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Transmission lowers US generation costs, but generator incentives are not aligned

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The US electricity grid is rapidly evolving with the entry of low-cost renewable electricity. As a result, new supply is not spatially matched to demand, and the transmission network has become more strained. Better market integration could thus lower US generation costs. We document that eliminating interregional constraints would have reduced electricity generation costs across the lower US 48 states by $5.8 to 7.1 billion in 2022 and $3.4 to 5.0 billion in 2023. But market integration creates winners and losers among generation companies, and we show that producers in some regions have incentives to delay or block grid integration despite the overall system benefits.

electricity markets | transmission | renewable energy | political economy of energy | energy transition

As electricity markets rapidly transform, improved grid integration through high-voltage transmission lines has become a central issue in electricity policy and energy markets (1, 2). Dramatic cost declines in renewable energy resources are changing the supply mix of US electricity, leading to an increasing mismatch between supply and demand. Many of the areas with high solar or wind resources are far from demand centers, straining the transmission network. Several studies argue that moving to a "net-zero" grid would require a massive build-out of transmission lines (3–5)—but even in the near term, expanding transmission could bring benefits in generation cost savings and improved reliability.

Connecting new, low-cost sources of supply with areas of high demand could allow for system-wide generation cost savings, which in turn could be good for the US economy. However, this same geographic integration will create winners and losers among generation companies—incumbents in high-cost markets would see a drop in profits. This is not a concern for the economy—market-wide cost effectiveness is improved. The challenge is that the US process for siting, building, and paying for new transmission lines gives incumbent companies many opportunities to delay or block projects that are not in their private economic interest (5, 6). This incentive problem interacts with the other challenges facing transmission build-out in the United States, with thorny issues also arising relating to cost allocation, land use, interconnection queue delays, and potential overinvestment in local transmission projects (1, 2, 5, 7–21). It also interacts with barriers to trade beyond those associated with physical infrastructure; an example is insufficient coordination on trade across regional markets, an area of recent interest in public discussions on the state of electricity markets (17, 21, 22).

We study how improved spatial integration of electricity markets in the lower 48 states would change system generation costs and generating company net revenues. We first document that transmission and other spatial constraints appear to be widespread across the country, with local supply responding to changes in local rather than market-wide demand. We then calculate the potential cost savings from better market integration—specifically, the aggregate short-term excess generation costs caused by transmission and other spatial constraints. We calculate measures of marginal cost at the generator-by-hour level, then construct supply curves under two scenarios: given either 1) current spatial constraints or 2) the removal of spatial constraints within each interconnection. This allows us to determine which power plants would be dispatched to meet demand in each scenario and to calculate aggregate generation cost savings from eliminating spatial constraints within the three interconnections that make up the US grid. In both cases, we assume generation markets are competitive (no market power), an assumption we discuss below.

We show that the potential for generation cost savings from integrating existing supply across regions is large and has been increasing: $5.8 to 7.1 billion under 2022 conditions and $3.4 to 5.0 billion dollars under 2023 conditions, substantially higher than in previous years. This value has risen as renewable generation has been increasingly

Significance

Transmission build-out and related grid reforms could bring electricity generation cost reductions, with low-cost wind and solar better able to provide energy to faraway demand centers. But market integration saves costs precisely because it pushes out high-cost suppliers, and we show that incumbent generators in some regions have financial incentives to block or delay transmission. Using hourly unit-level data on electricity supply across the lower 48, we document that removing spatial constraints would save billions of dollars in generation costs per year, but that East Coast suppliers in particular would see lower profits. As analysts and policymakers propose grid reforms, it will be important to consider the incentives of suppliers and therefore the role of grid governance.

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curtailed. The larger potential cost savings for 2022 is primarily a result of increased natural gas prices—highlighting how transmission can provide a form of insurance against fuel cost spikes.

Our model only measures the generation-side savings from increased integration and thus should be compared to the costs of building infrastructure. We do not perform a full benefit–cost analysis of new transmission lines. A complete comparison would also model the dynamic savings as the grid evolves in response to the market integration (e.g., new generator investment, generator retirements) and include the social costs of changes to both CO_2 and local air pollutant emissions; again, a complete accounting of this would include modeling induced investment in renewables. And, finally, it might consider how the interregional lines that we study interact with the need for local projects and the need for generation interconnection. We refer the reader to other analyses arguing that the benefits of new transmission often outweigh the costs of the grid build-out (2, 7, 23–26).

