Grid Connection Costs as a Barrier to Building New Generation: Evidence and Implications for Transmission Policy

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Meeting projected growth in electricity demand and climate goals will require building new electricity generators. The grid connection process is seen as a key constraint on this development. We collect new data on grid connection costs for PJM, the largest regional grid operator in the United States. We geographically match these costs to transmission spending to study their determinants. Using regression analysis, we find that grid connection costs, and especially the network upgrade portion of these costs, are difficult to predict: generators with similar characteristics can have very different costs. We also find that planned generators with high network upgrade costs are much more likely to be canceled. Finally, prior transmission spending by the grid operator is associated with lower network upgrade costs for connecting generators. These findings emphasize the critical role of transmission capacity in expanding electricity generation capacity.

After two decades of less than one percent annual growth in electricity demand, the US Federal

Energy Regulatory Commission predicts growth of three percent per year for 2025-2029 (*1*). This dramatic increase is driven by increased electricity demand from data centers, as well as manufacturing, buildings, and vehicles. Solar and wind accounted for most new generation capacity in recent years (*2–4*), raising the possibility that this increased demand can be met without sacrificing climate goals.

Yet, there is growing concern that barriers to building new generators will prevent timely investment to meet this demand. Connecting to the electric grid, obtaining the necessary permits, and securing local support are all challenges that can result in the cancellation of planned projects (*5, 6*). The North American Electric Reliability Corporation concluded in 2024 that more than half of North America was at risk of electricity shortfalls in the next ten years (*7*), and grid operators are asking coal plants to postpone planned retirements (*8, 9*).

This paper studies how the costs of grid connection impede investment in electricity generation capacity. New utility-scale generators must connect to the transmission grid before they begin operation. This process requires waiting in a queue for a series of engineering studies to determine the cost to connect, i.e., the interconnection cost. This cost consists of two components: the point-of-interconnection (POI) cost, which is the cost of attaching the generator to the grid, and the network upgrade cost, which is the cost of upgrading the transmission network to accommodate the generator's production. In most of the US, connecting generators are responsible for both types of costs (*10*).

Industry stakeholders have criticized these network upgrade costs and their underlying funding model. They argue that the current system places a disproportionate burden on new generation (*11, 12*), and that inadequate levels of centrally planned investment in transmission infrastructure result in overly high network upgrade costs. The debate surrounding these costs has become more pressing in recent years due to rising interconnection costs and their correlation with project cancellation: (*13*) compiles the first systematic data on these costs and finds that network costs have risen dramatically over the last decade, an increase driven by costs for projects that withdraw from the queue. This debate highlights the need for a deeper understanding of these costs. Yet, there has not been an analysis of their determinants and relationship with transmission investment.

We address this gap using new data on grid connection costs and transmission investment for PJM, the largest US regional transmission grid operator by customers served. PJM is a particularly interesting context because rising demand relative to new generation coming online contributed to record capacity market prices in 2025, prompting nine governors to suggest that their states were losing confidence in the grid operator (*14*). While (*13*) describes network upgrade costs for the US as a whole, our more comprehensive data for PJM allow us to carefully analyze the relationship between costs and project cancellation at each stage in the grid connection process. They also allow us to describe how estimated costs for the same generator evolve across subsequent engineering studies and quantify the determinants of these costs, notably transmission investment by the grid operator.

This paper provides three key findings that have implications for transmission policy. First, we show that network upgrade costs are unpredictable—generators with similar characteristics can face vastly different connection costs, with observable project characteristics explaining less than 40 percent of cost variation. Second, we find that high network upgrade costs lead to project cancellation: generators with network upgrade costs in the second study are 59 percent more likely to withdraw from the interconnection queue than those with no network costs. Among generators with non-zero costs, a doubling of these costs increases withdrawal probability by 16 percent. Third, we find that prior transmission investment by the grid operator reduces network upgrade costs for new generators: those in areas with high recent transmission spending are 50-68 percent less likely to face high network upgrade costs. These findings suggest that the current generator-pays model for network upgrades, combined with a lack of proactive transmission investment, creates a bottleneck that impedes the expansion of generation capacity.

New data on grid connection costs

Unlike many types of data on the electric power industry, interconnection cost data are not collected by the US Energy Information Administration. Nor are they made easily accessible by regional transmission grid operators (*13*).

We leverage new interconnection cost data for PJM, which serves about 65 million people in the Mid-Atlantic Region (*15*). As part of its interconnection process, PJM requires three engineering studies for most projects: a feasibility study, a system impact study, and a facility study. We refer to them as the first, second, and third study. Our analysis uses hand-collected interconnection cost data from these studies for all projects that entered the PJM interconnection queue from 2008-2020. Many of these projects are still in the queue, and our data on their studies goes through 2024.

We collect the two main components of interconnection costs separately: POI costs and network upgrade costs. Table S1 reports summary statistics for these data. The first study provides a POI cost estimate, while the second and third studies provide estimates for both POI and network upgrade costs. Most requests for interconnection have POI costs; those that do not are typically uprates, i.e., expansions to existing generators. Network upgrade costs are rarer; for example, 28 percent of second study observations have positive network upgrade costs. For more detail on data collection for these variables, see materials and methods. In (*16*), we also study the PJM interconnection queue, but that paper does not differentiate between these two types of interconnection costs and focuses on reforms to the queue design.

Over our sample period, PJM saw a dramatic increase in requests for interconnection. Figure S1 shows that entries to the queue were roughly five times as high in 2020 and 2021 as they were in 2011 and 2012. The increase in requested capacity was smaller, but still large: from roughly 20 GW per year to over 60 GW per year. This increase corresponded with a shift in the composition of requests away from natural gas and toward solar, wind, and batteries. Grid operators across the US and the world saw similar increases in requests and shifts toward renewable generators (*13*).

These data are complementary to the nationwide data on US grid connection costs from (*13*). Our data from one grid operator include the cost from every engineering study, while (*13*) collect data from the terminal engineering study for many grid operators. Observing data from many regions allows (*13*) to compare costs in regions with different resource mixes and policies; whereas, our data allow for a careful quantification of the relationship between costs and withdrawal decisions. Comparing generators at the same stage of the process is important because generators select out of the queue based on their estimated interconnection costs.

Network upgrade costs are difficult to predict

We first examine how network upgrade costs change over time and vary with project characteristics. We also compare them to POI costs. All costs are reported in 2023 dollars.

Figure 1 shows that network upgrade cost estimates increase over time for the second study but not the third study. In the second study, later cohorts of entrants have both a higher probability of having network upgrade costs (Panel A) and higher network upgrade costs (Panel C). This increase is present for both wind and solar (red) and other fuel types (blue). We do not see a similar increase in second study POI costs (figure S2). In the third study, the estimated network upgrade costs are low (D), and, if anything, the share of projects with network upgrade costs is decreasing over time (B).

We next map second study network upgrade costs and find that geographically adjacent projects can have very different network upgrade costs. Given the pattern of increasing costs over time, Figure 2 maps these costs separately for generators that entered the queue from 2011-2018 (Panel A) and 2019-2020 (Panel B). While costs tend to be higher along the coasts, the within region variation in these costs is greater than the across region variation. We also see that the pattern of rising second study network upgrade costs is not driven by one region of PJM. Figure S3 shows that POI costs can also vary significantly within narrow geographies.

We also use regression analysis to examine which project characteristics are most predictive of second study network upgrade costs. Table S2 shows that smaller projects are less likely to have network upgrade costs but, if they do have costs, have higher costs per kW. We do not find that network upgrade costs are higher for renewable generators than for other fuel types, as least on a cost per kW basis. Across all specifications, observable characteristics explain no more than forty percent of the variation in network upgrade costs. Observable characteristics explain more of the variation in POI costs but still less than fifty percent. We also do not find that network upgrade costs are higher when the transmission owner doing the study owns incumbent generators that may be harmed by new entrants (figure S4, more detail in materials and methods).

Network costs can change across studies

We next describe how network upgrade costs for the same generator evolve across studies. There are two explanations for the above finding that network upgrade costs have risen for the second but not the third study. One is that these costs fall systematically across studies. Another is that generators with high costs in the second study exit before they reach the third study. The first explanation implies that network upgrade costs for the same generator should, on average, fall across studies while the second does not.

