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Grid connection barriers to renewable energy deployment in the United States

Authors
Gorman, Will
Kemp, Julie Mulvaney
Rand, Joseph
et al.

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Article

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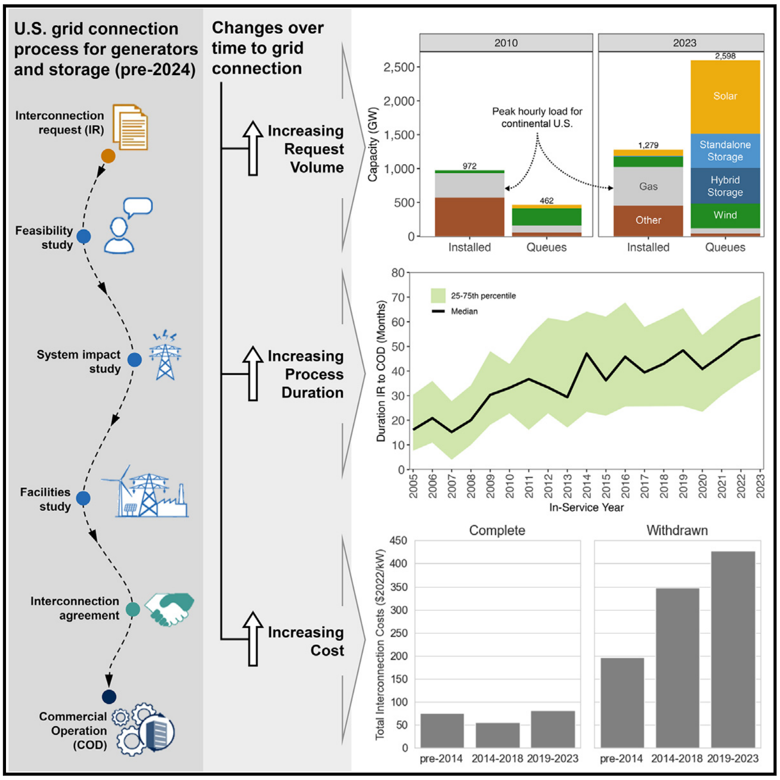
Graphical abstract



Highlights

- Grid connection processes are an emerging bottleneck to the energy transition
- Proposed capacity seeking grid connection is double the current installed capacity
- More than 80% of connection requests ultimately withdraw from the queues
- Connection costs have more than doubled over the last decade

Authors

Will Gorman, Julie Mulvaney Kemp, Joseph Rand, ..., Fredrich Kahrl, Kevin Porter, Will Cotton

Correspondence

wgorman@lbl.gov

In brief

Increased deployment of wind, solar, and storage technologies is needed to meet decarbonization goals. However, backlogged power grid connection queues have become an obstacle to the energy transition. Here, we quantitatively document the challenges of processing the rapid rise of grid connection proposals across the United States and discuss opportunities for institutional reform. We assess key drivers of connection barriers, comparing the speed, completion rates, and costs of grid connection by region, fuel type, transmission line proximity, and interconnection standard.

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Article

Grid connection barriers to renewable energy deployment in the United States

Will Gorman,[1,4,*] Julie Mulvaney Kemp,[1] Joseph Rand,[1] Joachim Seel,[1] Ryan Wiser,[1] Nick Manderlink,[1] Fredrich Kahrl,[1,2] Kevin Porter,[3] and Will Cotton[3]

[1]Lawrence Berkeley National Laboratory, 1 Cyclotron Road, MS 90-4000, Berkeley, CA 94720, USA
[2]3rdRail Inc., 1225 Allston Way, Berkeley, CA 94702, USA
[3]Exeter Associates, 10480 Little Patuxent Parkway, Suite 300, Columbia, MD 21044, USA
[4]Lead contact
*Correspondence: wgorman@lbl.gov
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CONTEXT & SCALE Substantial adoption of wind, solar, and storage technologies is essential to meet decarbonization goals. The grid connection study process, which is meant to ensure the reliability of a changing electricity system, has become backlogged due to a rapid increase of project proposals coupled with limited available transmission capacity. Left alone, this bottleneck will impede the pace of wind, solar, and storage deployment, jeopardizing society's decarbonization goals.

We evaluate the drivers of this bottleneck using data from all regions across the United States. Across the regions studied, assessed interconnection costs have increased over the last decade, particularly for projects that ultimately withdraw their proposals. Our findings suggest that interconnection reform is needed, and policymakers and regulators should establish tighter links between long-term transmission planning and project-level interconnection processes. More data and outcome transparency would allow key stakeholders to monitor the health of interconnection institutions.

SUMMARY

Bulk-power grid connection is an emerging bottleneck to the entry of wind, solar, and storage but has been understudied due to a lack of data. We create and analyze two novel interconnection datasets with more than 38,000 project-level observations that provide new information documenting interconnection challenges in the United States. Active grid connection requests are more than double the total installed capacity of the US power plant fleet (2,600 vs. 1,280 GW). The time required to secure a connection has increased by 70% over the last decade, and withdrawal rates remain high at 80%, suggesting a constrained transmission system that jeopardizes energy transition targets. Wide distributions of interconnection costs indicate the inherent uncertainty of the interconnection process. Interconnection requests that identify large transmission upgrades tend to withdraw from the process. These findings suggest the need for interconnection reforms, tighter links between long-term transmission planning and project-level interconnection processes, and more interconnection outcome transparency.

INTRODUCTION

The world aims to limit further climate change with many countries targeting net-zero energy-related CO_2 emissions by mid-century.[1] The rapid, large-scale deployment of wind and solar power plants is expected to be a key pillar of this energy transition. Researchers estimate that, on average, the United States (US), Europe, India, and China will need to deploy 70–160,[2–4] 65,[5] 100,[6] and 250[7] gigawatts (GW)/year of combined wind and solar installations to achieve net-zero emissions by mid-century. However, only an average of 27, 40, 20, and 180 GW/year of total wind and solar power capacity has been successfully installed between 2016 and 2023 in these regions.[8,9] Globally, the International Energy Agency projects that more than 700 GW/year[10] of wind and solar deployment is required to achieve net-zero CO_2 emissions, compared to the current deployment rate of 267 GW/year for those technologies.[8] Though there have been significant historical renewable energy cost-declines[11,12] and strong governmental support for renewable energy development,[13] there remains a gap between current rates of wind and solar deployment and the average rates thought to be needed to achieve net-zero CO_2 emissions by mid-century.

Many constraints limit the expansion of wind and solar development. Past research has focused on public acceptance and opposition,[14–18] cost reductions,[19,20] manufacturing/supply-chain issues,[21–24] land-use competition,[25–28] and variable resource balancing.[29–32] The lack of transmission infrastructure for wind and solar is another actively discussed barrier as past research has shown that wind and solar development requires significant transmission expansion.[33,34]

Grid interconnection, defined in this paper as the process of connecting new generators or energy storage to the existing electric grid, has emerged as one of the most recent and significant obstacles to renewable energy deployment.[35–38] While grid interconnection processes have important links to transmission system expansion, interconnection bottlenecks can often be tied to interconnection-specific institutional issues that are distinct from transmission development. Interconnection study processes are designed to ensure the safety and reliability of the electricity system as new generation and storage resources are synchronized and affect power system dynamics. This function of interconnection processes is especially important given recent electricity system disturbance events that have been associated with inverter-based resources (i.e., wind and solar power plants).[39] In response, the electric sector has begun to enhance wind and solar interconnection engineering standards.[40]

The collective set of power plants that have requested grid interconnection and initiated the interconnection study process is known as the "interconnection queue." These queues have become increasingly long across the globe.[41] In the UK, Italy, Spain, France, and Germany, queues have 596 GW of wind and solar capacity, equal to twice their existing installed capacity.[42] Key metrics used to track the health of interconnection processes include the time taken from the submission of an interconnection request (IR) to achieving commercial operations (CODs), the cost assigned to generators within the interconnection process, and the overall withdrawal rates resulting from processing interconnection applications. Such metrics are not always easy to calculate given current data transparency challenges, but the backlog of renewable projects waiting to be developed has recently increased public scrutiny of interconnection processes and corresponding outcomes. Policymakers across the globe have started to propose reforms to improve interconnection processes to reduce these backlogs and increase the speed at which new generation and storage projects connect to the grid. In the UK, the national utility and electric regulator have worked on enhancements to the process that manages generators within their interconnection queue.[43] In the US, the Federal Energy Regulatory Commission (FERC) recently enacted new interconnection process rules to more efficiently process interconnection applications.[44,45]

Countries take different approaches to interconnection policy. In the US, interconnection is managed in both restructured wholesale electricity markets and vertically integrated electricity systems by a policy of open access to the transmission system, which requires utilities to provide non-discriminatory access to their transmission systems. Such a policy is meant to encourage supply-side competition within the electricity sector. Though this approach is common in other market-oriented regions of the world, it is not universal. Another important interconnection policy choice is how resource developers are charged for grid connection. In many regions of the US, it is common for generators to pay for individual transmission upgrades associated with their specific project that are identified within the interconnection process. In other countries, such as Australia, Germany, and parts of Canada, interconnection costs are assigned directly to end electricity customers.[46,47] In the UK, generators are charged for upgrades on an average system cost, rather than an incremental project, basis.[48]

Regardless of this policy variability, the challenges and bottlenecks resulting from interconnection are not well understood, either in the US or globally—a research gap that remains due to the relative lack of comprehensive interconnection data. This gap makes it difficult to both monitor the progress of existing reforms as well as develop novel policies and technological recommendations that could improve global interconnection processes. Key goals for interconnection processes are transparency, low interconnection timelines, economic efficiency via increased transmission system utilization, and maintenance of system reliability.[49] It is difficult to monitor the achievement of these goals without sufficient data. Interconnection cost data have been particularly difficult to compile and compare across regions.[37] Such data are critical for understanding the cost allocation incidence of transmission development between resource developers and electricity system planners, as well as for evaluating cost variance and the underlying uncertainty created by interconnection policy choices. The effective and efficient coordination of transmission providers engaged in centralized transmission development with market participants engaged in decentralized generation investment has been a long-studied challenge for restructured electricity systems.[36,50–53] Whether interconnection processes or transmission planning institutions optimally trigger transmission investments remains a critical policy and research question.[38,54]

We add to the electricity system design literature by creating and analyzing two novel interconnection datasets that provide never-before-compiled information documenting both the development pipeline as well as the timeline and costs to interconnect electric generators in the US. In total, these datasets include more than 38,000 project observations, and our analysis provides new knowledge about why interconnection barriers threaten the achievement of decarbonization targets. In the US, separate, heterogeneous queues exist for each grid balancing area (i.e., independent system operator [ISO], regional transmission organization [RTO], or utility balancing authority). The US electric system consists of 7 ISOs/RTOs (i.e., ISO-NE in New England, NYISO in New York, PJM in the US midatlantic region, MISO in the US midwest region, SPP in the US plains region, ERCOT in Texas, CAISO in California) along with roughly 60 utility balancing areas. Johnston et al.[37] analyze similar interconnection issues to those in this paper, finding that the waiting time and high interconnection costs are key factors in a generator's decision to withdraw. They provide important policy proposals that could increase completed interconnection projects, but their analysis is limited to one RTO region in the mid-Atlantic portion of the US. Because our analysis covers the majority of the US, our insights are not limited to specific market conditions: the covered areas are diverse in their resource mixes, market characteristics, and regulatory institutions (e.g., vertical integration vs. competitive markets). We analyze historical interconnection delays and interconnection process completion rates in the US to estimate expected annual wind, solar, and storage deployment if current trends persist. Furthermore, we compare regional- and project-level differences in key interconnection outcomes to understand how barriers to interconnect can vary by fuel type, transmission line proximity, interconnection costs, and interconnection standards. This comparative analysis allows us to identify drivers for high interconnection withdrawal rates across the US.

