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Abstract

Encouraged by the declining cost of grid-scale renewables, recent analyses conclude that the United States could reach net zero carbon dioxide emissions by 2050 at relatively low cost using currently available technologies. While the cost of renewable *generation* has declined dramatically, integrating these renewables would require a large expansion in *transmission* to deliver that power. Already there is growing evidence that the United States has insufficient transmission capacity, and current levels of annual investment are well below what would be required for a renewables-dominated system. We describe a variety of challenges that make it difficult to build new transmission and potential policy responses to mitigate them, as well as possible substitutes for some new transmission capacity.

Encouraged by the declining cost of grid-scale wind and solar, recent analyses conclude that the United States could reach net zero[1] carbon dioxide emissions by 2050 at relatively low cost using currently available technologies (Princeton, 2021; Williams et al., 2021, National Academies, 2021). For example, Williams et al. (2021) find that the United States could reach net zero carbon dioxide emissions by 2050 at a cost of about $1 per person per day. These scenarios rely on, for instance, electrifying vehicles and home heating while transitioning the electricity grid to zero-carbon sources.

While the cost of renewable *generation* has declined dramatically, we focus in this paper on the large expansion in *transmission* that would be required. We first document recent US investments in renewables, then examine some of the issues already emerging in US electricity markets due to insufficient transmission capacity. For example, in some areas, wholesale electricity prices are now negative during more than 20 percent of all hours. While the United States is building more transmission, the current pace of investment is well below what would be required for the net zero future.

We describe several challenges which make it difficult to build new transmission. The US electricity grid is a disorganized patchwork that is the result of over a century of mostly disconnected individual utilities making independent decisions. There is no central authority for approving new transmission projects, so typically new projects must be approved by a combination of federal, state, and local authorities, and it can be hard to achieve consensus. Moreover, even when stakeholders agree on the need for transmission, there are disagreements about how to pay for project costs. In addition, siting and permitting challenges and NIMBY ("not in my back yard") concerns make it expensive and time-consuming to negotiate right-of-way permissions.

Finally, we describe potential policy responses. The public good characteristics of electricity transmission provide an economic argument for enhanced federal authority over siting decisions. We also point to the potential for increasing the capacity of existing transmission corridors. We then discuss potential substitutes, including storage and dynamic pricing. Neither of these is a panacea, but the challenges of expanding transmission capacity imply that the benefits from these substitutes are higher than they would be otherwise.

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[1] Net zero carbon refers to the recognition that to the extent that some CO_2 producing activities continue—whether continued burning of some carbon-based fuels or industrial or agricultural processes that emit CO_2 or other greenhouse gases as by-products— there will be a need for sufficient offsetting carbon capture and sequestration.

Throughout the paper, we focus on the United States, though both the need for transmission and the barriers to transmission expansion exist in other countries. The United States is neither the most ambitious country with regard to decarbonization, nor does it have the best options for renewable resources. But it is a significant contributor to greenhouse gas emissions, and a valuable case study for understanding the complicated challenges of building new transmission as well as for testing potential policy responses.

The Role of Renewable Generation in a Net Zero Carbon Future

Renewable electricity generation plays an outsize role in all scenarios for weaning economies off fossil fuels and moving to a net zero carbon future. This has broad implications for electricity system investments.

The Decline in Renewable Costs

The last decade has seen a dramatic decrease in the cost of grid-scale wind and solar generation.[2] Investment in these technologies grew rapidly during this period, and economies-of-scale, learning-by-doing, and other factors resulted in large cost declines. With wind power, one of the biggest changes was a move toward much larger turbines (Covert and Sweeney, 2022). With solar photovoltaics, the cost declines were the result of a series of incremental improvements in the manufacturing process, including better and more automated manufacturing equipment, supply chain optimization, and more efficient use of materials (Nemet, 2019).

Figure 1 plots typical costs for US grid-scale wind and solar. In 2010, electricity generation from wind and solar cost $200 and $500 per megawatt hour, respectively. Costs of generation declined sharply initially and then continued to decline throughout the period, falling below $40 by the end of the period. Between 2010 and 2022, costs declined 75 percent for wind and 90 percent for solar, such that today wind and solar are on par or cheaper than fossil fuels using a levelized cost basis—that is,

[2] We focus throughout on grid-scale wind and solar generation, as opposed to rooftop solar or other distributed generation. The costs of distributed renewable generation (including residential and commercial rooftop solar) have fallen, but they remain well above the costs of grid-scale renewables (NREL, 2022a), and the decarbonization scenarios mentioned earlier rely on grid-scale rather than distributed generation (National Academies, 2021).

a present discounted value of the costs over the lifetime production of the electricity-generating investment. In a 2022 report from the US Department of Energy (2010-2022), levelized costs of generating electricity per megawatt-hour are $38 for wind and $36 for solar, compared to $37 for "combined cycle" natural gas generation. For more details on levelized costs, a useful starting point in this journal is Borenstein (2012); and see Joskow (2011) on the challenges of comparing levelized costs across technologies.

The Need for Continued Capacity Growth in Renewable Energy Generation

Encouraged by these declining costs and concern about climate change, the United States is investing heavily in wind and solar. Figure 2 plots the percentage of total US electricity generation that comes from grid-scale wind and solar, from US Department of Energy (2023). In 2010, wind was less than 3 percent and solar was negligible. Over this period, total generation increased four-fold for wind and 120-fold for solar, such that by 2022, 10 percent of US electricity generation came from wind and 3 percent came from grid-scale solar. The other major categories of electricity generation in the United States are natural gas (40 percent), coal (20 percent), nuclear (18 percent), and hydroelectric (6 percent). Small-scale solar (for example, from rooftops) is not reflected in Figure 1 and is estimated to be smaller, only 1 percent.

This growth in renewable generation is impressive, but decarbonization scenarios require substantially more; in 2022, the two largest fuel sources for US electricity generation remained natural gas and coal. In recognition, 30 states have adopted renewable portfolio standards aimed at accelerating this transition toward renewables (Lawrence Berkeley National Laboratory, 2021). California, for example, has a goal of 60 percent renewables by 2030 and 100 percent renewables by 2045. While the state-level renewable portfolio standards typically also include geothermal, hydroelectric, and in some cases, nuclear, the vast majority of new renewable capacity between 2020 and 2050 is expected to come from wind and solar (US Department of Energy 2022a).

There is also growing enthusiasm for taking advantage of lower-carbon electricity generation not just to replace existing electricity generation, but also to reduce the carbon intensity of other sectors. The most significant component of the "electrify everything" movement would take the form of increased adoption of electric vehicles. In the United States alone, 350 million gallons of motor gasoline are used each day, according to the US Department of Energy (2022b), and electric vehicle proponents envision replacing much of this petroleum consumption with electricity, presumably generated from low- or zero carbon sources. Again, California has staked out a particularly aggressive goal, with the California Air Resources Board proposing a ban on new gasoline-fueled cars by 2035 (as reported by Friedman, 2022).

Electrification of all energy uses in buildings is also receiving increased attention. Vast amounts of natural gas and other fossil fuels are consumed on-site in the U.S. for heating and other end uses, and a growing number of policies are aimed at transitioning much of this over to electricity (Davis, forthcoming). New York City recently banned natural gas in new buildings, joining over 40 cities in California, Washington, Massachusetts, and Rhode Island that have either banned natural gas for new buildings or implemented "electric-preferred" building codes.

