Lone Star Grid: The Impact of Texas Electricity Interconnection *

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Abstract

Using a novel least average cost dispatch (LACD) algorithm, this paper evaluates the economic and environmental costs of Texas maintaining an isolated electricity grid. We build a structural model to characterize the supply of electricity and simulate counterfactual integration scenarios. We find that Texas's largest population zones connected with neighboring states to the East results in reductions of generation costs of $83M annually. We also show that accounting for fixed costs in the dispatch model allocates generation to units with lower average fixed costs than under least marginal cost dispatch. This change in allocation along the margin results in large differences in emissions impacts. Tracing each plant's emissions through a tract-level air quality model, we find that most interconnection scenarios raise population-weighted $PM_{2.5}$ exposure, because generation shifts toward lower-cost coal and lignite units. Health damages rise by up to $249 million per year and exceed the generation cost savings in eight of twelve scenarios. In nine scenarios, $PM_{2.5}$ rises for more than 90 percent of Texans. Revenue and generation shifts to Texas firms in nine of twelve scenarios. We also show that reductions in costs of maintaining reliability are as large or larger than generation cost reductions.

JEL codes: C53; L94; Q41; Q48
Key Words: interconnection; transmission; electricity supply; least cost dispatch; emissions; air pollution; health damages; cycle costs; fixed cost

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1 Introduction

Electricity interconnection reduces aggregate production costs, improves reliability, and reduces transmission constraints. The continental United States' electricity grid is made up of three interconnections. The Great Plains split the US into Eastern and Western interconnections with the Texas interconnection serving 90% of the state's population maintaining no interties to the rest of the country. The isolated Electricity Reliability Council of Texas (ERCOT) has drawn the attention of lawmakers and the U.S. Department of Energy (DOE). The Connect the Grid Act (H.R. 7348) proposed in February 2024 would require ERCOT to meet minimum interregional transmission capabilities with its neighboring regions (Casar, 2024). The DOE announced the Southern Spirit Transmission project, a $360 million investment to construct a 320-mile high voltage line connecting ERCOT to Louisiana and Mississippi (DOE, 2024). Understanding the impacts of integration and which geographic interconnection provides the largest benefits is critical for undertaking large energy infrastructure expansion.

The benefits of market integration are large. Utilizing a least marginal cost dispatch (LMCD) algorithm, Cicala (2022) finds that the introduction of electricity markets decreases production costs by 5 percent from reallocating production to more economical units. Hausman (2025) uses a LMCD algorithm to show that integration in two major markets could reduce production costs by $2 billion and that the four firms operating the least productive generating units would lose $1.6 billion in net revenues in 2022. However, ignoring cycle costs that occur in generating unit startup, ramp, and shutdown may attribute generation to units that would not be called upon to meet demand if these costs were considered.

We analyze how production costs, social costs of emissions, firm revenue, and costs of reliability change under integration scenarios for each of ERCOT's four zones to three external zones.[1] We extend the LMCD framework from Borenstein et al. (2002); Linn and McCormack (2019); Cicala (2022); Gonzales et al. (2023); Hausman (2025) and others, to estimate the magnitude of generation cost reductions and emissions impacts for interconnection candidates in Texas. We include the fixed costs of an operation cycle and remain in a static framework by building a least average cost dispatch (LACD) algorithm. We first construct supply curves for each independent zone without transmission constraints to serve as the pre-integration baseline. We also construct counterfactuals where each ERCOT zone is integrated with each external zone.

[1] A zone the most spatially granular geographic designation at which electricity demand (load) is observed.

We provide evidence that LACD better fits observed generation than LMCD. Under LACD, coal generation behavior and overall generation mix by fuel type more closely match the observed data than with LMCD by 8–16%. We also show that dispatching generating units in least average cost order allocates generation to a different set of units than under least marginal cost. This reshuffling of units around the margin yields negligible to moderate differences in production cost changes but very different emissions results from interconnection.

We show that interconnection reduces electricity production costs by up to $83 million annually. There is a great deal of heterogeneity across interconnection scenarios. Zones with the largest dependence on fossil fuel generation stand to see the largest reductions in generation cost from integration. This is largely driven by zone differences in unit productivity; a zone with low cost, high productivity units on average interconnecting with a zone with high cost, low productivity units for example. Interconnection of zones with large demand volume and variance also show greater reductions in generation costs.

While reductions in production costs from integration are to be expected as production shifts to the most productive units, it is not obvious if the most productive units are also the lowest emitting. We find that they often are not. Interconnection raises CO_2 emissions in most scenarios. When local pollution damages are assigned per MWh by fuel type, as in Gonzales et al. (2023), they also rise in most scenarios. We also trace each plant's SO_2, NO_x and primary $PM_{2.5}$ emissions through a reduced-complexity air quality model to 72,538 census tracts. Interconnection raises national $PM_{2.5}$ exposure and premature mortality in nine of twelve scenarios, by up to 25 deaths and $249 million per year. The increases are largest for the Houston interconnections. In eight scenarios, the increase in health damages alone exceeds the generation cost savings. Interconnection shifts generation toward low-cost coal and lignite units, such as the lignite plants in ERCOT North that gain generation in every North interconnection. Much of the added exposure falls on Texans: in nine scenarios, $PM_{2.5}$ rises in tracts home to more than 90 percent of the state's population.

We document how firm revenue and generation shifts across each integration scenario. One potential explanation for why ERCOT has remained isolated is to protect electricity generating firms within Texas. We find that revenues to firms in ERCOT increase in nine of twelve interconnection scenarios, indicating that neighboring regions and firms may also oppose transmission expansion.

Finally, we show that reliability cost reductions from integration are generally as large as or larger than the reductions in generation costs. These benefits are largest for zone pairs with high levels of demand and greater demand variability. Large zones in Texas, despite having demand

comparable to similarly sized external zones-experience disproportionately greater reductions in reliability costs from interconnection. As suggested by Hausman (2025), the reliability benefits from interconnection are larger than increases in allocative efficiency and may justify the costs of integration, though they must be weighed against the increases in carbon and health damages we find for most interconnections.

We address a gap in the literature on the impacts of incremental market integration on electricity production costs, emissions externality costs, and reliability benefits. Several studies evaluate the results of widespread transmission expansion and market integration (Borenstein et al., 2002; Cicala, 2022; Gonzales et al., 2023; Hausman, 2025), but we are the first to empirically estimate separate interconnection scenarios for an isolated grid to our knowledge. Analyzing incremental grid expansion is important as zones have unique generator composition and funds for transmission projects are scarce.

Closest to our paper on estimating reductions in generation cost from transmission interconnection, Hausman (2025) studies an overlapping region and how wind curtailment contributes to allocative inefficiencies as well as firm-level outcomes from alleviating transmission constraints. That paper documents how across-region constraints impact existing fossil generators. Gonzales et al. (2023) evaluate the investment impacts of renewable sources from Chile's transmission expansion and the implications for emissions and electricity prices. Cicala (2022) finds that regional market integration reduces production cost, increases gains from trade, and reduces allocative inefficiencies. Our work complements these studies by evaluating impacts of incremental interconnection to external markets for a currently isolated grid while extending the methodology used in the aforementioned papers.

Another study that considers the isolation of the ERCOT grid is LaRiviere and Lyu (2022), which looks at the impacts of a large East-West interconnection project within Texas. The new transmission line connecting renewable-rich West Texas with demand centers in the East of the state resulted in increased renewable investment and lower wholesale electricity prices. This paper shows one of the ways electricity producers and consumers in Texas could continue to benefit from increased grid integration with access to large quantities of low- or zero-marginal cost generation sources.

We are the first to analyze how generation and social costs differ under average cost versus marginal cost dispatch. Gonzales et al. (2023) incorporate costs of ramping in their dispatch model and show that it has little impact on matching observed market prices in their simulation. We

show that total generation cost decreases from interconnection are similar across both dispatch algorithms. The relative difference between marginal costs and average costs reorder the dispatch of generating units. This finding is consistent with other studies that show a reallocation of generation when incorporating start-up costs in dynamic models (Mansur, 2008; Jha and Leslie, 2025). We also show that units dispatched around the margin under LACD tend to emit more CO_2 than those dispatched around the margin under LMCD. This finding is especially relevant when considering the impact of transmission expansion on existing fossil generators. We also compare fuel-average damage estimates with plant-specific air quality modeling. The two agree in sign for most interconnections, but the air quality model implies health damages 2.5 to 30 times larger and shows where they fall.

