Transmission in the Energy Transition
PRELIMINARY: DO NOT CITE OR CIRCULATE

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Abstract

Economists, electrical grid analysts, policymakers, and renewable energy advocates have all called for substantial new investment in the U.S. electricity transmission network. Additional transmission lines could better integrate markets, reducing the total cost of electricity generation. They could also allow for the better integration of new renewable energy sources such as wind and solar, located in areas that traditionally did not have much generation capacity and that are far away from centers of demand. In this paper, I document the magnitude of allocative inefficiencies induced by transmission congestion and inadequate wind integration in two major U.S. electricity markets. I show that the allocative inefficiencies are rising over time, totaling nearly $3 billion in 2022. Moreover, I document an important political economy dimension not yet explored in the literature: the magnitudes of wins and losses from this market integration at a small number of *individual* companies is surprisingly large, with expected operating profit losses at just three companies totaling nearly $1 billion. I then tie these to reports of transmission hold-up in these markets. I argue that understanding firm-level winners and losers is just as important as understanding overall inefficiencies, particularly in an environment where incumbents may have the power to block new lines.

Keywords: Electricity markets, transmission constraints, renewable energy, market integration, political economy of energy markets, energy transition

JEL Codes: L94, P18, Q41, Q42, Q48

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1 Introduction

Market integration lowers aggregate production costs and brings gains from trade. This is true for electricity markets, where supply costs can be quite convex and where spatial integration can substitute for a lack of widespread storage. Moreover, grid integration – high-voltage transmission lines – is widely believed to be a key part of decarbonization strategy (National Academies of Sciences, Engineering, and Medicine, 2021; Princeton, 2021; Williams et al., 2021). Indeed, some scenarios have called for tripling the capacity of the grid (Davis, Hausman and Rose, Forthcoming).

The reason transmission may be particularly important in a transition towards decarbonization is that the grid of today is not spatially matched to the needs of a near-term decarbonized economy. Renewable resources like wind and solar are located in parts of the country that historically were not large sources of generation, and they are distant from most urban centers. New transmission lines have not kept up these new sources of generation, and as a result renewable energy gets "curtailed" (dumped) even at times when more expensive fossil plants are running in other regions. Concurrently, wholesale electricity prices have been low in renewable-rich regions, even though prices remain high in other regions (Seel et al., 2021), weakening incentives for new renewable investment.

In this paper, I study two major electricity markets in the heart of the U.S.: the Southwest Power Pool (SPP) and the Midcontinent Independent System Operator (MISO). Combined, these markets cover a renewable-rich swath of the windy Midwest, as well as demand centers stretching from Minneapolis and Detroit to New Orleans. I construct supply curves under counterfactuals with and without transmission constraints, calculating the allocative inefficiencies induced by the current lack of adequate transmission infrastructure. I also construct counterfactuals with and without wind curtailments. I find that in the recent past, transmission constraints were not particularly expensive (averaging $300 to $400 million per year over the 2016-2021 period).[1] However the costs of transmission constraints have been rising, with losses for 2022 equal to nearly $3 billion.

To further examine the causes of these costs, I next examine the actual behavior of generators in these markets. I document that generators tend to be dispatched in response to shocks within their own market (i.e., MISO generators in response to MISO demand). More striking, I find that generators tend to be dispatched in response to demand shocks in their own *subregion* of their market. I find an especially striking divide between the Southern part of MISO (the Gulf Coast) and the Northern and Central Parts (the Great Lakes).

It is of course possible that the $3 billion allocative inefficiencies I document for 2022

[1] Dollar values throughout are reported in $2022; I deflate using the CPI - all items less energy.

are socially optimal, if the cost of building new transmission lines is very high. However, many grid observers have argued that the transmission planning process in the U.S. does not lead to socially optimal investments, in particular for long-distance lines crossing regions. Davis, Hausman and Rose (Forthcoming) point to myriad problems in the planning process, ranging from NIMBY-ism concerns to bureaucratic procedures for cost allocation.

To examine one potential source of transmission planning failures, I turn to empirical estimation of the potential winners and losers from market integration. While gains from trade in the *aggregate* are to be expected, it is also to be expected that some agents will lose – in particular, incumbent generators in high-cost regions. There is nothing wrong here for overall social welfare, but understanding which power plants, which regions, and which companies stand to lose can point towards political economy barriers.

I show that the potential losses of operating profits are very large for a small number of companies – totaling over $1 billion per year at just two companies. Not surprisingly, these companies serve the Southern MISO region, an area known for inadequate connections to nearby regions. Moreover, the two companies with the most to lose from grid integration have been accused for decades of blocking new transmission lines. The tactics they have been accused of range from preventing competitors from accessing the company's transmission network, to slow-walking the market-wide transmission planning process, to hiring a consultant to pose as a concerned customer in public hearings.

A notable gap in the empirical literature on transmission networks is documentation of the magnitude of gains and losses to individual companies. Numerous papers cite this problem qualitatively (Hirst and Kirby, 2001; Joskow, 2021; Davis, Hausman and Rose, Forthcoming; Hogan, 2018; Wolak, 2020; Cicala, 2021), but empirical estimates are rarely reported. This is of particular importance given claims in the literature that "losers" may be holding up the transmission planning process. I argue that the allocative inefficiencies that are becoming widely documented are a result of the planning process we have in the US, and therefore understanding incentives for companies to block market integration is of both intellectual merit and policy relevance.

The paper most directly related to my analysis is Gonzales, Ito and Reguant (Forthcoming), which conducts a thorough examination of the role of transmission expansion in both the short-run dispatch and long-run investment decisions of the Chilean electricity market. Of most relevance for what I do, that paper shows how allocative inefficiencies arise as a result of transmission bottlenecks, and how these are exacerbated by renewables curtailments (in this case, solar). Another paper considering the dynamic relationship between renewables and the transmission grid is Johnston, Yifei and Yang (2023), which looks at interconnections – the transmission lines specifically needed for new renewables hook-ups

– in the PJM market. My paper complements their work by focusing on the across-region transmission constraints impacting existing generators.

Other related papers on the interaction of renewable generation and transmission network expansion include Doshi (2022); Fell, Kaffine and Novan (2021); Lamp and Samano (2023); LaRiviere and Lyu (2022); Qiu (2020), and Yang (2022). These papers study a variety of markets (Texas, Germany, and more) and a variety of modeling techniques. Taken as a whole, these papers show how transmission and renewable generation can be complements. This relates to evidence on the spatial misallocation of renewables investments in the US to date (Callaway, Fowlie and McCormick, 2018; Sexton et al., 2021).

There is also a broader literature on allocative inefficiencies arising from transmission constraints in electricity markets even aside from their interaction with renewable generation. Some of these papers emphasize how opportunities to exercise market power are increased in the presence of transmission constraints (Wolak, 2015; Davis and Hausman, 2016; Ryan, 2021). Widely assumed by policymakers, but less widely-researched in the academic literature, is the role of the transmission network in enhancing grid reliability (Borensten, Bushnell and Mansur, 2023). And finally, there is a broader literature on the regional integration of electricity markets, relating to market design rather than to physical transmission constraints (Mansur and White, 2012; Cicala, 2022).

The paper proceeds as follows. In Section 2, I provide brief contextual background. Section 3 summarizes the data sources I use. Section 4 summarizes the methods and results on allocative inefficiencies. Section 5 documents impacts at individual companies. Section 6 shows various robustness checks, and Section 7 concludes.

2 Background

In this Section, I provide brief contextual background. I study two U.S. electricity markets, the Southwest Power Pool (SPP) and the Midcontinent Independent System Operator (MISO). Each is a non-profit entity responsible for operating the electricity within their footprints: matching supply and demand offers, as well as ensuring grid reliability).

SPP's members are in fifteen states, roughly covering the Great Plains region from Montana to Texas.[2] MISO also serves fifteen states (roughly, from North Dakota to Michigan and south to Louisiana) and one Canadian province.[3] Some states are served by both SPP

[2]SPP's members are in Arkansas, Colorado, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming

[3]The states served are Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin – some (such as Montana and Texas) are only partly covered by MISO.

and MISO, but one can broadly think of SPP as covering the Great Plains and MISO as being more to the east (Great Lakes and the Gulf Coast).

Both SPP and MISO are part of the Eastern Interconnection. The U.S. electricity grid is physically divided into three such interconnections: one in the western half of the country, one in the eastern half, and one roughly covering Texas. There is almost no transmission between the three grids, a legacy of the way the grid originally developed in the U.S.

The generation mix of both MISO and SPP includes a mix of fossil power plants (coal and natural gas), nuclear, and a growing supply of wind (particularly in SPP). Both regions have small quantities of hydro, solar, and other units (e.g. thermal plants fueled by solid waste). Summary statistics are provided below.