Finally, to better understand the economic incentives for individual power plants, we estimate the net revenues for each plant in each scenario. We find stark differences across regions in terms of which plants benefit from and which are hurt by market integration. Market integration would benefit producers in the Great Lakes, Great Plains, and Rocky Mountain regions but hurt producers in the Northeast and Southeast. These changes are a product of changes in both prices from market integration (prices would equilibrate across space, whereas today's market sees much higher prices in some regions) and generator dispatch (with high-cost generators producing at lower quantities, driving the cost savings documented).

Numerous papers across economics and law raise the possibility that market integration will hurt some generating companies and that these companies thus have incentives to block or delay transmission build-out (5, 9, 12, 14–16, 27, 28). While a quantitative analysis exists for part of the US (6), our paper provides national estimation of generator incentives for and against market integration.

Prior work calculates the system cost and net revenue impacts of existing spatial constraints within just the Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO) electricity markets, finding both high levels of potential cost savings from market integration, and strong incentives for some incumbents to block the build-out of transmission within these footprints (6). By extending the geographic scope to the entire lower 48 states, we show that these same dynamics are true on a larger scale and generalizable nationwide. This is important, as parts of the country beyond MISO and SPP have different fuel mixes (for instance, less wind generation); different ownership structures (more independent power producers); and different dispatch procedures. Markets of all kinds will need to grapple with the problems that incumbents in high-price regions will generally want to avoid the competition that long-distance lines bring.

This analysis additionally goes beyond previous work (6) by explicitly studying the effects of transmission on entry incentives. Increasing transmission capacity will change the entry of new electricity generators, in addition to changing the dispatch of existing generators. The incentives should be similar for new and existing generators of the same fuel types and with comparable technologies—and we show that relaxing spatial constraints alters the profitability of building a new natural gas power plant following the same spatial patterns we see for existing plants. Integrating electricity markets will make it more attractive for new natural gas power plants to locate in the Midwest, Northwest, and the Rocky Mountains and less attractive to locate in the Northeast, Southeast, and California.

Results

Spatial Constraints in Lower 48 States. With multivariate regression analysis, we find that a majority of conventional power plants respond more to nearby demand shocks than distant demand shocks (Table 1). Specifically, 92 percent have a larger coefficient on the "own demand shocks" variable in our regression framework. Within each region we study, the majority of plants respond more to own demand.

As a result, the changes in total generation that are responses to own-region demand shocks, rather than other-region demand shocks, are also substantial. With a separate set of time series regressions (*SI Appendix*, Table S2), we find that for every 1 MWh of demand increase within California, for instance, natural gas and coal generators increase their production by 0.65 MWh. In contrast, for every 1 MWh of demand increase from surrounding states, California generators increase their demand by only 0.12 MWh. One region with a stark difference between responsiveness to nearby and more distant demand shocks is the Southeast, where the response to a nearby 1 MWh demand shock is 0.85 MWh for natural gas and coal generators, but there is almost no response to surrounding region demand shocks. Overall, the results in Table 1 and in *SI Appendix* are consistent with barriers to trade, including transmission and other spatial constraints, that prevent generators from responding to more distant demand shocks.

Potential Cost Savings. Fig. 1 plots the total potential cost savings from market integration per month from 2020 through 2023. These increased dramatically from 2020 to early 2022 before

Table 1. Conventional units are more responsive to own-region demand, summary of plant-level analysis

Region	Percent own-responder	Percent other-responder	Plant count
California	96.9	3.1	98
Carolinas	97.4	2.6	38
Central (SPP+)	95.7	4.3	117
Florida	77.3	22.7	44
Mid-Atlantic (PJM+)	90.2	9.8	204
Midwest (MISO+)	91.8	8.2	231
New England	77.6	22.5	49
Northwest (Mountain)	83.7	16.3	49
Northwest (Pacific)	73.5	26.5	34
New York	100.0	0.0	56
Southeast	98.2	1.9	54
Southwest	91.9	8.1	37
Tennessee	100.0	0.0	24
Texas	100.0	0.0	86
Total	92.0	8.0	1,121

This table summarizes the results of 1,121 plant-level time series regressions. The dependent variable is plant-level generation. The independent variables in each time series regression are own-region demand, nearby-region demand, and controls. The table columns show the portion of plants that have a larger coefficient on own-region demand than they do on connected-region demand. Some amount of "other-responder" results are to be expected with statistical noise. A map is shown in *SI Appendix*. The results for Texas are by construction, as the entire interconnection is one region.