Both replacing existing fossil-fueled electricity generation and building new generation to meet the increased demands of widespread electrification of vehicles and buildings as part of a decarbonization transition will require extremely large increases in renewables. For example, in the baseline scenario in the Princeton (2021) study, US renewable capacity triples from existing levels by 2030, increases nine-fold by 2040, and rises by a factor of 16 by 2050. Similarly, US renewables generation increases by a factor of 22 by 2050 under the baseline decarbonization scenario in Williams et al., (2021).

The Mismatch between Population Centers and the Prime Locations for Renewable Power

Conventional sources for generating electricity can be sited on suitable land close to population and load centers with fuel transported to generating plants. In contrast, renewable generation capacity such as wind and solar must be sited where those natural resources are found. Indeed, the cost-competitiveness of wind and solar depends on them being located at favorable sites, which are not evenly distributed across the United States.

The best wind resources are located in the middle of the country. In states like Nebraska, Kansas, and Oklahoma, wind "capacity factors" are 40% or more, meaning that wind turbines produce 40% of what they would produce if they operated at maximum capacity 24 hours a day, 365 days a year.[3] In contrast, capacity factors in the rest of the United States tend to be less than 30%. To date investments in wind generation have been heavily concentrated in states with the best wind resources. Texas, by itself, has 26 percent of US wind generation, more than the next three highest states combined: Iowa, Oklahoma, and Kansas. During 2022, the top ten states accounted for 75 percent of US wind generation, while having only 32 percent of the US population.[4]

The best solar resources are heavily concentrated in the Southwest and Southeast regions. Solar capacity factors in these states are nearly twice as high as in northern states. Typical capacity factors for grid-scale solar are 29 percent in Arizona and 28 percent in California, compared to only 17 percent in New Jersey and Massachusetts (US Department of Energy, 2019). Not surprisingly, investments in solar generation have been heavily focused on these states with the best solar resources. California is to solar what Texas is to wind, with 27 percent of US grid-scale solar, almost as much as the next three states combined (Texas, North Carolina, and Florida). During 2022, the top ten states accounted for 81 percent of US grid-scale solar generation, while having only 42 percent of the population.

This geographically uneven distribution of renewables points to the importance of electricity transmission. Not only is renewable generation potential distributed unevenly across states, but even within states with good renewable generation potential, the best locations often are far from major population centers and far from existing transmission infrastructure. It is not enough to generate renewable electricity at a competitive cost—getting this electricity to where it needs to go is increasingly just as important.

The Need for Transmission, Past and Present

The electricity supply chain relies, of course, not only on generation but also on delivery to consumers. As we described above, the costs of low-carbon generation have substantially fallen – but that has not solved the challenge of how to get that low-carbon electricity to potentially quite distant

[3] See Lawrence Berkeley National Laboratory (2022) for wind capacity factors by state. For maps of US wind and solar resources see NREL (2023a) and NREL (2023b), respectively.
[4] This information and the information about solar in the following paragraph are authors' calculations based on net generation by state from US Department of Energy (2023) and state-level populations as of 2022 from US Census Bureau (2023).

end-users. Our focus in this paper is primarily on transmission, that is, high-voltage, large-volume transportation of electricity over medium- to long-distances.[5] As we describe in this section, there is abundant evidence that the United States already does not have enough transmission capacity to integrate the growing levels of renewable generation.

One Sign of Insufficient Transmission: Renewables Curtailment

In a functioning local electricity grid, quantity supplied needs to equal quantity demanded. If quantity supplied in a local market exceeds quantity demanded, then— at least in the absence of significant storage resources in most areas and the presence of transmission constraints that limit the export of electricity to more distant demand centers—the quantity of electricity supplied to the grid needs to be reduced, or "curtailed."

One sign that many regions in the United States have insufficient transmission capacity is that renewables curtailment is becoming increasingly common, despite the zero or near-zero marginal cost of these resources. Renewables generation can be immediately and temporarily reduced—for example, the pitch controls on a wind turbine can be used to rotate the blades and generate less electricity, or solar arrays can be disconnected from the grid—and then quickly restored when this generation is needed again. For this reason, dumping power supplied by renewables can be easier than adjusting generation from fossil fuel and nuclear plants which have operational constraints limiting the speed with which they can ramp generation up and down.

Peak loads happen at different times in different places, and at the same time renewables are being curtailed in some locations, there are often other locations nearby that would have benefited from access to this excess supply. Transmission constraints prevent these mutually beneficial trades from occurring, and create divergence in local prices for electricity.

Figure 3 plots monthly renewables curtailment in two major US electricity markets, selected because of their high saturation of solar and wind, respectively. The California

[5] Whereas *transmission* refers to high-voltage large-volume transportation of electricity between the source of generation and high-voltage substations, *distribution* refers to low-voltage, lower-volume transportation between substations and the final customer. Although we do not focus on electricity distribution, there are important related challenges with regard to, for example, integrating residential electrification and electric vehicle adoption. See, e.g., Elmallah et al. (2022).

Independent System Operator (CAISO) oversees electricity transmission in California, and the Southwest Power Pool (SPP) manages transmission for large parts of 15 states including Arkansas, Colorado, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. Curtailment has increased dramatically in both markets.

At the beginning of the period, curtailment was negligible. Between 2015 and 2022, solar curtailment increased 18-fold in CAISO and wind curtailment increased 37-fold in SPP. Total solar curtailment in CAISO in 2022 was 1,734 gigawatt hours, equivalent to 4.4 percent of total solar generation. Total wind curtailment in SPP in 2022 was 11,124 gigawatt hours, equivalent to 10.3 percent of total wind generation.

These rising levels of curtailment reduce the incentive for additional renewables investments in these prime locations. After incurring large capital costs and finally getting a project online, the last thing a renewables developer wants to learn is that their generation is not needed during a large number of hours each year. Curtailment reduces the private and societal value of renewables investments, and points to the broader challenge of integrating increasing levels of wind and solar.

Another Sign of Insufficient Transmission: Negative Wholesale Electricity Prices

Many US markets now routinely evidence an even more severe indicator of insufficient transmission capacity, namely, an increasing prevalence of negative wholesale electricity prices. In most markets, producers stop supplying a good when the price reaches zero or below. However, electricity generators often have technological and institutional reasons to continue supplying power even when the price of power turns negative. For example, constraints on ramping power plants up or down (and other operational limitations), combined with the lack of cost-effective electricity storage, make electricity different from other goods. Quite simply, it is often not feasible to ramp down generation of a fossil-fuel or nuclear plant, even in response to several consecutive hours of negative prices. In these situations, generators may choose to pay to inject their power into the grid.

The design of policies meant to encourage renewable generation can further influence responses to negative prices. For example, wind generators tend to resist being curtailed because not producing means they do not receive the federal production tax credit (Aldy et al., 2023). Solar generators, in contrast, often receive an investment tax credit that does not depend on how much they produce and, thus, in general, are more willing to curtail generation when prices are negative.

