individual states have made aggressive decarbonization commitments. The states that do not have decarbonization commitments and do not recognize the environmental value of zero and low carbon resources do not want to pay for the incremental costs of transmission investments that get selected because of (in part) their decarbonization benefits.

There is no reason why RTO/ISOs and other Order 1000 planning regions cannot take the expected future decarbonization benefits of accessing and integrating wind, solar, and storage into account in their planning processes. Planning new transmission projects and upgrades of existing projects should be separated from the cost allocation process, rather than concerns about cost allocation controversies driving transmission planning as seems often to be the case now. The T&D utilities and potentially competitive load serving entities and their customers in states that value decarbonization would be allocated the incremental costs of the transmission upgrades that are selected with these benefits

in mind. The agreement between PJM and New Jersey for PJM to design and manage a competitive procurement for offshore transmission facilities to support contracts for offshore wind generation mandated by New Jersey is a step in the right direction. PJM has the expertise and New Jersey customers will pay for the costs. Merchant or private initiative projects, such as Champlain Hudson, New England Clean Energy Connect, TransWest Express (<http://www.transwestexpress.net/>), and others would be able to seek to have their projects added to the regional transmission plan with payment arrangements made with shippers and customers.

Compensation and Cost Recovery Models

Transmission projects are capital intensive and typically very long-lived. Private initiative or merchant projects are also more risky than regulated projects including in the core ISO transmission plan in the sense that significant resources can be expended on developing and permitting a project that ultimately does not receive the necessary permits or financial commitments and is abandoned and for pure merchant projects if the project goes forward the developer is at risk for construction costs, operating performance, and marketing transmission rights.³¹ There are a number of different methods that are being used for compensating transmission developers for the costs of their projects. The use of one compensation method or another is also often closely related to the type of project proposed and whether and how the project is included in the TSOs' planning processes. The choice of compensation method also affects the cost of financing the project if it ultimately receives all necessary permits and goes forward.

It is useful to consider three different general approaches to compensation for new transmission projects and the associated implications for financing and for achieving market efficiency, reliability, and decarbonization commitments efficiently.

1. *Traditional rate-base/cost of service regulation*: The typical method for recovering the costs of new transmission projects is some form of cost of service/rate-base/rate of return regulation. The

³¹ Planning and development costs incurred by incumbent transmission owners that are incurred in connection with core TSO transmission planning activities are recoverable through FERC regulated transmission tariffs.

regulator allows the owner of the transmission facilities to recover the “reasonable” capital and operating costs of the transmission facilities over a long time period while earning a rate of return reflecting some measure of the owner’s weighted average cost of capital (WACC). (Joskow 2007). The precise accounting formulas and methods for estimating WACC vary from place to place, but the basic principles are the same. For example, the U.S. and the UK use different formulas for calculating annual depreciation, the depreciated value of the rate (capital) base, the WACC, and the treatment of inflationary expectation.³² This recovery method may be accompanied by low-powered performance-based or incentive regulation mechanisms to encourage cost containment and good operating performance (Joskow 2014, Schill, Egerer & Rosellón 2015), used extensively in the UK and almost not at all in the U.S. The cost base typically includes planning and development costs. It should be relatively easy to finance projects regulated under this type of cost-based compensation regime. In the U.S., FERC’s policies for recovery of transmission costs are quite attractive due to the use of formula rates that largely eliminate regulatory lag with little if any review of costs and additional incentives are added to the allowed rate of return. In Europe, some TSOs in have argued that the WACCs used by regulators are too low, making financing more difficult (https://eepublicdownloads.entsoe.eu/clean-documents/mc-documents/210414_Financeability.pdf). Projects subject to this type of traditional cost-based regulation are typically selected through some type of TSO managed planning process.

2. *Merchant projects*: Classical merchant projects are proposed by developers who expect to be compensated entirely based on the revenues that they earn by selling some type of transmission rights to shippers, power buyers and intermediaries, or earned from the “merchandising surplus” produced by the transmission owners buying energy where prices are low and reselling it where prices are high (Biggar and Hesamzadeh, 2020, Felder 2020). Typically, the merchant developer must also pay for the costs of interconnection to the network and any AC upgrades required to maintain reliability criteria once the

³² Theoretically, the two “revenue requirements” accounting formulas have the same expected present discounted values.

power is delivered over the line. The merchant developer is at risk for planning and development costs if the project is abandoned and takes on energy market risk.