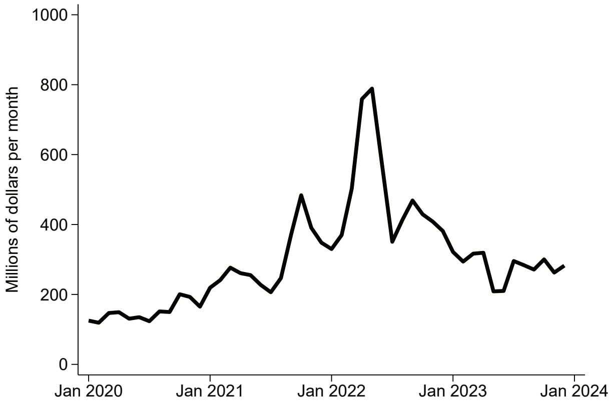

Fig. 1. Monthly potential generation cost savings from improved market integration in the United States (contiguous US, 2023 dollars). The model integrates markets within an interconnection but does not integrate across the three interconnections of the US, and it uses a lower bound for the impact of curtailments.

falling to a lower but still elevated level for the second half of 2022 and 2023. Potential generation cost savings totaled $5.8 to 7.1 billion in 2022 and $3.4 to 5.0 billion in 2023, up substantially from the $1.8 to 2.3 billion in 2020. We lack curtailment data for regions without wholesale markets (non-ISO, i.e., no Independent System Operator), so the lower bounds are from the assumptions that no renewable generation is curtailed in non-ISO regions and that integration is only possible within interconnections, matching the assumptions used in Fig. 1. The upper bounds are from the assumptions that non-ISO regions curtail at the same rate as ISO regions and that integration across interconnections is possible; a figure with these alternative assumptions is shown in *SI Appendix*.

Around eight percent of these cost savings estimates come from environmental compliance costs. Again, these represent costs to generators (which may be passed through to customers) but not necessarily social costs: For instance, cap and trade programs generate revenues that are then redistributed. A full cost–benefit analysis would instead include the social costs of pollution from all generators, which vary across fuel types, unit-level abatement choices, proximity to population, and weather conditions.

The time path of cost savings—rising overall, but with a particularly high spike under 2022 conditions—is consistent with this being driven by both renewables curtailments (rising over time) and natural gas prices (spiking in 2022), consistent with prior research (6, 26, 29).

Market integration would bring substantial generation cost savings, because we would see greater use of low-cost resources: both increased use of existing wind and solar resources that would be otherwise curtailed and a switch from inefficient to fuel-efficient conventional generators. These are the short-term gains from market integration, which lead to nationwide generation cost savings, benefiting consumers.

Our estimates are likely a lower bound on generation cost savings for several reasons. First, we do not model the forward-looking benefits that come from investing in lower-cost resources and retiring inefficient plants (30). Second, we have modeled only the benefits from increased long-distance transmission build-out within interconnections; our model does not include the benefits from increased highly local projects. Third, we have modeled generators as behaving competitively; we do so because of the large number of generation companies and because there are regulatory processes that monitor for and attempt to mitigate the exercise of market power (6). However, to the extent that spatial constraints enable the exercise of market power by shrinking the pool of suppliers (31, 32), our model understates the potential efficiency gains from integration. Fourth, we have not explicitly modeled the benefits from extreme weather events (33). Finally, we have assumed that the behavior of commercial, industrial, and cogeneration units would not change with market integration. Thus our estimates should be viewed as a subset of the benefits documented in other reports (25, 26).

Winners and Losers Among Power Plants. Power producers in the Great Lakes and Great Plains states would see significant revenue increases from increased market integration, and those in the Northeast, Southeast, and California would see lower revenues (Fig. 2).