Figure 4 plots the frequency of negative electricity prices during all hours in 2022. This map shows prices from more than 50,000 individual locations across the seven major US electricity markets. Some parts of the United States, including most notably the Southeast, do not have electricity markets, so no information is reported for those places. Negative prices happen throughout the United States, but have become particularly common in the middle of the country where so much of the investment in wind generation has occurred.[6]

This phenomenon is relatively new. As recently as 2015, negative wholesale prices occurred in less than 2 percent of all hours and locations. Since 2015, the frequency of negative prices has increased steadily, reaching over 6 percent in 2022. Strikingly, there are hundreds of locations, mostly in the middle of the country, that now experience negative electricity prices during more than 20 percent of all hours. Seel et al. (2021) documents the increase in negative prices over this period and shows a strong correlation between wind generation and negative prices.

Negative prices indicate the need for increased transmission investments because at the exact same time these negative prices are occurring in some locations, there often are other locations not far away with customers willing to pay for additional electricity supply. These price impacts are related to the broader operational and market design challenges associated with integrating renewables into electricity markets. For example, Joskow (2019) argues that serious market reforms are necessary to provide incentives for investment in "dispatchable" generation, storage, or other resources necessary to manage the intermittency of renewables. For additional discussion, see Gowrisankaran, Reynolds, and Samano (2016), Joskow (2019), and Mallapragada

[6] In related work, Bushnell and Novan (2021) document that renewables have decreased electricity prices in California, with a distinct hourly pattern with large decreases in midday prices combined with modest increases during "shoulder hours" like in the evenings when the sun is setting. They also show that while wind and solar tend to generate at different times, their combined profile does not exactly match the timing of demand.

et al. (2022). While market design improvements could reduce these operational challenges, they do not eliminate the value of more transmission.

A related infrastructure problem is the difficulty building new interconnection lines. In all US markets, new generation projects need to request and receive authorization before being connected to the electric grid. Typically, this process includes a series of studies aimed at evaluating how the new generation would impact grid operations and stability, with particular attention to any necessary transmission system upgrades or other additional physical infrastructure that would be required. As of 2021, there was almost one terawatt of solar and wind projects in US interconnection queues, and the amount of time that projects remain in these queues has been increasing steadily (Rand et al., 2022). In addition, there are widespread reports of renewables projects being withdrawn from interconnection queues because of concerns about transmission congestion, particularly in the Midwest (for example, as reported in Tomich, 2019 and Penrod, 2022).

Looking Ahead: Can the United States Build the Transmission Network It Needs?

Given the evidence that the United States does not have enough transmission capacity to efficiently utilize even the current level of renewables, one might reasonably ask what happens as we move toward a net zero carbon future. Figure 5 helps to put the necessary expansion of transmission in context, juxtaposing the assumed levels of total US transmission capacity under three prominent decarbonization scenarios with the historical record since 2005. These studies outline a range of different scenarios with varying levels of increased renewables, electrification of vehicles and buildings, carbon capture, and other features (Princeton, 2021; Williams et al., 2021, National Academies, 2021). The exact combination of strategies varies across scenarios, but a key feature of all three studies is that they are renewables-heavy and therefore assume an unprecedented level of investments in electricity transmission over the next several decades.

From 2005 to 2020, transmission capacity shown in Figure 5 grew by 27 percent. Although this increase may seem modest, it was actually a break in historic trends. The annual average increase in transmission capacity over 2015-2020 was greater than the annual average over the previous 30 years (US Department of Energy, 2015), which itself had followed decades of falling investment in the transmission system (Hirst and Kirby, 2001).

By the late 2010s, major US utilities were spending more than $20 billion annually on new transmission investments (US Department of Energy, 2021e). Some of the drivers of this growth were to integrate renewables, replace aging infrastructure, improve storm hardening, and improve reliability (US Department of Energy, 2018, 2021e). However, the majority of these projects were fairly small-scale—for instance, within the service territory of one utility and less than 100 miles (Catalyst Cooperative, 2022)—and did not involve the kind of cross-state or cross-region coordination that is particularly challenging.

The six scenarios plotted in Figure 5 all assume dramatic increases in US transmission capacity between 2020 and 2050. Even the least aggressive scenario entails more than a doubling of transmission capacity by 2050. The other scenarios involve three-, four-, or five-fold increases in transmission, depending on the extent to which decarbonization relies exclusively on renewables, as opposed to, say, nuclear power or carbon capture.

Under all of the assumed scenarios, the annual growth in transmission greatly exceeds the annual growth 2005-2020. It is difficult to overstate the scope of such an increase. In total inflation-adjusted dollars, a transmission expansion of this magnitude could cost more than historically massive investments like the national highway system—in which almost $600 billion (in 2022 dollars) was spent on 43,000 lane miles of highway over a 35-year period (Center for American Progress, 2012). Moreover, as we discuss in the following sections, there are additional factors, above and beyond financial cost, that make large-scale transmission projects particularly challenging.

The Overhang of Fragmented Regulated Utilities

While it makes sense today to think about generating wind power in Oklahoma to deliver to consumers in Tennessee, this type of long-distance cross-state transmission was not how the US electric grid was designed. The main exceptions, when portions of the grid were designed to move power over long distances, typically were associated with efforts to bring remote hydroelectric power to high-population load centers, like the electricity lines connecting power generated in the

Pacific Northwest to California, or to share the power from a large scale generation plant (particularly nuclear plants) across customers of more than one utility (Joskow, 2021).

A bit of history is helpful for understanding why it is so difficult to build large-scale transmission projects in the United States. The US electricity grid is not a single, centrally-designed entity; instead, it is a disorganized patchwork resulting from more than a century of mostly disconnected individual electric utilities making decisions for their own monopoly franchise territories. Fossil and nuclear fuel can be transported to generating plants, enabling utilities to choose generation sites based on proximity to load, subject to available land and environmental restrictions. This enabled transmission networks built to connect generating plants to load centers largely within a utility's service area; interconnections across networks were relatively limited and typically motivated more by resiliency and network reliability concerns. This system had little need to transport significant volumes of power across service territories or to connect utilities across different regions of the country (Joskow, 2021).

Moreover, the cost of service regulation traditionally applied in the US incentivized utilities to go it alone rather than cooperate with others. If a utility builds a power plant, the cost is a capital expense for which the utility earns a profitable rate-of-return, as the allowed rate of return typically exceeds the utility's cost of capital. Buy electricity from someone else, however, and the cost is operating expense for which the utility earns no profit.[7] Gold (2019) tells the story of a utility executive speaking to a developer for additional transition lines: "Why would we buy from you and make no money? We'd rather run our own plants and make money that way." Economists have long argued that rate-of-return regulation can create a bias toward capital-intensive investments (Averch and Johnson, 1962), and this preference for building, rather than buying, is part of the reason we have such a fragmented grid to begin with (Cicala, 2021).