While the early articulations of the merchant model in the U.S. anticipated that projects would be financed by receiving transmission congestion contracts issued by each RTO/ISO, reflecting differences in locational marginal prices (LMP) on a single network, the strategy now favored by merchant developers in the U.S. and other countries is very similar to the way new natural gas pipelines are financed in the U.S. The gas pipeline developer selects a route and project attributes including shipping capacity to various points on the proposed pipeline, designs the pipeline project, estimates what it expects shippers to pay to use the pipeline, seeks “anchor tenants” with long term contracts and then conducts an “open season” where shippers can submit offers, typically 10 year or longer contract commitments, to secure transportation rights. If sufficient shipping contracts are not secured to make the project financially viable it does not go forward and the developers eats the development costs. There are several electric transmission projects in various stages of development at the present time in the U.S. that have adopted this natural gas pipeline model. Since FERC regulates by interstate natural gas pipelines and interstate transmission, this model is familiar to it.

There are advantages and disadvantages to the merchant model. On the one hand, it opens up the transmission development process to “private initiative” free from often burdensome TSO transmission planning processes. In the case of projects designed to access attractive wind and solar resource areas it provides a mechanism, especially in the U.S., to develop projects without having to convince the TSO to take account of the system-wide benefits of decarbonization and in these cases avoids conflicts between states over cost allocation because of differences among them regarding decarbonization commitments. On the other hand, this process can lead to overall inefficiencies in the development of transmission networks (Joskow and Tirole 2005). It may also be difficult to arrange for shipping contracts that internalize all of the benefits of the project, making projects with high benefit-cost ratios the most likely projects to go forward. Merchant projects also have greater financial risk than traditional regulated projects since the developed is fully exposed to construction cost, operating cost and performance, and

contracting risks. As a result, they are likely to be more costly to finance. Very few pure merchant projects have made it to the finish line yet in the U.S., but several are well along in the development and permitting process.

3. *Hybrid Models*: Compensation models are emerging that combine features of the “private initiative” (my preferred term) or merchant model with the cost-of-service regulatory model with performance incentives (Vogelsang 2018). In these hybrid models, developers can propose specific projects to the TSO and relevant regulator either on their own or as a result of being the winning bidder in a competitive procurement process initiated by a state or ISO/RTO. The compensation received combined higher-powered cost containment and performance incentives with the regulated cost of service compensation model. That is, the terms and conditions to be reflected in the regulated cost of service have more aggressive cost containment and performance criteria and earned returns may be allowed to vary widely within a “zone of reasonableness” to reflect the performance of the project. Projects which will be compensated under a hybrid model such as this one are likely to have a higher cost of capital than a classic regulated project but also have stronger cost containment and performance incentives that are typical for the projects regulated pursuant to the purely regulated model. As with the pure merchant model, the private initiative project developer relying on the hybrid model must apply for interconnection rights, finance interconnection studies, pay for interconnection costs and any upgrades to the network to maintain reliability criteria once powers flows over the new facilities. This project by project “private initiative” model can also result in the same kinds of inefficiencies discussed by Joskow and Tirole (2005).

Compensation and Cost Recovery in Practice

Most intra-TSO transmission projects in the U.S. and Europe are compensated through traditional cost of service regulation with the revenue requirements allocated in some way among users of the network. The financing of interregional or interconnector projects has varied. Historically, in both Europe and the U.S. these were also primarily regulated cost of service projects with inter-system cost allocation negotiated between neighboring TSOs, including cost and benefit sharing, with the associated

costs included in a regulated tariff applicable to each TSOs' intra-TSO use of system transmission tariff. In both Europe and the U.S., the TSOs and regulatory authorities involved with the development interconnectors or inter-TSO projects must agree on the allocation of costs and benefits between them. The net allocated costs are then reflected in each TSOs intra-system transmission tariff. However, in both regions, many commentators initially expected new interconnectors and interregional transmission projects to be developed as merchant or private initiative projects that would be compensated with some form of transmission transfer capacity contracts and/or congestion revenues (merchandizing surplus). Few have been successful so far.

Texas took an innovative and pragmatic approach to the selection of a set of new transmission projects to increase access to and integration of attractive wind generation areas. It combined transmission planning to identify the attractive wind generation development regions, competitive procurement to select specific projects, and traditional cost of service regulation. Following directions from the Texas state legislature, in 2008, the Public Utility Commission of Texas (PUC) designated a set of Competitive Renewable Energy Zones (CREZ) in West Texas and the Texas Panhandle with excellent wind generation potential and launched a program to add (ultimately) 3,500 miles of new transmission lines with 18,500 MW of transfer capacity to integrate the anticipated development of a great deal of cheap wind capacity with load centers in Central and East Texas. (<https://poweringtexas.com/wp-content/uploads/2018/12/Transmission-and-CREZ-Fact-Sheet.pdf>) The PUC developed a competitive procurement process through which developers could offer specific projects with cost, right of way, and engineering attributes through which specific projects were selected. Projects selected were then built by both incumbent and new transmission developers.³³ The costs of the CREZ projects were then subject to traditional TPUC cost of service regulation and folded into the transmission tariffs of the transmission