Without adequate transmission lines, wind energy in the Midwest and Great Plains is often unable to get to the larger cities along the East Coast, causing prices in the Great Plains to bottom out while prices in the demand centers on the coast remain elevated. Eliminating spatial constraints within the Eastern Interconnection would allow power from the Great Plains and Midwest to reach the East Coast, increasing prices in the former (helping producers there) and decreasing prices in the latter (hurting producers but helping consumers).

The results in Fig. 2 roughly match the patterns in price dispersion across space, such as documented in the Lawrence Berkeley National Laboratory (LBNL) ReWEP tool (34). A few conceptual differences are worth noting. The LBNL maps are able to display a fine level of geographic granularity, as they rely on locational marginal prices. In contrast, we model transmission constraints at the broad regional level. As a result, the ISO-level patterns between Fig. 2 and the LBNL maps are similar: Prices are much lower in the Midwest and Great Plains than along the coasts, and market integration would equalize these differences. Note that our model does not account for congestion within subregions—for example, Kansas and Oklahoma have West/East congestion. However, in other ways, our model sheds light on aspects of regional patterns that do not appear in the LBNL maps. Our revenue results account for both price changes and generation quantity changes under market integration—that is, some of the profit changes would come from changes to dispatch and not merely equilibrium prices. Our model also opens a window into the non-ISO regions, which do not have locational marginal prices and thus cannot be studied with the LBNL maps; some of the largest producer losses are in the Southeast and Florida, for which price data are not available.

Precise results for individual plants will depend on fuel costs, demand levels, and curtailment levels, all of which have changed over 2020–2023 and will continue to evolve. *SI Appendix* shows year-by-year results; these do have some variation over time, but the broad regional patterns are generally stable. It also shows results averaging across all years but assuming a greater level of historical curtailment (as we do not observe non-ISO region curtailments)—broad regional patterns are again robust to this alternative assumption. Last, it shows a comparable map when also integrating across interconnections; regional patterns are again similar but with a greater drop in revenues in the West.

It is worth noting a few things about the regional results. First, we have not modeled California CO_2 permit costs, because our regionally constrained counterfactual is unable to incorporate pollution-related penalties the state places on imports; including permit costs for California plants would therefore overstate how much these plants are not competitive with plants in other states.