Utilities have traded electricity bilaterally for a long time and through organized wholesale markets in many parts of the United States since about 2000. These wholesale markets have tended to improve market efficiency (Cicala, 2022), but such trades have occurred subject to the constraints of a transmission system historically built almost entirely by individual utilities

[7] Traditional vertically integrated electric utilities receive a rate of return for both generation and transmission investments. See, e.g., Joskow (2005). However, generation has historically been a much larger component than transmission (Joskow and Schmalensee, 1988). Moreover, buying electricity from someone else typically involves using someone else's transmission line, in which case any transmission charges are an operating expense rather than a capital investment.

operating by themselves, not designed for long-distance market integration, and certainly not optimized from a centralized perspective. The United States has over fifty "Balancing Authorities," which are the system operators responsible for managing the power flows within their network and ensuring compliance with the operating criteria for the synchronized networks to which they are connected (Joskow, 2021). These range from relatively small single-utility systems to large Regional Transmission Operators (RTOs) and Independent System Operators (ISOs). In regions with deregulated wholesale generation markets, generation dispatch and the operation of the grid has been turned over to ISOs or RTOs, even as individual utilities continue to own most transmission lines. While RTOs/ISOs oversee transmission planning and investment decisions, most of their focus until very recently was on network reliability. Despite efforts by the Federal Energy Regulatory Commission (FERC) to extend planning criteria to include economic efficiency and policy objectives through its FERC Order 1000, transmission investment continued to be driven primarily by compliance with reliability standards (Pfeifenberger et al., 2021, Joskow, 2021).

The most obvious and immediate consequence of this history is that the US electric grid is inherently limited in terms of overall capacity for long-distance movement of power. There is virtually no capacity to move electricity between the three so-called "interconnections" in the continental United States—Eastern, Western, and Texas—despite evidence that the benefits of such connections would greatly exceed the costs (McCalley et al., 2012, NREL, 2021a). Apart from those relatively few high-capacity lines built long ago to transmit hydro power to distant customers within interconnections, there is a limited ability to move electricity, and this particularly binds during peak periods when those connections would be most valuable.

The lack of centralized decision-making means that proposals for large transmission projects typically require high degrees of consensus among affected parties. A new transmission line connecting several states, for example, usually requires approval by the utility commissions in each state as well as, in many cases, the major affected utilities as well. Depending on the state, siting authority usually rests with the public utility commission, another agency, or, in some cases, multiple agencies. The review typically includes economic analyses, environmental reviews, and public hearings, after which the state must decide if the project is in the public interest (for additional details, see FERC, 2020). But near-universal consensus can be difficult to achieve, because most projects create both winners and losers.

How Additional Transmission Creates Winners and Losers

When you take energy from a location with a low price and you move it to another location with a high price, you create economic value.[8] However, there are inevitably winners and losers from market integration. Commercial and industrial customers, ratepayer advocates, and other electricity buyers in renewables-rich areas tend to oppose new transmission because, for them, electricity flowing to other areas pushes prices upward. Similarly, owners of existing fossil-fuel power plants and other electricity sellers in receiving areas tend to oppose new transmission because, because receiving energy from other areas, it pushes prices downward. Even if a project creates large aggregate net benefits, those made worse off are likely to protest.

Utility regulation does not solve these challenges. Traditional vertically-integrated utilities in receiving areas tend to oppose new transmission because it makes their power plants less valuable, and because cheap electricity from other places reduces the need for new local investments in generation. Moreover, regulated utilities are under only weak incentives to deliver lower-priced electricity to their customers, so they tend not to be particularly motivated by potential cost savings.

In addition, some of the economic value from increased transmission of electricity generated with carbon-free methods comes in the form of reduced environmental externalities, but there is typically no stakeholder at the table in these negotiations to represent the interests of reducing global greenhouse gas emissions.[9] For the same reason, there typically is no direct financial incentive for projects with particularly beneficial environmental impacts. At least in theory, pricing carbon (and other environmental externalities) would help align incentives. But, of course, there is no price on carbon in most US states, and even if there were, it would not eliminate the kind of coordination issues described here where it can be difficult to build near-perfect consensus for any project that creates winners and losers.

[8] Gonzales, Ito, and Reguant (2022) document a vivid example of price convergence following recent electricity transmission expansions in Chile. Prior to the expansions, the two largest electricity markets in Chile were separate and disconnected. Market integration led to price convergence and enabled additional renewables investments which they find would not have been profitable without the expansions.

[9] In related research, Fell et al. (2021) use data from two major US electricity markets to show that the environmental benefits from wind generation are 30 percent larger when transmission is uncongested. This result happens in the markets they study primarily by offsetting more fossil generation in population-dense locations. Their results imply that a major recent transmission project in Texas (CREZ) increased the environmental benefits from Texas wind generation by $366 million annually.

Free Riders and Cost Allocation

Even when stakeholders agree on the overall need for particular transmission investment (or at least, do not oppose such an investment), disagreements often emerge over how project costs should be divided. To understand why cost allocation is such a challenge, it is helpful to compare electricity transmission to natural gas pipelines, and to think about how the network externalities with electricity transmission make it harder to finance. US interstate electricity transmission and natural gas pipelines are both regulated by FERC, but the two markets are very different. With natural gas, a pipeline owner has complete control over who injects natural gas at one end and who extracts it at the other. US interstate natural gas pipelines have been built mostly on a decentralized, contract-based framework, with private pipeline developers building projects paid for by pipeline customers. The simplicity, speed, and flexibility of this approach enabled the growth of a vast US network of interstate pipelines, and it has been nimble enough to respond to changes in market conditions (Adamson, 2018).

This decentralized, quasi-competitive approach to contracting has not worked well with electricity transmission. Part of the challenge has to do with the physical laws of power flow. Electricity is injected and withdrawn at many locations in the grid, and there are network externalities such that changes at any location affect the entire grid, with consequences for transmission constraints, market power, and other issues (Borenstein et al., 2000, Griffin and Puller, 2009, Joskow, 2012, Davis and Hausman, 2016, Ryan, 2021). These physical features of electricity transmission make it more like a public good, with the benefits from increased transmission experienced among a more diffuse set of beneficiaries. As such, electricity transmission is susceptible to free riding. A new transmission line can help relieve constraints and increase reliability throughout the broader region, including relatively distant parts of the grid, but quantifying those benefits and getting beneficiaries to recognize and pay for them can be challenging.

Not coincidentally, there are continued calls to reform the system of cost allocation used to finance electricity transmission (Hogan, 2018; Olmos et al., 2018). A series of orders from FERC have attempted to increase incentives for new investments in electricity transmission, including guidance that costs be allocated "roughly commensurate" with estimated benefits (Adamson, 2018, Joskow, 2020a, Joskow, 2020b). However, it can be difficult to precisely quantify the benefits of transmission and, even while following FERC cost allocation principles, two parties can reach very different conclusions about the magnitude of benefits. As FERC (2020) puts it, "Given this complexity and the general contentious nature of cost allocation issues, cost allocation determinations may continue to be prone to disagreement and litigation that present a challenge to development of transmission facilities, including high-voltage transmission." In practice, these and other challenges have frustrated FERC's efforts to encourage new transmission investment, in sharp contrast to the more dynamic natural gas pipeline sector.

Local Siting and Permitting Challenges

Siting and permitting issues, i.e. determining the line's route and securing the necessary land use authorizations, can stymy construction. Long-distance transmission projects typically require permission from hundreds of different landowners. Transmission project developers must convince landowners to allow construction on their properties, a process that is uncertain, expensive, and time-consuming. Landowners often oppose high-voltage transmission lines due to concerns about visual impacts, perceived health effects, site preservation, and other issues (Vajjhala and Fischbeck, 2007; Cohen et al., 2016; Mueller et al., 2017). Saul, Malik, and Merrill (2022) report the saga of the TransWest Express line, which sought to send power from Wyoming wind farms to California but was held up by land-use concerns.