³³ In unpublished research, Stephen Littlechild and Ross Baldick (Manuscript in process, Parts I-V, 2017-2019, previously provided to me in confidence) have studied the selection process for the CREZ projects. It was a very complex process that might best be described as competitive negotiation for the authority to build one or more regulated projects rather than the kind of open competitive procurement applied by ISOs under FERC Order 1000.

companies serving the load centers in ERCOT (they were “socialized”). The CREZ projects were completed in 2013.

This process combined “competition for the market” with cost-of-service regulation based on the competitive bids of the projects selected (Demsetz 1968). Although, Texas has generally taken a very “laissez faire” approach to electricity sector restructuring, wholesale market design, and retail competition, the state did not wait for developers to propose to build classical merchant projects that would be compensated through transmission contracts and congestion revenues. The state designated the best wind generation areas, the load centers, and recognized the need for transmission facilities to connect the former with the latter efficiently. It relied on a competitive process to select projects and commitments, but ultimately the transmission costs are being recovered through regulated tariffs. More recent competitive procurements following by other ISOs have used more refined auction and evaluation criteria.

Several merchant projects have been proposed in the U.S. which are specifically designed to increase access to wind and solar resource areas, where the project developers anticipate relying entirely on the sales of transmission rights (and perhaps some federal or state financial support), basically following the U.S. natural gas pipeline financing model.³⁴

The proposed HVDC Champlain Hudson Express project in New York is an example, though the solicitation of interest from shippers was not completed until August 2020 and the ultimate outcome is still to be determined (<https://chpexpress.com/>).³⁵ Hydro-Quebec is a potential power supplier and transmission customer. The SOO Green HVDC Link between MISO and PJM, primarily underground along existing railroad rights of way, is another example (<https://www.soogreenrr.com/project-overview/>). The TransWest HVDC/AC Project, under development since 2005, is a third

³⁴ I have discussed issues with relying heavily on merchant transmission investments elsewhere (Joskow and Tirole 2005) and as a practical matter very few major merchant transmission projects have been completed in the U.S. (Joskow 2020).

³⁵ This project may also qualify for Class 4 renewable energy credits (RECs) issued by the New York State Energy Research and Development Authority --- NYSERDA).

(<http://www.transwestexpress.net/>). The HVDC Zephyr transmission project between Utah and Wyoming, under development since at least 2009, is a fourth project relying on the gas pipeline development model (<https://www.transmissionhub.com/articles/transprojects/zephyr-transmission-project>).³⁶ The development, permitting, contracting, and construction process for these projects is lengthy, however.

This shipper contract model has worked well for the development of point-to-point natural gas pipeline projects in the U.S. Whether or not it will be successful for electricity transmission projects of this type remains to be seen, as few of these projects have gotten across the finish line so far. Many of these projects are HVDC projects³⁷ and it may be that this variation on the merchant model will work best with HVDC interconnectors since it reduces the cost allocation and transmission rights allocation issues that must be addressed with AC projects added to a synchronous AC system --- a burden of Kirchhoff's Laws. An important question, however, is whether this project-by-project development of transmission capacity in this way to access attractive wind and solar sites, isolated from the core TSO planning processes, is the most efficient way to access and integrate these resources?

The procedures that were used within ISO-NE to plan and finance expanding the new interconnection with Hydro-Quebec to import more zero carbon hydroelectricity and to develop transmission facilities to support off-shore wind development are examples of the application of the hybrid model. These procedures also demonstrate how competitive mechanisms and cost-of-service regulatory mechanisms can be combined in a hybrid framework while, at least so far, avoiding cost allocation controversies. They also highlight the question of whether from an overall transmission network perspective this is likely to be an efficient or inefficient approach. Efforts to avoid cost allocation controversies seem to be driving whether and how these projects are included in core TSO

³⁶ Goggin and Gramlich identify 22 “regionally significant” projects focused on expanding access to wind and solar resource areas, several of which appear to be following this model. <https://acore.org/wp-content/uploads/2021/05/Investment-Tax-Credit-for-Regionally-Significant-Electricity-Transmission-Lines-ACORE.pdf>.