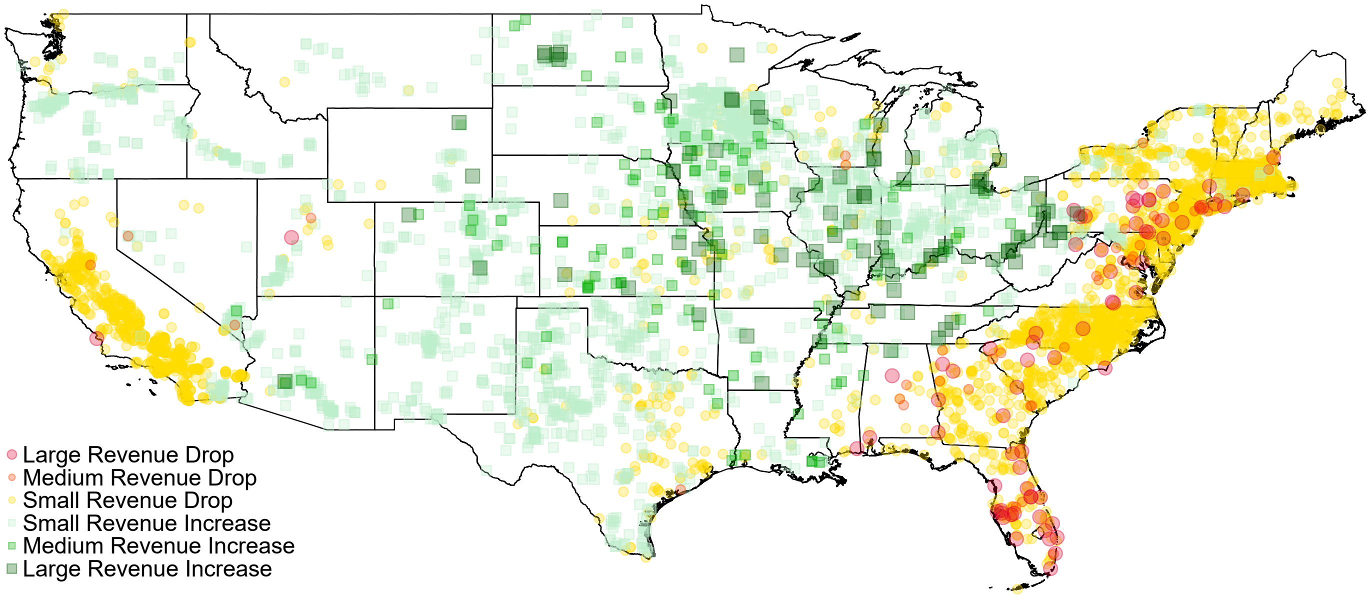

Fig. 2. Some Power Plants Would See Net Revenues Drop With Market Integration, and Others Would See Increased Net Revenues. This map plots the power plants that earn more net revenue with market integration (green) versus less net revenue with market integration (yellow, orange, and red). "Large" revenue changes are defined as greater than $20 million per year; "medium" revenue changes as $10 to 20 million; and "small" revenue changes as $0 to 10 million. Net revenue changes are calculated as the average annual difference (over the 2020–2023 period) relative to the congested scenario. Results by year and fuel type are shown in *SI Appendix*.

Second, in interpreting the results in Fig. 2 for Texas, our model does not allow for increased trade across interconnections. That is, transmission between Texas and its neighbors has been left unchanged. Profit changes for Texas plants thus come entirely from the model expanding wind and solar generation by removing curtailments. In other regions, we are implicitly assuming that transmission build-out allows curtailments to be eliminated. For Texas, our model is best interpreted as changes to the grid that eliminate curtailments but otherwise do not change congestion. The result is that wind producers in western Texas see increases in net revenues, and conventional producers in eastern Texas see falls in net revenues (maps separated by fuel type are shown in *SI Appendix*).

Third, we compare the results for MISO and SPP to prior work (6). That paper shows that the upper Midwest and Great Lakes would gain from market integration throughout MISO and SPP, consistent with Fig. 2. However, that paper also shows, and emphasizes, losses to MISO South producers in the Gulf Coast. In contrast, Fig. 2 shows gains in MISO South. These results are not inconsistent. That paper integrates only MISO and SPP, leaving trade flows with the Southeast, PJM, New England, etc. unchanged. This is a policy-relevant counterfactual given work within MISO and SPP to better integrate their footprints. In that case, MISO South is a relative loser under market integration. In contrast, Fig. 2 shows net revenue changes if all the Eastern Interconnection were integrated. In that case, MISO South units would fare better than competitors in, for instance, the Southeast and Florida. This serves as a reminder that which generating companies would win or lose will depend on the relative costs across the regions in question, which in turn depends on the scope and location of the new transmission infrastructure under consideration.

Fourth, we highlight that New England loses revenues under market integration with the rest of the Eastern Interconnection. Another scenario worth considering, given recent policy discussions, is what would happen if New England were better integrated with Canada. Data limitations prevent us from explicitly modeling the construction of a long-distance line connecting New England to Canadian hydropower. But to the extent that the motivation for the line is allowing imports of low-cost hydropower, we would again expect to see New England generating companies lose profits as a result.

All of these results are for the net revenues changes for existing generators. This is a good approximation of profits of independent power producers operating in wholesale electricity markets, but it translates less directly to regulated monopoly utilities and regions that do not have organized wholesale markets. The Southeast and most of the West (besides California), do not have wholesale electricity markets with market prices. Nevertheless, the marginal cost of the marginal producer still represents the shadow cost of producing additional electricity and may still serve as a reasonable approximation of companies' profit incentives. For vertically integrated investor-owned utilities, revenues and profits depend on negotiating rates with regulators. However, the utility may still be entitled to residual profits, and demonstrating that the cost of producing electricity is high may assist the utility in negotiating additional investment.

As another way to understand the incentives of price-regulated utilities, in *SI Appendix*, we explicitly model how much the variable profits of a new entrant would have depended on market integration. For utilities whose profits depend on a rate of return on capital investment, this may better shed light on their incentives to push for or to block market integration. Specifically, we estimate how the net revenues of a new natural gas plant built in 2020 to 2023 would have changed had the market been integrated. Our hypothetical new plant matches the typical capacity and efficiency of combined cycle natural gas plants actually built since 2016. The broad regional patterns are similar to those in Fig. 2 for existing generators: Market integration would make new plants more attractive in the middle of the country but hurt the profitability of new plants along the East Coast.