We find that a generator's estimated network upgrade cost is equally likely to increase or decrease across engineering studies, and large changes can occur. Figure 3 panel A shows how each project's estimated network upgrade cost in the second study compares to the same estimate in the third study. Most generators (67 percent) that make it to the third study had network upgrade cost estimates of zero for both studies. Of the generators with at least one non-zero network upgrade cost, the median change is -\$0.03/kW, the mean is -\$28/kW, and the standard deviation is \$191/kW. This pattern is consistent with generators with high costs in the second study withdrawing from the queue before the third study. Figure S5 shows that POI costs also often change substantially.

We next investigate why network costs for the same generator change across studies. One explanation is that conditions in the network change. For example, if a generator was planning to build a network upgrade but leaves the queue, costs may increase for remaining generators. Alternatively, a generator leaving the queue may make the initial network upgrade unnecessary, decreasing costs for the remaining generators. Projects that are sharing network upgrade costs may be especially prone to cost changes.

We find that the biggest predictor of a large change is if the generator shares costs with other generators. Figure 3 panel B shows select coefficients from regressing an indicator for a large change in network upgrade costs (>25%) between the second and third study on project characteristics. About 19 percent of projects that make it to the third study have a second study that lists which projects they share network upgrade costs with (cost-share group). These projects are 39 percentage points more likely to have a large change in network upgrade costs, a 156 percent increase over the mean of the dependent variable (0.25). Projects with a network upgrade cost reported in the second study (network allocation) are also more likely to see changes compared to those with no cost reported, which we code as a cost of zero. These two variables are not predictive of changes in POI costs (figure S5, panel B).

High costs result in project cancellation

We next use regression analysis to quantify how interconnection costs affect the probability that projects are canceled. We conduct analysis separately for Study 1 (feasibility), Study 2 (impact), and Study 3 (facility). The dependent variable is an indicator for withdrawing from the queue after receiving a study, and the two regressors of interest are the two components of interconnection costs. The first study rarely has network upgrade costs; instead, it provides an estimate the total network upgrades a project might share responsibility for, which we refer to as the combined cost. For the first study regressions, we use this combined cost as our measure of the network upgrade cost. For projects that reach the second study, the correlation between the first study combined cost and the second study network upgrade cost is 0.33.

Figure 4 plots the estimated coefficients, with each panel reporting estimates for a different sample. Panels A, C & E quantify the effects on withdrawal of having non-zero interconnection costs for all projects that receive the first, second, and third studies. Panels B, D & F examine the intensive-margin effects for the sample of projects with non-zero estimates for both types of costs, separately for each of the three studies. We report estimates from four models that vary from no controls (green triangles) to rich controls for project characteristics (orange circles).

Projects with high interconnection costs are more likely to be canceled. In the first study, we do not see that projects with non-zero POI or combined costs are more likely to withdraw from the queue than those with costs of zero (Panel A). But, among projects with non-zero costs, those with higher POI costs are more likely to withdraw: a doubling of POI costs increases the probability of withdrawal by 0.05, or 20 percent at the mean withdrawal rate (Panel B). Projects with a higher combined cost, an indication of future network upgrade costs, are also more likely to withdraw.

We estimate large effects of second study network upgrade costs on withdrawal (Panels C & D). Compared to projects without network upgrade costs, those responsible for network upgrades are 26 percentage points, or 59 percent, more likely to withdraw before receiving the third study. For the sample with positive network upgrade costs, a doubling of these costs increases the probability of withdrawal by 0.07, or 16 percent. We do not find that projects with higher second study POI costs are more likely to withdraw.

This pattern of estimates across studies is consistent with the interpretation that interconnection cost estimates contain new information that affects cancellation. Developers likely know whether a project will have POI costs but learn more information about how large these costs will be in the first study, which may explain the intensive margin effects we find in Panel B. Developers must largely wait until the second study to learn whether a project is likely to have network upgrade costs and how large they might be, at which point we find large impacts of these costs on the probability of withdrawal from the queue. These large effects are consistent with network upgrade costs being difficult for developers to predict.

These estimates likely understate the causal impact of interconnection costs on project cancellation. A developer would only plan a project that it expects to have high costs if the project was otherwise especially good. This behavior creates a positive correlation between unobserved project quality and interconnection costs, biasing the coefficients on these costs in the withdrawal regression toward zero. More generally, these estimates could reflect the effects of other variables that are correlated with interconnection costs, though, reassuringly, we find remarkably similar estimates as we add more control variables to the model.

Costs are lower after transmission investment

While there has been much discussion about the benefits of inter-regional transmission capacity (*17, 18*), most spending on electricity transmission in the United States is intra-regional (*19*). Grid operators plan transmission investments through a regional transmission planning process. We next summarize data on this planned transmission investment for PJM and look at the correlation between these investments and network upgrade costs.

Through its annual Regional Transmission Expansion Planning (RTEP) process, PJM approves $1-6 billion per year in transmission investments. This spending is roughly equally divided between baseline and supplemental projects. Baseline projects are those that are required to maintain "system reliability, operational performance, or economic criteria" while supplemental projects are those which are not (*20*). Supplemental projects, also known as local projects, primarily address aging infrastructure and customer service needs (such as connecting new loads (*21*)). They are planned by the local transmission owner, receive less oversight than baseline projects, and may be less cost-effective (*22*). Unlike the network upgrades made by connecting generators, both baseline and supplemental projects are paid for by load (electricity consumers) via transmission rates. Table S3 shows that baseline and supplemental projects are similar in terms of cost, number of substations the work is performed on, and time to operation. The average voltage for baseline projects is about 30 percent higher than that of supplemental projects.

We next study the relationship between this spending and network upgrade cost estimates for connecting generators. We regress an indicator for whether a project faces a high network upgrade cost (>$100/kW) in the second study on the total cost of nearby RTEP transmission projects that have entered operation. Specifically, we include RTEP that went into service between three years before and one year after the issue date of the second study. Because the transmission grid is a complex network, we present results for four definitions of nearby spending, acknowledging that all are imperfect. The first three measure aggregate transmission spending at substations within 10km, 20km, and 50km of the POI of the connecting generator. The fourth is the aggregate transmission spending by regions that we construct based on local wholesale electricity prices. Specifically, we use k-means clustering to group substations into 50 regions based on location and similarity in locational marginal prices. For comparability across models, we bin spending by the percentiles of the distribution for that definition, and coefficients are interpreted as effects relative to the omitted group, which is spending levels below the median for that definition. For more detail, see materials and methods.

We find that generators in areas with high levels of recent transmission investment are less likely to have high network upgrade costs. Figure 5, Panel A shows that we generally find a negative relationship between total transmission spending and the probability of a high network upgrade cost. This negative effect is statistically significant in the top two spending bins for spending within 50km, and for the 75^{th} to 90^{th} percentile bin for spending in the same region. For these two highest levels of geographic aggregation, our estimates imply that, compared to generators in areas with below-median transmission investment, those in areas above the 75^{th} percentile are 8-11 percentage points less likely to have high network upgrade costs. These effects represent a 50-68 percent reduction relative to the mean.

Panel B further disaggregates transmission spending by category and shows that these results are not driven by baseline transmission investment. This unexpected finding may be because the baseline and supplemental projects in PJM are similar in size. The vast majority of PJM's baseline projects are also reliability projects rather than congestion relief projects, and thus may be less likely to increase transmission network capacity. Only 1.3 percent of baseline projects address congestion relief, compared to 95 percent of baseline projects that are driven by reliability needs.

These estimates are likely biased toward zero due to measurement error and forward-looking behavior by project developers. We are using a coarse approximation, both spatially and temporally, for assigning transmission investment to a particular generator. Transmission investments take years to plan and build, and their benefits may not be realized in our observation window. This measurement error in the independent variable is likely to attenuate the estimated effect. Similarly, developers may disproportionately enter locations with new transmission, competing away its beneficial effects (see (*23*) and (*24*) for evidence that large scale transmission expansions spur entry). We control for prior entry in the models - and find a statistically significant positive effect of entry in the last three years on network upgrade costs - but our entry variable may not fully account for this behavior.