³⁷ TransWest combines an HVDC link and a connecting AC link.

planning process and transmission tariffs and inefficiencies may arise from this project-by-project approach relying on actions outside of the core transmission planning process.

Why is the ISO-NE approach potentially inefficient? ISO-NE has a category of transmission projects called “elective” transmission projects. The elective transmission category is designed to accommodate “private initiative” transmission projects that will not be compensated through the ISO’s general open access transmission tariff. Elective transmission projects could be pure merchant projects following the natural gas pipeline development model, or as is the case here, compensated through a separate FERC regulated tariff which requires the buyers of the transmission services to pay for the costs pursuant to a separate FERC regulated tariff. Elective transmission projects are not initially identified through the ISO-NE planning process. Rather, the projects are proposed by third-party developers and if they get far enough into the process they must apply to the ISO for interconnection rights to the ISO-managed synchronous transmission system.³⁸ Their interconnections with the ISO-NE system are evaluated as they would be if they were large generators and the projects must take responsibility for any AC upgrades required to mitigate any adverse reliability impacts the interconnection of these projects may have on the network, though there is no compensation for any reliability benefits.

The transmission projects in New England that were proposed to support additional imports of zero carbon electricity from Quebec are elective transmission projects. The costs of these projects, reflecting the cost containment provisions proposed by the winning bidders through the Massachusetts competitive solicitation, are to be recovered through a separate FERC regulated transmission tariff applicable proportionately to each of the distribution utilities in Massachusetts. This transmission tariff is effectively a long-term cost-of-service contract which assigns responsibility for payments under this regulated contract to the T&D utilities in Massachusetts which can then resell the power and the

³⁸ The Champlain Hudson project in New York has a similar relationship with the NYISO, though it is expected to be financed by selling transmission rights to shippers and potentially by selling special Class 4 Renewable Energy Credits issued by the New York State Energy Research and Development Authority (NYSED). <https://chpexpress.com/news/tdi-commences-open-solicitation-for-transmission-capacity-on-the-champlain-hudson-power-express/>. The distribution utilities and their customers in New York are ultimately responsible for acquiring and paying for the RECs.

associated RECs into the ISO-NE wholesale market. This facilitates financing the projects based on the strong balance sheets of the distribution companies and excellent credit ratings of the T&D utilities and the security of regulated “wires charges” if the sale of the electricity supplied under the contracts and the sales of the associated RECs does not cover the payments made by the T&D utilities under the contracts. Massachusetts has had retail supply competition for 20 years, so balance sheets of the distribution companies are effectively being used to support the financing of the transmission and associated power supply contracts.

This was a clever way to develop and finance a project designed specifically to meet decarbonization commitments made by Massachusetts, since it sidesteps cost allocation controversies that could arise since ISO-NE covers six states with varying decarbonization commitments and policies. However, this is far from an ideal approach. Does it really make sense for each state within a single transmission system and a single organized wholesale market covering all six New England states to plan and develop its own projects to meet very similar decarbonization commitments? Five of the six New England states have aggressive decarbonization commitments and are potential beneficiaries of more hydroelectricity supplied to New England. Moreover, the notion that the electricity is being generated in Quebec and “delivered” to customers in Massachusetts is an “electrical myth.” ISO-NE is a fully integrated transmission system with a well-developed wholesale market covering all six New England states, synchronous interconnections with New York and New Brunswick, as well as legacy DC interconnections with Quebec. There is relatively little internal transmission congestion on the ISO-NE network at present.³⁹ The electricity will flow into the entire New England system not specifically to Massachusetts and at least some of the economic (lower wholesale prices) and reliability benefits will be shared by the entire system. The capacity of the project was chosen by Massachusetts even though a larger project or different approaches to expanding interconnector capacity with Quebec might have

³⁹ <https://www.iso-ne.com/static-assets/documents/2020/05/2019-annual-markets-report.pdf>, pages 90 to 94. The most frequently binding transmission constraint is the interface (interconnections) with the NYISO from which New England is typically a net importer. New England imports from upstate New York and exports to downstate Long Island as a consequence of transmission constraints separating upstate from downstate on the NYISO ISO network

increased the collective benefits for the whole region if transmission expansion planning to meet decarbonization commitments had been considered in an integrated regional fashion. (New interconnections with Quebec must be DC because the Quebec network is not synchronized with the Eastern Interconnection.) The only thing being delivered uniquely to Massachusetts in isolation is a bill for transmission service, a bill for the costs of the power supply contract negotiated with Hydro-Quebec, and credits toward meeting Massachusetts decarbonization commitments. It is also not at all clear from an overall ISO-NE perspective that the companion contract for power from Hydro-Quebec represents the best use of that flexible resource in a deeply decarbonized ISO-New England system which must balance intermittency for the entire system. It might be better to utilize this resource as a big long-duration battery to help to manage intermittency (Dimanchev, Hodge and Parsons 2020).