Although this paper focuses on the US, it draws lessons for international audiences. The challenges faced in the US are mirrored elsewhere around the globe, and thus we conclude with a discussion of key insights relevant to global system planners and policymakers, while also proposing new opportunities for interconnection process research that could enhance wind and solar deployments. For example, our identification of challenges from delinking resource interconnection with broader transmission planning processes are applicable for many countries given that transmission constraints and interconnection backlogs are being experienced globally. Our approaches to quantifying and measuring the health of interconnection processes are also widely applicable. This paper focuses on transmission interconnection (i.e., generation connecting to the high-voltage bulk-power system); a distinct (though relatively similar) approach applies to distribution interconnection but is out of scope for our analysis.

RESULTS AND DISCUSSION

US interconnection queues have unprecedented amounts of renewable energy and storage

From 2000 to 2010, the US averaged between 500 and 1,000 new annual transmission IRs, corresponding to 150 to 200 GW of proposed generation each year. Over the last decade, new requests rose to 2,500 to 3,000 per year, representing anywhere from 400 to 900 GW per year of proposed wind, solar, and storage capacity, a 3- to 6-fold expansion. While the expansion of the queues suggests readiness for the energy transition, the withdrawal rates and queue durations documented below suggest US interconnection procedures were not designed to accommodate the deployment of such a massive amount of new electricity resources.

The analysis in this section summarizes data from the interconnection queues of all 7 ISOs/RTOs, along with 44 utilities as of the end of 2023. We estimate that these 51 entities collectively cover more than 95% of total installed US generation capacity.[55] All regions of the US are facing interconnection backlogs (see Figure 1). The amount of new power generation and energy storage in interconnection queues across the US has surged over the last decade, with over 2,600 GW of total capacity now actively seeking interconnection. This represents a 6-fold increase since 2014 (Figure 1). This proposed capacity is more than twice the total installed capacity of the US power plant fleet as of the end of 2023 (~1,280 GW[55]). Approximately 95% of the capacity in the queues is for solar (1,086 GW), storage (1,028 GW), and wind (366 GW). The active capacity in these queues represents more capacity than the system could feasibly absorb or that the market demands in the near- to medium-term; this situation is particularly acute in some regions like CAISO, where active capacity in queues represents more than six times that region's installed capacity (Figure 1). To some degree, this extraordinary volume represents more than just massive developer interest in new generation and storage; it also reflects an inefficient process in which resource developers are compelled to submit exploratory IRs as a form of price discovery.

Historically, most power plants that requested transmission interconnection in the US have subsequently withdrawn their applications. Looking across a subset of queues for which data are available, only 20% of proposed projects (and just 14% of capacity) seeking grid connection from 2000 to 2018 have subsequently reached CODs; 72% of plants (and 78% of capacity) have withdrawn and 7% (8% of capacity) are still actively seeking connection. Completion rates vary across technology types and grid balancing areas. Just 14% of proposed solar plants came online during this study period, compared to 32% of natural gas plants. More IRs, accompanied by lower completion rates, could be a sign of a healthy, competitive marketplace, as it suggests that resource developers are actively competing to find the best sites to develop new projects. Such an active ecosystem is needed to ensure that solicitation processes designed to procure new generation resources receive a healthy quantity of bids to make prices competitive.[56,57] However, completion rates that are too low can be a drain on transmission provider resources, could be a sign of excessive speculation due to low queue entry costs, and may pose an obstacle to the timely processing of IRs. Given the networked nature of the transmission system, interconnection studies assume the completion of projects that are further along in the interconnection process. Therefore, late-stage withdrawals from the interconnection process, in particular, are problematic and inefficient, especially since they may trigger cascading restudies for those projects that remain in the queue. The available data suggest that the frequency of these later-stage withdrawals is increasing (see Figure S3). What constitutes completion rates that are too low is likely to be region-specific, and the balance among different objectives for interconnection (e.g., quantity of resources bidding into competitive procurements) will be shaped by stakeholder negotiation. We do not attempt to determine an efficient level of completion rates in this paper.

Another key indicator of procedural and regulatory inefficiencies in the interconnection process is the long (and increasing) duration for projects to complete interconnection studies, execute interconnection agreements, and come online. The median duration from IR to COD (i.e., the time required to complete the interconnection study process) now approaches 5 years and has increased by 70% from 2010 (33 months) to 2023 (56 months). It is important to note that the distinct interconnection procedures across grid balancing areas can contribute to vastly different interconnection timelines: In Texas (Electric Reliability Council of Texas [ERCOT]), the median duration from IR to COD was 48 months for projects coming online from 2018 to 2023, compared to 61, 56, and 80 months in the New York (NYISO), Great Plains (SPP), and California (CAISO) regions of the US, respectively (see Figure S2). Importantly, ERCOT is not subject to FERC interconnection procedures and uses a streamlined interconnection study process that does not focus on thermal overloads on the transmission system

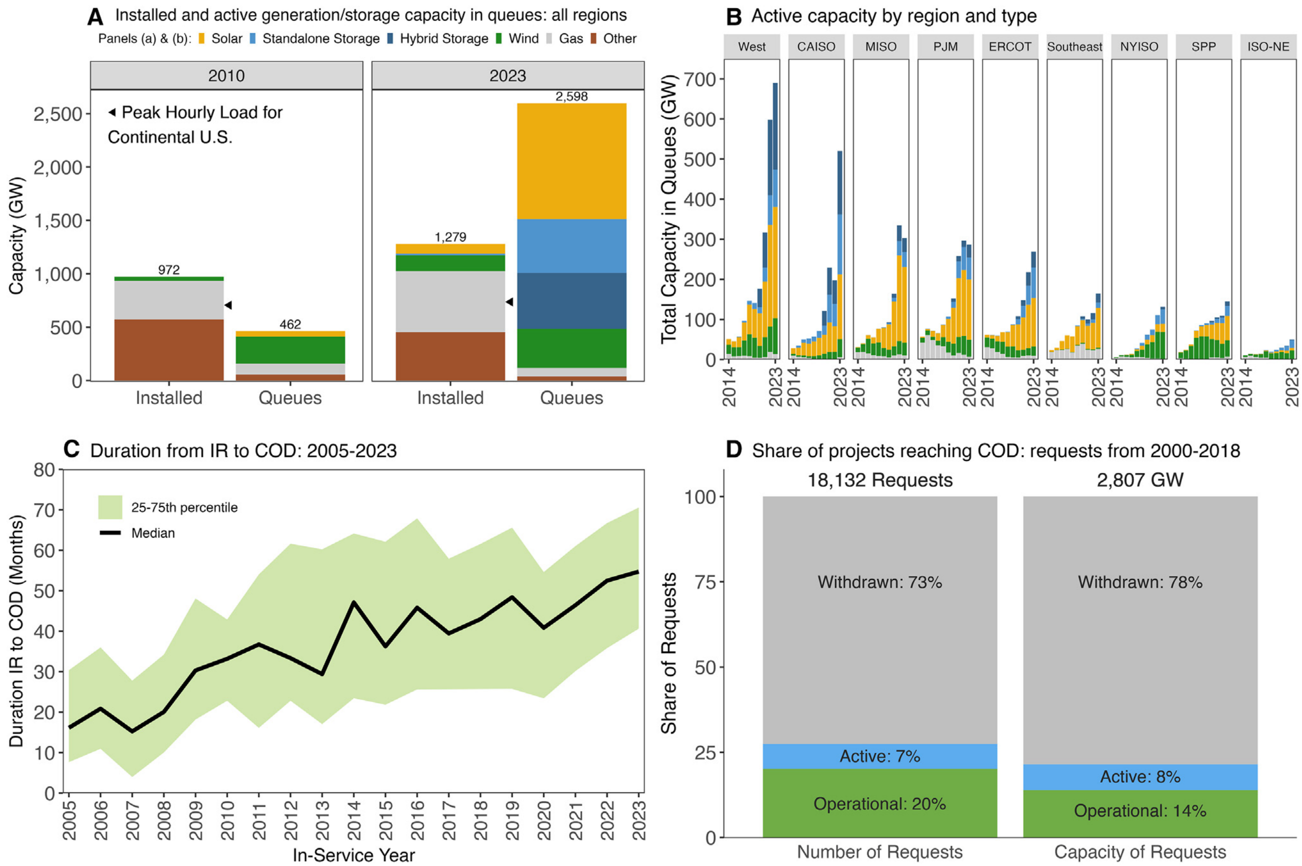

Figure 1. Interconnection queue trends

(A) Active generation and storage capacity in queues compared to installed US capacity.

(B) Active queue capacity by region, type, and year.

(C) Duration from IR to IA, 2014–2023.

(D) Share of projects reaching COD for requests submitted from 2000 to 2018.

(discussed in greater detail in network upgrades are driving rising interconnection costs within the withdrawn project sample). While this offers some advantages to connecting generators in terms of faster timelines and lower upgrade cost assignments,[58] it can also result in increased grid congestion or curtailment risks that could reduce revenue for generators and storage resources.[59] In general, ERCOT's approach defers to their wholesale market design to mediate interconnection outcomes, but occasionally ERCOT's regulators have had to intervene to improve transmission congestion outcomes (e.g., the development of the Competitive Renewable Energy Zone transmission expansion program in the late 2000s).