Discussion

The rise in network upgrade costs over the last decade may reflect a mismatch between the pace of transmission investment and the growing demand for transmission capacity. Our finding that generators are less likely to have high network upgrade costs after recent transmission spending is consistent with this explanation. While PJM has experienced a substantial increase in demand for grid connection over the last ten years, transmission investment has not kept pace (figure S6). This discrepancy may result from a transmission planning process that has historically not considered generators waiting in the queue until they reach the third study (*25*). We find that many generators with high network upgrade costs leave the queue after the second study and, therefore, would not be considered in this planning process.

Our finding that network upgrade costs are lower after transmission spending also has implications for the current debate over transmission cost allocation. It suggests that regional transmission spending that is paid for by load can reduce interconnection costs. In turn, this highlights how such investments provide value to connecting generators. Therefore, connecting generators should bear some of the cost of this investment. More broadly, the findings add credence to the argument that generator-funded network upgrades can produce system-wide benefits. Economic theory suggests that, if those paying for the transmission infrastructure do not capture all of its benefits, there will be insufficient investment in transmission infrastructure (*26*).

A key outstanding question is how much reducing network upgrade costs would increase generator completions. One extreme is that the conditional probability of advancing in the queue for projects with network upgrade costs would increase to that of those without these costs, resulting in a large increase in completions. The other extreme is that developers would plan fewer projects to the point that the same amount of generation capacity would be completed. Even in this second case, lower network upgrade costs would save the cost of developing projects that are later canceled due to high grid connection costs. It would also reduce demand for the necessary studies and hence delays, and survey and empirical evidence show that delays in these studies lead to project cancellation (*16, 27*).

While our focus is on PJM, these results likely generalize to most of the US. Other research has found that rising network upgrade cost estimates are ubiquitous (*13*), and other grid operators also require multiple engineering studies and share upgrade costs across generators in the queue. The transmission planning process in PJM is also similar to that of other grid operators, though it plans fewer of the economic and public policy projects that may be especially helpful for integrating new generators (*28*). The grid operators covering most of California (CAISO) and Texas (ERCOT) differ from our empirical context in that they do not require connecting generators to pay for network upgrade costs. Thus, we would not expect these costs to have the same effect in these states. Perhaps not coincidentally, California and Texas added new generation capacity equal to 6 and 5 percent of their existing capacity in 2023, compared to the US average of 3.5 percent (materials and methods).

Our results suggest that interconnection costs are a key barrier to expanding generation capacity, yet recent policy reforms have been criticized for not doing enough to address the burden these costs place on new entrants (*12, 29*). FERC's 2023 reform to the grid connection process (Order 2023) targeted the efficient processing of interconnection studies to reduce delays rather than interconnection costs (*30*). While FERC's 2024 reform to transmission planning (Order 1920) targeted these costs, much of its implementation is left to grid operators' discretion. The Order's main requirement in this area addresses historical interconnection bottlenecks: grid operators must consider network upgrades that have been repeatedly identified in the interconnection process in transmission planning. The order also allows for, but does not require, grid operators to identify geographic zones suitable for the development of large amounts of new generation and incorporate them into the long-term transmission planning process. For example, the grid operator SPP has proposed a new consolidated planning process where it proactively plans transmission for connecting generators and charges them an upfront and certain grid contribution fee for connection (*31, 32*). Our findings suggest that implementing reforms like SPP's proposal that go beyond the minimum required by Order 1920 may be essential for achieving reliability and climate goals.

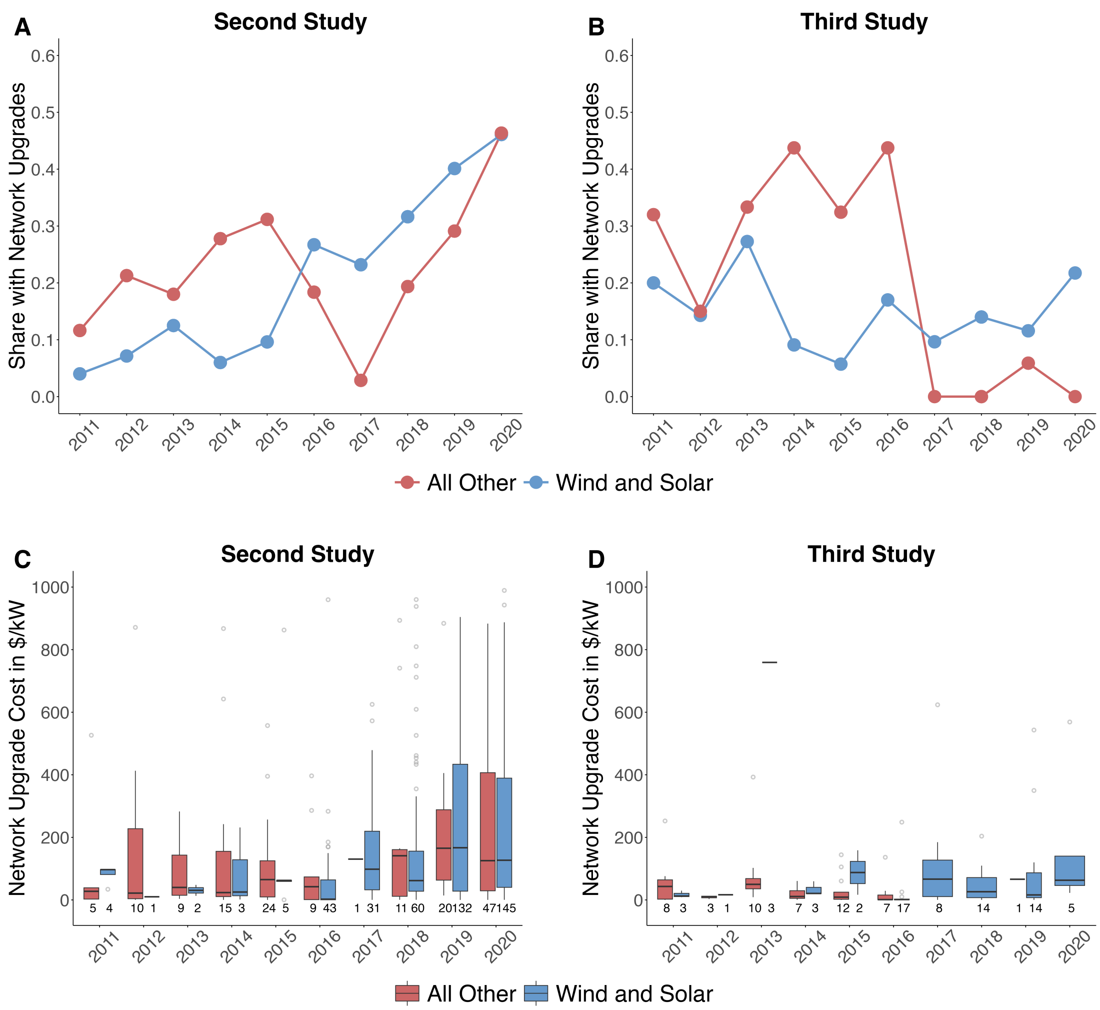

Figure 1: **Network Upgrade Costs by Year of Queue Entry and Fuel** (**A**) Share of projects with non-zero network upgrade costs in the second study. (**B**) Share of projects with non-zero network upgrade costs in the third study. (**C**) Box plot of second study network upgrade costs in $/kW for projects with non-zero costs. (**D**) Box plot of third study network upgrade costs in $/kW for projects with non-zero costs. Numbers below bars in C and D denote the number of projects with non-zero costs.