A similar process was followed by Massachusetts to select developers for offshore wind and associated transmission projects. Off-shore wind projects are also being developed through competitive solicitations by Rhode Island, Connecticut, New York, and New Jersey, all in proximate areas along the East Coast of the U.S. Each off-shore wind project was proposed with its own transmission interconnection with the onshore network rather than with an integrated network of off-shore transmission facilities and coordinated on-shore interconnect and AC upgrade facilities to support multiple off-shore wind projects. It is increasingly clear that a *network* of offshore transmission facilities interconnecting multiple off-shore wind projects would have economic and reliability benefits and conserve on on-shore landing sites and interconnection facilities (<https://rtoinsider.com/rto/nyiso-nypsc-grid-expansion-196048/>). An “All New England” or even better, a New England + New York + PJM offshore wind planning process and cost recovery framework, probably would lead to a more efficient outcome.

In Europe, financing of intra-TSO transmission investment follows the regulatory rules established by the National Regulatory Authority (NRA) in each TSO/country, with some form of regulatory cost recovery as the norm. The focus of the EU TEN-E regulation is on expanding interconnections *between* TSOs to facilitate market coupling and to support decarbonization goals.

Merchant projects supported by sales of transmission rights and/or the merchandizing surplus earned from the margins on sales from low wholesale price TSOs to higher wholesale price TSOs are permitted as they are in the U.S. However, many of the EU countries also have regulatory cost-of-service/rate of return routes to finance such interconnector facilities. In addition, subsidies in the form of grants from EU facilities⁴⁰ and financing by the European Development Bank are available for some PCIs. Most interconnectors in the EU that have been developed in the last several years depend at least in part on regulatory support from the TSOs involved. However, the EU is challenged to meet its minimum interconnection goals of 10% of each country's generating capacity by 2020 and 15% by 2030.

European-wide allocation of the costs of the core synchronous EU transmission network to support open access by all TSOs to the entire network is implicitly accomplished through the "inter-TSO compensation mechanism." The basic idea is to compensate each TSO based on measures of the use of its network by the other EU TSOs. The associated revenues are subtracted from the intra-TSO transmission costs when calculating the intra-TSO use of system charges.

https://extranet.acer.europa.eu/en/Electricity/Infrastructure_and_network%20development/Pages/Inter-TSO-compensation-mechanism-and-transmission-charging.aspx .

The UK (through OFGEM, the UK electricity and gas regulator) has developed and has now applied an alternative "regulatory route" to selecting and compensating new interconnectors that I would characterize as a hybrid model that combines merchant revenue opportunities and incentives but with regulatory caps and floors on cost recovery that reduce the developer's financial risk.

(<https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors>). Six interconnectors are already being developed under this model. They would increase the UK's interconnector capacity by a factor of about two times existing interconnector capacity. Developers of new interconnectors may still take the full "merchant route" if they choose to do so. However, under the alternative "regulated route," developers may propose interconnector projects for evaluation by OFGEM

⁴⁰ The grants come from a €30 billion fund created by the EU to help to fund energy, transport, and digital infrastructure. https://ec.europa.eu/energy/topics/infrastructure/projects-common-interest/funding-for-PCIs_en .

during application windows opened by OFGEM. Then for each proposed project OFGEM performs a very comprehensive assessment of the social welfare value (benefits and costs) and its allocation among consumers and generators in both countries interconnected by the proposed project, effects on market prices, revenues, and estimates of revenues from sales of transmission rights and any merchandizing surplus from trading energy by the transmission owner. If the projects are deemed to be socially beneficial, the compensation to be received by the transmission developer is determined in the following way. The basic regulatory approach is to specify a high (cap) and a low (floor) revenue requirement for a project determined by OFGEM based (effectively) on a high and a low earned rate of return on the (allowed) costs of the project. The project retains all revenues from sales of transmission rights to third parties. If the revenues yield returns that exceed the profitability cap, the developer must credit the difference back to the overall UK transmission system costs. If the revenues fall short of the floor profitability, then additional compensation is paid by the TSO to the developer to bring its revenues and profitability up to the floor. The credits and payments are ultimately recovered through National Grid's use of system tariff. This approach effectively places a collar on the developer's financial risk while creating incentives to control construction costs and to achieve high availability and sales of transmission capacity, though the incentives are necessarily constrained by the cap and the floor. In summary, this "alternative regulatory route" for interconnectors supports private initiative projects that meet OFGEM's social welfare criteria with partial, but significant, regulatory cost recovery protections.