The combined capacity of wind, solar, and storage currently active in the US queues is enough to approach a zero-carbon electric sector in the US by 2035,[4] were it all to come online (though, as noted above, it will not—and could not—all come online in the near term to medium term). The surging volume of clean energy capacity in the queues points to a major and imminent transformation of the US power system, but the growing backlog is also evidence of a significant structural and regulatory bottleneck for plants seeking grid connection. We leverage our queue database to quantify the potential impact of queue delays and withdrawals on future US clean power deployment. Assuming historical queue completion rates and timelines (see experimental procedures for details), Figure 2 forecasts installed solar and wind capacity year over year. In the near term (2024–2027), our analysis projects that the annual installation rate will be below the near-term ramp-up of installed capacity modeled in leading decarbonization studies.[2–4,60] In the medium term, the size of the current queues could allow for capacity expansion to become roughly in line with the lower range of capacity expansion study projections, assuming historical completion rates are sustained. Furthermore, decarbonization studies show an additional doubling of renewable energy deployment rates needed beyond 2030, which go significantly beyond our queue-based projection levels. The modeled queue projections are inherently uncertain and assume that historical interconnection completion rates and timelines will be maintained. The current volume of queue requests vastly exceeds the physical availability of interconnections today, which could significantly impact future withdrawal rates and project delays, and even lead completion rates to decrease in the near term to medium term. Such results suggest that long-term US energy transition targets will be

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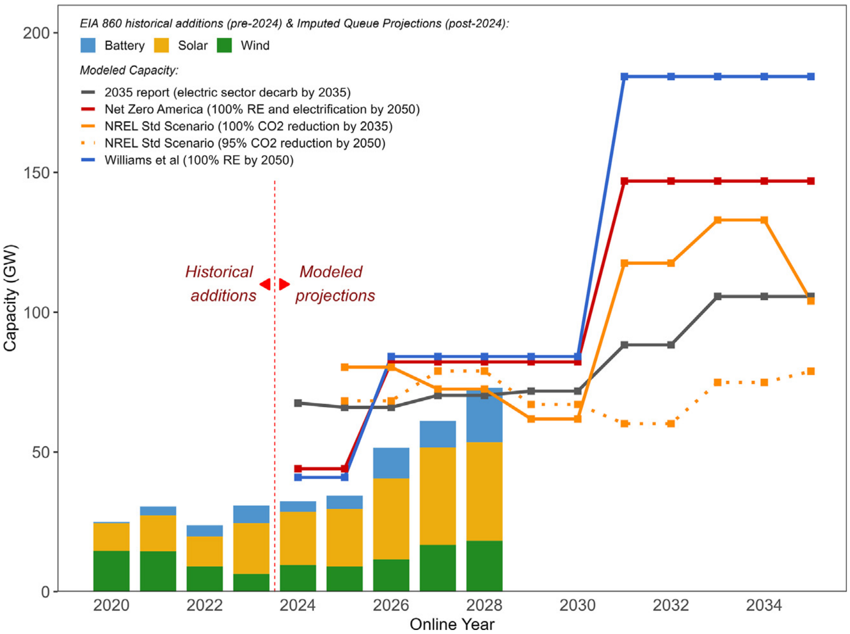

Figure 2. Projected capacity additions based on interconnection queue data compared with leading capacity expansion study targets for US decarbonization

difficult to meet without reductions in current withdrawal rates or interconnection durations.

COSTS TO INTERCONNECT ARE RISING AND ARE HIGHEST FOR RENEWABLE ENERGY GENERATORS

Active queue capacity, withdrawal rates, and durations indicate the increasing strain on interconnection institutions in the US. Alone, however, these metrics are not able to provide a complete explanation for why these strains have become more pronounced over time. In the remainder of the paper, we analyze interconnection cost data across the US to provide a more complete picture of interconnection process outcomes. We find that interconnection costs have risen over the last decade, in tandem with increasing withdrawal rates. These costs vary widely across individual projects submitting IRs, pointing to the uncertainty project developers experience at the beginning of the project development life cycle.

Cost data sample and distributions

Interconnection cost data are difficult to obtain since they are not made easily accessible by the transmission system operators who study and ultimately assign costs to individual generators. We collected interconnection cost estimates for 5,403 projects across six of the seven major ISOs/RTOs in the US (see experimental procedures for more detail on the data collection process for each region). We categorize cost data by three project status identifiers at the time of data collection: (1) complete, (2) withdrawn, or (3) active. “Complete” projects have finished all interconnection studies and either had been constructed and synchronized with the grid or were still active in the queue at the time of data collection, whereas “withdrawn” projects dropped out of the interconnection process before reaching CODs. “Active” projects were still working through the interconnection study process at the time of data collection. We also collect the date that the cost estimate was provided (i.e., year of study or interconnection agreement). Sample sizes across these categories are provided in the experimental procedures.

The cost to interconnect within our sample has a skewed distribution (see Figure 3). Nearly a quarter (24%) of the interconnection cost estimates are <$25/kW, suggesting that many project developers were able to identify locations on the transmission network that had transmission capacity to accept new generation at little to no cost. However, a substantial portion of wind and solar projects are assigned costs at least an order of magnitude greater; 25% saw interconnection costs over $250/kW. Projects that ultimately withdraw tend to face higher interconnection costs. Overall, there is a standard deviation of $156/kW for completed and $575/kW for withdrawn projects.

In part, this wide distribution of costs is related to the US approach of allocating interconnection costs to generator developers directly. US interconnection study processes are designed to encourage more efficient generator siting decisions by signaling potential locations on the electricity network that would be suboptimal for transmission connection.[61] Pricing mechanisms to incentivize efficient generation siting are not unique to US electricity systems.[62] However, prediction of these interconnection costs in advance is challenging, and the cost uncertainty represented in Figure 3 is evidence of a key limitation of the interconnection study process. Resource developers must use the interconnection study process as a price discovery mechanism. In recent years, this has contributed to the rapid rise of interconnection applications documented in US interconnection queues have unprecedented amounts of renewable energy and storage, which not only slows down the processing of applications, given the limited capacity for transmission providers to study all of these projects, but also creates more uncertainty as projects inevitably drop out once they are assigned costs that exceed their willingness-to-pay for interconnection. Current US interconnection pricing rules increase overall project development risk. Such problems are likely particularly acute in regions that separate transmission and interconnection planning from generator development.

Interconnection cost time trends by transmission region and resource type

Figure 4 presents interconnection costs by transmission operator and project status. Withdrawn projects have average

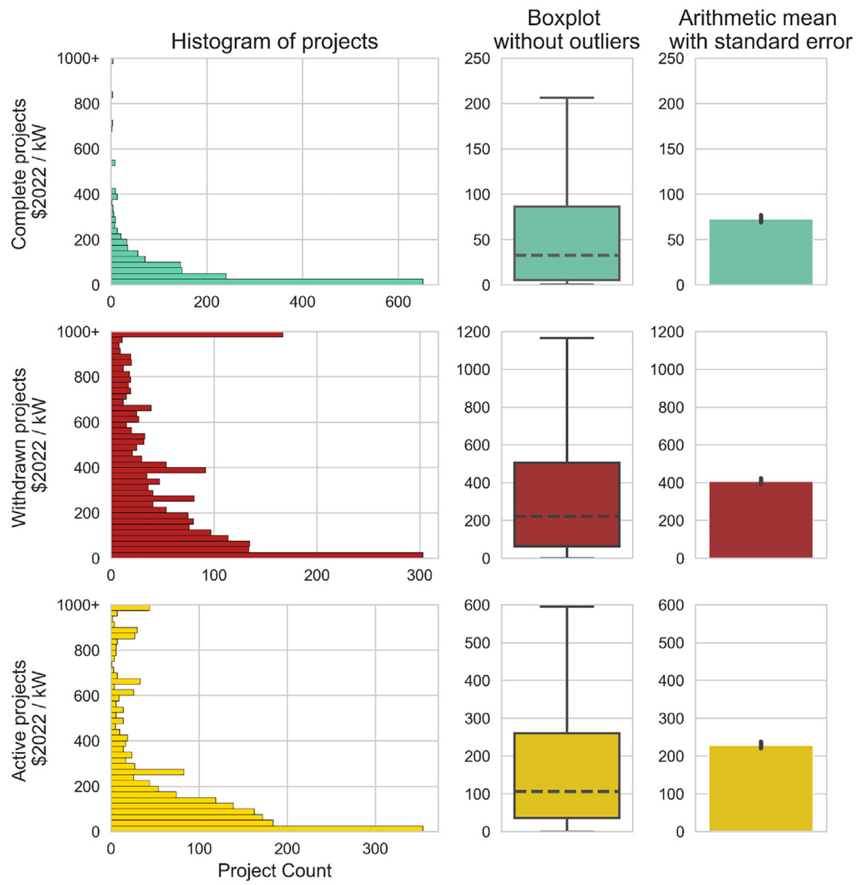

Figure 3. Distribution of interconnection cost data for complete, withdrawn, and active projects within six US transmission regions across all study dates

interconnection costs that are 412% greater than those of completed projects ($373/kW vs. $73/kW)—presumably a key reason for subsequent withdrawal. Projects that are actively moving through the interconnection process (and have not yet made final development decisions) have costs in between completed and withdrawn projects.

Interconnection costs for both completed and withdrawn projects have grown over time, though at significantly different magnitudes. Completed project interconnection costs reported during 2019–2023 ($81/kW mean) were 44% greater than during the preceding 5 years (2014–2018 mean: $56/kW), though only 7% greater than before 2014 ($76/kW mean). Meanwhile, withdrawn project interconnection costs reported during 2019–2023 ($428/kW) were 23% greater than the preceding 5 years (2014–2018 mean: $348/kW) and 117% greater than before 2014 ($197/kW). Since resource developers are incentivized to minimize project capital costs, self-selection likely explains part of the difference in average costs between completed and withdrawn projects. However, the significant increase in withdrawn project costs over time suggests increasing constraints within the transmission system. In the US, transmission development typically occurs through one of three channels: centrally planned through a regional system operator, independently constructed by a merchant transmission developer, or identified within generator interconnection processes. Our results suggest that average interconnection cost upgrades are increasingly identified within the generator interconnection process, which was not intended to be a cost-efficient mechanism for expanding the transmission network due to its piecemeal nature.[36]

The trends of rising interconnection costs for withdrawn projects and lower overall interconnection costs for completed, compared to withdrawn, projects tend to hold for each transmission operator analyzed, as shown in Figure 4. A key exception to these trends is New York, where complete and withdrawn projects have similar costs, suggesting that something other than interconnection costs drives ultimate withdrawal decisions. Another exception is California, where interconnection costs for completed projects have declined considerably over time, taking it from the most expensive to the least expensive region for projects that complete the interconnection process (California still sees increasing interconnection costs for projects that ultimately withdraw). Both California and New York have developed long-term planning processes that seek to build larger transmission investments aligned with future demand for wind and solar resources, which results in more socialization of deep network upgrades outside of the interconnection process.[63,64] California's implementation of this approach has been more recent (2022),[65] so its new processes likely did not drive the historical trends we analyze in this paper, and future work should track these metrics to observe changes in California's withdrawn interconnection projects' costs.

Comparing interconnection costs across resources types (Figure 5), irrespective of a project's request status or study date, we find the greatest costs on average for solar ($243/kW), battery storage ($265/kW), solar-plus-storage hybrids ($272/kW), and onshore wind ($218/kW) projects; lower costs for hydro ($89/kW) and natural gas ($71/kW) projects; and the lowest costs for coal projects ($20/kW). Though the differences between resources are smaller when only complete projects are considered, this overall trend of higher interconnection costs for solar, wind, and battery storage tends to hold within each request status. Solar-plus-storage hybrids are one exception; they have among the lowest complete project costs, yet the highest average of withdrawn and active projects. Another exception is the small number of hydro projects, most of which are complete and have high average costs relative to other complete projects.