An unusually large number of agencies are involved in this process. It is common for the siting application of a new line to reference coordination with multiple federal agencies (for example, the Army Corps of Engineers, Fish and Wildlife Service, Forest Service, Federal Aviation Administration, and Department of Agriculture) and state-level authorities (for example, agencies responsible for environmental protection, transportation, agriculture, and historic preservation), along with county, municipal, and tribal authorities. Examples of laws that may apply to land use are the Clean Water Act, the Rivers and Harbors Act, the Bald and Golden Eagle Protection Act, the Endangered Species Act, the National Historic Preservation Act, and the Federal Aviation Administration Act (FERC 2020). And if a project crosses federal land, then the project must also satisfy National Environmental Policy Act (NEPA) requirements, including detailed environmental impact assessments (FERC 2020). Permitting Institute (2023) provides a remarkable flowchart that references these and other agencies in illustrating the complicated permitting process that may be required for new US transmission projects. Moreover, the challenge is not just the numerous agencies – but the potential throughout for these process to be co-opted by private economic interests.

Related research on local opposition to energy projects shows how it can significantly increase costs. For example, Jarvis (2022) finds that local opposition to wind projects in the United Kingdom pushes these projects toward less-desirable locations, increasing total project costs by between 10 percent and 29 percent. Indeed, the UK's investments in off-shore wind are viewed, in part, as a response to how difficult it is to overcome local opposition to on-shore wind projects (Jones and Eiser, 2010). Of course, local opposition to large infrastructure projects is not unique to energy infrastructure. Brooks and Liscow (2023) find that spending per mile on interstate highways increased three-fold between the 1960s and 1980s. Increasing incomes and housing prices explain just over half the increase, which they interpret as the rising cost of "citizen voice."

Electricity transmission sometimes ends up on the ballot. Maine residents voted in 2021 to reject a 145-mile transmission line that would have connected Canadian hydropower with electricity consumers in New England (as reported by Kamp, 2021). A similar project was rejected in New Hampshire by a government committee in 2018 (as reported by Ailworth and Kamp, 2018). Opponents in both cases compared the project to an extension cord stretched through their forested landscape, highlighting visual impacts, local site preservation, and other issues, while also emphasizing that much of the benefit would go to other states. There is often interaction between local siting issues and political support for green policies. For example, Stokes (2016) finds a backlash by voters who live within three kilometers of newly-sited wind turbines in Ontario, Canada.

Resolving these tensions between the broader public good and local land use concerns is one of the key barriers preventing faster growth in energy infrastructure. Whether it is an electricity transmission line to connect hydro power from Quebec to consumers in New England, or new connections to renewables in the Midwest, or a new wind farm in the United Kingdom, the benefits of energy infrastructure are usually widely dispersed, while the land use concerns are highly localized.

Paying for New Transmission Lines

Even after all the relevant stakeholders have approved a project, the transmission lines still need to be built. Transmission lines are large capital investments; building a high-capacity long-distance transmission line can cost $3 million or more per mile (WECC, 2019). Unlike the costs for grid-scale renewables, there is little evidence that the costs of transmission lines have declined over time.[10] In fact, the most expensive transmission projects in recent years have had much higher costs per mile than the most expensive projects in the early 2000s (authors' calculations, based on Catalyst Cooperative, 2022). Whereas renewables have benefited from economies-of-scale and learning-by-doing, the technology for electricity transmission is largely unchanged from what it has been for decades.

There is also the related question about whether transmission lines will be used enough to justify the required capital costs. With a typical fossil fuel or nuclear power plant, it is possible to size transmission to guarantee that the lines are used at close to full capacity, 24 hours a day, 7 days a week. This is not the case for renewables: a transmission line connecting a solar-rich area to the rest of the grid may be operated only 30 percent of the time, for example. This capacity factor problem tends to mean that electricity systems based on renewables need more total transmission capacity than systems based on fossil fuels (Sioshansi and Denholm, 2012).

What Can Be Done?

In this section we discuss several approaches for accelerating US electricity transmission projects. We also briefly discuss two potential substitutes for additional transmission: storage and dynamic pricing. While neither substitute would eliminate the need for additional transmission, both could play an important role accommodating renewables growth, even if the United States proves unable to build new transmission at the pace suggested by recent decarbonization studies.

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[10] Evidence on costs comes from industry sources like the Western Electricity Coordinating Council that coordinates the entire Western interconnection system, the Southwest Power Pool that manages the grid for the central United States, and the Midcontinent Independent System Operator that manages the high-voltage grid across 15 US states and Manitoba. For examples, see WECC's 2012 "Capital Costs for Transmission and Substations," WECC's 2014 "Capital Costs for Transmission and Substations," WECC's 2019 "Transmission Capital Cost Tool - with E3 Updates, SPP's 2016 "The Value of Transmission," SPP's 2021 "The Value of Transmission," and MISO's 2020 "Transmission Cost Estimation Guide."

Approaches for Increasing Transmission

Probably the most discussed potential policy reform is enhanced federal authority for siting and permitting new transmission lines. Whereas the current approval process is split between federal, state, and local agencies, the public good characteristics of electricity transmission provide a clear economic argument for greater centralization of these decisions (Brown and Botterud, 2021). Increased transmission capacity creates economic benefits that are widely diffused across states, and a federal agency can take these spillovers into account when evaluating projects in a way that individual states or utilities are not incentivized to do. FERC has long been the central authority for siting natural gas pipelines, and a similar approach could be adopted with electricity transmission (Borenstein and Kellogg, 2021, Cicala, 2021). MIT (2011) argues that enhanced authority should be reserved for interstate transmission lines, given the especially large coordination challenges for those projects. Reforms in Europe have to some degree followed this prescription (Joskow, 2021).

Enhancing federal authority for siting would not be easy. The Bipartisan Infrastructure Law of 2021 and the Inflation Reduction Act of 2022 take steps in this direction, for example, giving FERC the authority to overturn state objections to transmission projects (Sud et al. 2023). But it is too soon to say to what extent FERC will be willing or able to exert this new authority. Previous attempts to enhance federal authority, for example, with FERC Order 1000, have run into considerable challenges with state and local regulators unwilling to cede their authority (Joskow, 2020b). Additional legislation proposed in 2022 by Chuck Schumer and Joe Manchin would have gone further, taking steps to address many of the barriers we discussed including improved cost allocation rules; enhanced federal authority for permitting; simplified NEPA procedures, and simplified multi-agency coordination (Goggin and Gramlich, 2022), but this legislation faced significant political hurdles and did not pass.