Both SPP and MISO have independent market monitors, who evaluate the functioning of each market, including both reliability metrics and whether generators appear to be exercising market power. Annual reports from both market monitors covering my sample period indicate very competitive generation markets.

3 Data

3.1 Data Sources

I build a detailed panel dataset on these two major U.S. electricity markets (SPP and MISO), incorporating data from several government agencies as well as both market operators.

From the U.S. Environmental Protection Agency's CEMS dataset, I observe hourly generation (in MWh) and hourly fuel use (in mmBtu) at each thermal generating unit; a typical power plant has between one and eight generating units.[4] The main summary statistics are provided in Table 1; additional summary statistics are in the Appendix. Average generation is 72 MWh, but 230 MWh when conditional on a unit operating (i.e., the average non-zero value). [5]

Also from CEMS, I observe the fuel type of each unit (coal, natural gas, and oil), the unit's technology (boiler, combined cycle, or combustion turbine), and the unit's location

[4]The EPA data are limited to generating units with a capacity of at least 25 MW; smaller units are observable only at the annual level, from a separate data source (the Energy Information Administration's EIA-923 survey). However, the average capacity of a thermal unit in the U.S. is XX MW, so these unobserved units are quite small – make up only XX percent of total thermal generation, according to the EIA-923 panel.

[5]One perhaps unfortunate feature of the CEMS data is that the reported generation is "gross" rather than "net" – the difference is generation used for in-house operations, and therefore not sold on the wholesale market. To convert from gross to net generation, I follow the literature (Cicala, 2022) in matching gross generation from CEMS to net generation from the Department of Energy's Energy Information Administration's EIA-923 dataset (available at the annual level), then constructing a plant-specific conversion factor; details are in the Appendix.

Table 1: Summary Statistics

	N	Mean	SD	Min	Max
Panel A: Panel data					
Generator characteristics:					
Generation, MWh	52,605,900	71.8	149.9	0	890.9
Generation when dispatched, MWh	16,417,765	229.9	188.8	0.00096	890.9
Fuel type indicator: Coal-fired	52,605,900	0.21	0.41	0	1
Natural gas	52,605,900	0.74	0.44	0	1
Oil-fired	52,605,900	0.046	0.21	0	1
Technology indicator: Boiler	52,605,900	0.34	0.47	0	1
Combined cycle	52,605,900	0.15	0.36	0	1
Combustion turbine	52,605,900	0.51	0.50	0	1
Location indicator: MISO	52,605,900	0.66	0.47	0	1
Ownership indicator: IOU	52,605,900	0.92	0.28	0	1
Panel B: Time-series data					
Wind curtailed in MISO, MWh	26,232	525.7	719.8	0	4925
Wind curtailed in SPP, MWh	61,031	387.4	894.4	0	8953.9
National fuel prices:					
Coal, $/MMBtu	61,032	2.34	0.16	2.04	2.65
Coke, $/MMBtu	61,032	2.76	0.91	1.30	5.02
Natural gas, $/MMBtu	61,032	4.37	2.12	2.29	18.5
Oil, $/MMBtu	61,032	15.6	4.59	7.51	29.2

Note: This table provides summary statistics for my main estimation sample, at the generator by hour level. The sample is an unbalanced panel covering the period 2016-2022, with 992 generating units at 367 power plants. This represents all CEMS-reporting power plants (generally, fossil-fuel fired units with a capacity of at least 25 MW) in the MISO and SPP footprints. The main sample excludes commercial and industrial units and cogeneration units. There are fewer observations for the "quantity of wind curtailed" variables because the MISO reports this beginning in only December 2019, and because SPP data are missing for a small number of days. Additional summary statistics are in the Appendix.

(latitude and longitude). Around half of units in the sample are combustion turbines, one third boilers, and fifteen percent combined cycle units (however note that boilers and combined cycles are larger and are dispatched more frequently, so the generation-weighted shares are quite different; as described below). The majority (74 percent) of units are natura-gas fired, 21 percent are coal-fired, and only five percent are oil-fired. From the Energy Information Administration's EIA-860 survey, I observe additional characteristics of each plant: its location in MISO versus SPP, the name of its owner, and whether its owner is an investor-owned utility or a merchant generator. Two thirds of the units I observe are in MISO, which has a larger footprint than SPP. The majority (92 percent) of units are operated by investor-owned units.

From the CEMS hourly generation, I calculate each unit's heat rate, a measure of how efficiently it converts fuel into electricity (and a primary component of marginal cost), as the annual fuel used divided by annual generation. An additional component of marginal cost is variable operations and maintenance costs; these are available by unit type from a MISO report (MISO, 2021). I calculate each unit's capacity as the 99th percentile of observed generation. Generating units are taken offline frequently for maintenance, so I assume monthly outage rates from a market monitoring report (Potomac Economics, 2022).

The two market operators also release detailed data. From each, I observe ISO-wide hourly generation by fuel type – this is important for understanding the behavior of nuclear and renewable generation, as those fuel types are not represented in the CEMS data.[6] I also observe hourly wholesale electricity prices at the regional level within each ISO – MISO reports these for eight regional hubs, and SPP reports prices for the northern and southern parts of its footprint. Each ISO also reports total quantity demanded at the hourly level (called "load" in electricity markets) for three regions each (northern, central, and southern).

As discussed in Section 2, wind has been increasingly curtailed in both MISO and SPP. MISO does not make hourly curtailment data available, but I assemble curtailment data for each day for the period December 2019 through December 2022, in the peak versus off-peak period, from the slide decks published for its monthly Informational Forum web presentation. From SPP, I observe hourly wind quantity curtailed. In recent years, MISO has curtailed an average of over 500 MWh of wind in each hour, more than the average generation of two dispatched coal plants. For the sample as a whole, SPP has curtailed an average of nearly 400 MWh. In a typical hour in 2022, curtailments were around 4-8 percent of wind generation in SPP and 3-5 percent in MISO.[7]

[6]MISO but not SPP also releases hourly generation by fuel type at a broad regional level (north, central, south) – which I leverage later when examining counterfactual revenues.

[7]Four percent is the SPP median and 8 percent the mean; 3 percent is the MISO median and 5 percent the mean.

Fuel prices are published by the EIA. At the daily level, I observe the Henry Hub natural gas price and the West Texas Intermediate (WTI) oil price. At the monthly level, I observe the average fuel price paid by power plants for coal, natural gas, and oil.

Additional control variables are published by a variety of sources. From the EIA's 930 report, I observe total load in various regions throughout the U.S.; I focus on load in the Eastern Interconnection. Finally, daily temperature at various locations around the MISO and SPP footprints is published by the National Oceanic and Atmospheric Administration (NOAA).

4 Allocative Inefficiencies

4.1 Constructing Marginal Cost Curves

To construct market-wide marginal cost curves, I first construct the marginal cost of each thermal generating unit as follows:

$$mc_{i,t} = fp_t \cdot hr_i + om_i \tag{1}$$

where fp is the fuel price in each hour, hr is the heat rate of each unit, and om is the unit's variable operating and maintenance costs. Recall that the EIA publishes both monthly data on average prices paid for fuel by power plants and daily upstream fuel prices (Henry Hub for natural gas and WTI for coal). It is important to capture both this daily variation for natural gas and oil as well as the mark-up, so I construct fuel prices as the upstream price (varying daily) plus a time-invariant average mark-up (the sample-wide difference between the upstream and downstream prices reported by EIA). Coal prices have vary little variation across days within a month, so I simply use EIA's monthly data on average price paid by power plants. I assume technology-specific om values from Energy Information Administration (2019) where possible and otherwise from Energy Information Administration (2022).

An additional, albeit quite minor, marginal cost for most units in my sample is costs paid to purchase permit prices to cover pollution emissions. Units in these states are covered by a variety of EPA cap and trade programs, such as the Acid Rain Program, which regulates sulfur dioxide emissions. I observe hourly emissions from the EPA CEMS dataset and annual permit prices from the EPA's Power Sector Programs Progress Reports. These costs have at some points in US history been very high, but for my sample this increases marginal cost by less than one percent.

My primary sample focuses on the coal, natural gas, and oil power plants for which marginal costs are well-known. My primary sample drops a small number of thermal units

with fuel types such as wood and municipal solid waste; these make up only XX percent of generation. As my primary analysis constructs counterfactuals regarding changing the dispatch of thermal units, this is akin to assuming that their behavior does not change in my counterfactuals. Similarly, I drop commercial and industrial and cogeneration units (e.g., generating units located at chemical plants, hospitals, and universities) – again, marginal costs at these units are not clear, and dropping them is simply assuming that they would not respond to changes in market incentives.