Finally, our study contributes to the policy relevant discussion of expanding transmission infrastructure. We are the first to quantify the change in generation, negative externality, and reliability costs of each Texas region interconnecting its electricity grid to neighboring regions. Botterud et al. (2024) summarizes work-in-progress evaluating the Connect the Grid Act (H.R. 7348) proposed in early 2024 in the U.S. Congress. This study shows that 20GW of transmission capacity spread between ERCOT and its three neighboring regions would reduce generation costs $1.5 billion annually. Our findings complement their work showing the generation cost change for each potential ERCOT zone interconnection.

The remainder of this paper is organized as follows. Section 2 provides background on the electricity transmission and market geography. Section 3 details the sources and construction of our data and provides summary statistics. Section 4 presents the least cost dispatch methodology used to characterize electricity generation. Section 5 presents generation costs results. Section 6 presents impacts on emissions and on $PM_{2.5}$-related health damages. Section 7 documents how revenues shift from interconnection. Section 8 estimates the reliability benefits of interconnection across all scenarios. Section 9 concludes and discusses avenues for future research.

2 Institutional Background

The North American electricity grid is divided into three main interconnections: the Western Interconnection, the Eastern Interconnection, and the Texas Interconnection (Figure 1). Texas grid isolation stems from avoiding federal regulation under the Federal Power Act of 1935 (Galbraith, 2011). Without transmission spanning state lines, Texas utilities remained exempt from federal

oversight. ERCOT was formed in 1970 as a non-profit independent system operator (ISO)[2] to manage grid operations and ensure reliability while maintaining independence from federal regulation. Today, ERCOT serves approximately 27 million customers representing nearly 90% of Texas's electrical load (FERC, 2022) and operates under oversight from the Public Utility Commission of Texas alone.

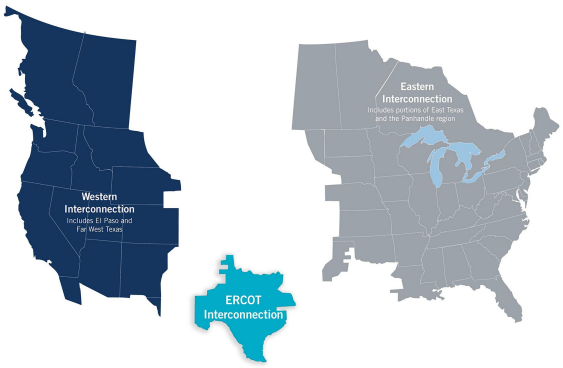


Figure 1: North American Interconnections

Notes: This figure displays the three interconnections in North America.

We study four zones within ERCOT and three neighboring zones.[3] A zone is the geographic area established by the ISO from which aggregated load data is derived and prices are published. Figure 2 displays the footprint of these seven zones. ERCOT comprises four load zones: West, North, South, and Houston. Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO) serve as ISOs for zones bordering Texas.[4] EPE borders ERCOT to the West and does not belong to an ISO.

SPP and MISO belong to the Eastern Interconnection and trade electricity between zones. EPE belongs to the Western Interconnection and imports and exports electricity with neighboring utilities and producers.

[2]ISOs operate the transmission system independently of, and foster competition for electricity generation among, wholesale market participants (Commission, 2025).

[3]ERCOT zones: West, HOU - Houston, North, and South; Midcontinent Independent System Operator South (MISO) comprised of Arkansas, Louisiana, Mississippi, and parts of Texas; Southwest Power Pool South (SPP) comprised of Central & Southwest Services (CSWS), Oklahoma Gas & Electric (OKGE), and Southwestern Public Service Co. (SPS); El Paso Electric (EPE) which does not belong to a wholesale electricity market.

[4]Mississippi is included although it does not border Texas because the least aggregated level of load data available for MISO encompasses Mississippi, Arkansas, Texas, and Louisiana.

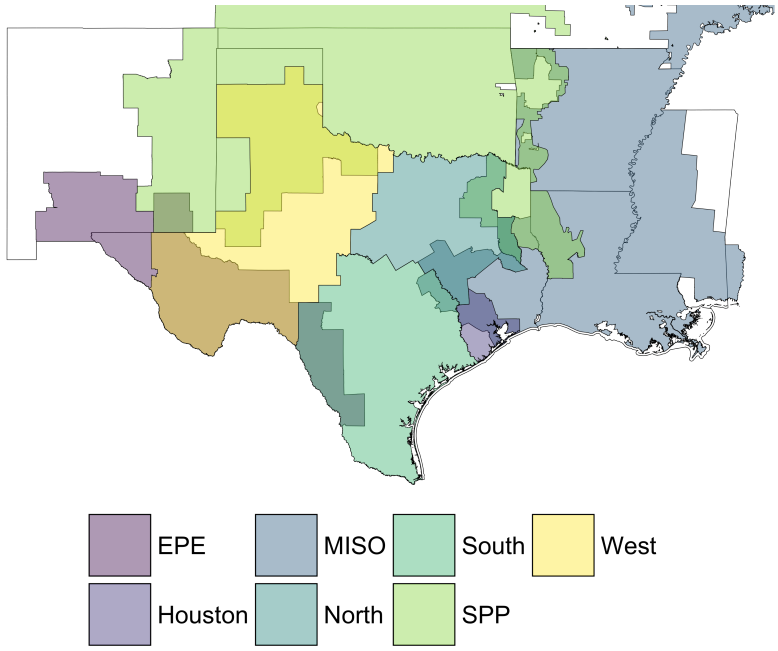


Figure 2: Zones

Notes: Map displays the seven zones studied in this paper. Zones studied fall into Texas, New Mexico, Oklahoma, Arkansas, Louisiana, and Mississippi.

3 Data

We combine data from public and proprietary sources to characterize the supply side of the electricity market in Texas and neighboring regions. We construct a generation-unit-by-hour panel from July 2018 through December 2023 for the universe of fossil fuel, renewable, and nuclear generation sources.[5] We construct an unbalanced panel with over 30.9 million unit-by-hour observations covering the 677 thermal generating units in our study region, as well as all renewable and nuclear generation.[6]

[5] A generating unit is the most disaggregated level at which electricity production can be observed. For most power plants, this is the unit that converts mechanical energy into electric energy. Power plants often contain multiple generating units which may use different fuels or technology.

[6] There are 706 thermal units in our sample region that report to EPA CAMPD, however, we drop 29 for having zero electricity generation in the entire sample period. These units produce steam for other plant processes not electricity to be sold to the grid.

3.1 Data Sources

We collect hourly, unit-level data on gross generation (in MWh), fuel input (in mmBtu), and pollution emissions for all fossil fuel thermal generating units with a capacity of at least 25 MW.[7] These units are required to report to the United States Environmental Protection Agency's (EPA) Clean Air Markets Program Database (CAMPD) electronically every 30 days. We pair the hourly operational data with information on unit fuel type, technology and location. The data consists of observations on 677 thermal generating units with positive generation in our sample period.

Gross generation is an imperfect measure of a unit's output to the grid because it includes power used to operate the plant. We obtain monthly unit-level net generation for thermal, renewable, and nuclear units from the Department of Energy's Energy Information Administration (EIA) Form 923. We scale each unit's hourly generation by its monthly ratio of gross-to-net generation to determine hourly net generation.

To estimate marginal costs we need to convert fuel inputs measured in quantities to costs in dollars. Fuel costs vary over time and space and make up the largest share of a unit's marginal costs. We collect monthly state-level average fuel costs for coal and natural gas (in $ per mmBtu) from the EIA Electricity Data Browser.[8]

We collect variable operating and maintenance costs from the 2023 EIA Electric Power Annual at the national level. We calculate the average operating and maintenance costs for the years 2018-2022. We assign the "Fossil Steam" average to coal burning units and the "Gas Turbine and Small Scale" for the other thermal units.[9] As in Hausman (2025) we assume these are constant over our sample period.

We collect fixed costs of cycling (in $/MWh of capacity) by unit, fuel type, and technology or size of the generating unit from the National Renewable Energy Laboratory's (NREL) 2012 report "Power Plant Cycling Costs." Cycling refers to the operation of generating units at varying generation levels from startup, ramping, minimum generation operation, and shut down (Kumar et al., 2012). Every time a generating unit is turned on and off, the components are stressed by large variation in temperature and pressure, causing microscopic damage. Over time that damage accumulates, leading to fatigue-induced failures of critical components such as turbine blades, boiler

[7] According to the EPA's eGrid 2021 dataset units under 25 MW comprise less than 1 percent of total coal and natural gas generation.

[8] Other thermal generating units, which make up less than 3% of our sample by generation, are assigned $10.27/mmBtu from Table 7.1 in the 2023 EIA Electric Power Annual as the 2018-2022 average for petroleum fuel plants.