Discussion. Numerous barriers to transmission siting, planning, permitting, and construction have been identified (1, 5, 7–12, 14–21). These include disagreements over cost allocation and the need to obtain land use rights over long distances and to obtain environmental clearance. A barrier that can interact with and exacerbate these obstacles is the current governance structure for transmission planning. Transmission planning (and changes to market rules governing the trade of electricity across regions) largely depends on obtaining consensus across incumbent generation companies, who hold much of the decision-making power in regional transmission organizations (11). In particular, incumbents frequently have a greater say in transmission planning than do other key stakeholders: Consumers that would see cost savings and potential new generators.

Yet our results show that incumbents in many regions would have financial incentives to delay or even block the development of new long-distance lines. In this section, we discuss how the regional patterns apparent in Fig. 2 compare to documented patterns in both the need for new transmission and obstacles to building that transmission.

As the DOE reports, "the need for additional interregional and cross-interconnection seams transmission capacity is particularly acute between the Plains, Midwest, Delta, Texas, and Southeast regions and their neighboring regions" (2). This is primarily driven by high price differentials and/or growing renewables penetration, but new transmission capacity could also provide resilience during extreme weather events, such as hurricanes and major winter storms.

Some of these regions have seen successes in new transmission build-out. The Plains, Midwest, and Texas have each built the most circuit-miles of any region, and observers have noted the relatively proactive within-region transmission planning in these places (2, 15, 26, 35). The Plains and Midwest have also been proactive in seeking out connections between the two regions (36, 37). Notably, though, Texas remains its own interconnection, with almost no transmission linking it to surrounding areas.

More generally, transmission connections across regions have seen almost no growth. Only two percent of new circuit-miles installed over 2011–2020 were for interregional lines (2). Relatedly, the majority of new investment over this period was for local reliability concerns, rather than generation cost savings (2)—and within-region lines generally do not threaten incumbent utilities' bottom lines.

Some observers have critiqued the very regions where we see the most potential for incumbent losses. The Southeast has been criticized for lacking transparency and proactive transmission planning (35, 38, 39). Utilities in the Northeast and Gulf Coast regions have been criticized for holding up interregional transmission—including, for instance, the NextEra opposition to a line that would bring Canadian Hydropower to Maine, and Entergy's opposition to the Southern Spirit line linking the Delta and Texas regions (12, 40–43). These are two cases where incumbent opposition was quite visible. In other cases, it may take place within regional transmission organization structures, in ways not apparent to outside observers (20). For further details and case studies of how a utility might delay or block a new transmission project, see refs. 6, 10, 12, and 14–16.

We note that the mapping from power plant profit changes to generation company profit changes depends on the spatial pattern of power plant ownership. Many (but not all) generation companies own assets primarily within one state or region, such that a transmission build-out would lead to correlated losses or gains across power plants in their footprint. Further details are provided in *SI Appendix*.

Future research could examine how interregional lines interact with local lines and with interconnection queues. Other areas for future research include incorporating the dynamic behavior of hydropower into the model, incorporating capacity markets, and incorporating renewable energy certificate markets. Long-run analyses to see how much new generation entry might be induced with additional transmission would also be useful. And finally, quantification of consumer surplus benefits would be of value—*SI Appendix* discusses impacts on wholesale prices and why mapping these into retail price effects is complex.

It is beyond the scope of this analysis to propose specific reforms, which will require incorporating a complicated legal, market, and engineering context. As analysts and policymakers propose reforms, it will be important to consider the incentives of suppliers and therefore the critical role of grid governance.

Materials and Methods

Data. Our two main data sources are the US Energy Information Administration (EIA) EIA-930 and the US Environmental Protection (EPA) Continuous Emissions Monitoring System (CEMS) dataset. From EIA-930, we use hourly supply and demand variables for 13 regions covering the entire lower 48 states. We also use information from EIA-930 on which regions are connected to one another: This allows us to construct demand shock variables for adjacent regions. Both the supply and demand variables have some implausible outliers, which we drop (e.g., occasional negative quantities or quantities with large changes from one hour to the next). Summary statistics for these supply and demand variables (and other primary variables) are provided in *SI Appendix*.