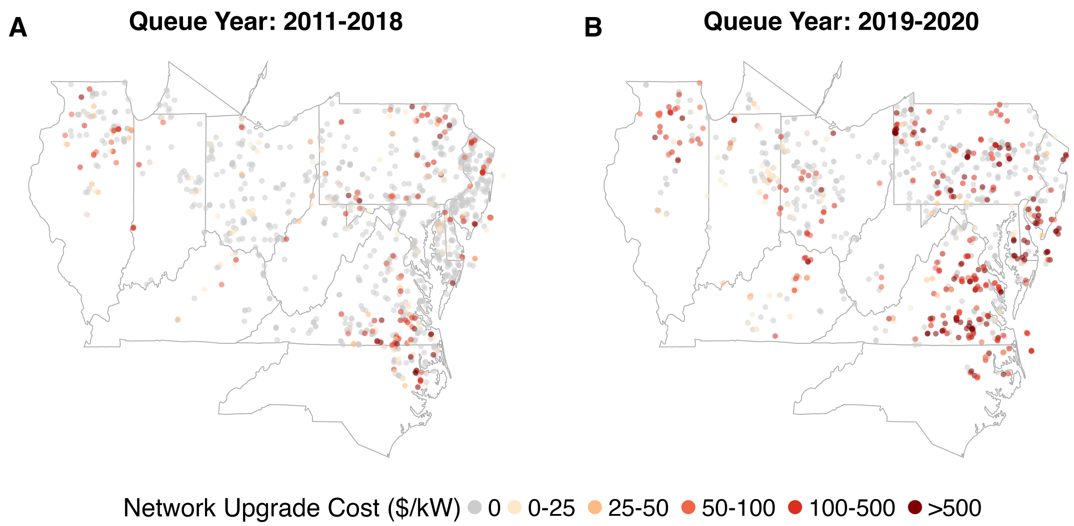

Figure 2: **Network Upgrade Costs by Year of Queue Entry and Location** Estimated network upgrade costs from the second study for the 1,031 projects that entered the queue in 2008-2018 (**A**) and the 844 projects that entered the queue in 2019-2020 (**B**).

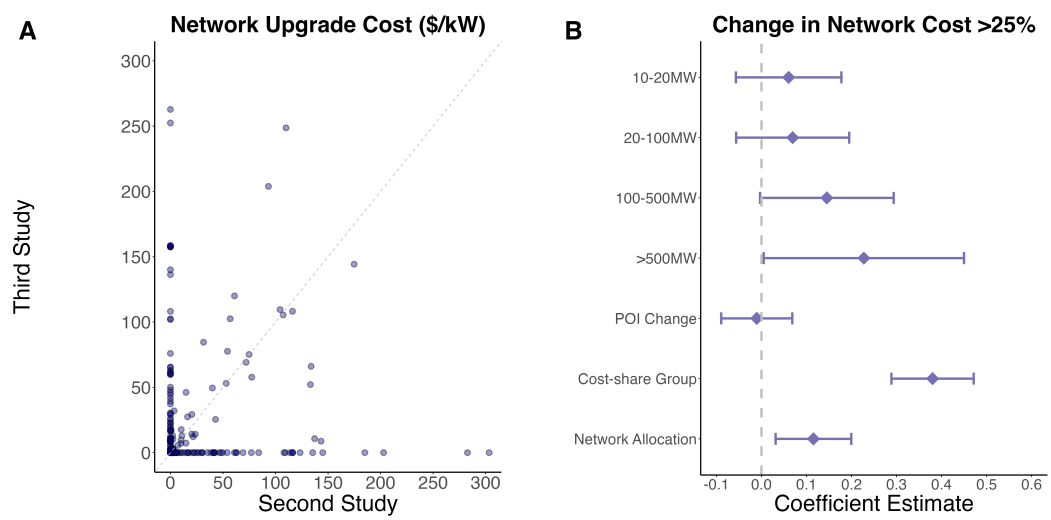

Figure 3: **Comparison of Study 2 and Study 3 Network Upgrade Costs for the Same Project and Predictors of Large Changes.** (**A**) Third study versus second study network upgrade costs for the 750 projects with both studies; excludes 19 projects with at least one cost greater than 300$/kW. Plot includes 546 projects (73%) with network upgrade costs of zero for both studies. (**B**) Estimated coefficients from a linear probability model predicting the probability of a network upgrade cost change greater than 25% between the second and third study (sample mean = 0.25). Size coefficients are relative to an omitted bin for 0-10 MW. POI Change indicates the POI changed between the second and third studies. Cost-share group is an indicator for a second study that lists other generators that a project shares network upgrade costs with. Network allocation is an indicator for a explicit network upgrade cost in the second study; this cost may be $0. The model controls for fuel type, uprate, year of entry into the queue, state, transmission owner, and voltage.

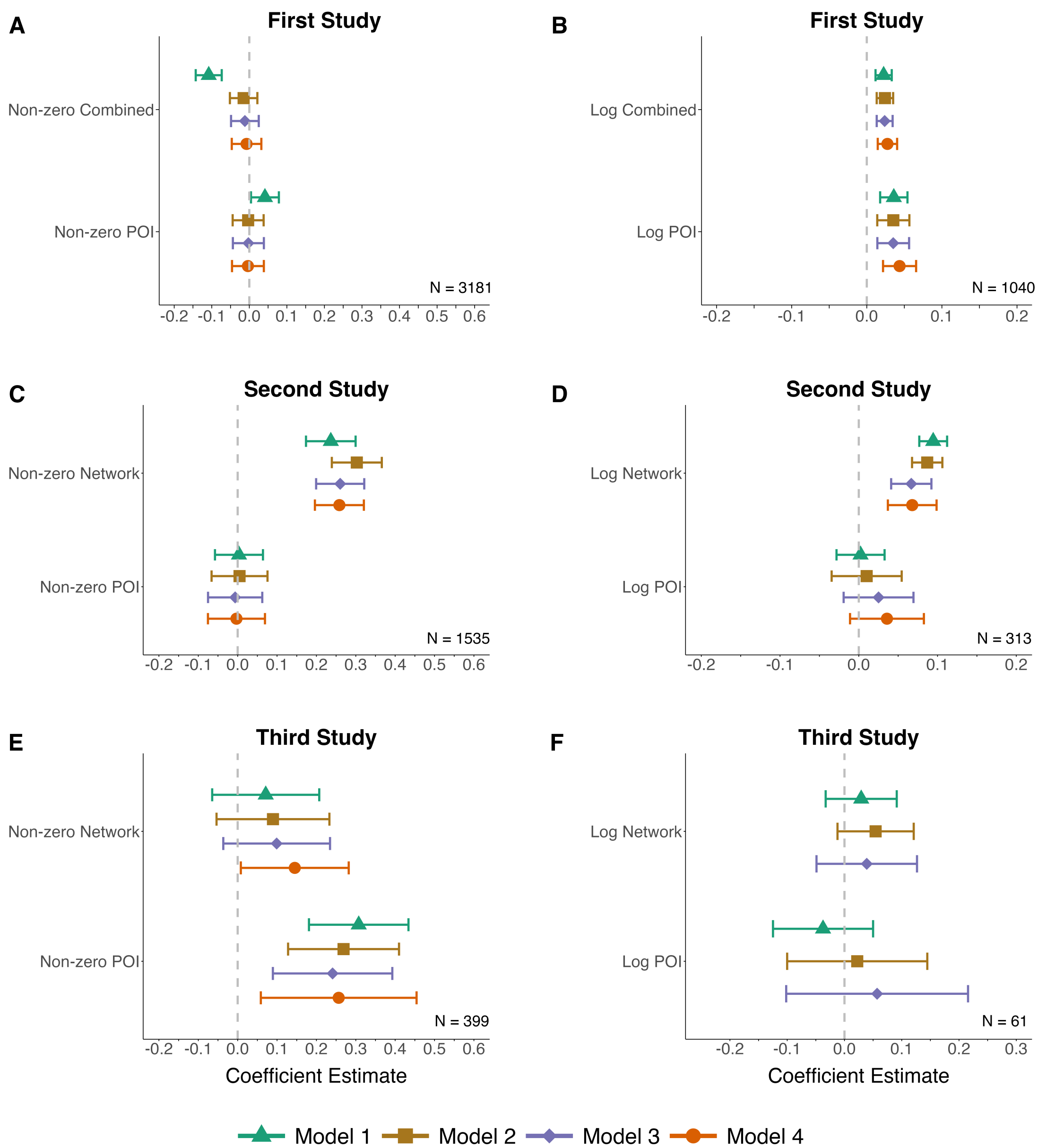

Figure 4: **Effect of Interconnection Costs on Probability of Withdrawal.** Coefficient point estimates (triangles, squares, diamonds, and circles) and 95% confidence intervals from a linear probability model. Projects that entered the queue from 2011-2020, active projects excluded. Dependent variable is an indicator for withdrawing from the queue before the next study (studies 1 and 2) or beginning operation (study 3). Model 1 (green triangles) has no controls, Model 2 (brown squares) controls for project size and fuel type, Model 3 (purple diamonds) also controls for year of entry into the queue and Model 4 (orange circles) also controls for state, transmission owner, and voltage. Samples for (**A**-**F**) are all projects with a first study (**A**), projects with positive first study combined and POI costs (**B**), all projects with a second study (**C**), projects with positive second study network and POI costs (**D**), all projects with a third study (**E**), projects with positive third study network and POI costs (**F**).