[9] Less than 3% of generation in our sample comes from oil, biomass, or waste fueled units.

tubes, and heat exchangers. These include both increased maintenance expenses for repairing or replacing damaged equipment and efficiency losses from operating units outside their optimal design parameters. The magnitude of these costs varies substantially across different generation technologies, with coal and nuclear plants typically experiencing higher cycling costs than natural gas combined cycle units due to their longer startup times and greater thermal stress during ramping operations.

The estimates in Kumar et al. (2012) provide a baseline to understand the costs a unit incurs from a single generating cycle. We use median values for a cold start in our baseline specification and show the cycle costs assigned to each unit type in Table A1.[10]

We collect hourly zone-level electricity demand data as well as unit to zone crosswalk data from Yes Energy. We match about 95% of units to the corresponding zone using the crosswalk. The remainder of the units are mapped by looking up the plant name using https://www.gem.wiki and https://openinframap.org.

3.2 Data Construction

We merge all hourly thermal generating unit-level data by the unique combination of the plant and unit identifier. The panel is unbalanced because of unit entry and exit during our sample period. Our data set includes 677 generating units belonging to 216 power plants. Figure 3 shows every power plant included in our sample and the zone it belongs to.

Non-fossil fuel plants are not required to report to the hourly CAMPD database. We calculate generation for nuclear, solar, and wind at the zonal level using a two-step allocation process.

For nuclear units, we use market data on hourly generation by fuel type and plant location data to assign nuclear generation to the correct zone. With only a few nuclear plants in three of the seven zones in our sample, it is straightforward to allocate generation to the correct zone. Only ERCOT North, ERCOT South, and MISO have nuclear generation in our study.

To calculate hourly renewable generation at the zonal level, we allocate market-level hourly generation by fuel type to zones using zone shares derived from monthly data. First, we use EIA-923 monthly net generation and unit location data to calculate each zone's share of total renewable generation by fuel type within its market for each month. Second, we multiply the market's hourly

[10] We show robustness to differing our baseline specification with the 25th and 75th percentile cycle costs in Figures 6 and 7, Table A2, and Figure A2.

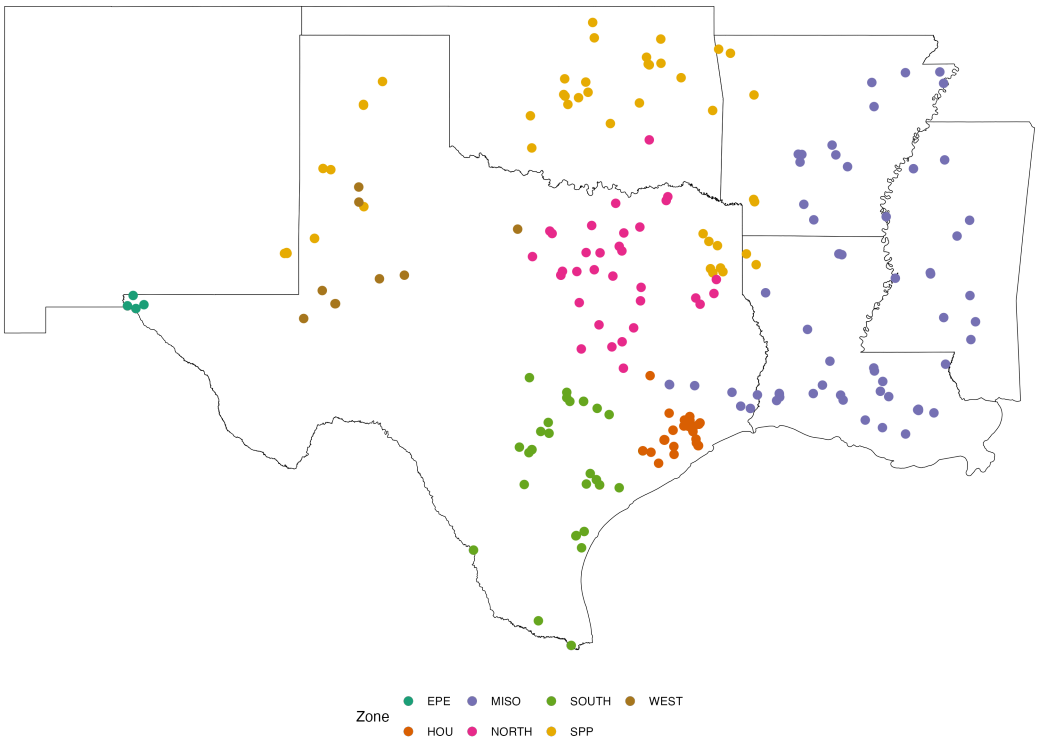


Figure 3: Power Plants by Zone

Notes: This map displays the location of all 216 power plants color-coded by zone. Kiamichi Energy Facility in Oklahoma is the only plant outside of Texas that sells electricity to ERCOT and belongs to ERCOT North.

generation by fuel type by the relevant zone share to obtain hourly zone-level generation.[11] This approach holds zone shares constant within each month but allows them to vary across months as seasonal factors and unit entry and exit change the distribution of renewable generation across the grid.

We collect unit-by-hour CO_2 emission rates (tons/MWh) from the observed emissions from CAMPD. There are a small number of observations where units do not operate in the observed data but do run in the simulation.[12] For these observations we assign the CO_2 emissions rate to be the fuel type-specific average CO_2 emissions rate.

Heat rate is the central measure of a unit's productivity, quantifying its ability to convert fuel into electricity. We compute each unit's average heat rate as total fuel inputs (mmBtu) divided by total net generation (MWh). A higher heat rate indicates lower productivity because more fuel is required to generate each MWh of electricity. Heat rates vary across fuel type, technology, and age

[11] For example, if SPP reports 100 MWh of wind generation in a particular hour and 10% of SPP's wind generation in that month came from units in SPS zone, we assign that zone 10 MWh of wind generation in that hour.

[12] We observe units operating in the simulation, but not in the data for around 2% of total hours.

of unit and are the primary determinant of a unit's marginal cost.

We estimate a unit's generation capacity as the 99th percentile of its observed generation. Following Cicala (2022) and Hausman (2025) we calculate generating capacity using observed generation and stochastically applied outages. Any thermal generating unit has a 10% chance of being out in any given hour.[13] Renewable generation is determined by weather conditions so we assign renewable capacity as generation empirically observed in that hour. Nuclear generation is extremely costly to ramp up or down. We follow Hausman (2025) and assume nuclear plants are unresponsive to market demand and therefore assign capacity as what was generated in that hour.

We construct unit fixed costs as total cycle cost ($/MWh of capacity) from Kumar et al. (2012) multiplied by unit capacity (MW). Our unit fixed costs are in line with startup costs found in Reguant (2014) for coal ($62,000 on average) and natural gas ($14,000 on average) units.

We construct the marginal cost $mc_{i,t}$ of generating unit i at hour t as:

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

following Hausman (2025) where fuel price fp_t in time t (in dollars per mmBtu) multiplied by the unit's heat rate, hr_i (in mmBtu per MWh) plus variable operating and maintenance costs om_i (in dollars per MWh).[14] We winsorize marginal costs at the 1st and 99th percentiles to account for a small number of implausibly high and low heat rate estimates. We follow the literature and model renewable generation (solar, wind, hydro) as zero marginal cost. We assume marginal costs for nuclear units to be $15/MWh.[15]

To construct average costs we need unit average fixed costs which is total cycle cost fc_i (in dollars) divided by unit-level average cycle generation $\bar{q}_i$ (MWh). We calculate unit average cycle generation as the unit's total net generation in the sample divided by the number of cycles observed over our sample period. We create an indicator variable for a unit being on if net generation is positive in an hour. We calculate the number of cycles as the sum of instances a unit went from zero generation to positive generation.

We construct average cost $ac_{i,t}$ of generating unit i at hour t as the unit average fixed costs plus

[13] This method of applying outages is similar to both Borenstein et al. (2002) and Hausman (2025). Following Hausman (2025) we do not Monte Carlo over these outages as having 30.9 million unit/hour observations, it is unlikely any one observation would materially affect our results.

[14] We exclude environmental compliance costs which account for less than 1% of operating costs (Hausman (2025)).

[15] This is in line with calculations from Davis and Hausman (2016) and Hausman (2025).

marginal cost:

$$ac_{i,t} = \frac{fc_i}{\bar{q}_i} + mc_{i,t}$$

where $\frac{fc_i}{\bar{q}_i}$ is the unit average fixed costs. We model renewable generation as having zero average fixed cost. Due to the large startup costs and long run cycles, we have no way to precisely estimate the cycle costs of nuclear plants and assume average generation costs are \$17.50/MWh. This aligns with studies showing that nuclear generation is the first to be dispatched after renewables (Cicala, 2022; Hausman, 2025).