Our second main data source is CEMS, which reports hourly production and fuel use at nearly every conventional generator. CEMS comprises the universe of coal, natural gas, oil, and other combustible fuel generators with capacity over 25 MW, but not nuclear or renewable generators. We drop CEMS units whose main function is not selling into electricity markets (e.g., generators at hospitals and refineries)–specifically, commercial, industrial, and cogeneration units. CEMS also reports annual characteristics for each unit, including technology and fuel type, geographic location, and coverage by environmental regulations. In *SI Appendix*, we discuss how we convert gross to net generation and how we calculate heat rates, emissions rates, and unit capacity from the CEMS data.

Fuel prices are constructed from daily wholesale prices (Henry Hub for natural gas, West Texas Intermediate for oil) plus a mark-up constructed from EIA data on fuel prices paid by power plants, both from EIA. Operations and maintenance costs are from refs. 44 and 45. Environmental trading program permit prices are from the EPA and the Regional Greenhouse Gas Initiative (RGGI). Power plant outage rates are from MISO. We use the "CPI: Total for US" series from the Federal Reserve Bank of St. Louis's FRED to convert all prices to 2023 dollars.

Wind and solar curtailments in California are from CAISO; data for other regions were shared by LBNL (46, 47). The wind curtailments variable is limited to regions with ISOs; the solar curtailment data are limited to California and Texas. We make two bounding assumptions on curtailments in non-ISO regions: In a "low curtailment" scenario, we assume no curtailments in these non-ISO regions; in a "high curtailment" scenario, we assume that wind and solar facilities in the non-ISO regions curtail at the same rate as in the ISO regions. For analyses using curtailments data, we drop 2019, as the curtailments data begin only in 2020.

Methods. To examine power plant responsiveness to nearby versus distant demand shocks, we estimate a separate time series regression for each power plant in the CEMS data (6):

$$g_{i,t} = \beta_1 d_{\text{own demand},t} + \beta_2 d_{\text{connected dem.},t} + X_t\Theta + \varepsilon_{i,t} \qquad [1]$$

The unit of observation is a power plant i in an hour t. The dependent variable of interest, g, is net generation (MWh). We observe two demand variables of interest: *own demand* is the demand within the suppliers' own region, and *connected dem.* is the demand in regions directly connected to the suppliers' region.

We control for a time trend, various seasonal and other time effects (month, day of the week, and hour), and natural gas fuel prices, coal fuel prices, and oil fuel prices. We are interested in β_1 and β_2, particularly in how they compare with each other. If β_1 is larger for a given plant, then this plant is more responsive to nearby demand shocks, consistent with transmission and other spatial constraints.

Next, to calculate the market equilibrium under various assumptions about spatial barriers to trade (6), we first construct marginal cost ($mc_{i,t}$) for each thermal generator i at hour t as

$$mc_{i,t} = fp_t \cdot hr_i + om_i + ec_{i,t}, \qquad [2]$$

where fp_t is the price of fuel used by generator i in time t (in dollars per MMBtu), hr_i is the heat rate of unit i (in MMBtu per MWh), om_i is the unit's operating and maintenance costs (in dollars per MWh), and $ec_{i,t}$ is the environmental compliance cost (in dollars per MWh).

To construct daily natural gas and oil prices, we take the upstream benchmark price (Henry Hub for natural gas, West Texas Intermediate for oil) and add a state-by-year specific markup. This allows us to capture both day-to-day volatility and geographic dispersion in markups. Coal and coke prices do not have comparable high frequency upstream benchmark prices available, but these fuels also exhibit much less high frequency price volatility, so we simply use prices paid by generators at the state by sample month level.

We construct each generator's nameplate capacity from CEMS and apply outages to find hourly specific available capacity. Thermal generator plants are offline due to maintenance or outages a significant fraction of the time, making their handling important for modeling supply. Using the rate of planned and unplanned outages, we stochastically apply the latter across unit/hours (as in ref. 48) and derate capacity in the remaining operable hours by the planned outage share. Due to the convexity of the supply curve, taking entire units offline at the same hour will have larger implications for system costs than lowering capacity uniformly in all hours of the year. Planned outages are typically coordinated to limit the number of units offline at the same time, motivating a uniform derating of capacity, but unplanned outages sometimes occur all at the same time, motivating the decision to apply them stochastically across hours.