Figure 5 also shows that it has become increasingly costly to interconnect wind and solar resources. Compared to before

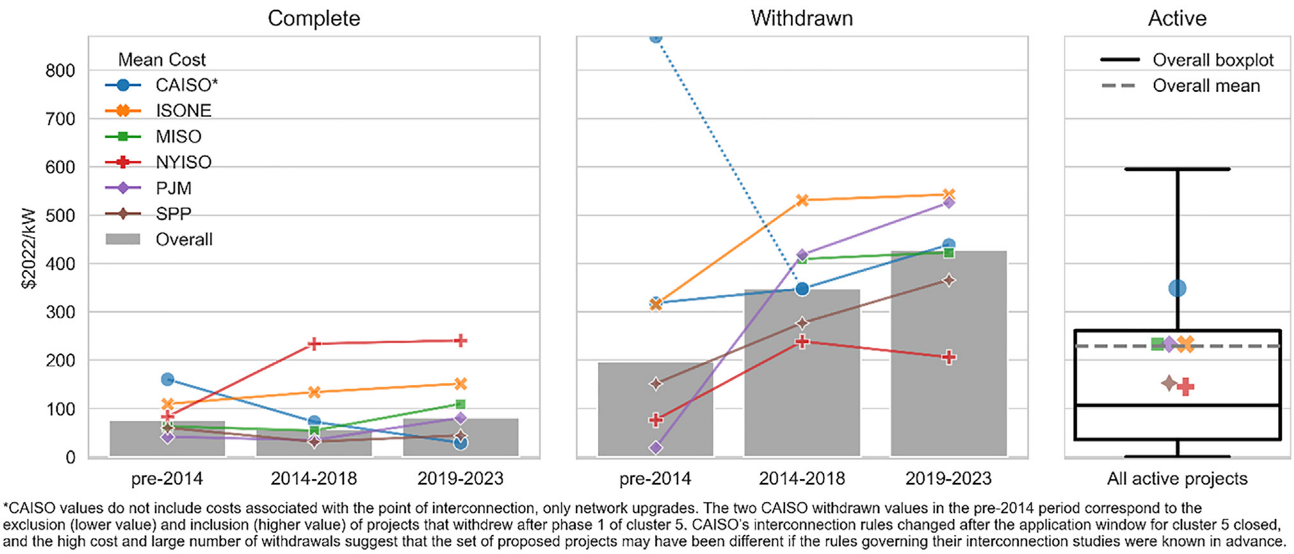

Figure 4. Average interconnection costs over time by transmission operator and project status

Active projects are not differentiated by date because the interconnection cost of active projects may still change based on additional studies that have yet to be conducted. Sample sizes for each data point are listed in Table 3.

2014, interconnection costs over the last decade (2014–2023) were 236% and 134% higher for solar and wind, respectively, compared to 4% for natural gas. Interconnection costs now make up, on average, 8% of total project capital expenses for completed solar and 6% for completed wind projects.[12,66] For solar projects that withdraw, interconnection costs would have represented on average 30% of project cost or 37% for wind.[12,66] These results suggest that renewable resources are increasingly proposed in locations where interconnection to the transmission network is more expensive, consistent with the hypothesis that renewables are less likely to be proposed at sites with an already well-developed transmission network.

NETWORK UPGRADES ARE DRIVING RISING INTERCONNECTION COSTS WITHIN THE WITHDRAWN PROJECT SAMPLE

The above section provided trends in interconnection costs but provided limited insight into the drivers of those trends. This section shows that the type of interconnection cost and interconnection service has important impacts on interconnection cost trends. Interconnection costs can be grouped into two main categories: (1) local interconnection costs at the point of interconnection (POI) with the broader transmission system (also known as attachment facilities) and (2) broader network upgrade costs that become the responsibility of an individual interconnection customer in the US but can often be located much deeper in the transmission network than the immediate interconnection facilities. We classify our cost sample into these two categories and present the proportion of interconnection cost associated with each in Figure 6.

On average, completed projects have roughly 43% of the overall interconnection costs associated with network upgrades—a ratio that has been consistent over time within our aggregate sample of complete projects. Withdrawn projects, on the other hand, have seen network costs rise from 40% to 70% of interconnection costs, mimicking the rise in overall project costs. Projects that were actively being processed in the queue at the time of data sampling have a median network upgrade cost proportion of 0.8, suggesting that the elevation of network upgrade costs observed in the most recent withdrawn sample will remain in the future. There are economies of scale for POI costs, with larger projects tending to have lower costs per kW, but we found limited evidence for a relationship between network upgrade costs per kW and the project capacity (see Figure S6).

In the US, interconnection costs are dependent on the type of interconnection service requested and the corresponding interconnection study assumptions. A critical choice that an interconnection customer makes is between “energy” service, which allows interconnection customers to make use of the transmission system on an “as available” basis, accepting some level of congestion risk, and “capacity” service, which aims to ensure deliverability of an interconnection resource during times when the transmission system is congested or operating under contingency conditions. The choice between these service types determines a power plant’s ability to participate in resource adequacy programs. The categorization of specific service types into the two classes is further detailed in the experimental procedures.

Figure 7 shows that interconnection with energy service typically costs less in SPP, where it is common, and in PJM, where it is rare, but costs roughly the same as capacity service in ISO-NE. Given that energy interconnection service is intended to allow customers to interconnect to the system on an as available basis, it is surprising to see energy service costs comparable to capacity service costs in many cases. We found similar results when focused on the metric of duration from submitting an IR to

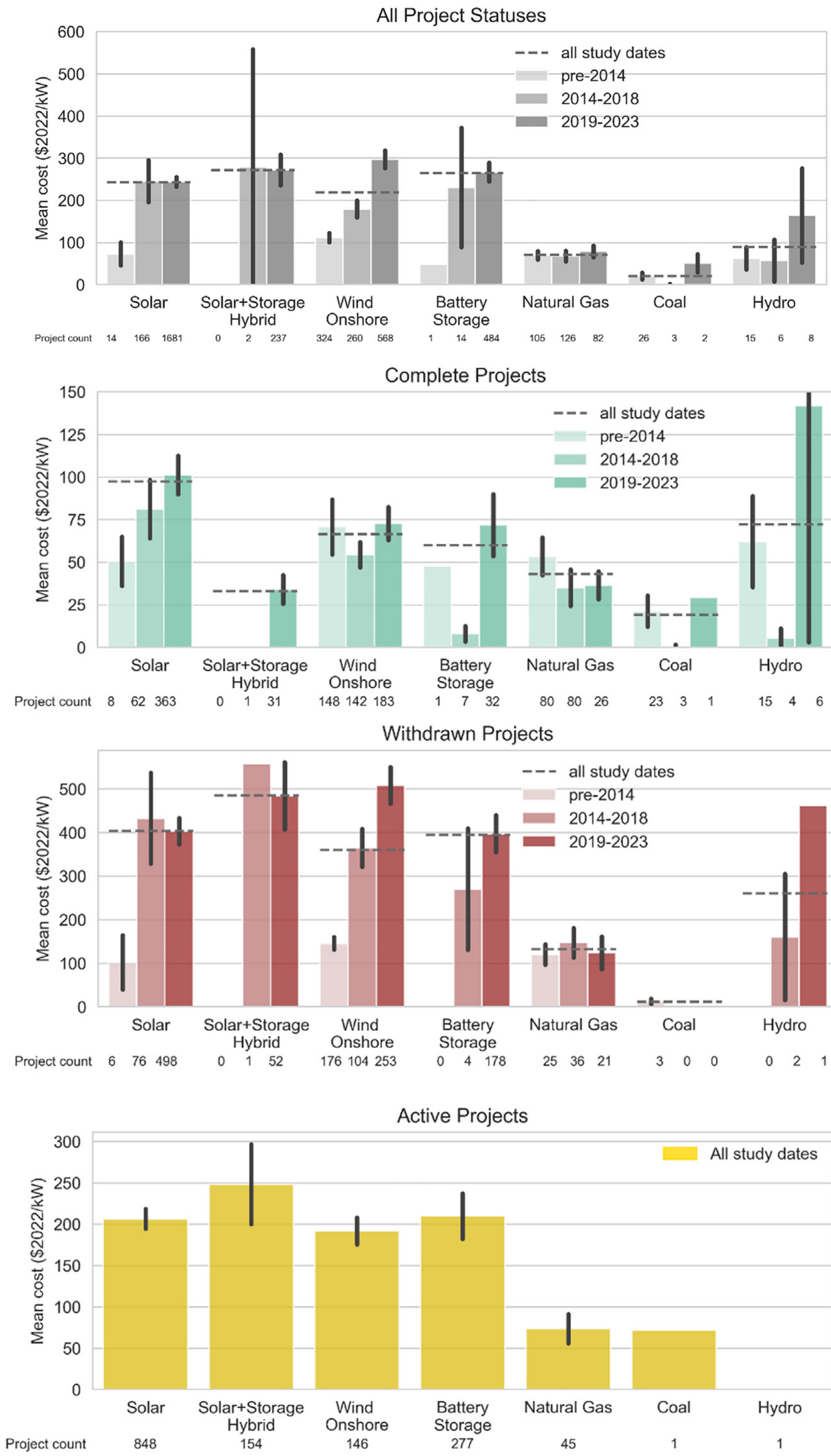

Figure 5. Average interconnection costs over time by resource type and request status

Resource types with few complete or withdrawn projects are not shown (e.g., offshore wind, biomass, and oil). Excludes CAISO due to data limitations. Vertical lines reflect the standard error of the distribution. Active projects are not differentiated by date because the interconnection cost of active projects may still change based on additional studies that have yet to be conducted. Figure S5 reports these results by ISO.

receiving an interconnection application (see Figure S1). A priori expectations for non-firm service would be that they trigger fewer network upgrades and take a shorter amount of processing time. Recent research has suggested that the distinction between these two service requests in practice, however, is not well defined and subject to transmission provider business rules that are not always clear, a hypothesis that is quantitatively supported by our analysis.[58] A clearer distinction between these two interconnection service requests could be warranted, especially as the capacity contribution of non-dispatchable resources, such as wind and solar, declines with increasing penetration rates, which, in turn, may result in less appetite for capacity interconnection services.

In the transmission networks of Texas, Australia, and the UK, a "connect and manage" approach to interconnection has been used that allows resources to connect to the transmission systems without paying for individual transmission upgrades. Such an approach has been shown to decrease interconnection process timelines but increase congestion and curtailment-related risk for resource developers. Our analysis shows that the US is running up against transmission constraints, suggesting that making more efficient use of the transmission system and accepting some more risk of re-dispatch and curtailment should be an option. That option is not available in most parts of the US.