3.3 Descriptive Statistics

Table 1 shows generation cost summary statistics across different fuel types. Average costs and marginal costs are reported at the unit-by-hour level across fossil fuel types. Total cycle generation is the average amount of electricity generated over a cycle, this is $\bar{q}_i$. Total cycle costs for unit i are fc_i and are constant over time. Average fixed costs, $\frac{fc_i}{\bar{q}_i}$, described in the previous subsection are unit-specific and time-invariant. Cycle counts are the sum of the amount of times a unit went from zero generation to positive generation in our sample.

Table 1 shows the variation in different types of costs across and within fuel type. Generation costs for natural gas units vary more than coal units. The total cycle cost for a coal unit is more than four times as large as natural gas on average. On average coal units generate about ten times as much electricity per cycle natural gas units. These patterns cause natural gas units to cycle almost eight times more often than coal units. The heterogeneity in costs across units will determine the order in which grid managers dispatch units to meet demand.

The gap in generation costs between coal and natural gas units could lead to a misallocation of generation in least cost dispatch algorithm that does not account for fixed costs. Coal units produce electricity at a lower total average cost than natural gas and other thermal generating units. Accounting for cycle costs widens the gap in generation costs between these units on average. As coal units become relatively more affordable under LACD some of these low average fixed cost coal units may become infra-marginal.

There are stark differences in generation by fuel type among zones in our sample. Table 2 shows the share of hourly generation from the corresponding fuel by zone. We observe large heterogene-

Table 1: Cost Summary Statistics

	N	Mean	SD	Min	Max
Average Costs ($/MWh)					
Natural Gas	27212235	60.47	61.67	8.16	490.50
Coal	2454918	37.38	10.43	11.71	156.35
Fossil Other	482220	107.58	47.50	44.96	177.87
Marginal Costs ($/MWh)					
Natural Gas	27212235	53.43	59.62	8.04	490.45
Coal	2454918	37.02	10.38	11.54	156.16
Fossil Other	482220	106.11	46.03	44.91	177.76
Total Cycle Generation (MWh)					
Natural Gas	612	30852	68646	10	675024
Coal	55	361016	282967	16272	1391252
Fossil Other	10	132201	95417	188	286940
Total Cycle Costs ($)					
Natural Gas	612	13726	10998	256	55281
Coal	55	61705	19578	23175	98555
Fossil Other	10	14046	6907	2475	22619
Avg. Fixed Costs ($/MWh)					
Natural Gas	612	7.07	11.58	0.00	90.77
Coal	55	0.37	0.39	0.03	1.63
Fossil Other	10	1.48	4.12	0.04	13.20
Cycle Counts					
Natural Gas	612	398.80	351.30	1.00	1749.00
Coal	55	60.67	53.69	1.00	269.00
Fossil Other	10	64.90	67.35	14.00	229.00

Notes: This table shows summary statistics for various costs and cycle counts across fuel type. The sample is an unbalanced panel for the period July 2018 through December 2023, with 677 thermal generating units.

ity in electricity source across zones. Natural gas is the primary fossil fuel source in our sample accounting for 15% to 81% of hourly zone generation on average. On average, coal makes up a minority share of hourly generation for all zones except EPE. All of the zones in our sample have some renewable generation but it is not evenly distributed across zones. Most renewable generation in Texas is focused in the West and South zones. Only three zones in our sample generate electricity from nuclear. Nuclear generation accounts for almost a quarter of their hourly generation on average but has accounted for all of their generation at times.

It is clear that zones reliant on high cost generation units could benefit the most from interconnection to zones with low generation cost units. For example, coal and natural gas reliant EPE could import excess electricity from ERCOT West where in an average hour most electricity is generated

at zero marginal cost. Large decreases in generation costs could arise from connecting two fossil fuel dependent regions with large differences in generation costs as well. It is unclear whether these benefits would arise from decreases in marginal costs or average costs. In the following section we use a least cost dispatch framework to identify the decreases in total generation costs by interconnection pair stemming from these apparent differences.

Table 2: Generation by Fuel Type and Zone

		Share of Generation			
Fuel Type and Zone	N	Mean	SD	Min	Max
Coal					
EPE	48216	0.53	0.17	0.00	0.87
HOU	48216	0.17	0.07	0.00	0.44
MISO	48216	0.11	0.06	0.00	0.32
NORTH	48216	0.30	0.06	0.13	0.60
SOUTH	48216	0.19	0.06	0.04	0.63
SPP	48216	0.30	0.11	0.00	0.68
WEST	19728	0.04	0.05	0.00	0.39
Fossil Other					
MISO	48216	0.01	0.01	0.00	0.05
NORTH	48216	0.00	0.00	0.00	0.01
Natural Gas					
EPE	48216	0.45	0.16	0.13	1.00
HOU	48216	0.81	0.06	0.56	1.00
MISO	48216	0.63	0.07	0.29	0.93
NORTH	48216	0.48	0.12	0.00	0.73
SOUTH	48216	0.39	0.12	0.03	0.69
SPP	48216	0.53	0.13	0.01	0.87
WEST	48216	0.15	0.12	0.00	1.00
Nuclear					
MISO	48216	0.23	0.05	0.00	1.00
NORTH	48216	0.15	0.06	0.00	1.00
SOUTH	48216	0.21	0.05	0.00	1.00
Renewable					
EPE	48206	0.02	0.02	0.00	0.34
HOU	48206	0.01	0.02	0.00	0.19
MISO	48206	0.02	0.01	0.00	0.07
NORTH	48206	0.06	0.05	0.00	0.35
SOUTH	48206	0.21	0.11	0.00	0.63
SPP	48206	0.18	0.12	0.00	0.98
WEST	48206	0.83	0.14	0.00	1.00

Notes: This table shows summary statistics for share of hourly generation by fuel type and zone. Renewable data begins on 7/2/2018 at 6am.

4 Least Cost Dispatch Methodology

We extend the least cost dispatch framework (Biggar and Hesamzadeh, 2014) in two ways. We account for fixed costs as an average fixed cost per MWh. Failure to account for fixed costs of a generator's on/off cycle could lead to inaccurate estimates of allocative inefficiencies from frequent cycling of high fixed cost units to meet demand spikes, and these costs are not captured in a standard least cost dispatch algorithm.

This algorithm has previously been used to evaluate allocative inefficiencies in already connected electricity markets. Since candidate zones belong to larger markets, we do not analyze an autarky scenario between proposed interconnections. We modify the typical least cost dispatch model to evaluate benefits from potential incremental interconnection scenarios. We constrain interconnection candidates to generate observed generation for their respective zones rather than demand. This approach ensures the trade balance between candidate interconnection zones and their established interconnections remains unchanged. With this assumption we estimate reductions in generation costs for interconnected zones that are part of larger markets.

4.1 Least Marginal Cost Dispatch - One Zone

The standard least cost dispatch approach ranks generators by marginal cost and dispatches them in least cost order to meet demand in a given region. This model is widely used in economics (Borenstein et al., 2002; Cicala, 2022; Hausman, 2025; Ham et al., 2026) and engineering (Deetjen and Azevedo, 2019; Mills et al., 2021). This algorithm represents the cost minimizing optimum where grid operators dispatch units in least marginal cost order and generate up to unit capacity with no transmission or physical constraints. In each hour t, quantity $g_{i,z,t}$ electricity is generated at unit i in zone z to minimize total production cost that meets zone-wide demand subject to a capacity constraint $(C_{i,t})$ at each unit:

$$\min_{g_{i,z,t}} \left(\sum_{i \in (1,2,..,I_z)} mc_{i,t} g_{i,z,t} \right) \quad s.t. \quad \sum_{i \in (1,2,..,I_z)} g_{i,z,t} = demand_{z,t}; \qquad g_{i,z,t} \leq C_{i,t} \quad \forall i; \tag{1}$$

This approach ignores physical transmission constraints and technical generator constraints such as ramping costs, shutdown costs, and minimum dispatch quantities. Generators vary by fuel

and technology type and therefore vary in fixed costs associated with a generation cycle (start up, generating, and shut down).