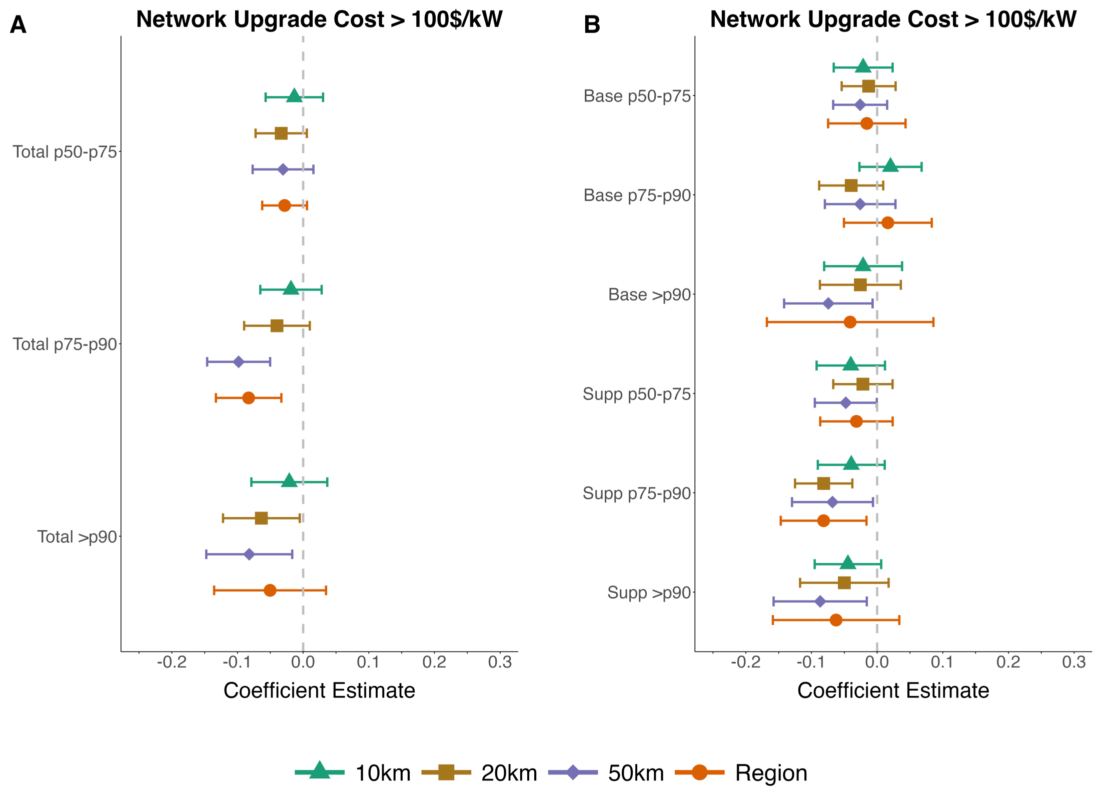

Figure 5: **Relationship Between PJM Transmission Spending and Network Upgrade Costs.** Coefficient point estimates (triangles, squares, diamonds, and circles) and 95% confidence intervals from linear probability models. Sample is projects that entered the queue from 2011-2020. Dependent variable is an indicator for a second study network upgrade cost greater than \$100/kW (mean = 0.16). Independent variables are binned indicators for recent RTEP transmission spending. Each model corresponds to a different definition of nearby spending: 10km (green triangles), 20km (brown squares), 50km (purple diamonds), or regions constructed based on similarity in locational marginal prices (red circles). Spending is grouped into percentile bins: 50–75th, 75–90th, and 90–100th percentiles; the omitted category is spending below the median. Panel A reports results from regressions with three bins based on overall spending. Panel B reports results for regressions with 6 bins, 3 for Baseline spending and 3 for Supplemental spending. All specifications control for project size, fuel type, uprate, transmission owner, queue year, and state. They also control for the log of the MW entering the queue in the past three years in the geographic area matching the area used for the transmission spending variables. Standard errors clustered by substation for the 10km, 20km, and 50km models and by region for the Region model.

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Supplementary materials

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Supplementary Materials for
Grid Connection Costs as a Barrier to Building New Generation: Evidence and Implications for Transmission Policy

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Materials and Methods

Interconnection Cost Variables

We collect data from each of the three engineering studies a proposed generator requires. The interconnection process begins with a Feasibility Study (Study 1). It provides a preliminary assessment of the generator's technical feasibility and potential system impacts along with an initial interconnection cost estimate. Next is the System Impact Study (Study 2) which assesses system stability, identifies necessary network upgrades to accommodate the new generation, and provides a more accurate cost estimate. The final study is the Facilities Study (Study 3), which provides detailed engineering designs and cost information for the required system upgrades. Studies are sometimes revised, and we record data from the final version of each study (as of August 2024).

Twenty-seven percent of the generators require fewer than three engineering studies to complete the process. PJM has an expedited interconnection process that is primarily intended for projects less than 20 MW. If PJM determines that a proposed generator needs no network upgrades and affects no nearby projects, it issues a combined Feasibility and Impact Study. In our analysis, we classify this combined study as Study 1. Roughly 5 percent of these projects still need to complete a Facilities Study, which we classify as Study 2. PJM may also issue a Feasibility Study and an Impact Study to the generator but allows the generator to skip the Facilities Study. About 45 percent of the projects that require fewer than three engineering studies fall into this category.

When collecting interconnection cost data, we follow PJM's categorization and differentiate between two types of costs: POI costs and network upgrade costs. The POI cost, also known as the physical connection cost, is the estimated cost to connect a generator to the electric grid. In the engineering studies, these expenses are classified as the direct connection cost, indirect connection cost, and attachment cost. We calculate the POI cost as the sum of these three components. We record the POI cost as zero if a study explicitly provides a zero-cost estimate or states that no such costs were identified. Currently, 28, 17, and 10 percent of observations are missing POI costs for the first, second, and third studies. For our analysis, we replace these missing values with zero, so that every observation in our sample has a non-missing POI cost.

The network upgrade cost is the estimated cost for transmission system enhancements that the generator is responsible for paying. We extract these costs from sections of the engineering studies that are labeled as referring to network upgrade costs. Network upgrade cost estimates are rarely provided in the first study: only 4 percent of observations have a non-missing network upgrade cost for the first study. Network upgrade costs may also be missing in the second and third studies. If a study explicitly reports zero costs or states that no such costs were identified, we record the Network Upgrade cost as zero. At this point, 42 percent of second study observations and 39 percent of third study observations are missing network upgrade costs. These observations do not mention network upgrade costs anywhere in their engineering studies, nor do they include a section relevant to these costs. For our analysis, we assume this lack of information means the project was not responsible for any contribution to network upgrade costs and record the network upgrade cost as zero.

The combined cost is the total estimated cost for all potential network upgrades a project may share responsibility for. When multiple projects contribute to overloading the transmission grid, PJM shares the cost of the system upgrades necessary to resolve the overload across these projects, in proportion to their contribution to the overload. The combined cost is the total cost of all the upgrades that a project may need to contribute to and thus gives some indication its network upgrade cost. This variable serves as our measure of network upgrade cost for the first study. Following the same approach as with the Network Upgrade cost, we record the combined cost as zero if a study explicitly reports zero combined costs or does not identify any such costs. At this point, 43 percent of first study observations have a missing combined cost. These observations have no mention of a combined cost in their studies, nor do they have a section relevant to these costs. For our analysis, we record their combined cost as zero.

We construct a measure of project capacity that we use to transform these costs into the cost per kW measures used in our analysis. Each request for interconnection specifies the requested kW of energy resource and the requested kW of capacity resource. Energy resource is the kW that can participate in the energy market while the capacity resource is the kW that can participate in capacity market. These two values are highly correlated, though the requested capacity kW tends to be lower than the requested energy kW. As our measure of capacity, we use the maximum of these two values.