There also are opportunities for shifting where new transmission investments are happening. Rather than focus on new transmission projects in greenfield locations, more of the emphasis could be shifted toward upgrading lines in existing transmission corridors. High-voltage lines can be upgraded to expand capacity, for example, from 230kV to 345kV. There is also the potential to increase the capacity of existing high voltage alternating current (HVAC) lines by converting them to high-voltage direct current (HVDC) lines or hybrid AC/DC lines. Reed et al. (2019) explains that such conversions can increase total transmission capacity by up to four times. Capacity expansion projects still require large capital investments, but can be easier from the perspective of local siting concerns. New transmission projects could also be placed along waterways, railroads, highways, and other corridors that have already been designated for public infrastructure use (Cicala, 2021). This approach of using public infrastructure corridors can be easier than negotiating right-of-way permissions with a large number of individual landowners (FERC, 2020) and has the potential to significantly reduce local siting concerns relative to projects that break new ground.[11]

Increasing Storage

Perhaps the closest substitute for additional transmission is more capacity for electricity storage. Whereas transmission allows for arbitrage across locations, storage allows for arbitrage across time. In an electricity market with ample storage, you would not expect to see renewables curtailment or frequent negative prices. Moreover, when storage is co-located with renewables, transmission can be used for a greater fraction of all hours throughout the year, improving the financial viability of transmission investments.

Electricity storage is expensive, so historically there has been very little of it. By far the largest form of electricity storage worldwide is pumped hydro, which refers to facilities with two water reservoirs at different elevations, as well as pumps for moving water uphill. When electricity is scarce, water is released down through turbines to generate electricity. Then, when electricity is plentiful, water is pumped back up. Until recently, pumped hydro represented more than 90 percent of US grid-scale storage, but capacity is growing relatively slowly, mostly from upgrades to existing facilities (US Department of Energy, 2021c).

The fastest-growing form of electricity storage relies on lithium ion batteries. For example, the 400 megawatt Moss Landing project in Monterey, California has been called the largest battery storage facility in the world (Gearino, 2021). US electric utilities have spent billions over the last few years building battery storage projects like Moss Landing. Total US battery capacity on the grid reached 1,650 megawatts at the end of 2020, and is forecasted to reach 12,000 megawatts by the end of 2023 (US Department of Energy, 2021d). But even with this recent growth, total battery storage is

[11] Relatedly, there are also potential opportunities for siting renewable generation facilities on the grounds or near retired power plants, as reported in Shao (2022). Hundreds of US coal plants have closed or are planning to close, and these locations are already connected to the grid with existing transmission infrastructure.

still small compared to the size of the market. Peak electricity demand in the United States is about 700,000 megawatts (US Department of Energy, 2021b). Thus 12,000 megawatts by the end of 2023 is not negligible, but still represents less than 2 percent of peak US demand. Of course, during high demand periods, it can be very valuable to have even a relatively small amount of stored electricity available (for an example, see Blaustein, 2022). But current battery storage investments can play only a modest role in addressing hour-to-hour imbalances between supply and demand.

Could grid-scale storage scale up dramatically? It is not clear. Grid-scale battery storage costs did fall more than 70 percent from 2015 to 2019 (US Department of Energy, 2021a), but battery storage is still not cost-effective (Karaduman, 2021; NREL, 2021b). There is scope for some optimism about battery storage costs declining further, given that these technologies potentially benefit from economies-of-scale and learning-by-doing. NREL (2021b) predicts steep further declines for lithium ion batteries over the next several years. Moreover, engineers are working on a range of differential alternative battery technologies that show promise (MIT, 2022). As one example, an MIT-based startup called Form Energy is trying to develop a cost-effective battery using iron, air, and water (as reported in McCarthy, 2022; Ramkumar, 2022).

The challenges associated with building electricity transmission imply that the private and societal benefits of new storage technologies are larger than they would be otherwise. A breakthrough in battery technology would significantly offset the need for additional transmission. Thus, an indirect but potentially important policy response to the challenges of building new electricity transmission would be to increase US government support for research and development in storage and other substitute technologies. Innovation generates knowledge spillovers, a positive externality. It appears that knowledge spillovers have contributed to the cost declines in wind turbines (Covert and Sweeney, 2022); and more broadly that solar, wind, and energy storage create knowledge spillovers (Noailly and Shestalova, 2017). Other researchers have argued that path dependency in technological development justifies government investment in research and development on clean technologies (Acemoglu et al., 2016, Aghion et al., 2016).

Dynamic Pricing

Another potential substitute for electricity transmission is dynamic pricing. The vast majority of electricity customers face time-invariant prices, which fail to efficiently communicate real-time changes in market conditions (Borenstein, 2005, Borenstein and Holland, 2005). If instead customers faced higher prices during peak periods, they would demand less electricity during those periods. In turn, this would allow for smaller investments in generation and transmission capacity, which are driven by peak demand, not just average demand.

Dynamic pricing is relatively rare, particularly in the residential sector. Consumer groups often object to dynamic pricing, raising concerns that customers do not understand complex prices or cannot rapidly respond to price changes, and that some customers would pay more (Joskow and Wolfram, 2012). Dynamic pricing can also increase the overall volatility of electricity bills, which is particularly challenging for lower-income households who have less resilience to economic shocks (Borenstein, 2013).

Nonetheless, economists have argued for decades that electricity markets would be more efficient with dynamic pricing (Boiteux, 1960). In addition, dozens of empirical studies document reductions in electricity demand in response to dynamic pricing including, both the residential and non-residential sectors (Ito et. al., 2018, Blonz, 2022). Consumers are also becoming more able to respond to real-time price changes as communications technology, and in particular, automation, continues to improve (Jessoe and Rapson, 2014, Bollinger and Hartmann, 2020). Smart thermostats, smart electric vehicle chargers, and other automated technologies mean that consumers can preset which adjustments will (or will not) occur when prices rise, and so they do not need to be aware of price changes in order to be price responsive.

The benefits from dynamic pricing are thought to be particularly large in systems with high renewables penetration. Imelda at al. (forthcoming) applies a model of investment, supply, storage and demand to evaluate the economic benefits from dynamic pricing on the island of Oahu, Hawaii. They find that the gains from dynamic pricing are 6 to 12 times higher for a high-renewables system relative to a system dominated by fossil fuels. Dynamic pricing plays several roles in the optimized system including not only moving demand from peak to off-peak periods, but also addressing challenges associated with cloudy days and other forms of renewable intermittency. Oahu is a compelling setting, in part, because of its lack of connectivity with other electricity markets. In some sense, examining Oahu is to ask what an electricity system would need to look like if building electricity transmission were completely impossible. This is, of course, more extreme than the situation faced on the continental United States, but it nonetheless provides a valuable setting for demonstrating the potential for dynamic pricing in transmission-constrained scenarios.

Conclusion

Many of the technologies that could decarbonize the US economy are getting cheaper, most notably wind and solar generation, but getting to full decarbonization is nonetheless a challenge. The most promising scenarios presented to date rely on massive investments in the electricity sector. And a key sticking point with current technologies is the need to dramatically grow the transmission capacity that would transport all the new low-cost wind and solar generation to homes and businesses. This problem is particularly true in the United States, but most of these constraints exist in other countries as well. As Joskow and Schmalensee (1988) wrote: "The role of the transmission network in transporting power and in coordinating the efficient supply of electricity in both the short run and the long run is the heart of a modern electric power system."

We have highlighted the many signs pointing towards barriers to this expansion and the myriad reasons that it is hard to build new transmission. Some of these are bureaucratic, and others are about economic fundamentals, like the public good nature of transmission, and the winners versus losers problem inherent with any market integration. We have described potential policy remedies, as well as the potential role of storage and dynamic pricing, probably the two most important substitutes to transmission.