We modify this algorithm to dispatch generators until zone observed generation $obs_gen_{z,t}$ is met:

$$\min_{g_{i,z,t}} \left(\sum_{i \in (1,2,..,I_z)} mc_{i,t} g_{i,z,t} \right) \quad s.t. \quad \sum_{i \in (1,2,..,I_z)} g_{i,z,t} = obs_gen_{z,t}; \\ g_{i,z,t} \leq C_{i,t} \quad \forall i; \tag{2}$$

This algorithm represents the analogous scenario where transmission constraints are alleviated, but we constrain the sum of generation in hour t to equal observed generation instead of observed demand. Zones are members of larger interconnected regions and therefore the unconstrained counterfactual of interest maintains the zone's trade balance rather than autarky as in Hausman (2025). This assumes that after alleviating constraints, a load zone that was a net exporter in hour t (net generation greater than demand) maintains the same trade balance in the least marginal cost dispatch counterfactual. We make this assumption because we consider individual load zones interconnecting to another individual load zone, both of which belong to larger interconnections, as opposed to fully interconnecting both ISOs.

The cost in the constrained scenario is the cost of production to generate the quantity observed in the data. In each hour t, total production cost is observed generation $net_gen_{i,z,t}$ at unit i in zone z multiplied by marginal cost $mc_{i,t}$ satisfying zone-wide observed generation:

$$\sum_i mc_{i,t} \cdot net_gen_{i,z,t} \quad s.t. \quad \sum_i net_gen_{i,z,t} = obs_gen_{z,t}; \tag{3}$$

This represents total cost of observed generation with all real-world transmission and generating constraints present.

We calculate the change in generation marginal costs from alleviating within-zone constraints as:

$$\Delta GenCostsWithin_{z,t} = \sum_i mc_{i,t} net_gen_{i,z,t} - \sum_{i \in (1,2,..,I_z)} mc_{i,t} g^{\star}_{i,z,t} \tag{4}$$

where $g^{\star}_{i,z,t}$ are the equilibrium quantities that solve equation (2). Figure 4 shows an example of marginal cost curves for ERCOT North for a single hour. We choose the hour in which observed generation in ERCOT North is closest to the zone's mean observed generation.

We calculate the area between these two curves as in equation 4 for each hour to find total

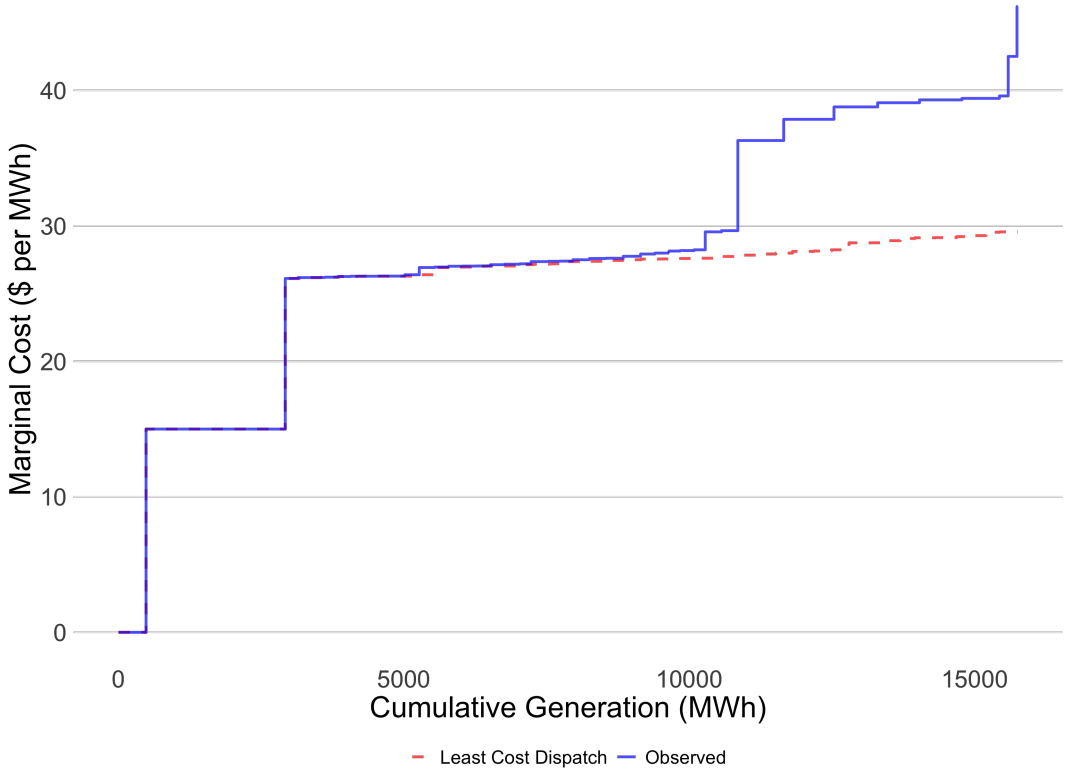


Figure 4: ERCOT North Marginal Cost Curves

Notes: This figure displays the marginal cost curves for ERCOT North in a representative hour of generation. The hour shown here is 13:00:00 on 1/26/2020. The constrained generation scenario is represented by Eq. 3 and is the higher, solid curve. The unconstrained scenario is represented by Eq. 2 and is the lower, dashed curve.

change in generation costs from alleviating within zone constraints. This independent unconstrained dispatch serves as the benchmark to compare the interconnected counterfactual. Within zone allocative inefficiencies, shown as the area between the two marginal cost curves, arise from physical generation constraints and transmission constraints. Generating units often run at minimum dispatch requirements during lower demand periods such as the middle of the night to avoid incurring shutdown and startup costs when prices rise in the morning (Reguant, 2014). Other physical constraints include planned and unplanned shutdown for maintenance, which is undifferentiated in the data and appears as zero generation in that hour. Transmission is often constrained during high demand hours or hours of high renewable generation, making it difficult to transport renewable generation to demand centers (Gonzales et al., 2023; Hausman, 2025).

4.2 Average Fixed Costs

We model fixed costs capitalized over expected quantity of electricity generated in a cycle as shown in Section 3.2. We make this simplifying assumption to account for the fact that when a unit is turned on, the plant manager expects to recover fixed costs over the length of the unit's cycle. We calculate a unit's average fixed cost as the unit's fixed cycle cost divided by the unit's average cycle generation.

4.3 Least Average Cost Dispatch - One Zone

In our least average cost dispatch algorithm, we rank each generator unit i by average cost $ac_{i,t}$ and dispatch them in ascending order to meet observed net generation in a given region. In each hour t, quantity $g_{i,z,t}$ electricity is generated at unit i in zone z to minimize total production cost that meets zone-wide observed generation $obs_gen_{z,t}$ subject to capacity constraint $(C_{i,t})$ at each unit:

$$\min_{g_{i,z,t}} \left(\sum_{i \in (1,2,..,I_z)} ac_{i,t} g_{i,z,t} \right) \quad s.t. \quad \sum_{i \in (1,2,..,I_z)} g_{i,z,t} = obs_gen_{z,t}; \qquad g_{i,z,t} \leq C_{i,t} \quad \forall i; \tag{5}$$

This algorithm is analogous to equation (2) except that generating units are ranked by average cost, inclusive of average fixed cycle costs, and total production costs are calculated from unit average cost rather than marginal costs. Equation (5) is the counterfactual for least average cost dispatch without proposed interconnection with no transmission or physical generation constraints. We constrain total generation to equal the observed level.

We estimate generation costs from observed generation similar to equation (3), replacing marginal cost with average cost. In each hour t, total production cost is observed generation $net_gen_{i,z,t}$ at unit i in zone z multiplied by average cost $ac_{i,t}$ satisfying zone-wide observed generation:

$$\sum_i ac_{i,t} \cdot net_gen_{i,z,t} \quad s.t. \quad \sum_i net_gen_{i,z,t} = obs_gen_{z,t}; \tag{6}$$

This represents total cost of observed generation with all real-world transmission and generating constraints present.

4.4 Coal Unit Ramping and Minimum Generation Constraints

Following Gonzales et al. (2023), we incorporate ramping and minimum generation requirements. Estimating these parameters is beyond the scope of our study, so we use existing empirical evidence (Reguant, 2014; Borrero et al., 2024). We constrain coal units to generate a minimum of 40% of their capacity conditional on running. We also assume that coal units can only ramp up or down their production by 10% of capacity in any hour.