Beyond the choice between interconnection service options, if these transmission constraints (and associated scarce and high-cost interconnections) continue, another option resource developers may consider to potentially reduce interconnection upgrade costs is to install "inside the fence" storage to reduce their requested injection capacity (i.e., POI limit). Data to assess the POI limit relative to the ultimate size of the generators located behind the POI is limited. In the one ISO where these data are available (CAISO), it appears that the POI request is usually sized below the summed generator and storage capacity (see Figure S12), showing that this practice is common in CAISO.

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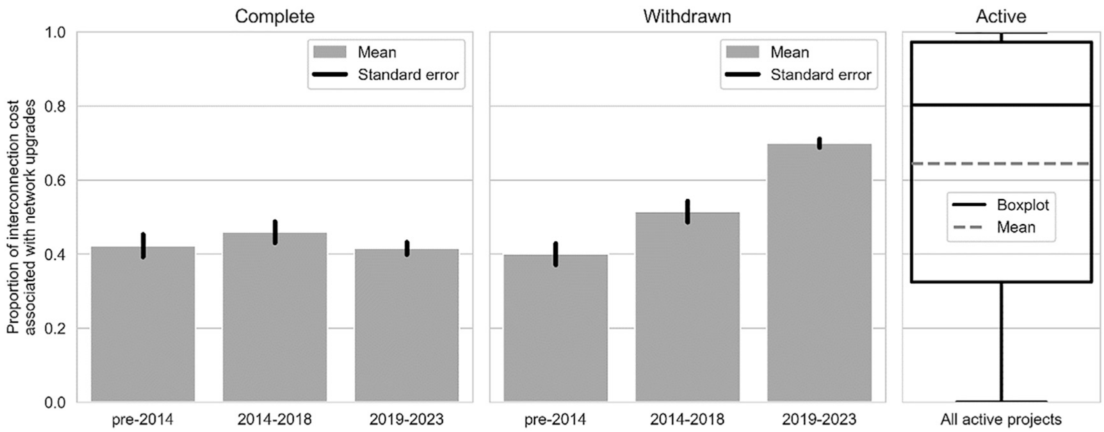

Figure 6. Proportion of interconnection costs attributable to network upgrades

Results are based on a subset of all analyzed projects for which total costs could be reliably divided into POI and network components: 100% of analyzed projects in SPP, 100% in MISO, 85% in PJM, 77% in NYISO, and 48% in ISO-NE. See Figure S11 for results by ISO.

GEOGRAPHIC COMPARISON OF QUEUE CAPACITY AND INTERCONNECTION COSTS DEMONSTRATES THE IMPORTANCE OF TRANSMISSION INFRASTRUCTURE

Our analysis of geographic heterogeneity can be used to further assess the predictability of interconnection costs. Figure 8 shows the geographic variation in currently active queue capacity as well as historical interconnection costs for the full sample of projects collected for this study. These graphics showcase the relationship between transmission infrastructure and the location of proposed generation and storage. Areas of the country without proposed projects also tend to not have high-voltage transmission networks. Despite this general correlation, active queue capacity for wind and solar projects, and to a lesser degree storage projects, is more geospatially distributed across the US relative to natural gas projects, as shown in the supplemental information.

For PJM and SPP, we were able to collect geospatial coordinates that allowed more precise comparisons between interconnection costs and proposed project locations relative to transmission lines. In SPP, the locations used are POI locations; in PJM, the locations tend to represent the project site, but precise characterizations of the location data were not available. Figure 9 shows a general trend that network interconnection costs are positively correlated (Pearson correlation of 0.20) with the distance to the high-voltage transmission network in PJM. This is consistent with the hypothesis that more network upgrades are often required to interconnect projects far from the high-voltage network, because these projects typically interconnect with lower-voltage lines, which are more likely to be highly utilized, and each line upgrade may involve more line-miles. Yet, the correlation is weak, and much of the observed variation in costs is not explained by this factor alone. In SPP, projects farthest from 345 kV+ lines also tend to pay greater network costs, but the overall trend is even more modest (Pearson correlation of 0.16), and it is not a key driver of cost variation. This result is split out by resource type in Figure S10.

CONCLUSIONS

The electricity system is amid a rapid and widespread energy transition. Historical declines in wind, solar, and storage costs, coupled with customer demand for clean energy resources and supportive policies, are driving the rapid rise of IRs. Policymakers and regional stakeholders are actively deciding whether the rules and processes that govern interconnection need to be updated to reflect the new electricity network paradigm influenced by the transition to clean energy. In the US, some of this work is already underway as the US FERC issued Order 2023 to improve generator interconnection processes and Order 1920 to improve transmission planning processes. In this paper, we analyze key issues related to interconnection backlogs, timelines, withdrawal rates, and costs, providing evidence that the interconnection process and corresponding transmission expansion are not set up to achieve the established energy transition targets of the US. In so doing, we provide new transparency into the interconnection process and its corresponding challenges.

We find that from 2000 to 2010, the US averaged between 500 and 1,000 new transmission IRs each year, corresponding to 150–200 GW per year of proposed capacity. Over the last decade, however, new IRs have risen to between 2,500 and 3,500 each year, representing anywhere from 400 to 900 GW per year of proposed capacity, a 3- to 6-fold expansion. Currently, the active capacity of renewable energy and storage projects in the interconnection queue is twice the installed capacity of the US grid, and over the last decade, the timeline from IR to CODs has increased by 70%. We find only 20% of projects applying for interconnection from 2000 to 2018 achieved CODs. In combination, these factors currently lead to lower renewable capacity deployment than what is needed to achieve decarbonization targets, despite significant deployment interest by project developers.

Furthermore, we show that there remains a wide and skewed distribution of interconnection costs identified within the interconnection process. Such cost uncertainty can lead to

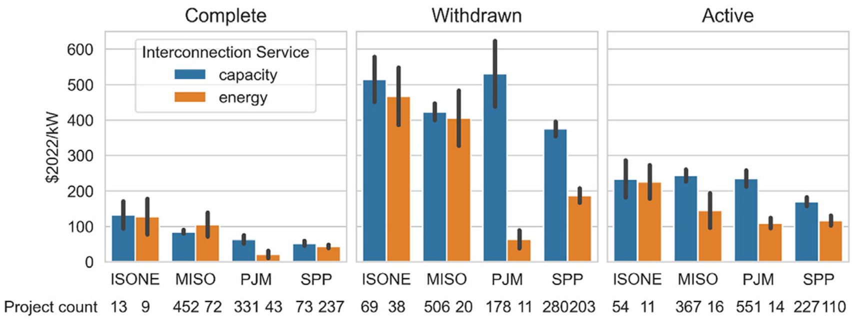

Figure 7. Average interconnection costs by interconnection service type and project status

Lines reflect the standard error of the distribution.

exploratory requests, which in turn exacerbate interconnection process times. These findings are consistent with Johnston et al.[37], who study similar interconnection cost and timeline questions in a smaller geographic area of the US. We also find that interconnection costs have increased over time and are highest for wind, solar, and battery storage projects. These findings correlate with the increasing withdrawal rates from the queue. Interconnection costs for network upgrades represent a larger proportion of interconnection costs over time, suggesting that transmission capacity constraints are becoming a more important factor in interconnection outcomes. Finally, our geospatial analysis suggests that project location and costs are not strongly correlated, further reinforcing the conclusion that interconnection cost predictions are difficult to make in advance of participation within the interconnection process.

Taken together, our findings about higher volumes, longer timelines, and rising costs suggest that the US electricity system is experiencing an increasingly constrained transmission system. Given long timelines on transmission development via transmission planning processes, as well as the piecemeal, slow, and non-proactive process of transmission development via the interconnection process, electric system planners will need to find ways to make better use of the existing transmission system in the near term. Some technological opportunities, commonly referred to as grid-enhancing technologies, exist but have yet to be deployed at scale. US transmission providers are also developing hosting capacity maps to provide guidance on optimal locations to interconnect, though these maps would need to be frequently updated to be useful to interconnection customers given the dynamic nature of a constantly evolving transmission network. Additional research is needed to evaluate the potential for new resources to connect via new types of interconnection service agreements that can take advantage of re-dispatch strategies to mitigate temporary congestion, rather than paying for costly and time-consuming network upgrades via the interconnection process. In the long term, given the bifurcation of the generator procurement and interconnection process in market regions, researchers and practitioners can also evaluate options for, and trade-offs in, separating interconnection processes from cost assignment for incremental network upgrades. Such a separation could involve assigning network upgrade costs to end electricity customers, rather than to interconnecting resources, as is done in Texas, Australia, and Germany. Alternatively, it could involve an upfront, average interconnection fee that is applied broadly to all generators interconnecting to a given region and tied to expected network upgrade costs, similar to what is done in the UK and what is being proposed in the SPP region of the US. These suggestions are not US-specific and apply to other countries experiencing similar constraints within their interconnection processes or that have adopted similar interconnection pricing policies. However, these different approaches all involve trade-offs among cost certainty, economic efficiency, simplicity, and stakeholder acceptance. The balance among these different objectives will likely be region-specific.

Future research should also evaluate whether there are market-based approaches to rationing IRs and thus better identifying more appropriate quantities of projects that should be studied through the interconnection process. Interconnections available for actual projects certainly need to increase to meet energy transition goals, but more approaches need to be developed to rationalize the number of projects worth studying. Though IRs are a sign of resource developer interest, exploratory requests, which could be incentivized by limited queue entry costs or a lack of significant penalties for unjustified withdrawals, can cause a strain on the workforce required to process the substantial rise in interconnection applications. Such rationing approaches raise interesting questions related to the fundamental regulatory foundation of open access transmission networks in restructured electricity systems.

Ultimately, transmission providers, regulators, and interconnection customers need access to credible information to monitor reform progress and improve decision-making that effectively removes bottlenecks caused by current interconnection rules. Collecting interconnection data for this paper was laborious and difficult. Interconnecting resources to the electrical grid involves multiple parties and numerous laws, regulations, and technical study processes, and limited evidence on optimal institutional structures exists, in part, because of the lack of transparency on these processes. Governments should prioritize interconnection data more actively, such that the relative contribution of the various barriers associated with clean energy deployment can be more accurately assessed.