The UK's cap and floor process is analytically intensive, relying on comprehensive social welfare analyses that should be familiar to all economists, but in the U.S. context requires a level of technical and analytical expertise that is most likely to reside in the RTO/ISOs rather than state regulators or FERC. OFGEM recognizes that this kind of comprehensive benefit-cost evaluation is necessary because these are regulated projects and partially (or perhaps largely) insulated from market performance incentives. However, this regulatory framework has yielded proposals for several new interconnector projects in the six or seven years that it has been in operation (<https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors>).

There is no reason why this hybrid project solicitation, evaluation, and incentive regulation process could not be adopted in the U.S. for interregional projects and even for major intra-regional projects. It could be combined effectively with competitive procurement or other incentive regulation mechanisms discussed above. In my view, transmission compensation policies that combine well-designed competitive solicitation programs, or open project proposal solicitation windows as in the UK for interconnectors, well designed auctions and proposal evaluation criteria that include all costs and benefits, including decarbonization benefits, with cost of service recovery combined with performance incentives, will facilitate more rapid and efficient transmission developments to support decarbonization commitments as well as traditional reliability criteria and market efficiency benefits. Classical merchant project proposals should always be welcome and integrated into the TSO planning process, but changes in how they are integrated into core transmission planning and interconnection policies to avoid inefficiencies need further attention.

Lack of a Unified National Comprehensive Decarbonization Policy in the U.S.

The U.S. does not yet have a national decarbonization policy or legally binding decarbonization commitments. A growing number of U.S. states do have aggressive decarbonization goals and commitments for electricity supplies to consumers in their states. However, most states do not and some are hostile to pursuing decarbonization. This creates potential conflicts regarding planning and cost allocation in multi-state ISOs and some Order 1000 planning regions, leading to the kinds of cost recovery workarounds discussed for ISO-NE. Both CAISO and NYISO are single state ISOs, both California and New York have aggressive decarbonization goals, and both ISOs have integrated decarbonization goals into transmission planning, relying heavily on competitive procurement of transmission projects designed to support decarbonization commitments, whose costs are ultimately recovered through regulated transmission charges, subject to cost containment and performance incentives (Joskow 2020).

The absence of a unified national decarbonization policy complicates transmission planning, development and financing. However, as discussed above, the benefits of decarbonization can still be

taken into account, along with reliability, market efficiency, and other public policy benefits in each TSOs core transmission planning process. The incremental costs of providing these decarbonization benefits can then be allocated to the users of the system who value them based on the cost causality/beneficiary pays principle in Order 1000.

The EU has a unified commitment to be net-zero carbon emissions by 2050 with interim 2030 decarbonization goals.(https://ec.europa.eu/clima/policies/strategies/2050_en). <https://www.mckinsey.com/business-functions/sustainability/our-insights/how-the-european-union-could-achieve-net-zero-emissions-at-net-zero-cost>), as does the UK (<https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035>) . While the individual EU member states have a variety of short-term and long-term strategies of varying degrees of consistency with the EU policies, a common decarbonization policy can help to reduce conflicts between countries and their respective TSOs. Moreover, the EU has adopted policies to expand interconnectors between TSOs in furtherance of its decarbonization commitments. Finally, the EU has an emissions trading system that places a price on carbon emissions.

Until the U.S. has a unified national set of decarbonization policy, expanding transmission capacity to access and integrate the most attractive wind, solar, and other carbon resource locations, it will be challenged and require thoughtful “workarounds” to identify, develop, permit and finance such projects.

Opposition By Stakeholders: NIMBY and More.

Finally, let me turn to opposition to new transmission projects by stakeholders, often referred to as NIMBY, though I think that this term is too narrow. The relevant stakeholders may be residents who live near proposed transmission lines and who are concerned about visual or potential health effects, landowners whose land would be taken by eminent domain (or equivalent), environmental groups seeking to protect sensitive areas from disturbance by transmission corridors and transmission lines, groups organized around recreational uses, commercial users of proximate land or offshore areas (e.g. fisherman)

generators interested in being protected from more competition, and others. Permitting new lines often involves multiple federal, state, and local regulatory agencies, so there are many venues where opposition can be expressed and projects slowed or derailed. The discussions of the history of the second interconnector between France and Spain and the Northern Pass project in New England are examples of how stakeholders can derail projects. As I will discuss below, there are processes that can be implemented to minimize but not eliminate the impacts of unreasonable opposition --- work with stakeholders early, minimize the footprint, spread the benefits, consolidate regulatory review processes.