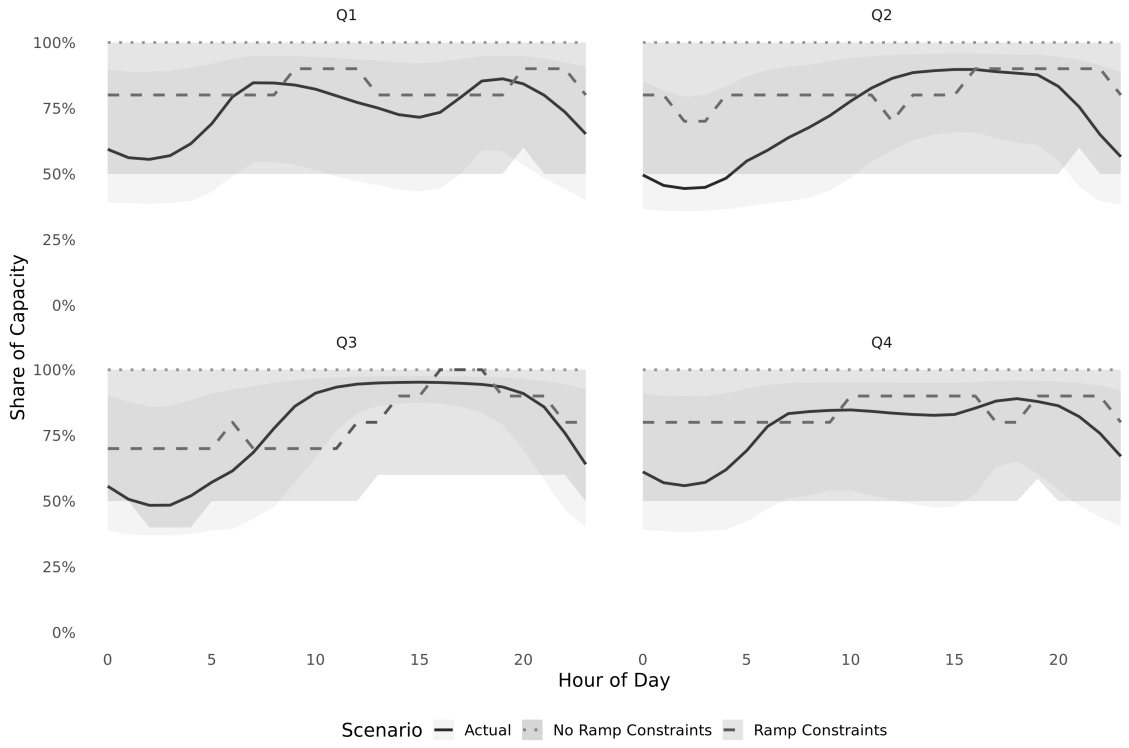


Figure 5: Coal Capacity Factor Conditional on Positive Generation (LACD)

Notes: This figure displays the median and interquartile range of generation as a share of capacity for all coal units across hour of day, split out by quarter of year.

Figure 5 shows coal generation as the share of units' capacity across hour of day split by quarter of year. Including ramping and minimum generation constraints gets coal units to generate much more similarly to observed levels. Without any ramping or minimum generation constraints, conditional on running, coal units operate at 100% of capacity at least as low as the first quartile. We match coal generation behavior particularly well in quarters one, three, and four. Quarter three corresponds to July, August, and September, which are the highest load months in our sample due to high temperatures and demand for cooling. We match capacity factor better under LACD, which provides empirical support for including units' fixed cycle costs.

4.5 LACD vs. LMCD

We provide evidence that LACD better matches the generation behavior of coal and natural gas units than LMCD by analyzing the hour-by-hour difference in generation mix. Figure 6 displays how sample-wide generation differs by dispatch model compared to observed. We calculate each hour's total coal and natural gas generation for the observed and dispatch simulations. We plot mean squared differences between observed and each dispatch method by hour of day and quarter of year. Generation mix is closer to observed under LACD across all hours of day and quarters of year. Incorporating average costs more closely represents observed dispatch behavior and generation mix by fuel type.

Both dispatch algorithms over-dispatch natural gas and under-dispatch coal compared to observed, but LACD better matches observed levels. This is due to the inability to model all transmission congestion and physical constraints. Incorporating generator fixed cycle costs of start up and shut down results in a more realistic generation mix online in any hour.

Figures 6 and 7 display the mean squared differences in thermal generation quantity and by coal capacity factor comparing the LMCD baseline to LACD with the low, median, and high average cost (AC). In figure 6 we show that any LACD improves model fit of thermal generation both for natural gas and coal generation. All lines associated with simulated generation from LACD algorithms result in smaller mean squared differences from observed with the baseline median LACD in between the high and low AC bounds, but closer to the low AC bound. Coal capacity factors in Figure 7 demonstrate a slightly different pattern. Across all hours of day and quarters of year, the baseline LACD better matches observed capacity factors than either high or low AC as well as LMCD. In quarters one, three, and four, the high and low AC algorithms perform about the same or slightly worse than LMCD.

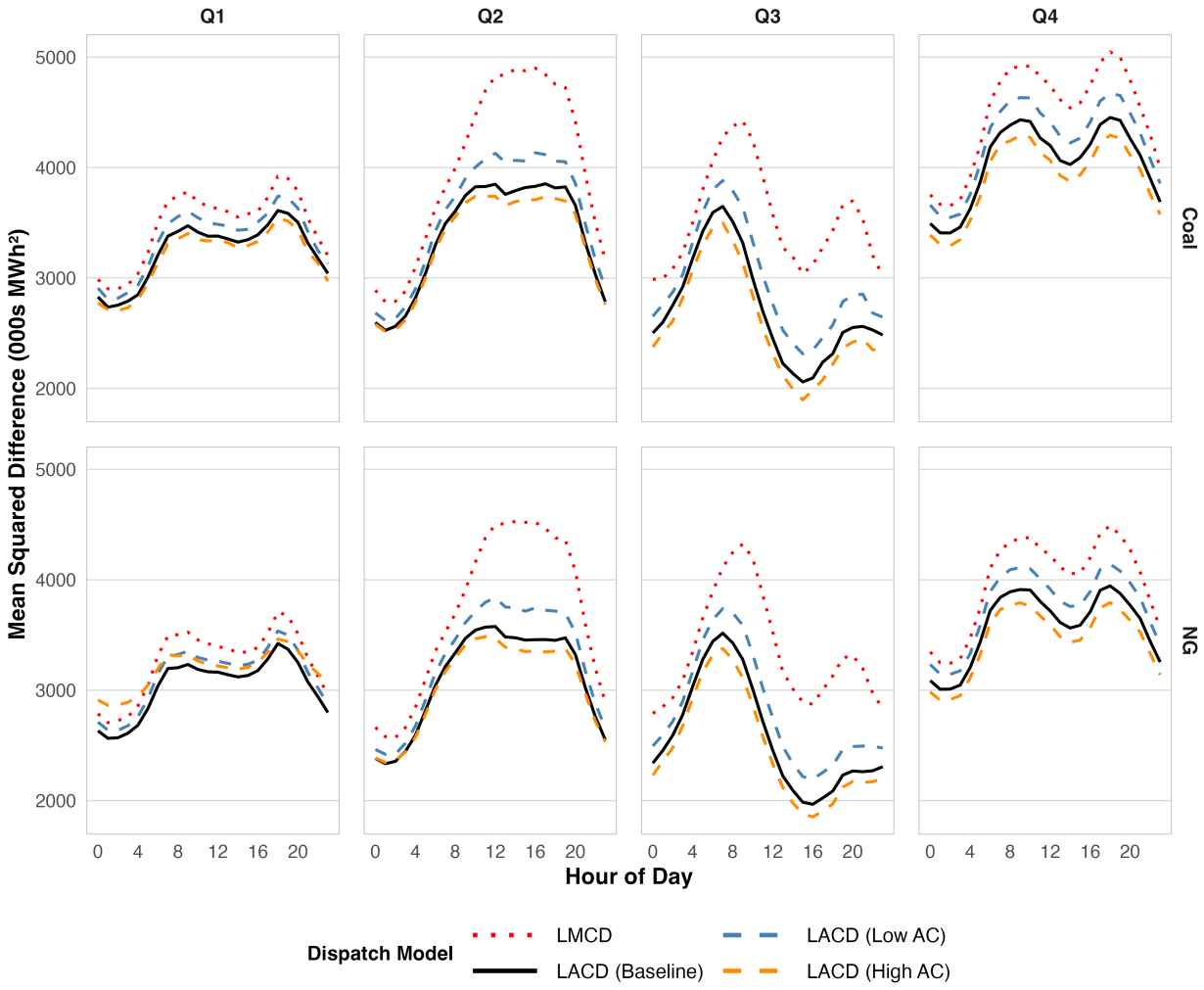


Figure 6: Mean Squared Difference from Observed Generation (MWh) LACD vs LMCD

Notes: Figure displays the mean squared differences for all coal and natural gas generation comparing simulation dispatch to observed varying the NREL cycling cost. The total coal and natural gas generation is calculated hour-by-hour and displayed by hour of day and quarter of year. Dashed lines are the mean squared differences from LACD with 25th and 75th percentile cycling costs. Solid lines are mean squared differences from baseline LACD with median cycling costs. Dotted lines are mean squared differences using LMCD.