EXPERIMENTAL PROCEDURES

The interconnection process

In the US, the interconnection process for the bulk-power system is typically regulated at the federal level by FERC, with the exception of the ERCOT, which is not under FERC's jurisdiction. A power plant developer seeking to connect to the transmission system initiates the interconnection process by submitting an IR, thereby entering the queue. The proposed plant then undergoes a series of interconnection studies, which determine how the plant would affect grid system safety, reliability, and power quality (e.g., voltage stability). The interconnection studies further determine what equipment upgrades would be necessary to mitigate potential issues and safely connect the plant, as well

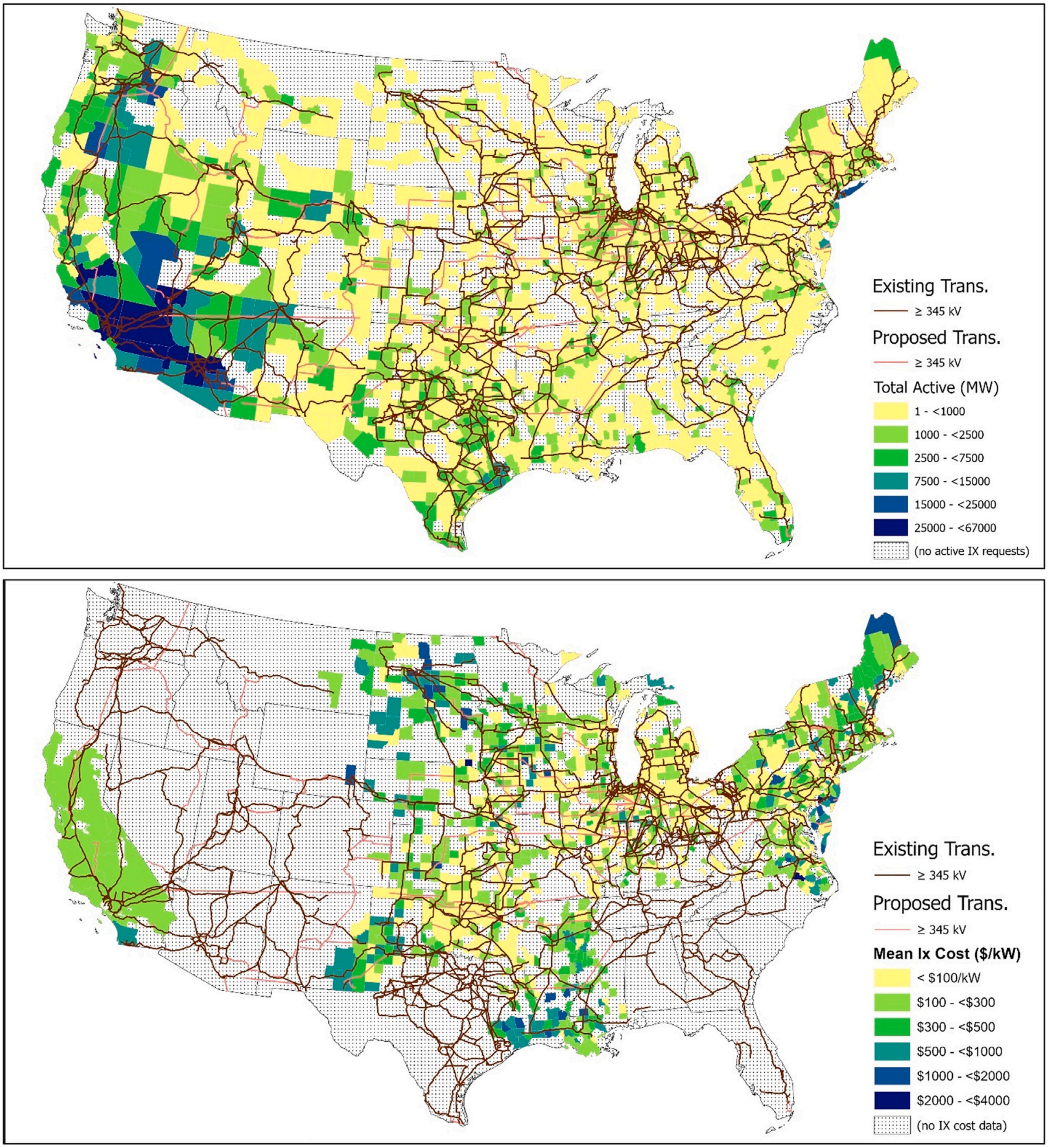

Figure 8. Geographic variation in active queue capacity and historic interconnection costs

Data samples are different between the two figures. Queue capacity data (top map) are collected across most of the US, while interconnection costs (bottom map) are only collected in six of the seven ISOs. Costs in CAISO are summarized at the utility level; other regions are shown by county. See Figure S7 for the active queue capacity by resource type.

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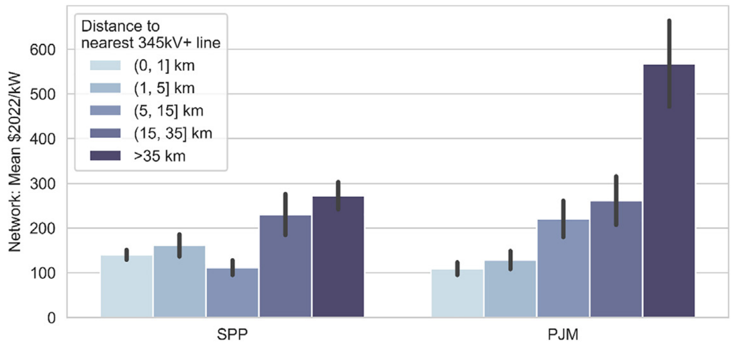

	SPP					PJM				
Project count	300	83	93	104	131	141	174	226	115	235
Mean nameplate MW	227	193	162	187	178	178	103	65	111	66

Figure 9. Average interconnection network upgrade costs by distance to the nearest high-voltage transmission line for SPP and PJM projects (2019–2023)

Lines reflect the standard error of the distribution. Excludes 74 SPP projects and 4 PJM projects that lack precise location information. See Figures S8 and S9 for results by project size and resource type, respectively.

as the cost of those upgrades. The process culminates in an interconnection agreement, which is a contract between the plant developer/owner and the transmission balancing area that stipulates the plant's operational terms and upgrade cost responsibilities. At any point in the process, a developer may withdraw their IR, essentially canceling the project and forfeiting their place in the queue.

Although the finer details of this interconnection process vary by region, and numerous reforms have been implemented in the ISO regions over the past two decades, this overarching structure is relatively similar across US balancing areas (BAs), and all BAs are required to publish public data files summarizing their interconnection queues. After executing an interconnection agreement, the typical power plant spends another two years to secure offtake agreements (e.g., power purchase agreements) and local siting permits, construct the power plant, and achieve CODs.

BAs also require fees and deposits as IRs advance through the process. Historically, these fee structures vary widely across BAs, but many have applied increasing fees and at-risk deposits at each subsequent phase of the study process. FERC Order 2023 standardizes this tiered, increasing deposit structure across all regions, which will result in higher costs to withdraw later in the process going forward (Figure 10).

Data collection from interconnection queues

The analysis in the section "US interconnection queues have unprecedented amounts of renewable energy and storage" relies on the 2024 edition of "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection."[67] As part of this report, we collected interconnection queues request data from 7 ISOs/RTOs and 44 non-ISO BAs. See Table 1 for the list of the specific entities and Table 2 for a breakdown of the queue sample by BA and request status. These entities collectively represent greater than 95% of currently installed electric generating capacity in the US. The interconnection queue data include projects that connect to the bulk-power system and exclude distribution-connected or behind-the-meter resources. We manually downloaded publicly available interconnection queue data from each ISO/RTO and BA. In certain jurisdictions, additional data were obtained via non-disclosure agreements. Once downloaded, we applied data cleaning, standardization, and QA/QC processes to ensure accuracy, identify hybrid power plants, and align the queue data for further analysis. Standardized data not secured via non-disclosure agreements are made publicly available for download online.

The level of data standardization required varied by jurisdiction, but in general, the process involved standardizing resource type designations, queue and interconnection agreement status information (e.g., operational, active, withdrawn, and suspended), interconnection study phase (e.g., feasibility, system impact, facility study, or executed IA), and date formats. In certain jurisdictions, the publicly available queue data were augmented with other data made available by the ISOs/BAs, such as more detailed information on the status of the interconnection agreement and the date on which the agreement was signed. Once standardized, we appended data from each jurisdiction into a single database representing all queue requests as of the end of 2023.

The compiled, standardized, and quality-controlled database was used for a range of calculations presented in the section US interconnection queues have unprecedented amounts of renewable energy and storage. For example, the active capacity in interconnection queues represents the sum of generator (and storage) capacity with a status of "active" as of the end of 2023. Interconnection durations (e.g., Figure 1C) were calculated as the difference between the endpoint date (e.g., COD) and the date of the submission of the IR. Completion rates (e.g., Figure 1D) were calculated as the fraction of all IRs submitted from 2000 to 2018, which had a status of "operational" as of the end of 2023.

Some time-series analyses required the use of historical interconnection queue databases, assembled in the same manner described above. Our team of analysts has been downloading and compiling interconnection queue data on an annual basis (through the end of each calendar year) since 2007 to produce this historical time-series of queue volumes. For example, Figures 1A and 1B utilize these historical datasets.

Figure 2 synthesizes data from various sources, including Queued Up.[67] Historical capacity additions (pre-2024) for batteries, solar, and wind (in GW) were estimated using the US Energy Information Administration's (EIA) Form EIA-860, which includes nameplate capacity information for power plants greater than 1 MW.[55] Imputed queue projections (post-2024) were derived from queue requests submitted after 2019 for battery, solar, and both onshore and offshore wind projects across all ISOs and non-ISO BAs. To estimate future capacity additions from the projects currently in the queue, we assumed a 5-year duration to COD and applied historical completion rates (i.e., the percentage of projects in the queue that ultimately get built) for battery (5%), solar (10%), and wind (15%). These three data points were combined to project capacity additions from the current interconnection queue through 2028.