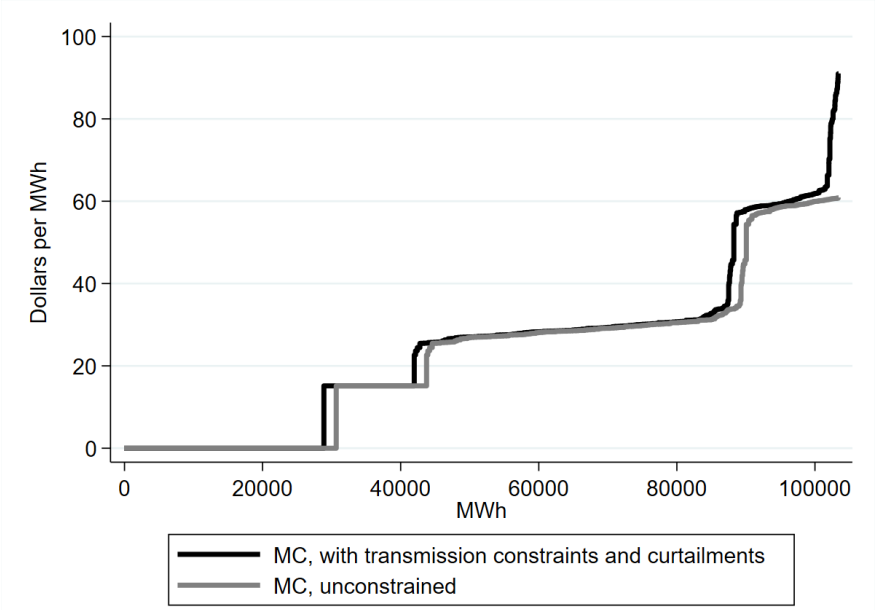
Marginal costs for renewables and nuclear generation do not depend on heat rates and permit prices. Following the literature, I assume that renewables (wind, solar, and hydro) have zero marginal cost. Capacity for these types varies across hours, depending on weather (e.g. how windy it was that hour). I construct capacity as observed generation for each fuel type, plus the quantity curtailed. For nuclear units, I assume a marginal cost based on the average operating expenses for nuclear units reported in Energy Information Administration (2023).[8] I again construct capacity as the observed generation in that hour; nuclear units do not respond to fluctuations in marginal cost because of operational constraints (Davis and Hausman, 2016).

With hourly marginal costs constructed as in equation 4.1, I can construct market-wide marginal cost curves. For my first counterfactual, I use a simple least-cost dispatch framework: I rank the units by their marginal cost and dispatch units until demand is met. This approach is widely used in the literature (Borenstein, Bushnell and Wolak, 2002; Deetjen and Azevedo, 2019; Cicala, 2022). A limitation of this approach is that it ignores transmission constraints and various technical constraints of generating units themselves (ramping costs and other dynamic considerations, and minimum dispatch constraints). Below, I augment with additional counterfactuals to incorporate these constraints.

An example marginal cost curve is shown by the grey line in Figure 1. I choose a sample hour that is "typical" in terms of total quantity demanded, fuel prices, and wind quantity curtailed for 2022; additional sample hours representing different market conditions are shown in the Appendix. For this hour, 29,000 MWh of generation are provided by zero-cost renewables, an additional 13,000 MWh by nuclear, and then the remaining 61,000 MWh are provided by a mix of thermal generating units. For the latter, marginal cost varies across units both because of varying heat rates (a function of vintage and technology type) and fuel prices (a function of the fuel type used).

[8]Table 8.4 of Energy Information Administration (2023) reports average fuel costs of around \$6.80/MWh for my sample period. Operations and maintenance costs average \$16.80/MWh; I assume that half of these are fixed O&M and half are variable O&M, i.e. half are marginal to generation. This gives a marginal cost estimate of \$15.15/MWh, comparable to the California-specific estimate used in Davis and Hausman (2016).

Figure 1: Example Marginal Cost Curves, With and Without Transmission Constraints and Wind Curtailments



Note: This figure shows two constructed marginal cost curves for a representative hour in 2022. The grey line shows the marginal cost curve for least-cost dispatch, with no restrictions on electricity flows across space, and with the dispatch of wind that was, in practice, curtailed that hour. In contrast, the black line constrains quantities generated within a NERC subregion to the quantity observed in the actual data (to approximate transmission constraints), and curtails wind generation at the level observed in the actual data. Zero marginal cost resources are largely wind, but also include hydro and solar generation. Nuclear generation is assumed to have a marginal cost of \$15/MWh. The remaining units are powered by coal and natural gas, with differences in marginal cost reflecting differences in heat rates and fuel type. The date and hour displayed are chosen because they have fuel costs, quantity demanded, and quantity curtailed close to the sample average for 2022. Additional date-hour combinations (with alternative fuel costs, quantity demanded, and quantity curtailed) are shown in the Appendix.

4.2 Modeling Transmission Constraints

For the second counterfactual, I assume that the system is constrained in two ways. First, I incorporate regional transmission constraints. I model transmission constraints in a reduced form way as follows. I assign each generating unit to a North American Electric Reliability Corporation (NERC) subregion. NERC is a non-profit organization that oversees electric grid reliability in the US, Canada, and part of Mexico, and it monitors reliability across approximately two dozen subregions. I infer transmission constraints across subregions at the hourly level by calculating the total quantity supplied by thermal generating units in each hour in each subregion using the CEMS generation data. As I dispatch units using the least-cost dispatch algorithm described above, I constrain generation in each subregion in each hour to what I empirically observe. That is, I force each subregion to generate no more than what was actually generated in the real world.[9]

Ideally, one would model transmission constraints in a more sophisticated way, but that is not feasible here for several reasons. Accurate modeling of the transmission network would require knowing the topography of the grid, including not only line locations but also line ratings (the capacity of each line); detailed information on this topography is not publicly available. Furthermore, modeling the flow of electrons across this network is complicated. One should not picture something like a pipeline network for natural gas or water, in which one would simply need to observe quantities flowing in and out of the pipelines. Instead, electron flow across a network is governed by complex laws of physics (Joskow, 2012). Moreover, congestion is constantly changing as demand, generation, and weather change. As such, my reduced form model instead provides a reasonable approximation that uses publicly available data, that can be calculated for every hour using observable data, and that is computationally not too burdensome.

This counterfactual also assumes that wind generation is curtailed because of transmission constraints, following what I see in the real world. Whereas the first counterfactual constructed wind capacity as equal to observed generation in each hour plus observed quantity curtailed in each hour, this second counterfactual constructs wind capacity as equal to only observed generation in each hour.

The market-wide marginal cost curve for this second counterfactual is shown with the black line in Figure 1. Zero-cost generation shifts inward, by the quantity curtailed. Nu-

[9] In a very small number of hours, my model predicts that too little capacity is available in some regions. This is because I derate capacity according to typical outage patterns; and in practice there are some hours when fewer plants were experiencing outages than what is typical. In these hours, I force all units to operate slightly above their outage-derated-capacity. This changes generation by more than 1 MWh for fewer than 0.05 percent of observations.

clear units are unaffected, by construction.[10] Also, some higher-cost thermal units must be dispatched because of the regional transmission constraints. As a result, the marginal generating unit has a marginal cost of around $33/MWh.

4.3 Calculating Annual Allocative Inefficiencies

The wedge between the black and gray lines in Figure 1 represents the additional costs required to generate electricity that are induced by regional transmission constraints and the need to curtail wind. By calculating the area between the two curves in each hour, I can construct a time series of the allocative inefficiencies induced by transmission constraints and wind curtailments. Figure 2 shows this time series at the monthly level. I focus on 2020 through 2022, the period for which wind curtailments data are available from MISO; a time series with inferred wind curtailments for 2016-2020 is shown in the Appendix.

Figure 2 shows that transmission and curtailment-related allocative inefficiencies have been rising over time for the MISO and SPP markets. This is a combination of increasing curtailments and increasing natural gas prices, as detailed below. By the 2022, the average monthly allocative inefficiencies total $220 million, translating to nearly $3 billion for 2022. Table 2 shows an annual summary of the allocative inefficiency.