Table A2 explicitly shows how much LACD improves thermal generation behavior over LMCD along with the low and high AC versions for robustness. We show that using any LACD improves generation mix over LMCD by 4.8-16.6%. In the preferred median LACD, generation mix improves by 7.9-14.2%. The preferred LACD algorithm is the only dispatch method that improves coal capacity factor over LMCD. Our preferred dispatch method better matches observed dispatch than LMCD by at least 15.9%.

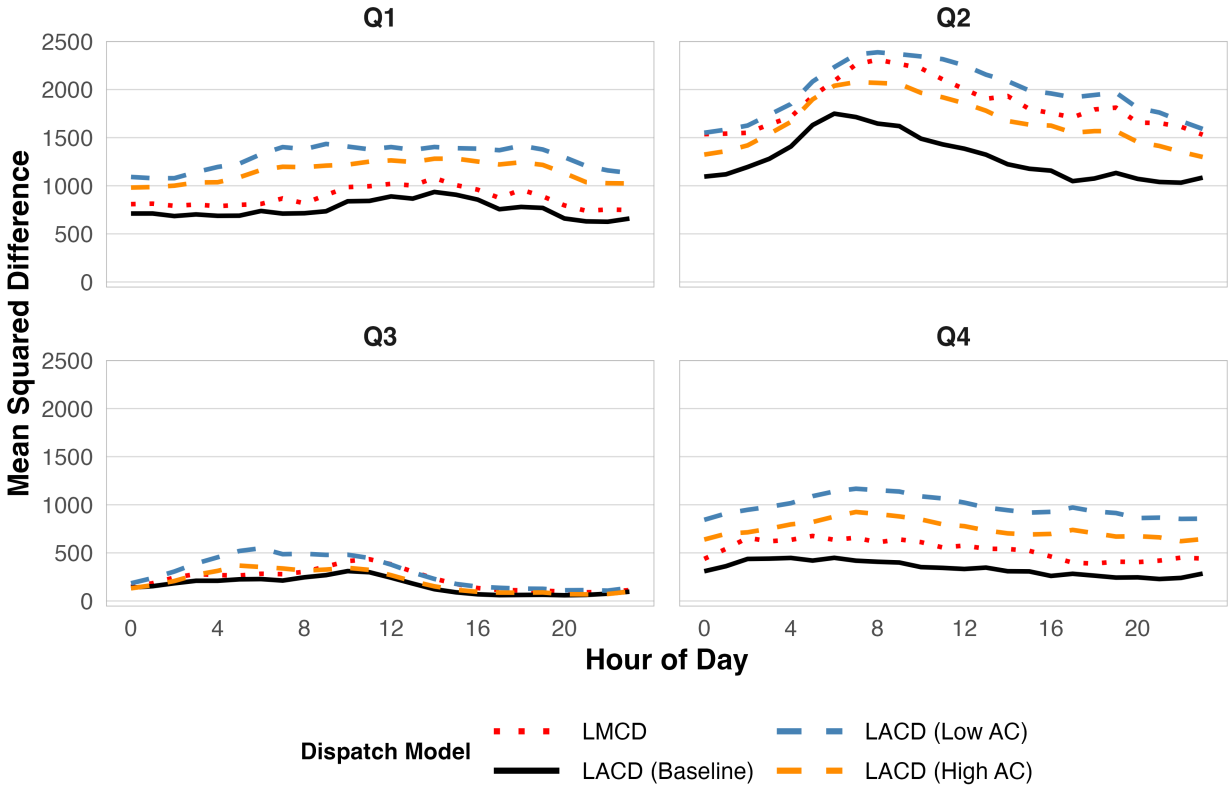


Figure 7: Coal Generation Capacity Factor LACD vs LMCD

Notes: Figure displays the mean squared differences for coal generation capacity factor comparing simulation dispatch to observed. Capacity factor is calculated hour-by-hour and displayed by hour of day and quarter of year. Dashed lines are the mean squared differences from LACD with 25th and 75th percentile cycling costs. Solid lines are mean squared differences from baseline LACD with median cycling costs. Dotted lines are mean squared differences using LMCD.

Although generation mix under LACD is more representative of observed, we see no difference between models in the marginal cost of the final unit each hour. Figure A1 shows no distinguishable difference in the marginal cost of the final unit by hour of day and quarter of year by dispatch model. Using the final unit's marginal cost as a reasonable approximation for the market price of electricity, we draw the same conclusion as Gonzales et al. (2023): incorporating cycle costs does not improve model fit. Model fit can also be evaluated on generation fuel mix, and including cycle costs in the dispatch algorithm substantially improves model fit. We contrast how primary results differ under the different dispatch models and rely on the LACD algorithm with ramp and minimum generation constraints for extensions.

4.6 Least Average Cost Dispatch - Proposed Interconnection

We construct a least average cost dispatch for zones z_1, z_2 in proposed interconnection pair p. In each hour t we rank generating units belonging to p by average cost $ac_{i,t}$ and dispatch generation for each unit up to capacity $C_{i,t}$ until total combined observed generation $obs_gen_{p,t}$ is met:

$$\min_{g_{i,p,t}} \left(\sum_{i \in (1,2,..,I_p)} ac_{i,t} g_{i,p,t} \right) \quad s.t. \quad \sum_{i \in (1,2,..,I_p)} g_{i,p,t} = obs_gen_{p,t}; \qquad g_{i,p,t} \leq C_{i,t} \quad \forall i; \tag{7}$$

Generating units are dispatched in least average cost order generating up to capacity until the sum of observed generation of the two zones z_1, z_2 in p is met. As in the marginal cost version, this counterfactual assumes no transmission constraints, ramping constraints, or physical constraints other than the stochastically applied outages accounted for in capacity $C_{i,t}$. This means a unit can generate up to its capacity regardless of whether it was running in the previous hour, as long as it is online. Both the marginal and average cost dispatch algorithms assume each hour is independent. Our preferred specification adds the coal ramping and minimum generation constraints described above to both the independent-zone and interconnected dispatch. Dispatching by least average cost may re-order units and low average fixed cost units may become infra-marginal.

5 Interconnection Generation Cost Change

5.1 Total Cost Change

We evaluate interconnection benefits as independent zones moving to interconnection. The change in total generation costs from interconnection is:

For $z_1, z_2 \in p$

$$\Delta TotalCosts_{p,t} = \sum_{i \in (1,2,..,I_z)} ac_{i,t} g^{\dagger}_{i,z,t} + \sum_{i \in (1,2,..,I_z)} ac_{i,t} g^{\ddagger}_{i,z,t} - \sum_{i \in (1,2,..,I_p)} ac_{i,t} g^{*}_{i,p,t} \tag{8}$$

where $g^{\dagger}_{i,z,t}, g^{\ddagger}_{i,z,t}$ are the quantities that solve the least cost dispatch algorithms for independent zones z_1, z_2 and $g^{*}_{i,p,t}$ are the quantities that solve the least cost dispatch algorithms under interconnection. Table 3 shows total generation cost changes from each interconnection scenario using

LACD and LMCD. Column 3 results from optimal quantities that solve independent zone LACD and LACD for proposed interconnection pairs. Column 4 results from optimal quantities that solve independent zone LMCD and LMCD for proposed interconnection pairs. Column 5 presents the relative difference between the two dispatch algorithms.

Both dispatch algorithms rank the interconnection scenarios identically, yet the relative difference in their estimated cost changes ranges from about two percent for the MISO pairs to roughly 28 percent for West-SPP. The relative difference is largest where the generation cost change is smallest and renewable penetration is highest, so a modest reshuffling of marginal units is a large share of a small total. The two methods differ by less than 10% where cost changes are largest. The reshuffling on the margin has little effect on total cost because units near the margin differ by less than 50 cents per MWh. This reordering of units means that different technologies or fuel types are used under different methods, which could have larger impacts on emissions. We explore these implications in the next section.

Table 3: Interconnection Total Cost Change w/ Ramp Constraints

Zone 1	Zone 2	LACD Total Cost Change (Millions)	LMCD Total Cost Change (Millions)	Relative Difference (%)
HOU	MISO	458	471	-2.9
NORTH	MISO	408	417	-2.3
HOU	SPP	325	354	-8.0
NORTH	EPE	322	352	-8.3
NORTH	SPP	278	333	-16.6
SOUTH	EPE	261	290	-10.0
SOUTH	MISO	210	223	-5.8
SOUTH	SPP	181	220	-17.5
HOU	EPE	179	142	25.9
WEST	EPE	155	129	20.0
WEST	MISO	123	98	25.3
WEST	SPP	105	82	28.2

Notes: Total production cost reduction from interconnection ($M), summed across both jurisdictions, with ramp constraints; a positive value is a reduction. LACD/LMCD: least-average-/least-marginal-cost dispatch. *Rel. Diff.*: (LACD − LMCD)/LMCD in percent. Winter Storm Uri is excluded.