To contextualize our estimates of historical and projected capacity additions with the requirements for transitioning to a net-zero energy grid, we included modeled capacity additions through 2035 in Figure 2. The capacity estimates were derived from the following studies:

- 2035 Report: Plummeting solar, wind, and battery costs can accelerate our clean electricity future (Goldman School of Public Policy)[4]
- Net-Zero America: Potential Pathways, Infrastructure, and Impacts (Princeton)[3]
- 2023 Standard Scenarios Report: A U.S. Electricity Sector Outlook (NREL)[60]
- Carbon-Neutral Pathways for the United States (Williams et al.)[2]

From the 2035 Report, we utilized model outputs for the 90% clean energy policy scenario, assuming base technology and financing costs, along with base gas price assumptions. The capacity projections from the Net-Zero America report are for the E+RE+ scenario, which assumes nearly full electrification of transportation and buildings by 2050, with no new fossil or nuclear use permitted by 2050. From the NREL study, we referenced two scenarios: the mid-case with 100% decarbonization by 2035, and the mid-case with 95% decarbonization by 2050. The data from Williams et al. correspond to the 100% renewable primary energy scenario, which assumes no fossil fuels or nuclear power allowed by 2050. For each study,

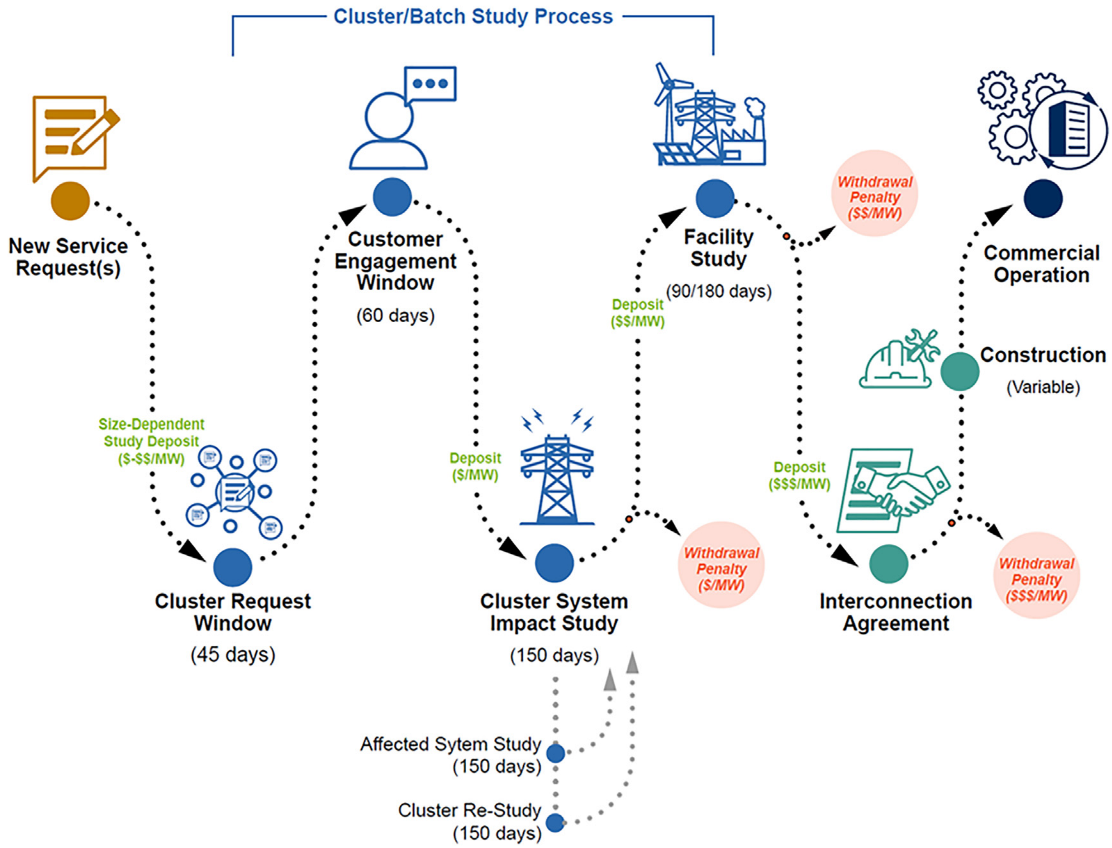

Figure 10. Interconnection process under FERC Order 2023 requirements
Note increasing deposits and withdrawal penalties as the process progresses.

we focused on new additions of utility-scale solar, battery storage, and onshore and offshore wind capacity. Where the studies provided estimates for year bins or groups (e.g., 2021–2025), we imputed annual capacity addition estimates.

Interconnection cost methods

The results in earlier sections (costs to interconnect are rising and are highest for renewable energy generators, network upgrades are driving rising interconnection costs within the withdrawn project sample, and geographic comparison of queue capacity and interconnection costs demonstrates the importance of transmission infrastructure) reflect the creation of a new database, which involved data collection from original sources, data processing, analysis and interpretation of the raw data. Table 3 describes the size of this new database across key dimensions. The specific data collection methods for each region are described in the following sections. When processing the data, we screened out projects that were not new generation or storage facilities interconnecting to the bulk-power system, such as uprates, transmission project interconnections, or distribution-level generator interconnections, and those that had been superseded by a more recent request for the same project. In cases where multiple cost estimates were available for a proposed project, we used only the most recent estimate. If an interconnection study reported a cost of $0 for a project, we included that cost estimate in the data. However, if no cost estimate was available, we treated the data as missing and, in the absence of a valid estimate from a different study, excluded the project. Costs were indexed by interconnection study year (not queue entry date) and converted to real 2022 dollars using a GDP-based deflator. Results are reported in cost-per-unit-of-interconnection-capacity terms, which is obtained by dividing a project's converted cost by its capacity limit (measured in kW) at the POI. These data are made publicly available online. For a visual representation of the cost sample statistics shown below, see Figure S4.

We categorized interconnection costs into two broad categories: (1) POI costs: local interconnection costs at the POI with the broader transmission system, and (2) Network costs: broader network upgrade costs that become the responsibility of an individual interconnection customer but can oftentimes be located much further in the transmission network than the immediate interconnection facilities. Note that POI costs do not include electrical facilities at the generator itself, such as transformers or spur lines between the generator and the bulk-power system. For MISO and SPP, the breakdown of total interconnection cost into the POI and network categories was possible for all available cost estimates. In PJM, NYISO, and ISO-NE, not all interconnection studies provided enough information to classify the project's costs in this way. For these regions, the results in Figure 6 are based on the subset (PJM: 85%, NYISO: 77%, ISO-NE: 48%) of all analyzed projects for which total costs could be reliably divided into POI and network components. For NYISO, the results in Figure 6 are based on the most recent cost estimate that could be split into these categories (for 47 projects we had to leverage an older cost estimate than was used elsewhere in this paper).

The process to label upgrades and costs between the POI and network cost categories varied by region. In ISO-NE, individual upgrades were classified according to our best judgment, with substation-related upgrades typically considered to be POI costs and line or relay work typically considered to be network costs. Elsewhere, we group the following under the POI category: MISO—Interconnection Facilities; NYISO—Connecting Transmission Owner Attachment Facilities, Stand-alone System Upgrade Facilities; PJM—Attachment Facilities; SPP—Transmission Owner Direct Assigned Interconnection Facilities, Stand-Alone Network Upgrades, Non-Shared Network Upgrade Costs.

Table 1. Balancing areas where queue requests were collected

Region Type	Balancing areas
ISOs/RTOs	CAISO; ERCOT; ISO-NE; MISO; NYISO; PJM; SPP
Southeast (non-ISO)	Associated Electric Coop; Georgia Transmission Corp.; Dominion; Jacksonville Electric Authority; Duke Carolinas; LG&E & KU Energy; Duke Florida; Santee Cooper; Duke Progress; Seminole Electric Coop; Duke/Progress; Southern Company; Florida Municipal Power Pool; Tampa Electric Co.; Power, Florida & Light; Tennessee Valley Authority
West (non-ISO)	Arizona Public Service; Imperial Irrigation District; Public Service Co. of CO; Avista; L.A. Dept. Water & Power; Public Service Co. of NM; Black Hills Colorado; Navajo-Crystal; Puget Sound Energy; Bonneville Power Admin; Northwestern; Salt River Projects (4 entities); Cheyenne Light Fuel & Power; NV Energy; Tri-State G&T; El Paso Electric; PacifiCorp; Tucson Electric Power; Grant PUD; Platte River Power Authority; WAPA (4 regions); Idaho Power; Portland General Electric

We group the following under the Network category: MISO—Backbone Network Upgrades, Thermal/Voltage/Steady State/Reactive/Transient Stability, Short Circuit, Local Planning Criteria, Affected System, Deliverability, Shared Network Upgrade; NYISO—System Upgrade Facilities, System Deliverability Upgrades, Affected System Upgrades, Part 2 Allocation, and Headroom Payments; PJM—Direct Connection Facilities, Total Direct Connect Costs, Direct Connection Network Upgrades, Total Non-Direct Connection Costs, Network Upgrade Facilities, Non-Direct Connection Facilities, Non-Direct Connection Network Upgrades, Non-Direct Local Network Upgrades, Allocation for New System Upgrades, Contribution for Previously Identified Upgrades, Other Charges; SPP—ERIS (energy resource interconnection service) and NRIS (network resource interconnection service) network upgrades, Shared Network Upgrades, Affected System Upgrades.

The interconnection service type terminology and definitions also vary by region. We group the following service types under the "capacity" label: ISO-NE—CNR (capacity network resource); MISO—NRIS, External NRIS, NRIS-only; PJM—capacity; SPP—NRIS. The following service types are included under the "energy" label: ISO-NE—NR, MIS; MISO—ERIS; PJM—energy; SPP—ERIS. Note that NYISO does not provide information on the interconnection service type of projects in their interconnection queue and thus is not included in Figure 7.

ISO-NE data collection

This study analyzes interconnection cost data from 194 projects that were evaluated in interconnection studies between 2010 and 2021, including at least 55% of all new generation and storage projects requesting interconnection to the ISO-NE system during 2010–2019. This sample is based on all available studies on ISO-NE's website as of May 2022. (Due to the time it takes to conduct interconnection studies, only 35 of the 120 projects with a 2020 or 2021 queue entry had cost studies available as of May 2022. On the other hand, studies for older requests that were once posted are often no longer available due to document retention policies.) Cost data were gleaned from the following study types: feasibility (92 studies), system impact (148 studies), facilities (10 studies), cluster-enabling transmission upgrade regional planning (2), and cluster-interconnection system impact (1). All studies were in PDF format and required access granted by ISO-NE to view due to the Critical Energy Infrastructure Information (CEII) designation of detailed upgrade information that some studies contain. Manually extracting cost information from study PDFs typically took 30–45 min per project for a total of about 170 h.

MISO data collection

This study analyzes interconnection cost data from 1,465 projects that were evaluated in MISO interconnection studies between 2001 and 2023, including 63% of all projects requesting interconnection to the MISO system during 2011–2021. We include 303 cost estimates that were collected in 2018[68] from studies that have since been removed from the online MISO system. The remaining data came from 105 studies: 11 feasibility, 32 definitive planning (DPP) phase 1 system impact studies (SIS), 24 DPP phase 2 SIS, 26 DPP phase 3 SIS, 6 SIS restudies or addendums, 4 other SIS, and 2 affected systems studies. For each project mentioned in any of these studies, most of which contain information on a group of projects, we collected cost data from the study published most recently. Manually extracting cost information from study PDFs took about 205 h.

NYISO data collection

This study analyzes interconnection cost data from 294 projects that were evaluated in NYISO interconnection studies between 2006 and 2021. This sample is based on all available studies on NYISO's website as of May 2022 and represents 43% of projects that applied for interconnection during 2003–2019. (Due to the time it takes to conduct interconnection studies, only 3 of the 238 projects with a 2020 or 2021 queue entry had cost studies available as of May 2022.) Cost data were gleaned from the following study types: feasibility (180 studies), system (reliability) impact (304 studies), and class year facilities (52 studies). All studies were in PDF format and required "Stakeholder" access granted by NYISO to view due to the CEII designation of detailed upgrade information that some studies contain. Manually extracting cost information from study PDFs typically took 25–40 min per project for a total of about 430 h.