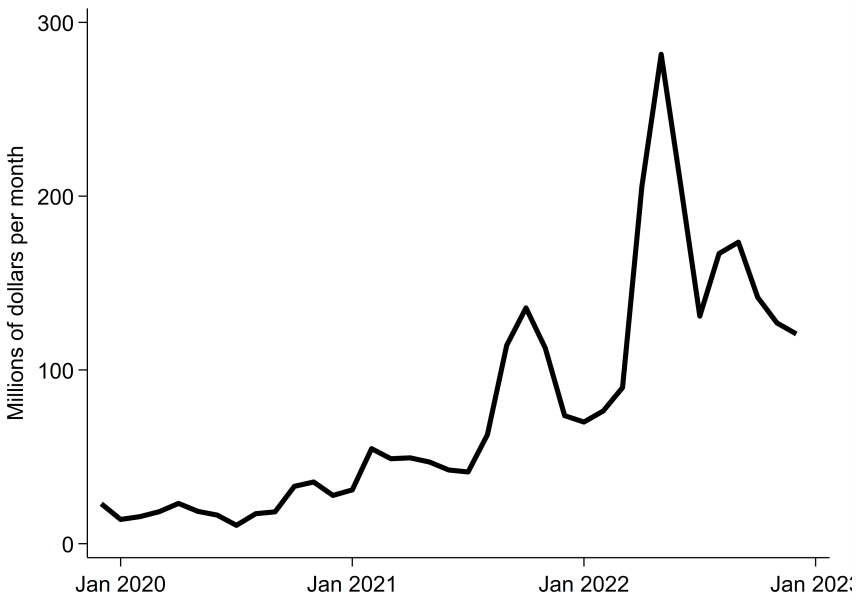
For the sample as a whole, annual allocative inefficiencies total $0.6 to $0.7 billion dollars (the range comes from what one assumes about MISO wind curtailments for the 2016-2019 period). However, this average masks a large difference between the 2016-2021 period – with an annual average of $0.3 to $0.4 billion dollars – and the 2022 period – with annual inefficiencies of $2.75 billion.

This stark difference in 2022 costs is primarily the result of increasing curtailments and increasing natural gas costs, and it has important policy implications. To decompose the source of the increase, the Appendix shows the time series of allocative inefficiencies holding various market conditions constant (annual demand, curtailments, and fuel prices). [XXdescribe results from this exercise].

The increase over time points to important policy implications. First, it is clear why some policymakers and grid observers have been increasingly calling for new transmission infrastructure in recent years. The transmission network basically did what it needed to – connecting thermal power plants to load in population centers. But in a world with increasing quantities of renewable generation, the existing network doesn't match the spatial distribution of generation.

[10] As described above, it is technologically difficult and expensive to ramp nuclear units up and down; as a result, nuclear units are vary rarely curtailed. They are occasionally forced to limit their generation because of safety concerns, which I do not model as part of this counterfactual.

Figure 2: Additional Generation Costs From Transmission Constraints and Wind Curtailments



Note: This figure shows the monthly generation costs in MISO and SPP that arise from transmission constraints and renewables curtailments. Transmission constraints are modeled at the NERC subregion level and so do not include within-subregion transmission constraints. Costs are rising over time from a combination of increasing natural gas prices and increase curtailments. Robustness checks are shown in the Appendix. Additional time series, holding various factors constant, are also shown in the Appendix.

Table 2: Annual Allocative Inefficiencies

Time period	Average annual cost, billion dollars
2016-2022	0.67 to 0.75
2016-2021	0.32 to 0.41
2022	2.80
2022, across-ISO constraints	0.16
2022, within-ISO constraints	1.15
2022, curtailments	1.49
2022, within-SPP constraints	0.12
2022, within-MISO constraints	1.03

Note: This table shows the average annual generation costs in MISO and SPP stemming from transmission constraints and renewables curtailments. Matching Figure 2, the table shows the increase after 2021 in these costs. The next three rows decompose the 2022 cost into three factors: renewables curtailments, transmission constraints between MISO and SPP, and transmission constraints across NERC sub-regions within MISO and SPP. The bottom two rows separate within-ISO constraints into those within MISO and those within SPP.

Second, low natural gas prices in recent decades had flattened the market-wide marginal cost curve for electricity. But with natural gas prices surging up, the marginal cost curve has rotated, and dispatching the "wrong" unit – because of something like a regional transmission constraint – has gotten much more expensive.

Table 2 next shows (rows 4-6) that the largest source of the 2022 inefficiencies is curtailments ($1.42 billion). With wind facing a marginal cost of essentially zero, curtailing it and having to dispatch a fossil unit can significantly raise the costs of dispatch. The second largest source of inefficiencies in 2022 was within-ISO constraints ($1.17 billion), whereas across-ISO constraints totaled only $0.16 billion. Moreover, the within-ISO constraints are largely coming from MISO rather than SPP (rows 7 versus 8). I next turn to descriptive evidence of the sources of these transmission constraints.

4.4 Sources of Transmission Constraints

Section 4.3 shows that total generation costs can increase substantially if generation is regionally constrained. Specifically, in 2022, across-ISO and within-ISO regional constraints together added $1.33 billion in generation costs for fossil units. Of this, the single largest source is within-MISO constraints ($1.06 billion). To better understand these constraints, I next turn to descriptive evidence on observed generator dispatch.

Specifically, I use the CEMS data on hourly generation for each fossil generating unit in

MISO and SPP, and I run "horse race" regressions on the observed load in different regions. These regressions are designed to answer the question: to which load (demand) is generator dispatch most likely to respond? If the electrical grid were physically unconstrained, generators would be expected to respond equally to a demand shock in any location. If we observe that generators are more often dispatched in response to a demand shock in their own region, that suggests that the electrical grid is constrained in some way.

I primarily rely on one identifying assumption: I must assume that demand shocks are exogenous. This assumption is made in most papers on electricity economics that use hourly generation – the majority of consumers do not face real-time prices, and so are not incentivized to respond to hourly shocks to supply.

I run a separate regression for each power plant, as follows:

$$g_{i,t} = \beta_1 d_{SPP,t} + \beta_2 d_{MISO,t} + \beta_3 d_{EI,t} + X_t\Theta + \varepsilon_{i,t} \tag{2}$$

where generation g at power plant i in hour t is a function of demand d in hour t in SPP, MISO, and the Eastern Interconnection. The U.S. electricity grid is divided into three interconnections, with very limited (nearly zero) flows across interconnections. MISO and SPP are both located in the Eastern Interconnection, so I control for demand in the rest of that interconnection (after subtracting out MISO and SPP demand).

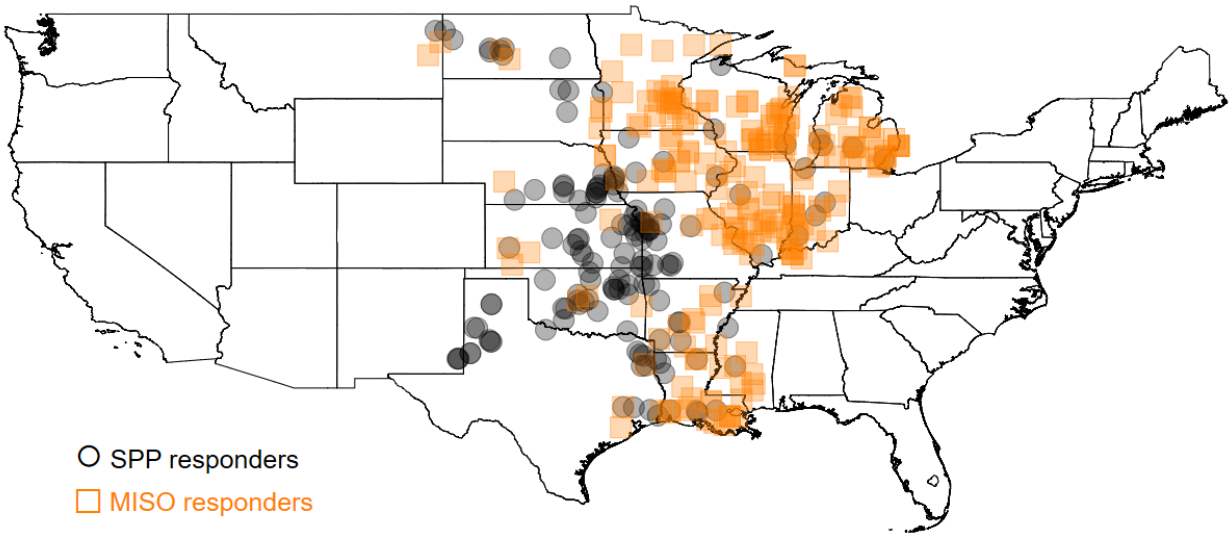
Under the assumption that demand is exogenous, additional control variables may not be needed for estimating equation 4.4. Nonetheless, I follow the literature in including controls X for fuel prices (natural gas, coal, and oil), weather (ambient temperature), a time trend, month-of-year effects, day-of-week effects, and hour-of-day effects. These controls may be useful for accounting for things like maintenance outages are planned for specific months of the year, which are correlated with demand. Additionally, the controls may help with precision. In the Appendix, I show results without controls.

I estimation equation 4.4 separately for each of the 394 fossil units in my CEMS sample, with each regression using hourly data covering the 2016-2022 period.[11] I then collect the estimated $\hat{\beta}$ coefficients, and I examine whether $\hat{\beta}_{SPP}$ or $\hat{\beta}_{MISO}$ is larger for each power plant. That is, is each power plant dispatched more in response to demand in its own ISO or in the neighboring ISO.