The topic of electricity transmission is ripe for research. While numerous white papers and government reports explore the problem of transmission expansion in the US, recent academic research in this area is strikingly sparse. Empirical work on the impacts of past transmission policy changes, on transmission market design, or on the spillovers between transmission and generation markets could contribute to a better understanding of and resolution of the current policy challenge.

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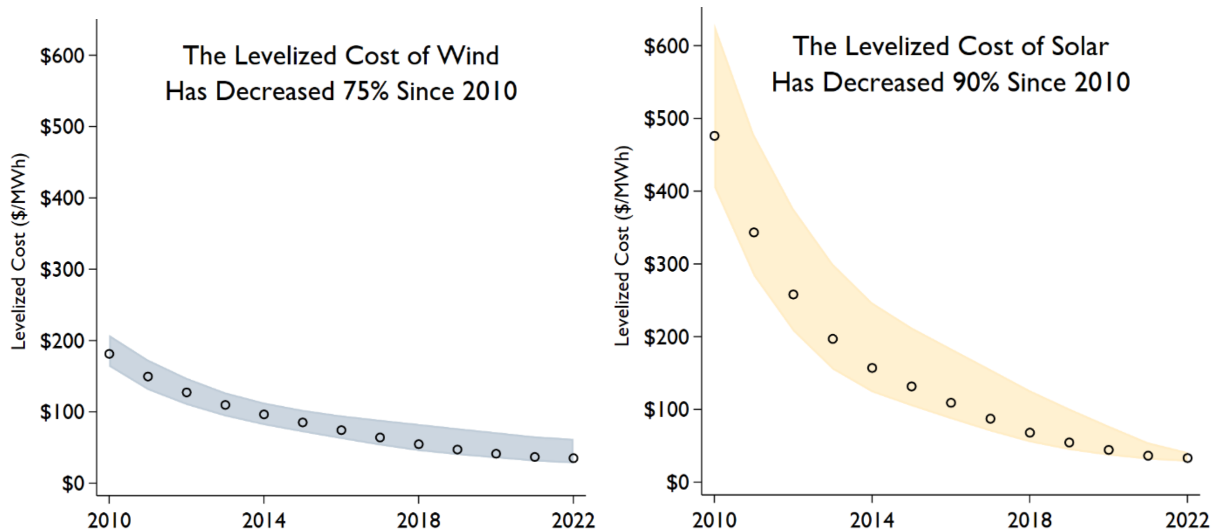
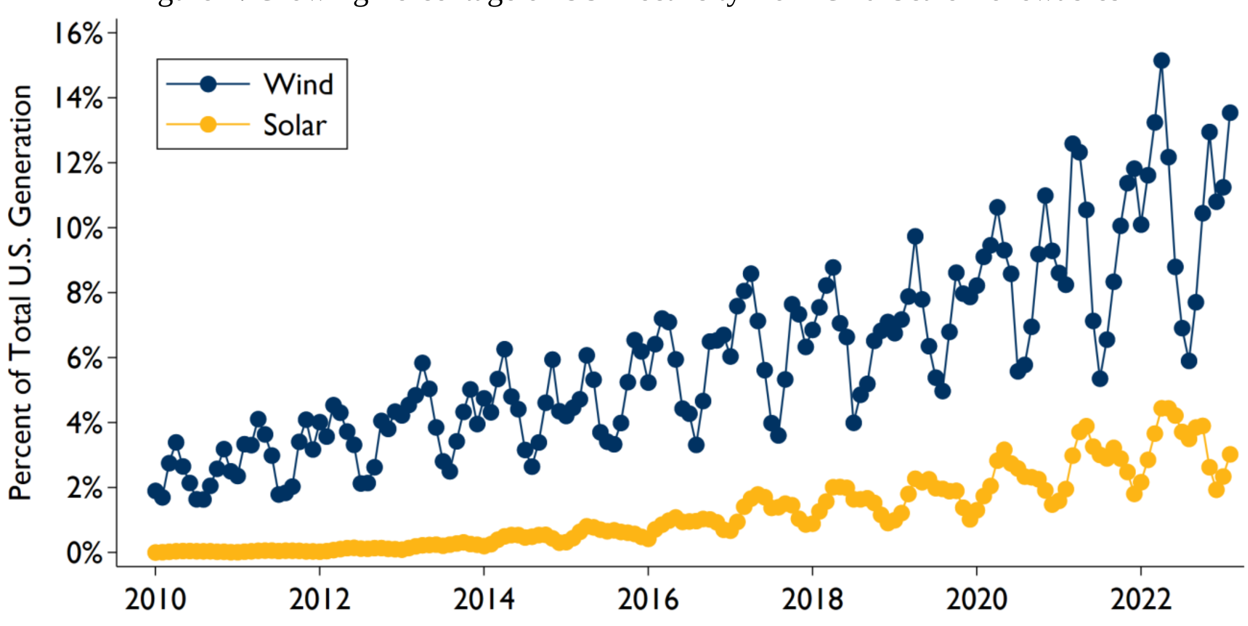
Figure 1: Decreasing Cost of Grid-Scale Renewables



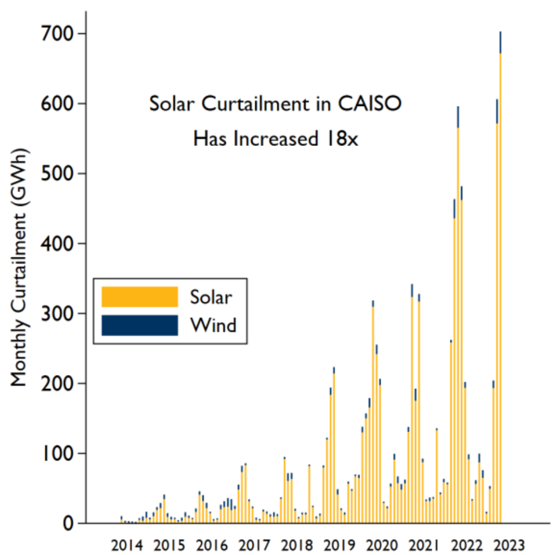
Note: This figure was created by the authors using levelized costs calculations from the US Department of Energy (2010-2022), and reflects lifetime project costs including construction, financing, and operations. The circles indicate the US average levelized cost in each year without tax credits for onshore wind and solar photovoltaics. The range indicates regional variation. A small amount of smoothing has been applied to emphasize the overall pattern rather than idiosyncratic year-to-year fluctuations. All values in the paper have been deflated to reflect year 2022 dollars.