PJM data collection

This study analyzes interconnection cost data from 1,127 projects that were evaluated in PJM interconnection studies between 2000 and 2022, equivalent to 86% of all new unique generator requests over that period. (Due to the time it takes to conduct interconnection studies, as of July 2022 no studies were available for projects entering the queue after March 2021.) We include 634 cost estimates that were collected in 2018[68] from studies that have since been removed from the online PJM system. Additional cost estimates were obtained for all projects with cost data available in PJM's public-facing online system as of July 2022. For over 90% of projects, a cost estimate was obtained from the most recent available study or agreement; for the remaining projects, the most recent study did not contain sufficient information, so the second-most recent study was also reviewed. In total, data were gleaned from 770 SIS, 262 (interim) interconnection service agreements, 71 facilities studies, 64 combined system impact/feasibility studies, and 7 feasibility studies. Manually extracting cost from study PDFs typically took 30–50 min per project, for a total of about 550 h.

In addition to the interconnection studies, we obtained location information from a publicly available map published by PJM: https://mapservices.pjm.com/renewables/.

SPP data collection

This study analyzes generator interconnection cost data from 1,171 projects that were evaluated in SPP interconnection studies between 2002 and 2023, equivalent to 53% of all IRs entering the SPP queue between 2001 and 2022. Our interconnection cost dataset is based on many, but not all, of the 1,441 unique generator interconnection studies that were accessible in the online SPP system (many of which do not include cost data). We obtained 85 cost estimates by reviewing 31 of the 204 feasibility cluster studies (containing 146 of 472 IRs) posted in March 2022. The majority of the feasibility cluster studies pertain to older projects that withdrew from the queue before receiving an interconnection cost estimate, so we did not prioritize reviewing these studies. From the 2016-and-earlier Definitive Interconnection System Impact Study (DISIS) cluster cohorts, we reviewed roughly half of the 664 available impact studies and found that only a very small subset included cost estimates. Recently, SPP started publishing preliminary system impact study cost estimates in Excel format for more recent queue entrants. We reviewed all available cost data from this source, which resulted in 708 cost estimates from 11 studies for the DISIS cohorts 2017 to 2023 (posted between November 2021 and September 2023). Facility studies are more refined than system impact and feasibility studies, and thus were a key focus. Our team gathered 453 cost estimates by reviewing all 572 available facilities studies in PDF format (except when studies were superseded by an updated analysis). These data are the best available interconnection cost estimates in SPP's posted data, as the final generator interconnection agreements are not public. Overall, we spent more than 400 h assembling the SPP cost sample.

Table 2. Queue sample size by balancing area and request status (end of 2023)

ISO/region	Utility	Active	Suspended	Withdrawn	Operational	Total sample
CAISO	–	995	NA	1,630	198	2,823
ERCOT	–	1,090	NA	803	358	2,251
ISO-NE	–	405	NA	605	255	1,265
MISO	–	1,669	NA	2,113	458	4,240
NYISO	–	492	NA	843	100	1,435
PJM	–	3,309	133	4,588	1,163	9,193
SPP	–	703	4	1,419	271	2,397
Southeast (non-ISO)	Associated Electric Coop.	37	NA	52	NA	89
	Dominion	8	NA	55	NA	63
	Duke (all regions)	250	38	520	47	855
	Florida Municipal Power Pool	NA	NA	1	NA	1
	Florida Power & Light	242	NA	101	68	411
	Georgia Transmission Corp.	46	NA	NA	41	87
	Jacksonville Electric Authority	7	NA	1	1	9
	LG&E & KU Energy	35	6	73	2	116
	Santee Cooper	70	1	128	45	244
	Seminole Electric Coop.	9	2	20	3	34
	Southern Company	251	NA	609	68	928
	Tampa Electric Co.	30	2	63	21	116
	Tennessee Valley Authority	149	NA	378	65	592
West (non-ISO)	Arizona Public Service	85	21	394	52	552
	Avista	24	5	101	10	140
	Black Hills Colorado	16	NA	21	10	47
	Bonneville Power Admin.	554	NA	586	170	1,310
	Cheyenne Light Fuel & Power	13	NA	10	4	27
	El Paso Electric	24	3	25	2	54
	Grant PUD	8	NA	2	NA	10
	Idaho Power	71	25	456	223	775
	Imperial Irrigation District	37	NA	NA	NA	37
	L.A. Dept. Water & Power	49	1	40	8	98
	Navajo-Crystal	7	NA	NA	NA	7
	Northwestern	48	6	307	61	422
	NV Energy	176	55	191	27	449
	Portland General Electric	45	NA	47	NA	92
	Public Service Co. of NM	114	NA	181	34	329
	Platte River Power Authority	26	NA	20	5	51
	Public Service Co. of CO	18	4	289	47	358
	Puget Sound Energy	48	NA	66	15	129
	PacifiCorp	376	12	1,239	219	1,846
	Salt River Projects (4 entities)	101	NA	63	20	184
	Tucson Electric Power	79	NA	36	NA	115
	Tri-State G&T	58	7	32	9	106
	WAPA (4 regions)	57	NA	264	72	393
Total		11,831	325	18,372	4,152	34,680

"NA" values indicate that no projects were observed for a given region and status. Those observations could be 0 or they could indicate that the region does not publicly release such data.

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Table 3. Cost sample sizes across key categories of interest (project status, transmission region, and time period)

	Complete			Withdrawn			Active		All				
	Pre-2014	2014–2018	2019–2023	Pre-2014	2014–2018	2019–2023	2014–2018	2019–2023	Pre-2014	2014–2018	2019–2023	Total	All unique interconnection requests (% is cost sample share)
CAISO	66 (33%)	102 (27%)	59 (10%)	135 (67%)	258 (69%)	245 (42%)	12 (3%)	275 (47%)	201	372	579	1,152	1,816 (63%)
ISO-NE	5 (21%)	14 (27%)	3 (3%)	19 (79%)	36 (71%)	52 (44%)	1 (2%)	64 (54%)	24	51	119	194	353 (55%)
MISO	101 (100%)	122 (71%)	303 (25%)	0 (0%)	36 (21%)	500 (42%)	14 (8%)	389 (33%)	101	172	1,192	1,465	2,325 (63%)
NYISO	23 (26%)	8 (12%)	1 (1%)	66 (74%)	32 (48%)	16 (12%)	27 (40%)	121 (88%)	89	67	138	294	684 (43%)
PJM	92 (97%)	98 (72%)	183 (20%)	3 (3%)	25 (18%)	161 (18%)	14 (10%)	551 (62%)	95	137	895	1,127	1,310 (86%)
SPP	87 (39%)	66 (40%)	157 (20%)	136 (61%)	97 (60%)	291 (37%)	0 (0%)	337 (43%)	223	163	785	1,171	2,209 (53%)
Total	374 (51%)	410 (43%)	706 (19%)	359 (49%)	484 (50%)	1,265 (34%)	68 (7%)	1,737 (47%)	733 (14%)	962 (18%)	3,708 (69%)	5,403	8,033 (67%)
Total (all years)	1,490 (28%)			2,108 (39%)			1,805 (28%)		5,403 (100%)				

Percentages indicate the share of projects by status in an ISO relative to all projects of the same cohort irrespective of their project status. The right-most column indicates the cost sample relative to all unique interconnection requests with potential cost data.*

*Total unique interconnection request number differs from what is shown in Table 2 as we exclude here requests representing capacity upgrades to existing facilities and superseded projects and those without any interconnection study results at the close of interconnection cost data collection (between 2022 and 2023).

In addition to the interconnection studies, through a non-disclosure agreement with SPP, we obtained geographic coordinates of the POI location for the most active and recently active projects in their interconnection queue.

CAISO data collection

This study analyzes generator interconnection cost data from 1,193 projects that were evaluated in CAISO interconnection studies for queue clusters 1 through 14 between 2011 and 2022. These studies cover only network costs; POI costs were not available. Unlike in all the other regions, where costs were collected at a project level, in CAISO we could only obtain aggregate interconnection costs for groups of projects that are studied together in a cluster. We compiled 181 cluster-level cost estimates (91 phase I, 90 phase II) that, in aggregate, represent the interconnection costs of 2,141 projects: 1,538 transmission-level, 516 at the distribution or subtransmission level, and 87 categorized as other. We allocated costs across projects within each study on a capacity-weighted basis and then analyzed only the transmission-level projects in this paper. Access to these interconnection studies was possible through a non-disclosure agreement with CAISO; they are not publicly available. Manually extracting costs from study PDFs typically took 50–60 min per project, for a total of about 180 h.

Evolving interconnection study methodologies affect our approach to phase I of cluster 1–5. Regarding clusters 1 and 2, CAISO conducted a reassessment of phase II after it was initially published that applied a different methodology to identifying delivery network upgrades and that substantially reduced costs for many projects.[69] (We also adjusted the phase II costs to reflect the final cost after reassessment.) This revised methodology was then applied to the phase II study of clusters 3 and 4. Since phase I of clusters 1–4 was studied with a different methodology than what was ultimately used to assign costs, we excluded the data we collected from an additional 32 phase I studies from this analysis. After the application window for cluster 5 closed, the new Generation Interconnection and Deliverability Allocation Procedures used to study them were finalized. Most projects withdrew after phase I, and since these projects applied without full knowledge of the rules that would be used to study them, we show results in Figure 4 with and without cluster 5 phase I.

RESOURCE AVAILABILITY

Lead contact

Requests for further information and resources should be directed to and will be fulfilled by the lead contact, Will Gorman (wgorman@lbl.gov).

Materials availability

This study did not generate new unique reagents.

Data and code availability

- Data have been deposited at the Open Science Framework and are publicly available as of the date of publication at https://doi.org/10.17605/OSF.IO/Y8WA2. The one exception is CAISO interconnection cost data, which are confidential, and the authors are not authorized to make publicly available.
- All original code has been deposited at the Open Science Framework and is publicly available at https://doi.org/10.17605/OSF.IO/Y8WA2 as of the date of publication.
- Any additional information required to reanalyze the data reported in this paper is available from the lead contact upon request.

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AUTHOR CONTRIBUTIONS

Conceptualization: W.G, J.M.K, J.R., J.S., R.W., and F.K. Supervision: W.G. and J.R. Funding acquisition: W.G., J.R., and R.W. Methodology: W.G., J.M.K., J.S., and J.R. Data curation: W.G., J.M.K., J.R., J.S., N.M., K.P., and W.C. Visualization: J.M.K., J.R., J.S., and N.M. Validation: J.M.K, J.S., and J.R. Formal analysis: J.M.K, J.R., J.S., and N.M. Writing – original draft: W.G., J.M.K., and J.R. Writing – review and editing: W.G., J.R., J.S., R.W., N.M., and F.K. Project administration: J.R. and K.P.

DECLARATION OF INTERESTS

The authors declare no competing interests.

SUPPLEMENTAL INFORMATION

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