Figure 3 maps the location of each power plant, with separate markets to show whether the plant is dispatched at higher levels of generation more in response to SPP load (red

[11]The primary sample for equation 4.4 drops a two week period in February 2021, when Winter Storm Uri disrupted energy markets in Oklahoma and Texas. During that period, natural gas prices quadrupled XXcheck (leading to outliers in my control variables), and some generators were forced to shut down because of weather. In the Appendix, I show results that include this period.

Figure 3: Power Plants Are Dispatched For Own-ISO Load



Note: This figure shows whether power plants are dispatched at higher levels of generation in response to SPP load (black circles) or in response to MISO load (orange squares). The response generally matches the footprint of ISOs, with generators in states such as Nebraska responding to variation in SPP load, and generators in states like Illinois responding to variation in MISO load. Horse-race regressions are used to determine to which ISO's load the generator is dispatched, following equation X in the main text.

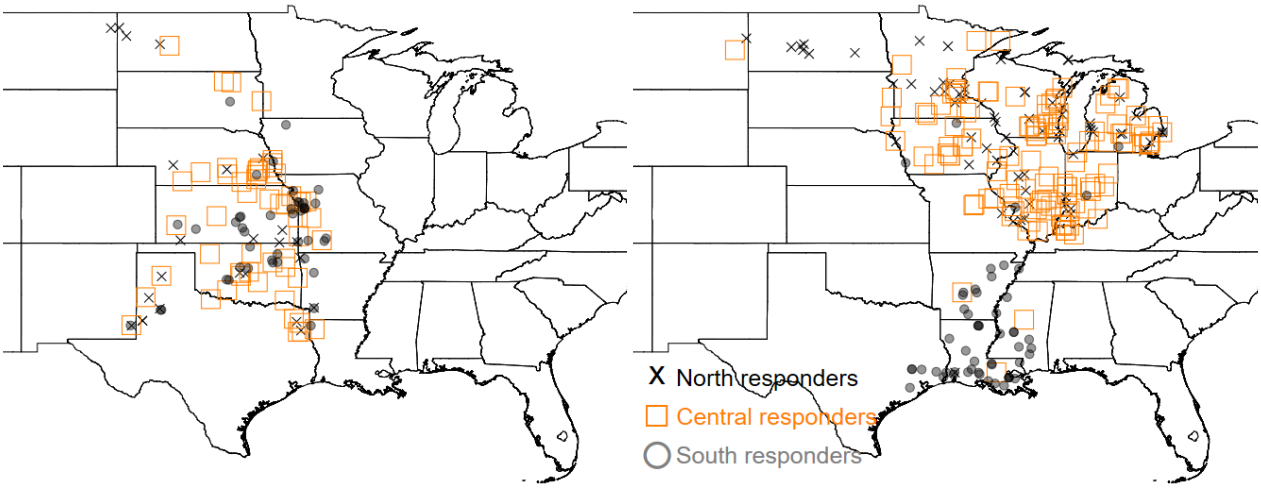
circles) or to MISO load (green squares). The response appears to match the footprint of each ISO, with Western generators being dispatched in response to SPP load and Eastern generators in response to MISO load. It is worth noting that the MISO service territory extends northwest into North Dakota and Montana; the SPP and MISO footprints are intermingled in those states.

Appendix table A2 shows that 88 percent of SPP plants have $\hat{\beta}_{SPP} > \hat{\beta}_{MISO}$ and 84 percent of MISO plants have $\hat{\beta}_{SPP} < \hat{\beta}_{MISO}$ – the large majority of power plants are dispatched more in response to load within their own region. The appendix also shows that results are similar for alternative horse race specifications and various weighting schemes.

I next extend the horse race regressions to examine the possibility of within-ISO constraints. Specifically, I break out demand into three regional variables – North, Central, and South – for each ISO (the level at which each ISO reports regional demand). For power reasons, I do not include all six regional load variables in the horse race regression; rather, I include the three regional demand variables for a power plant's own ISO, plus total demand in the other ISO, and total demand in the rest of the Eastern Interconnection. For a SPP-located unit, for instance, the regression is:

$$g_{i,t} = \beta_1 d_{NorthSPP,t} + \beta_2 d_{CentralSPP,t} + \beta_3 d_{SouthSPP,t} + \beta_4 d_{MISO,t} + \beta_5 d_{EI,t} + X_t\Theta + \varepsilon_{i,t}. \quad (3)$$

Figure 4: Some Power Plants Are Dispatched More For Own-Region Load



Note: This figure shows whether power plants are dispatched at higher levels of generation in response to Northern (black X), Central (orange square), or Southern (grey circle) regional load within their own ISO. Within SPP (left panel), no clear pattern is detectable. In contrast, MISO generators (right panel) appear to respond more to nearby load than to far-away load.

Figure 3 displays whether each fossil power plant responds more to Northern (black X), Central (orange square), or Southern (grey circle) regional load within their own ISO. For SPP, no clear pattern is detectable. This is consistent with the results in Table 2, which showed that within-SPP constraints contribute very little to the annual allocative inefficiencies. In contrast, a clear pattern emerges within MISO, where power plants in the north (e.g. North Dakota) tend to be dispatched in response to shocks to northern load; plants in places like Illinois tend to be dispatched in response to central load, and plants in Louisiana in response to southern load. This is consistent with transmission constraints tending to bind *within* MISO, and can explain why the within-MISO allocative inefficiencies are a large contributor in Table 2.

Overall, these horse race regressions are useful for several reasons. First, they are a new way of demonstrating the role of grid constraints across space. In doing so, they provide additional empirical support for the argument that eliminating transmission constraints could improve grid outcomes by allowing power plants to respond to demand shocks in far-away regions. Finally, they confirm what Table 2 shows: within-ISO constraints are important, not only across-ISO constraints, and this is particularly true within MISO.

5 Political Economy Implications: Winners and Losers

I have thus far showed that power plant dispatch in the Midwestern U.S. is more costly than it would be in a world without curtailments and without transmission constraints. This is in line with evidence from other regions, including Texas and Chile (LaRiviere and Lyu, 2022; Gonzales, Ito and Reguant, Forthcoming). I have also shown that the magnitude of the resulting inefficiency has grown over time, becoming more policy relevant with increasing curtailments and increasing fuel prices. I next turn analysis of how eliminating curtailments and transmission constraints might affect individual power plants and their owners. In particular, I calculate operating profits for each power plant under a least-cost dispatch scenario and a constrained and wind-curtailed scenario.

The literature to date on transmission constraints and renewables integration has focused on total allocative inefficiencies – the importance for society of reducing generation costs is clear. However, the literature has largely ignored the role of producer surplus at individual plants or individual firms. Yet understanding the impacts of better grid integration on individual firms is also crucial for policy analysis. Transmission planning is largely a consensus-based process, with opportunities for actors to hold up new transmission development throughout the transmission planning process (Davis, Hausman and Rose, Forthcoming). For political economy reasons, then, it is important to understand the incentives of firms to push for or to block new transmission lines.

The counterfactuals described in Sections 4.1 and 4.2 yield predicted quantities generated at each power plant. I can also use those counterfactuals to calculate the equilibrium price, equal to the marginal cost of the marginal generating unit. I then calculate operating profits as the revenues minus variable costs; this static analysis ignores fixed costs (equivalently, I assume that fixed costs are equal across my two counterfactuals). For each generating unit, I calculate operating profits in each of 8,760 hours, where hourly electricity market conditions are based on real-world 2022 conditions (that is, total quantity demanded, fuel prices, etc. use 2022 values). I then aggregate across generating units to the power plant level.

5.1 Incentives to Block Transmission Increase as Renewables Enter

As shown in Section 4.3, the allocative inefficiencies from inadequate transmission have been rising over time, in part as a function of increasing curtailments of renewables. Relatedly, the incentives for incumbents to block new transmission lines are also increasing as new renewables enter. Integrating the market implies that those low-cost renewables can be exported to other regions, which can both displace fossil generation and also lower market

prices for the remaining fossil generation.

To understand the magnitudes of this, I regress operating profits at the hour by company level on the quantity of wind available across the MISO and SPP footprints. "Available wind generation" is the sum of wind generation that actually occurred and wind generation that was curtailed. I estimate three regressions, each with a different dependent variable: (1) operating profits in the transmission-constrained counterfactual; (2) operating profits in the integrated market counterfactual; and (3) the change in operating profits a company experience when the market moves from constrained to integrated. Following the literature, I control for other determinants of generator dispatch and prices: fuel prices, quantity demanded, various time effects (month of year, day of week, hour of day), and a utility-level fixed effect.

[In progress.]