1. Identify and engage with the stakeholder groups which are most likely to oppose or support the proposed project as early as possible in the development and permitting process.

Experience makes it fairly clear that it is important to identify and begin open discussions about the proposed project as early in the process as possible. This is not easy, since there are many possible interest groups which may raise a potentially long list of issues as well as multiple permitting authorities which have a say in the ultimate permitting decision. Stakeholders can raise many different types of concern. Studies of the regulatory review process for transmission lines and renewable energy projects make it clear that early cooperative and transparent engagement with stakeholders, perhaps with the assistance of a respected facilitator as was the case with the France/Spain interconnector and the Intertie between the northwest and southwest in the U.S., can help to channel opposition and support constructively. (Susskind 1990, Swain 2019, Ciupuliga and Cuppen, 2013). The permitting challenge for major transmission projects compared to say a wind farm is that transmission lines are “long and thin,” affecting many more stakeholders over a “long” geographic area. This increases the need for thoughtful, comprehensive, *early* stakeholder engagement and cooperative planning.

2. Mitigate project impacts at the initial design stage in consultation with stakeholders.

It is important to seek opportunities to mitigate the adverse impacts of the project on potential interest groups. Perhaps the most important potential mitigation measure is to minimize the need for new facilities on new rights of way. This may be accomplished by using “smart grid” technology like dynamic line ratings which can adjust effective transmission capacity to reflect real time changes in

temperature, wind, icing, sag, etc., rather than relying on static often worst-case assumptions, to increase the effective capacity of existing transmission facilities.⁴¹

Existing transmission facilities on existing rights of way may be reconducted and upgraded to higher voltages and capacities. Using existing rights of way that are or were used, by railroads, canals, highways etc. may reduce new visual impacts and impact groups that have adapted to the impacts associated with the use of these corridors. Opportunities to place facilities where they will not be seen (e.g. underwater, underground) may reduce opposition, though underwater transmission projects can still attract opposition from fisherman, recreational users, and environmental groups concerned about impacts on fisheries, sea and river beds, etc. (Swain 2019) and underground high voltage transmission is five to ten times more costly than overhead lines

(https://www.aeptransmission.com/docs/UndergroundTransmissionLine_TriFold_AEPTrans_V14.pdf).

The 338 mile Champlain Hudson project in New York was designed so that it is completely buried under the Hudson River or underground (<https://chpexpress.com/project-overview/route-maps/>). Yet, it has attracted opposition from some environmental groups, sometimes reflecting opposition not to the link but to the sources of power it will support (<https://biologicaldiversity.org/w/news/press-releases/regulators-warned-of-champlain-hudson-power-express-projects-environmental-impact-2020-10-08/>). As noted, the SOO Green HVDC project will be underground along existing railroad rights of way. And the second France-Spain interconnector is also underground.

Avoiding protected and pristine areas that support recreational activities and conservation goals should also be helpful. However, the Northern Pass project in New England agreed to underground portions of the project that went through the White Mountains in New Hampshire, but it still was denied a necessary permit. On the other hand, placing the new link between France and Spain underground to

⁴¹ FERC Issued a Notice of Proposed Rulemaking that addresses dynamic transmission line ratings <https://www.troutmanenergyreport.com/2020/12/ferc-issues-proposed-rulemaking-on-transmission-line-ratings/> and dynamic line rating has attracted the interest of ENTSO-E as well <https://www.entsoe.eu/Technopedia/techsheets/dynamic-line-rating-dlr>.

avoid adverse impacts in the Pyrenees mountains was critical to getting the project through the permitting process (Ciupuliga and Cuppen, 2013).

There is no magic solution to reducing real and imagined impacts to zero, but the smaller the impact the fewer stakeholders will be affected and the more likely will be the project to go through.

3. Be prepared to compensate stakeholders who are affected by the project but do not benefit directly from it.

If stakeholders see no benefits from the project to them, it is more likely that they will oppose the project. Some stakeholders may simply see a “hold-up” opportunity to extract some money from the developers of the project. Compensation of some kind may be necessary to dilute opposition. Opposition to the Clean Energy Connect project in Maine argued that there were no benefits to Maine since the project “delivered” electricity only to Massachusetts. The Hydro-Quebec Phase 2 HVDC project stretching from Quebec to Massachusetts reduced opposition significantly by finding ways to compensate towns along the proposed route (Swain 2019).

4. Work with relevant federal, state, and local authorities to consolidate necessary regulatory reviews required for the project to receive the necessary permits.