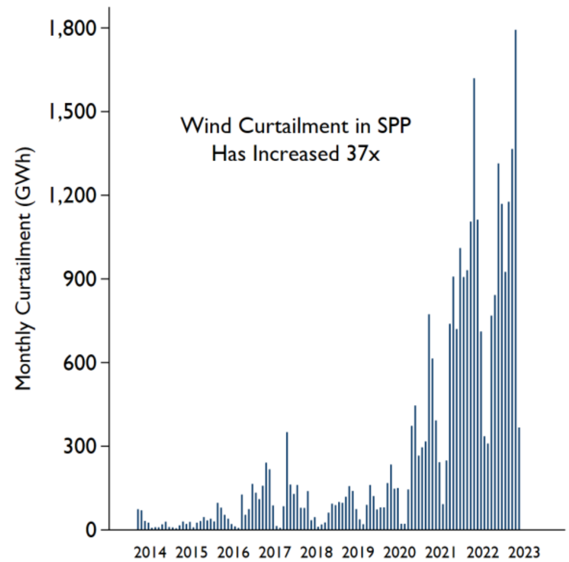
Figure 2: Growing Percentage of US Electricity from Grid-Scale Renewables



Note: This figure was created by the authors using monthly net generation by category from US Department of Energy (2023). Wind and solar are grid-scale generation as a percentage of total grid-scale generation from all sources. The seasonality reflects that during summer months (June-Aug), wind generation is 10 percent lower than other months whereas solar generation and total generation are 18 percent and 6 percent higher, respectively.

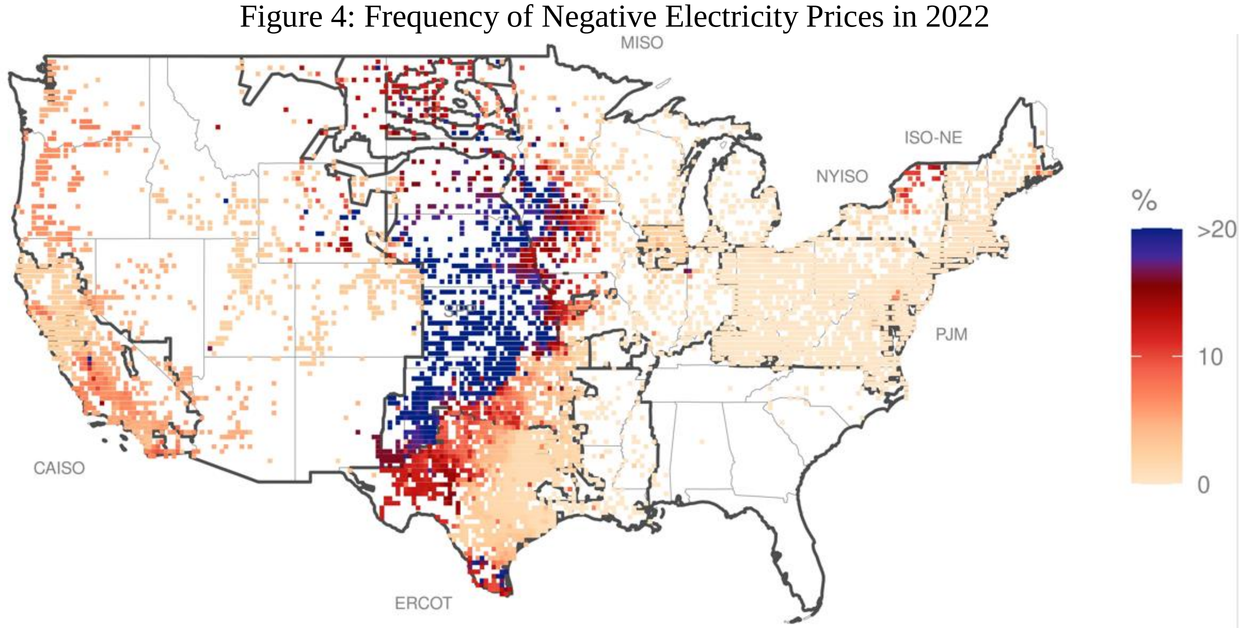
Figure 3: Increasing Curtailment of Renewables





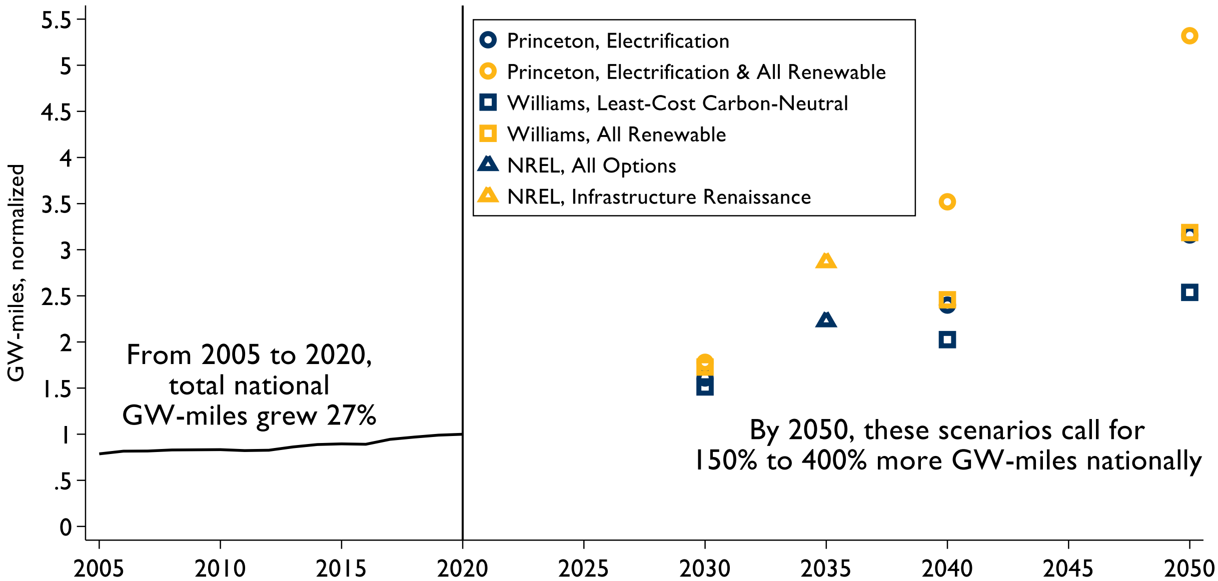
Note: This figure was created by the authors using data on renewables curtailment from the California Independent System Operator (CAISO, 2023) and the Southwest Power Pool (SPP, 2023). In CAISO, solar curtailment in 2022 was 1,734 gigawatt hours which was 4.4 percent of total grid-scale solar generation. In SPP, wind curtailment in 2022 was 11,124 gigawatt hours which was 10.3 percent of total wind generation. SPP has members in 15 states (Arkansas, Colorado, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming).

Figure 4: Frequency of Negative Electricity Prices in 2022



Note: This figure was reproduced with permission from Millstein et al (2023). The figure plots the frequency of negative local marginal electricity prices during all hours in 2022. The underlying price data in the ReWEP tool was compiled through the commercial product "Velocity Suite" based on prices from over 50,000 individual local nodes across the seven major US independent system operators. To verify the map, we spot-checked the negative price frequency at hundreds of locations in MISO and SPP (roughly, North Dakota to Michigan to Oklahoma) using hourly wholesale market price data.

Figure 5: Decarbonization Likely Requires Vastly More Transmission



Note: This figure juxtaposes historical US electricity transmission capacity (normalized to one in 2020) with the future capacity called for in three prominent decarbonization studies (Princeton, 2021, Williams et al., 2021, and NREL, 2022b). The left-hand side of the figure was created by the authors using data on transmission miles from FERC Form 1, 2005-2020 (Catalyst Cooperative, 2022). Details on the conversion from FERC's miles data to our reported GW-miles are provided in this paper's data archive.