5.2 Winners and Losers Are Located in Different Places

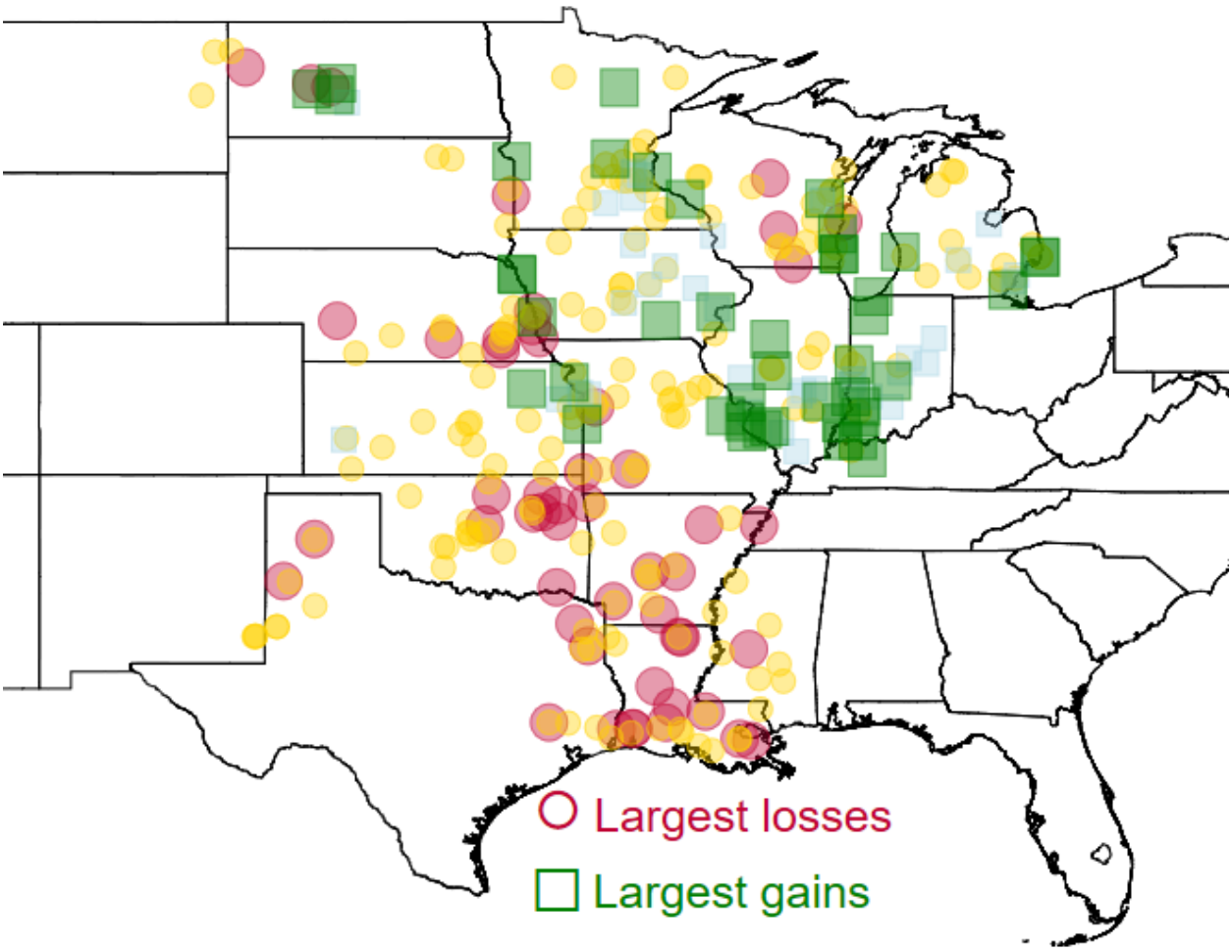
Figure 5 displays the location of each fossil power plant in SPP and MISO, along with how profits compare under my two counterfactuals. Specifically, I calculate whether operating profits would rise or fall with transmission constraints and curtailments were eliminated. The plants that would lose the most (at least $10 million annually) from eliminating transmission constraints and curtailments are shown in large red circles; the plants that would gain the most are shown with large green squares. Plants that are less affected are shown with smaller markers.

Consistent with Table 2 and Figures 3 and 4, there is a pronounced regional pattern. Plants in northern MISO stand to gain the most, and plants in southern MISO to lose the most. This regional pattern has political economy implications. Generation companies operating in southern MISO have no incentive to develop new transmission lines that better integrate their power plants with SPP, central MISO, and northern MISO. In fact, in a consensus-based transmission planning process, these companies have strong financial incentives to block new lines.

To understand the magnitude of the political economy problem, Table 3 shows the annual operating profit change at the four companies that stand to lose the most from a more integrated electrical grid.[12] The three companies that would lose the most operating profits

[12]While I have primarily focused on fossil power plants, Table 3 also includes operating profit changes at these companies' nuclear plants. Nuclear plants are assumd to be baseload in my simulations, so relieving transmission constraints and removing curtailments does not change their quantity generated (and therefore the behavior of nuclear plants is not a source of allocative inefficiencies). It does, however, change the revenue received at these plants. Entergy Arkansas and Entergy Louisiana each have sizeable nuclear capacity, although it is smaller than their fossil capacity.

Figure 5: Winners and Losers Are Located in Different Places



Note: This figure shows whether individual fossil power plants would win or lose if transmission across regions were increased and wind fully dispatched, rather than curtailed. Plants losing more than 10 million dollars per year, based on 2022 counterfactuals, are displayed in large red circles. Plants with operating profit losses less than 10 million dollars are in small gold circles. Plants with operating profit gains of at least 10 million dollars are in large green squares, and plants with smaller profit gains in small blue squares. Profit changes for wind units are not shown, as plant-level data are not available, but rough estimates of utility-level revenue changes for wind are included in Table 3.

Table 3: Individual Companies Could Win or Lose A Lot

Company	Primary location	Operating profit change, million dollars per year
Entergy Arkansas LLC	AR	-520
Entergy Louisiana LLC	LA	-350
Basin Electric Power Coop	MT, ND, SD	-130
Nebraska Public Power District	NE	-130
Union Electric Co MO	IA, IL, MO	460
MidAmerican Energy Co*	IA, IL	330
Northern States Power Co MN*	MI, MN, ND, SD, WI	230
Duke Energy Indiana, LLC	IN	200

Note: This table shows the four companies with the largest potential annual decrease in operating profits across their fossil, nuclear, and wind portfolios, if regional transmission constraints were eliminated and all wind dispatched (rather than curtailed), as well as the four companies with the largest potential annual increase in operating profits. Counterfactuals are based on 2022 electricity market conditions. *Note that MidAmerican and Northern States Power each operate both fossil and wind units, and the wind portion of the profit estimate is imprecise, as I do not observe the hourly generation and curtailment at individual wind sites – I have apportioned wind generation based on annual site-level totals and hourly regional data. The same table is repeated in the Appendix with robustness checks and alternative time periods.

are all located in southern MISO: Entergy Arkansas, Entergy Louisiana, and Cleco Power. These three companies combined would have seen a drop in operating profits of over $1 billion in 2022 if the grid had been fully integrated and wind not curtailed. This is equal to more than a quarter of the total allocative inefficiencies for 2022, and it is on the same order of magnitude as the total allocative inefficiencies arising from within-MISO constraints.

Thus while the literature to date has focused on allocative inefficiencies, I argue that the magnitude of potentials wins and losses at individual companies is just as important. Table 3 also shows the companies that stand to win from better integration, primarily located in states like Missouri, Kansas, and Indiana. The magnitudes here are also striking, with one single company standing to earn nearly $500 million more.

Table 3 also shows the potential operating profit gains to wind producers. Unfortunately, I do not observe wind generation disaggregated to individual locations. Nonetheless, I can calculate the aggregate profit gains to wind in three broad regions of MISO (and separately, to wind in SPP as a whole), using generation and curtailments data from each ISO along with the equilibrium prices calculated above.[13] I estimate that the over 100 wind producers in MISO as a group stand to earn $610 million more annually (under 2022 conditions) if they were not curtailed.

[13]Unfortunately, I do not observe wind generation at the subregion level; only at the ISO-wide level for SPP and in three broad regions of MISO (north, central, south). I apportion generation in each hour to a region based on the annual generation shares reported in EIA-923. Also, curtailments are not reported by region in MISO, so I assume the hourly portion of wind curtailed is equivalent across regions of MISO.

One caveat to bear in mind when analyzing Table 3 is that the counterfactual operating profits at individual power plants will depend on the specifics of the dispatch model used, as well as the grid conditions (e.g. demand levels and fuel prices). In the Appendix, I show that the specific dollar amounts vary across alternative counterfactual construction, but in general the rank order of company wins and loss across locations, as well as the order of magnitude of operating profits changes, is fairly stable.