Finally, with generator-specific marginal costs and outage-adjusted capacities at the hourly level, we construct dispatch curves in two different scenarios to calculate measures of potential generation cost savings from market integration. We dispatch each unit i from the set I_r of units in region r to generate quantity of electricity g in hour t in order for total market supply in region r to equal market demand in region r at the lowest cost subject to the technical constraints. The constraints ensure that total market supply in region r matches total demand in region r at each hour and that each generating unit produces no more than its maximum capacity C. Formally, the cost minimization problem is

$$\begin{aligned} &\min_{g_{i,t}} \left(\sum_{i \in I_r} mc_{i,t} g_{i,t} \right) \\ &\text{s.t.} \sum_{i \in I_r} g_{i,t} = demand_{r,t} \quad \forall r \\ &g_{i,t} \leq C_{i,t}. \end{aligned} \qquad [3]$$

For the spatially constrained scenario, we use the North American Electric Reliability Council (NERC) subregions, as reported in the EPA's eGRID dataset, as our definition of geographic markets (r) and assume that for every hour demand for thermal generated electricity, $demand_{r,t}$, equals the observed generation from thermal generators within that market. This essentially constrains flows across regions to levels observed in each hour in the real world.

To examine model fit in the spatially constrained scenario, we compare our modeled dispatch to observed dispatch. As shown in *SI Appendix*, modeled and observed generation are highly correlated ($r = 0.63$ at the generator by hour level, and $r = 0.95$ at the generator level aggregated over time).

In the primary integrated scenario, we assume no transmission or other spatial constraints within each of the three interconnections, such that demand in each one is met with the lowest cost generators within it (though we continue to assume the separate interconnections act as distinct markets). We do not model transmission line losses; for a detailed discussion of how those might affect the modeling results, see ref. 6. That some electricity is lost across long-distance lines means that our estimates slightly overstate the benefits to market integration. However, increased transmission capacity can reduce line losses, and this is one of the benefits observers point to for justifying greater transmission investment (2). Moreover prior work finds that the modeling error introduced by ignoring line losses is small in comparison to the calculated generation cost savings (6).

We assume that relaxing spatial constraints allows for curtailed renewable electricity to be used productively, and therefore the demand for thermal electricity in an interconnection at time t is equal to observed generation from thermal generators within the interconnection minus the total quantity of wind and solar electricity curtailed within the interconnection at time t. Allowing curtailed renewable electricity to be productively used therefore represents a leftward shift of the residual demand curve for thermal electricity.

We construct the total additional generation costs caused by within-interconnection spatial constraints as the difference between total thermal costs in the current regionally constrained and the integrated-market scenarios. Doing so implicitly assumes that the behavior of nuclear, hydropower, and other facilities not included in the sample of thermal units is unchanged between the two scenarios. This is most realistic for nuclear and run-of-river hydropower facilities. Allowing hydropower to reoptimize its behavior requires a dynamic framework, which is beyond the scope of our model.

We calculate net revenues (i.e., variable profits) at individual power plants in each scenario as follows. For each scenario, we identify the marginal power plant in each market at each hour and set the market-clearing price equal to its marginal cost. Net revenues for an individual power plant in each hour are therefore calculated as the quantity produced multiplied by the difference between the market-clearing price and marginal cost. This calculation ignores revenues from three sources: capacity markets (small in most places); ancillary services revenues (again, small); and Renewable Energy Certificates (RECs) for wind and solar sites. In the spatially constrained scenario, our model yields a separate price in each region, with price dispersion across space driven by differences in fuel costs, generator fuel efficiencies, regional demand levels, and the extent to which transmission constraints bind. In the integrated scenario, our model yields just three prices in each hour: one in each interconnection, determined by the marginal cost of the marginal generator in that interconnection.

Data, Materials, and Software Availability. Code has been deposited in OpenICPSR (49). Processed study data are in the same repository, and information on how to access raw data is available in the same repository (49).

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