Transmission Spending Analysis Variables

We use data from PJM's transmission planning process (RTEP) to construct a set of transmission spending variables. These data are publicly available from PJM and include all transmission projects that were identified by or proposed to PJM from 2003 to 2024.

These spending measures capture transmission spending that is nearby the generator receiving the second study. The RTEP project descriptions list the affected substations, and these are the locations to which we assign transmission spending. For each generator, we create four sets of transmission spending variables by aggregating transmission projects in geographic proximity to the generator's POI substation. The first three sets of measures aggregate total investment at substations located within 10km, 20km, and 50km of the POI. If a single transmission project involves construction at multiple substations within the relevant area, it is counted only once.

For the fourth measure, we define regions by clustering substations based on the similarity of their local wholesale electricity prices. Each generator is then assigned the transmission investment associated with its corresponding region. Wholesale prices are measured as the average of hourly real-time Locational Marginal Prices (LMPs) at each substation, using data from the 5th, 15th, and 25th of each month over the study period. To construct the regions, we apply a hierarchical k-means clustering algorithm that groups substations into 50 regions based on two dissimilarity measures: geographic proximity and wholesale market prices. Both measures are normalized by their maximum values to ensure comparability. We assign equal weights to LMP similarity and spatial distance. This approach ensures that the resulting clusters reflect both electrical and geographic proximity. Our results are robust to alternative specifications, including increasing the LMP similarity weight to 60% and adjusting the number of regions to 40 or 60.

When constructing these measures, we only include RTEP investments with operation dates between three years before and one year after the study issue date. We include RTEP projects that are within a year of their operation date because these projects are often accounted for in the estimated network upgrade costs. We do not include RTEP projects that began operation more than three years before the study issue date because we expect other generators to have entered in the interim and eroded the benefits from these older transmission investments. For the same reason, we include total entry in the geographic area corresponding to the spending variables as a control variable in these regressions. Our measure of entry is the MW that entered the PJM queue in that geography in the three years prior to the study issue date.

Finally, from each transmission spending measure we create four indicator variables that capture different levels of spending. These bins are below the 50th percentile, the 50th to 75th percentile, the 75th to 90th percentile, and above the 90th percentile. In the analysis, we include the top three bins, so coefficients should be interpreted relative to spending levels below the median.

Analysis with Transmission Owner–Owned Generation Capacity

To examine the spatial heterogeneity in network upgrade costs, we construct a measure of the generation capacity owned by each transmission owner (TOs). In PJM, TOs are responsible for conducting the engineering studies and issuing them on PJM's behalf. Some TOs own generation assets, which could create a conflict of interest. New generators typically have lower marginal costs of production, which may suppress electricity prices and reduce revenues for incumbent generators, including those owned by TOs.

We use publicly available data from the Energy Information Administration (EIA) Form 860 to construct a measure of TO-owned capacity. Form 860 reports each generator's capacity, ownership, and the transmission owner to which it is interconnected. We manually match generator owners to PJM transmission owners. For each TO, we calculate the total generation capacity within its service territory and determine the share of this capacity that is also owned by the TO.

New Generation Capacity Additions by State

We also use data from EIA Form 860 to compare new capacity additions in 2023 in Texas and California to the US as a whole. We first calculate, by state, the total new capacity that began operation in 2023. We then calculate, by state, the total capacity in operation as of December 31, 2022. The ratio of these two variables gives 0.049 for Texas and 0.06 for California. We do the same calculation for the entire US to arrive at 0.035.

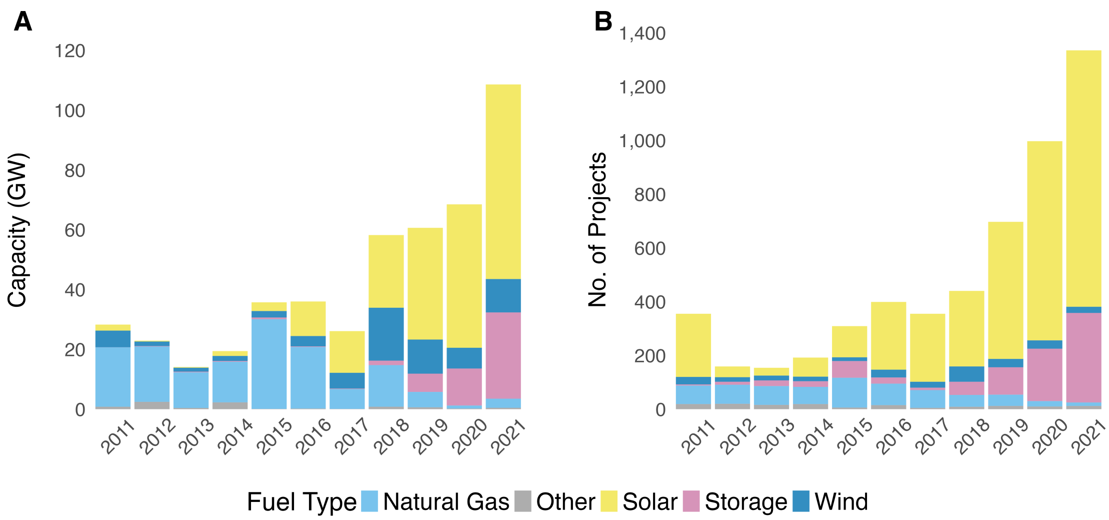

Figure S1: **Entrants to the PJM Queue by Year and Fuel Type.** New entrants to the PJM queue from 2011-2021.(**A**) Total Capacity in GW. (**B**) Number of Entrants. Storage is stand alone storage; hybrid storage projects are counted as wind or solar.

Supplementary Text

Figure S4 shows that the probability of receiving a positive network upgrade cost differs significantly across TOs, but there is no clear relationship with the share of TO-owned generation capacity. In particular, projects are most likely to receive some network upgrade costs in some of the TOs with no TO-owned generation.

In Figure S6, we plot PJM's transmission investment (Regional Transmission Expansion Plan, or RTEP) across years. We also separate two types of RTEP. The red represents baseline investment, which is necessary to maintain the regional grid reliability. The green represents the supplemental investment, which addresses local operational and economic needs. The overall level of investment has been stable over time, but the share of baseline investment has been low in recent years.