5.3 Case Study: MISO South

The fact that the three companies standing to lose the most from grid integration are all in MISO South is not surprising – this area has long been known as a pocket with inadequate transmission ties to the rest of MISO. The history of the interactions between Entergy and MISO regarding transmission planning are particularly illuminating here. Entergy has a market cap of nearly $20 billion (as of October 2023) and has generation, transmission, distribution and retailing divisions across much of MISO South (including Arkansas, Louisiana, Mississippi, and Texas). Most relevant, for more than a decade it has faced allegations of using both its own transmission system and the transmission planning process in MISO to prevent competition for its generation business.

Indeed, Entergy joined MISO in 2012 following a Department of Justice investigation into "allegations that Entergy has engaged in exclusionary conduct in its four-state utility service area spanning parts of Arkansas, Louisiana, Mississippi and Texas... Specifically, the division has been exploring whether Entergy has harmed consumers by exercising its control over its transmission system and dominant fleet of gas-fired power plants to exclude rival operators of low-cost combined-cycle gas turbine (CCGT) power plants from competing to sell long-term power. In particular, the division has been evaluating whether Entergy's practices have effectively foreclosed these more efficient rivals from obtaining long-term firm transmission service, a necessary input for selling long-term power products to wholesale customers in the Entergy service area. As part of the conduct investigation, the division has also been reviewing the competitive impact of, and circumstances surrounding, Entergy's serial acquisition of rivals' CCGT power plants" (Department of Justice, 2012). Entergy joined MISO and sold off transmission assets, but has since been accused of stalling the MISO transmission process, again to protect its fossil plants.

The recent accusations against Entergy are instructive. First, watchdog groups and green advocates have said that Entergy tries to throw wrenches in the transmission planning process (Tait, 2020; Tomich, 2021); this is exactly what one might predict in a consensus-based planning process where incumbent generators have a seat at the table (Davis, Hausman

and Rose, Forthcoming). Relatedly, one watchdog group noted that "Entergy secretly placed a consultant to advance its interests in MISO stakeholder meetings under the guise of a 'MISO South customer,"' which the group argued may have been part of an attempt to prevent integration of wind generation by competitors (Tait, 2020). Finally, twice Entergy has built new fossil plants in an apparent move to forestall new transmission lines (Kovvali and Macey, 2023; Howland, 2023).

One caveat is that some of the most vocal opponents of Entergy have been renewable energy stakeholders, who may stand the most to gain from grid integration. Industry reports cite the Southern Renewable Energy Association as stating "Entergy appears to be using an anti-competitive strategy of capturing, delaying, and/or canceling transmission projects with local generation assets at significant cost to local ratepayers, while at the same time, not resolving underlying load pocket problems" (Howland, 2023). One might decide to take the accusations against Entergy with a grain of salt given the incentives of renewable energy stakeholders – on the other hand, my analysis shows that the greater integration would bring greater market efficiency and thus improve overall welfare.

Overall, I argue that understanding the political economy of new transmission lines is just as understanding the potential gains in allocative efficiency. There are many tactics an incumbent company might use to protect its generation assets, as the Entergy case studies show, and the financial incentives to do so may be tremendous. Ultimately these incentives depend on the mix of generation, transmission, distribution, and retailing that a company owns and operates – a utility that is a net purchaser of generation and primarily engages in distribution and retailing may have an incentive to seek out low-cost generation. It also depends on whether the utility is price-regulated, and if so, what relationship it has with a utilities commission. And I am aware of no reports like those regarding Entergy that have emerged for other utilities whose generation assets would be worth less under a more integrated grid. Nonetheless, the results in this section suggest that the current consensus-based planning process is problematic given the fact that market integration typically brings losses to some incumbents.

6 Robustness Checks

[In progress]

7 Conclusion

[In progress]

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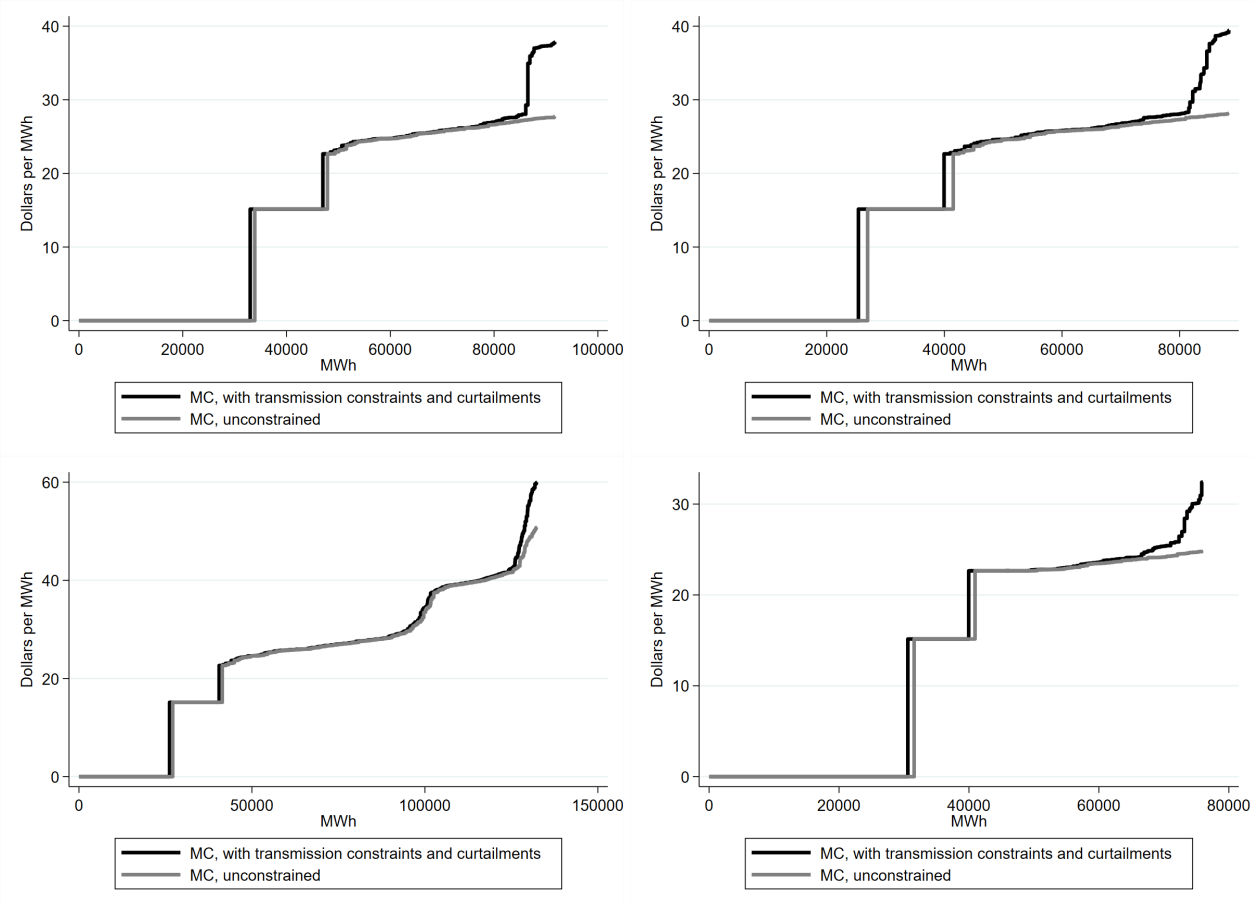
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Figure A1: Additional Example Marginal Cost Curves

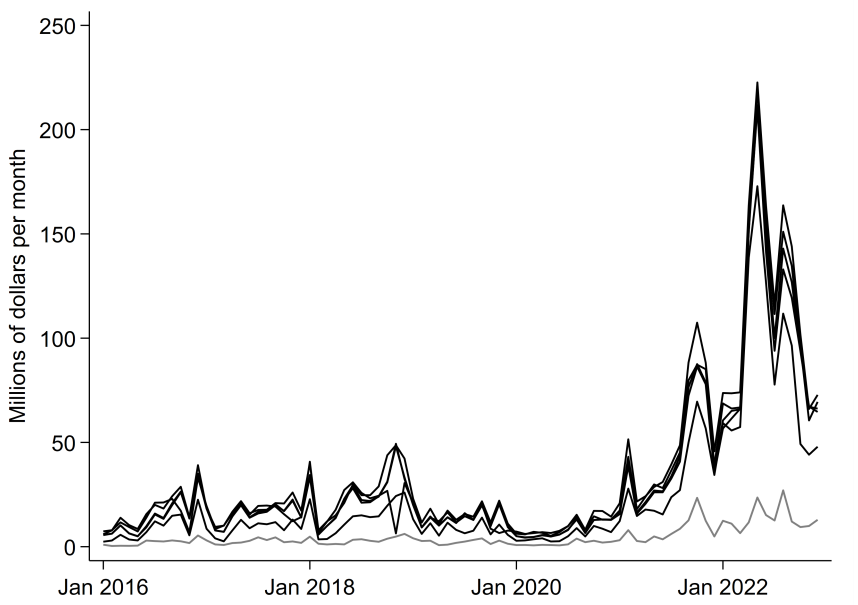


Note: This figure is constructed like Figure 1 in the main text, but showing alternative date-hour combinations. Note the scales of both axes vary across the four panels. The upper left panel shows an hour typical of the whole sample (2016 to 2022). The upper right panel shows an hour with particularly high curtailments (approximately two standard deviations above the sample mean for 2016-2022). The lower right panel shows an hour with high demand (two standard deviations above the sample mean), implying the dispatch of higher cost units. The bottom right panel shows an hour with low demand (two standard deviations below the sample mean).