In the end, numerous government regulatory authorities at various levels of government will determine whether all necessary permits are ultimately awarded, perhaps after design changes agreed to during the consultation process, and how long it takes to go through the process. Dealing with a large number of regulatory agencies with diverse stakeholder participation is very time consuming, expensive, and inefficient. Governments can help to reduce these burdens by consolidating as much as the regulatory review process in as small a number of proceedings as is possible. Independent facilitators can also be helpful.

Conclusions

There is little disagreement among analysts, wind and solar project developers, and policymakers that accessing and integrating the most attractive wind and solar resources to support an efficient and

reliable transition to a fully or close to fully decarbonized electricity sector will require significant increases in transmission capacity both within TSOs and between two or more TSOs. This is true in the U.S., in Europe, China, and elsewhere. There is much less agreement about whether and how transmission should be expanded and who should pay for it. The question of “whether” transmission capacity should be developed to facilitate access to and integration of wind and solar resources is a U.S. problem reflecting ongoing disputes about decarbonization policies between states, created by the absence of a unified comprehensive national decarbonization policy. This development strategy has been embraced in the EU. Answering the question of “how” is more complicated. Existing transmission system planning and compensation arrangements are themselves quite complicated and involve local, national, and international political and regulatory institutions. They reflect differences in regulatory institutions in different countries. These institutions will need to adapt to the decarbonization task at hand. In my view, Europe has made much more progress on this front than has the U.S. and the U.S. has much to learn from the institutions and regulations that the EU has put in place to increase interconnector capacity to support decarbonization and market integration goals.

Simply putting band aids on existing regulations and institutions in the U.S. is unlikely to accelerate investments in the transmission capacity needed to support an efficient decarbonization path. Two sets of institutional change should be high on the agenda in the U.S. The progress that FERC has made from order 888, to 889, to 1000 has been quite positive. However, the “original sin” guiding transmission planning by RTO/ISOs was to focus exclusively on “reliability” projects and associated cost responsibility principles. FERC has gradually expanded the types of projects that could be included in RTO/ISO planning procedures to include “market efficiency” projects and “public policy” projects. Expanding the range of projects included in the RTO/ISO planning processes was a good thing, though the multistate RTO/ISOs have not taken adequate advantages of new regulatory principles . Overall, slicing up different kinds of transmission projects on the same network like a salami is not going to lead to efficient outcomes. The impacts of projects that fall into each bucket are not independent but rather are interdependent. Treating them as if they are not interdependent is a mistake. Transmission planning

should encompass all types of projects, including private initiative projects as discussed, and reflect all of the benefits and costs of these projects in the planning process. Concerns about cost allocation should not drive how transmission planning is done. Rather, the starting point should be to figure out the best plan for expanding transmission capacity given all of the potential benefits and then figure out who should pay by applying cost causality and beneficiary pays principles.

Order 1000 ended the federal right of first refusal enjoyed by incumbent transmission owners, provided a path to use competitive procurement processes to select project developers and competitive procurement in turn provides a mechanism to incorporate cost containment and performance commitments into regulated transmission tariffs. However, meaningful use of competitive procurement in the U.S., opened up by Order 1000 has been too limited and FERC has not been sufficiently aggressive in embracing it (Joskow 2020). The UK has been much more creative in using competitive procurement and incentive regulation mechanisms. There are many kinds of transmission projects (e.g. local upgrades to lower voltage facilities, upgrading existing facilities, expanding the use of existing rights of way, etc.) where competitive procurement makes little sense. But for many of the kinds of projects discussed here competitive procurement does make a lot of sense. Regulators should define more precisely the attributes of projects that should be selected through competitive procurement,⁴² make it clear that cost containment and performance commitments made by winning bidders will be reflected properly in regulated transmission tariffs, and should be more aggressive about promoting the use of competitive procurement mechanisms by TSOs.

The second institutional change that I think should be high on the agenda should be the creation of a national U.S. (or North American) transmission planning organization like ENTSO-E in Europe. I outlined here what such an organization could look like. Order 1000's goal of expanding interregional transmission planning, leading to interregional projects has not been very successful so far. The planning

⁴² The criteria that have been developed by OFGEM in the UK for competition to select the developers of new on-shore transmission provides some very useful guidance. <https://www.ofgem.gov.uk/electricity/transmission-networks/competition-onshore-transmission> .

areas are just too small and the incentives to engage in wide-area planning are too weak. We need an umbrella transmission planning organization like ENSOE-E that can evaluate a full range of wide-area transmission project opportunities in enough detail that they can be integrated into ISO/RTO planning and development processes and/or picket up by “private initiative” developers.

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