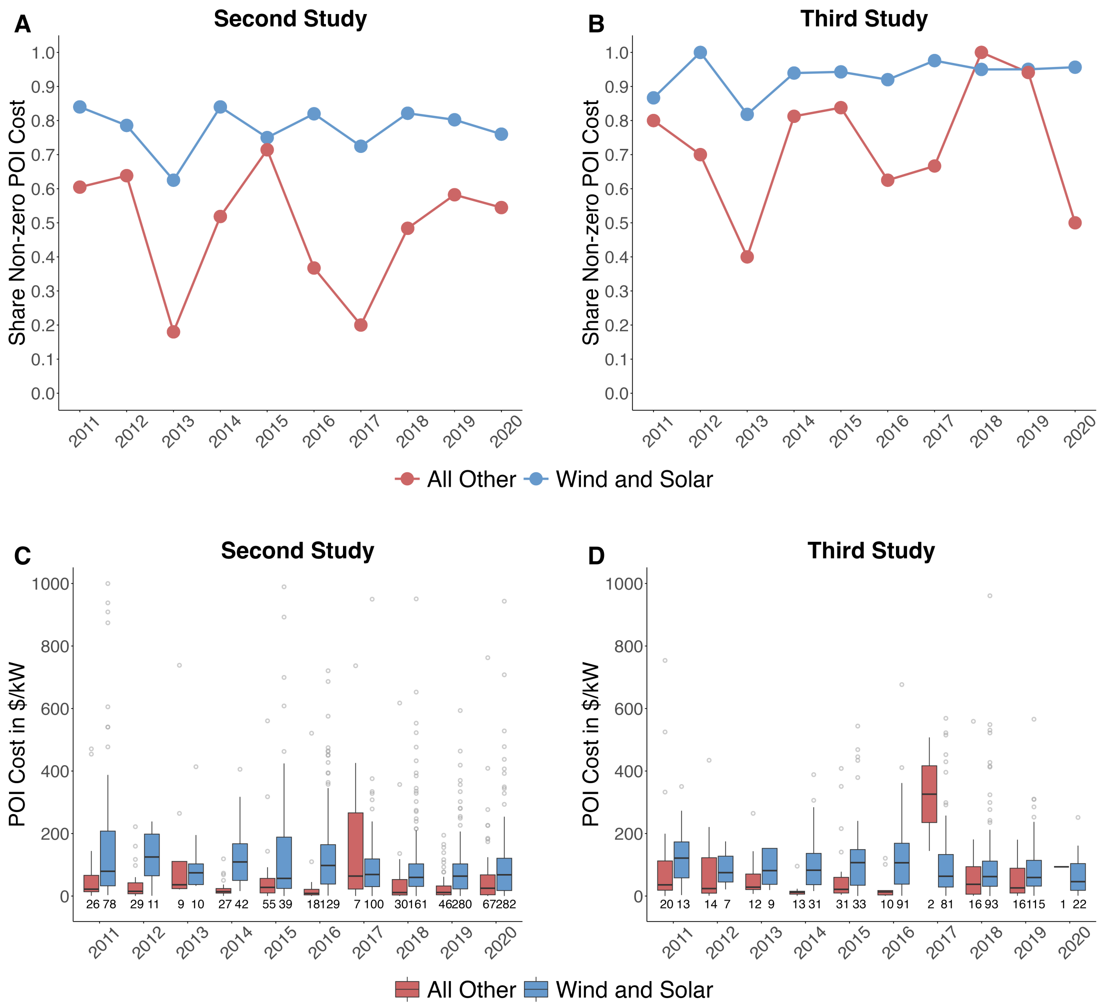

Figure S2: **POI Costs by Year of Queue Entry and Fuel** (**A**) Share of projects with non-zero POI costs in the second study. (**B**) Share of projects with non-zero POI costs in the third study. (**C**) Box plot of second study POI costs in $/kW for projects with non-zero costs. (**D**) Box plot of third study POI costs in $/kW for projects with non-zero costs.

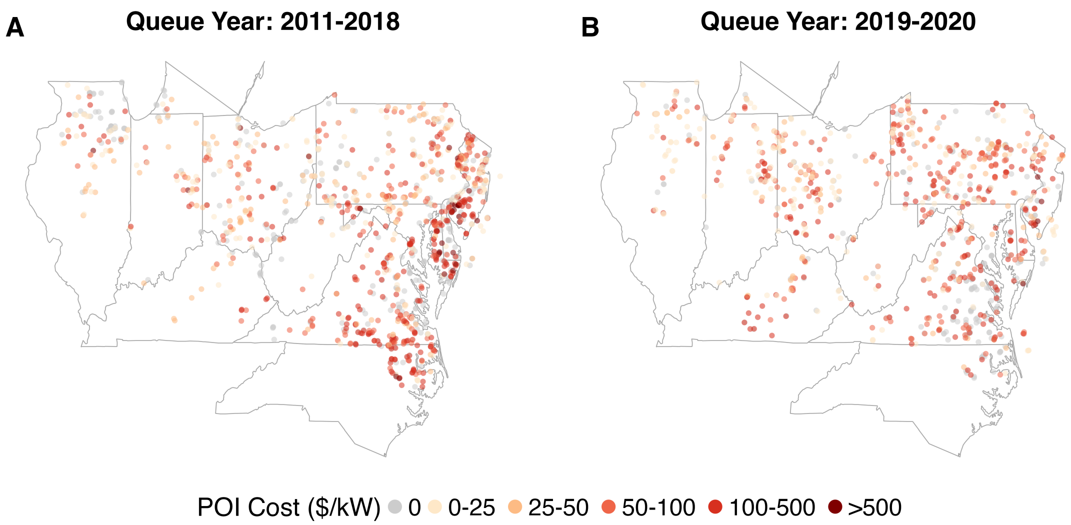

Figure S3: **POI Costs by Year of Queue Entry and Location** Estimated POI costs from the second study for the 1155 projects that entered the queue in 2008-2018 (**A**) and the 850 projects that entered the queue in 2019-2020 (**B**).

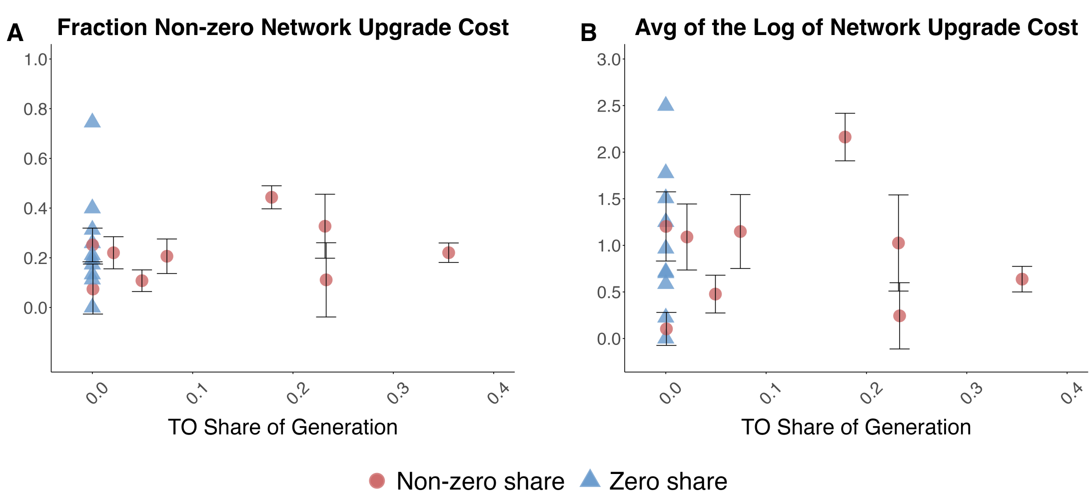

Figure S4: **Network Upgrade Costs and Share of TO-owned Generation Capacity** A red dot is a TO with positive share of TO-owned generation capacity. A blue triangle is a TO with no TO-owned generation capacity. In (**A**), the y axis plots, by TO, the mean of an indicator for non-zero network upgrade cost. In (**B**), the y axis plots, by TO, the average of the log of network upgrade cost. For TOs with a positive share of TO-owned capacity, we also plot the corresponding 95% confidence intervals. The sample includes projects queued from 2011 to 2020 (N=1988).

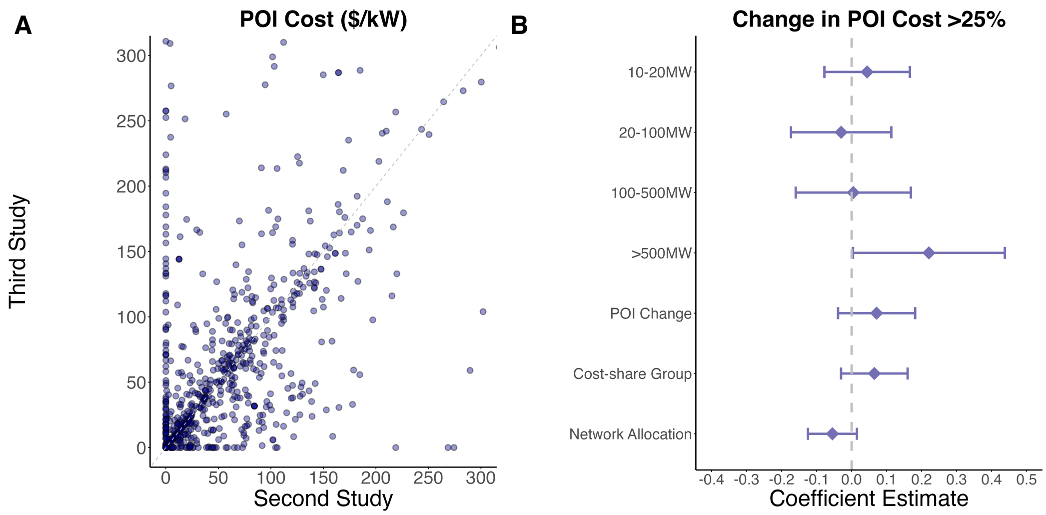

Figure S5: **Comparison of Study 2 and Study 3 POI Costs for the Same Project and Predictors of Large Changes.** (**A**) Third study versus second study network upgrade costs for 701 projects with both studies; excludes 71 projects with at least one cost greater than 300$/kW. (**B**) Estimated coefficients from a linear probability model predicting the probability of a POI cost change greater than 25% between the second and third study (sample mean = 0.52). Size coefficients are relative to an omitted bin for 0-10 MW. POI Change indicates the POI changed between the second and third studies. Cost-share group is an indicator for a second study that lists other generators that a project shares network upgrade costs with. Network allocation is an indicator for an explicit network upgrade cost in the second study; this cost may be $0. The model controls for fuel type, uprate, year of entry into the queue, state, transmission owner, and voltage.