A1 Appendix

[In progress]

Figure A2: Additional Generation Costs From Transmission Constraints and Wind Curtailments, Robustness Checks



Note: This figure matches Figure 2 in the main text, with robustness checks added. Black lines show the wedge: (1) as calculated in the main text; (2-3) calculated using either of two alternative region definitions used to define transmission constraints; (4) calculated after constraining combustion turbine generation, as a proxy for non-transmission operational constraints; and (5) calculated after constraining units that were observed to operate at their minimum load, as an alternative proxy for non-transmission operational constraints. The grey line shows the wedge when only across-ISO transmission constraints are included, i.e. constraints across NERC sub-regions within an ISO are dropped.

Table A1: Additional Summary Statistics

	N	Mean	SD	Min	Max
Generator characteristics:					
Generation, MWh	52,605,900	71.8	149.9	0	890.9
Generation when dispatched, MWh	16,417,765	229.9	188.8	0.00096	890.9
Fuel type indicator: Coal-fired	52,605,900	0.21	0.41	0	1
Natural gas	52,605,900	0.74	0.44	0	1
Oil-fired	52,605,900	0.046	0.21	0	1
Technology indicator: Boiler	52,605,900	0.34	0.47	0	1
Combined cycle	52,605,900	0.15	0.36	0	1
Combustion turbine	52,605,900	0.51	0.50	0	1
Location indicator: MISO	52,605,900	0.66	0.47	0	1
Ownership indicator: IOU	52,605,900	0.92	0.28	0	1
Ratio of minimum constraint to maximum capacity	52,605,900	0.44	0.11	0.29	0.56
Indicator: 1 if subject to ARP	52,605,900	0.86	0.35	0	1
Indicator: 1 if subject to CSAPR (SO2)	52,605,900	0.69	0.46	0	1
Indicator: 1 if subject to CSAPR (NOx)	52,605,900	0.95	0.21	0	1
Estimated compliance cost for ARP and CSAPR, $/Mwh	52,605,900	0.22	1.09	0	47.0
Wind curtailed in MISO, MWh	26,232	525.7	719.8	0	4925
Wind curtailed in MISO, assumed where missing, MWh	60,360	439.4	509.5	0	4925
Wind curtailed in SPP, MWh	61,031	387.4	894.4	0	8953.9
Solar curtailed in SPP, MWh	8,711	0.71	6.24	0	126.1
Wind curtailment divided by wind generation, in MISO, MWh	59,497	0.073	0.10	0	4.13
Wind curtailment divided by wind generation, in SPP, MWh	60,955	0.028	0.054	0	0.71
National fuel prices:					
Coal, $/MMBtu	61,032	2.34	0.16	2.04	2.65
Coke, $/MMBtu	61,032	2.76	0.91	1.30	5.02
Natural gas, $/MMBtu	61,032	4.37	2.12	2.29	18.5
Oil, $/MMBtu	61,032	15.6	4.59	7.51	29.2
Market-wide quantities:					
Load (demand) in MISO, MWh	60,146	75863.3	12113.9	48827.3	121232.7
North MISO only	60,146	16856.8	2458.1	10772.1	26555.6
Central MISO only	60,146	39173.9	6738.9	23961.3	66434.4
South MISO only	60,146	19832.7	3764.0	11878.9	32612.0
Load (demand) in SPP, MWh	61,008	30499.5	5641.5	0	52954.7
North SPP only	61,000	3377.4	509.4	2112.3	5233.4
Central SPP only	61,000	3743.2	833.0	1819.1	7156.8
South SPP only	61,000	23382.9	4647.1	15120.5	42004.3
Load (demand) in the Eastern Interconnection, MWh	60,115	225931.0	41031.0	91624.6	393893.1
Generation by fuel type by ISO:					
Coal, MISO	61,032	28239.2	8663.1	0	49653.1
Natural gas, MISO	61,032	20302.4	7493.1	0	53013.9
Hydro, MISO	61,032	1180.0	598.3	0	3714.5
Nuclear, MISO	61,032	10945.3	1839.6	0	13446.7
Other, MISO	61,032	937.4	302.8	0	2263.5
Solar, MISO	61,032	159.5	450.4	0	3361.8
Storage, MISO	61,032	11.7	66.3	0	589.9
Wind, MISO	61,032	7346.6	4686.0	0	24089.7
Coal, SPP	60,989	11914.0	4258.8	0	23343.8
Oil, SPP	60,989	24.7	46.0	0	960.3
Hydro, SPP	60,989	1274.7	556.5	0	2765.9
Natural gas, SPP	60,989	7011.3	3625.3	0	23127.4
Nuclear, SPP	60,989	1854.0	515.6	0	2610.3
Solar, SPP	60,989	58.1	75.7	0	227.7
Waste disposal, SPP	60,989	10.9	1.91	0	19.1
Wind, SPP	60,989	8547.8	4735.2	0	22696.9
Other, SPP	60,989	28.4	6.45	0	114.0
Cooling degree days, Missouri	61,032	3.79	5.59	0	22
Heating degree days, Missouri	61,032	13.2	14.7	0	67

Note: This table provides summary statistics for my main estimation sample, at the generator by hour level. The sample is an unbalanced panel covering the period 2016-2022, with 992 generating units at 367 power plants. This represents all CEMS-reporting power plants (generally, fossil-fuel fired units with a capacity of at least 25 MW) in the MISO and SPP footprints. The main sample excludes commercial and industrial units and cogeneration units. There are fewer observations for the "quantity of wind curtailed" variables because the MISO reports this beginning in only December 2019, and because SPP data are missing for a small number of days.

Table A2: Power Plants Are Dispatched For Own-ISO Load

	(1)	(2)	(3)	(4)	(5)	(6)
MISO	0.84	0.84	0.79	0.85	0.81	0.93
SPP	0.90	0.90	0.77	0.78	0.87	0.97

Note: This table shows the portion of power plants in each ISO that had a bigger coefficient on own-ISO load in the horserace regressions (equation X in the main text). The first row shows the portion of MISO-located plants ($n = 243$), and the second row the portion of SPP-located plants ($n = 121$). Column 1 shows the baseline specification. Column 2 includes the February 2021 anomaly in the horserace regressions. Column 3 drops controls from the horserace regressions (such as fuel prices, month effects, hour effects, and weather), but does control for load in the rest of the Eastern Interconnection. Column 4 weights observations in the table by the average hourly generation of the power plant over the 2016-2022 time period. Column 5 weights instead by the count of non-zero generation hours. Column 6 weights instead by the t-stat from the horserace regression.

Table A3: Robustness Checks: Individual Companies Could Win or Lose A Lot

Company	Operating profit change, million dollars per year
Panel A: Price at 99th percentile	
Entergy Arkansas LLC	-570
Entergy Louisiana LLC	-380
Nebraska Public Power District	-150
Basin Electric Power Coop	-140
Union Electric Co - (MO)	400
MidAmerican Energy Co	300
Northern States Power Co - Minnesota	210
Duke Energy Indiana, LLC	190
Panel B: Price at 95th percentile	
Entergy Arkansas LLC	-700
Entergy Louisiana LLC	-480
System Energy Resources, Inc	-150
Louisiana Generating LLC	-130
Union Electric Co - (MO)	330
MidAmerican Energy Co	220
Duke Energy Indiana, LLC	160
Northern States Power Co - Minnesota	120
Panel C: No redispatch of CTs	
IN PROGRESS	
Panel D: No redispatch of units below their minimum constraint	
IN PROGRESS	
Panel E: 2016-2022	
Entergy Arkansas LLC	-280
Entergy Louisiana LLC	-210
Nebraska Public Power District	-180
Wisconsin Power & Light Co	-160
Union Electric Co - (MO)	240
DTE Electric Company	200
MidAmerican Energy Co	170
Duke Energy Indiana, LLC	100

Note: This table matches Table 3 in the main text, but for various robustness checks.