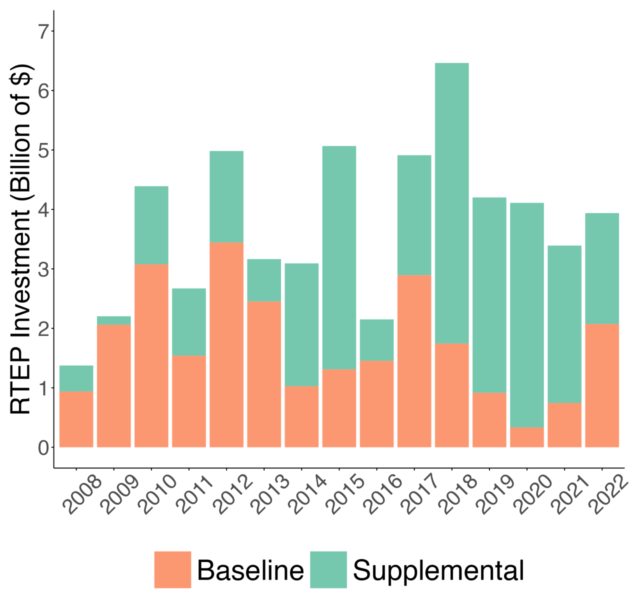

Figure S6: **Transmission Investment in PJM by RTEP Year** Total spending on transmission investments in PJM's Regional Transmission Expansion Plan (RTEP). Transmission projects are assigned to the year they entered the process—either the date the project was first reviewed by the Transmission Expansion Advisory Committee or its in-service date, whichever is earlier. Baseline projects are identified by PJM to address regional reliability or operational needs, while supplemental projects are proposed by individual transmission owners to address local requirements.

Table S1: **Summary Statistics for PJM Interconnection Queue Data.**

	First Study		Second Study		Third Study	
	Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.
Network Upgrade Cost ($/kW)	-	-	77.43	243.66	13.96	68.92
. . . Fraction Non-Zero	-	-	0.27	0.45	0.18	0.38
Combined Cost ($/kW)	931.68	3,073.11	707.15	1,815.28	61.90	134.38
. . . Fraction Non-Zero	0.41	0.49	0.21	0.41	0.04	0.20
POI Cost ($/kW)	104.88	221.92	82.82	167.07	102.37	168.94
. . . Fraction Non-Zero	0.63	0.48	0.71	0.45	0.88	0.33
Size (MW)	97.75	196.45	105.65	190.71	157.49	257.86
Uprate	0.21	0.41	0.23	0.42	0.15	0.36
High Voltage	0.45	0.50	0.51	0.50	0.57	0.49
Wind/Solar	0.68	0.47	0.70	0.46	0.73	0.44
N	4,133		2,472		823	

The sample is all generators that entered the queue from 2008 and 2020. We collect data from the final version of each study. Costs are in 2023 dollars per kW. Fraction Non-zero is the share of observations with cost estimates of non-zero. Size (MW) refers to the maximum of the generator's requested energy or requested capacity in MW. Uprate is an indicator for a capacity increase to an existing generator. High Voltage is indicator for voltage >115kV. Wind/Solar is an indicator for wind or solar project.

Table S2: **Predictors of Network Upgrade Costs and POI Costs.**

Dependent variable	Network Upgrade			POI		
	Non-zero	Cost in \$/kW	Log of Cost	Non-zero	Cost in \$/kW	Log of Cost
Project Size						
. . . (10MW, 20MW]	0.10***	43.43*	-0.57*	0.04	-85.09***	-0.91***
	(0.03)	(25.04)	(0.34)	(0.04)	(19.75)	(0.16)
. . . (20MW, 100MW]	0.25***	85.55***	-0.72**	0.24***	-66.79***	-0.94***
	(0.03)	(24.90)	(0.32)	(0.03)	(19.20)	(0.16)
. . . (100MW, 500MW]	0.42***	125.47***	-0.71**	0.28***	-98.75***	-1.45***
	(0.04)	(28.30)	(0.34)	(0.04)	(20.10)	(0.18)
. . . >500MW	0.60***	134.48***	-0.75	0.43***	-125.93***	-2.03***
	(0.06)	(31.01)	(0.51)	(0.05)	(23.66)	(0.25)
Fuel Type						
. . . Solar	0.03	-9.74	-0.22	0.27***	22.59*	0.51**
	(0.04)	(25.05)	(0.44)	(0.04)	(12.52)	(0.21)
. . . Wind	0.11**	45.41*	-0.17	0.21***	9.01	0.32
	(0.05)	(27.00)	(0.40)	(0.04)	(11.38)	(0.23)
. . . Storage	0.10**	18.82	-0.54	0.29***	-14.87	-0.14
	(0.05)	(30.23)	(0.47)	(0.05)	(14.15)	(0.25)
. . . Other	0.02	12.84	0.19	-0.00	17.57	1.23**
	(0.05)	(18.97)	(0.73)	(0.06)	(17.88)	(0.53)
Transmission Zone						
. . . MidAtlantic	-0.17**	-134.71**	-0.57	0.19***	-27.42	-0.31
	(0.07)	(59.49)	(0.69)	(0.07)	(26.02)	(0.39)
. . . SouthWestAtlantic	-0.19***	-137.37***	-2.52***	0.13	-16.79	-0.03
	(0.06)	(45.13)	(0.81)	(0.09)	(31.39)	(0.38)
. . . Southern	0.19**	13.34	0.71	0.07	-24.56	0.02
	(0.09)	(63.15)	(0.56)	(0.07)	(28.85)	(0.42)
. . . Western	-0.10	-76.24	-0.90	0.24***	-19.67	-0.46
	(0.06)	(48.50)	(0.59)	(0.06)	(27.27)	(0.36)
High Voltage	-0.06**	-46.76**	-0.14	-0.02	-11.21	-0.13
	(0.03)	(18.56)	(0.19)	(0.03)	(7.24)	(0.09)
Uprate	-0.03	32.38	0.45**	-0.42***	-71.46***	-2.39***
	(0.03)	(22.59)	(0.21)	(0.03)	(7.11)	(0.19)
Mean of dependent var.	0.30	90.00	4.32	0.71	71.68	3.69
R^2	0.24	0.15	0.41	0.40	0.19	0.44
N	2,066	2,066	628	2,066	2,066	1,457

Generators that entered the queue from 2011-2020 and received a second study. SEs in parentheses; clustered by substation. Omitted fuel is natural gas, omitted zone is East Mid-Atlantic. High Voltage is indicator for voltage >115kV. All specifications control for state and the year of entry to the queue. * $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$.

Table S3: **Summary Statistics for PJM Transmission Planning Data.**

	Baseline RTEP		Supplemental RTEP	
	Mean	Std. Dev.	Mean	Std. Dev.
Investment (in Million $)	11.09	39.69	10.79	24.38
No. of Substations	1.38	0.67	1.48	0.78
Voltage (kV)	199.82	123.29	148.37	105.53
Time to In-Service (Months)	39.13	20.60	36.25	26.58
N	2,627		2,500	

The sample includes all RTEP projects that went into service or are proposed to be in service in PJM from 2008 to 2026. RTEP projects are classified by PJM as either Baseline or Supplemental. Investment refers to the estimated cost of the RTEP project in million dollars. The number of substations represents the total substations associated with the RTEP project's construction. Voltage indicates the operating voltage of the transmission asset. Time to In-Service measures the number of months from the initial planning date to the in-service date.