The two interconnection scenarios with the largest reductions in generation cost result in decreases of $408 to $458 million over the sample. Across scenarios, reductions range from 0.3% to 2.1% of total generation costs, as shown in Table A3. The largest reductions come from interconnecting ERCOT's Houston and North zones with MISO, the largest external zone. These two pairs rank first and second in both generation cost reduction and in baseline generation volume,

proxied by within-zone generation cost in Table A3. Larger, more fossil-intensive pairs tend to realize bigger reductions, though the relationship is not monotonic. The pairs with the smallest cost reductions from interconnection do not follow this pattern. The West-SPP and West-MISO interconnections show the smallest cost decreases by dollar amount and relative amount, respectively. These zones already generate much of their power from renewables and have limited room to reduce generation costs further by allocating generation to more efficient fossil units. They also have small relative efficiency differences between their units.

Whether these reductions in generation costs come from dispatching lower cycle cost units or lower marginal cost units remains unclear. In the next subsection we isolate reductions in marginal costs. Comparing total cost change to marginal cost change in an interconnection scenario reveals whether cost decreases arise from dispatching lower average fixed cost units or lower marginal cost units.

5.2 Marginal Cost Change

We isolate the change in marginal costs from interconnection. We treat independent zones as the baseline and compare marginal costs of meeting combined observed generation after interconnection. The change in marginal costs from interconnection is:

For $z_1, z_2 \in p$

$$\Delta MarginalCosts_{p,t} = \sum_{i \in (1,2,..,I_z)} mc_{i,t} g^{\dagger\dagger}_{i,z,t} + \sum_{i \in (1,2,..,I_z)} mc_{i,t} g^{\ddagger\ddagger}_{i,z,t} - \sum_{i \in (1,2,..,I_p)} mc_{i,t} g^{**}_{i,p,t} \tag{9}$$

where $g^{\dagger\dagger}_{i,z,t}, g^{\ddagger\ddagger}_{i,z,t}$ are the quantities that solve the least cost dispatch algorithms for independent zones z_1, z_2 and $g^{**}_{i,p,t}$ are the quantities that solve the least cost dispatch algorithms under interconnection. Figure 8 shows generation marginal cost changes from each interconnection scenario using LACD and LMCD. Differences in marginal cost reductions between dispatch algorithms range from \$5 to \$43 million.[16] Although these differences are small relative to total electricity generation cost, they follow the same direction for all interconnection scenarios. Figure 8 shows that dispatching units in marginal cost order results in larger changes in marginal costs from interconnection. However, total cost changes from interconnection are only greater in interconnections with high dependence on fossil fuel generation.

[16] Table A7 displays the data that go along with this figure.

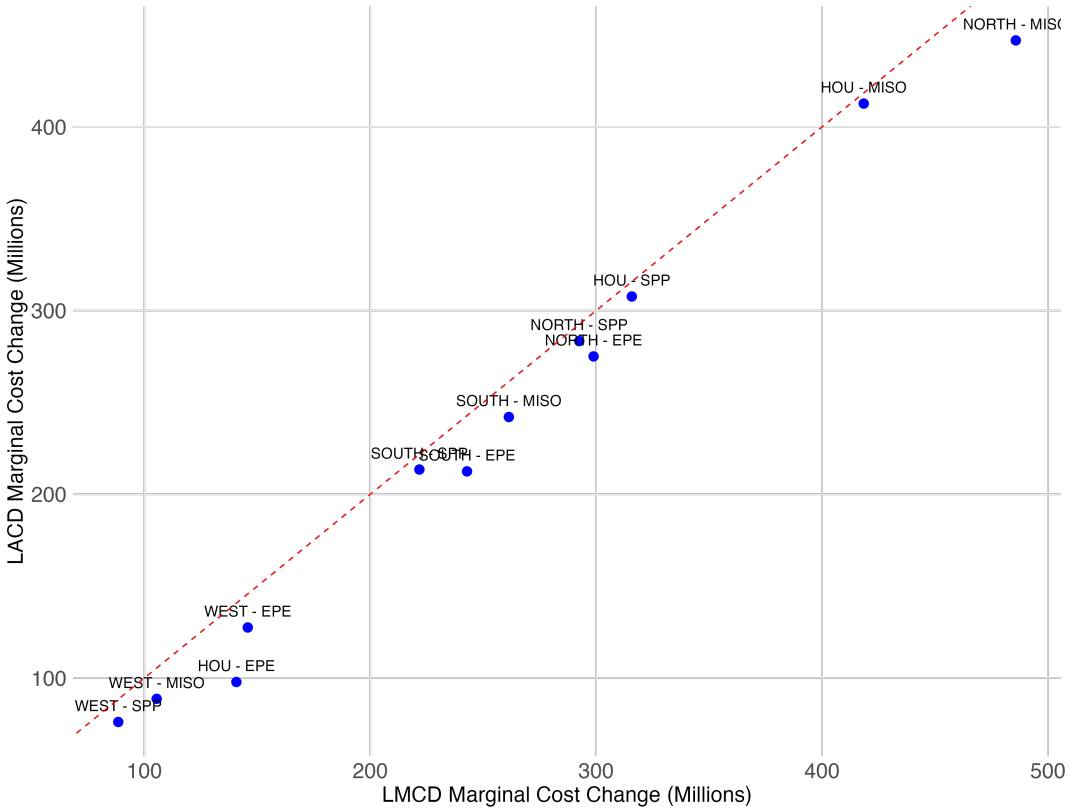


Figure 8: Interconnection Marginal Cost Change w/ Ramp Constraints

Notes: This figure displays the marginal cost changes by interconnection scenario under LACD vs LMCD. Both dispatch methods include ramping and minimum generation constraints. The dashed line is 45-degrees representing equal marginal cost changes between dispatch methods.

Marginal costs decrease $76 to $447 million under LACD, and $88 to $486 million under LMCD, from interconnection over the five and a half year sample period. These estimates align with those from Hausman (2025) once differences in generation volume between samples are accounted for. As shown in Table A4, this represents a 0.25% to 1.8% decrease in marginal costs from observed levels. Cicala (2022) finds larger estimates of marginal generation costs decreasing around 5% due to the transition to electricity markets.

The two interconnection scenarios with the largest decreases in generation marginal costs are the same as total cost changes, with Hou-MISO switching order with North-MISO. Interconnecting either of ERCOT's largest population zones with MISO results in the largest decreases in both marginal and total costs. The order of marginal cost reductions by interconnection is almost identical to total cost reductions. A new pattern emerges from both cost reduction tables. Marginal cost changes are greater than total cost changes for some interconnections, and this differs by dispatch algorithm.

Interconnection scenarios show heterogeneity in sources of generation cost reductions. Generation costs could decrease from dispatching lower average fixed cost units, lower marginal cost units, or both. When marginal cost change from interconnection exceeds total cost change, higher fixed cost units with much lower marginal costs are dispatched relative to the pre-interconnection baseline. These interconnections reduce generation costs by incurring higher fixed costs and generating from units with much lower marginal costs. This occurs for North-MISO, North-SPP, South-MISO, and South-SPP interconnection scenarios under LACD. Tables A8 and A9 show that zone pairs West-EPE, West-SPP, and West-MISO flip from marginal cost change greater than total cost change to less than when moving from LMCD to LACD, while North-SPP flips the other way. Under LMCD, 6 of 12 interconnection scenarios have greater marginal changes than total cost changes. Under LACD, that number drops to 4 out of 12 interconnection scenarios with three switching out and only one switching in. When units are dispatched in least average cost order, units with lower average fixed costs may become infra-marginal while units with high average fixed costs are pushed to the margin.

The reshuffling of units between dispatch algorithms is possible because unit fixed and marginal costs are only weakly to moderately correlated within fuel types. Appendix Table A11 shows correlation between unit-level fixed and marginal costs. If these costs are highly correlated, including fixed costs in the dispatch algorithm would not substantially change the stack of units generating in a given hour, and therefore cost changes and emissions changes would not differ between models. We show that there is considerable heterogeneity across both fuel type and zone. In West ERCOT, the high marginal cost units also tend to be high fixed cost units. This is because nearly all of hourly load is met by renewables, and thermal plants in this zone are high-cost peaker plants that do not produce electricity every day. Larger zones tend to have a larger and more diverse portfolio of thermal plants. Coal units' costs are moderately correlated but minimally correlated by rank according to the Spearman correlation. In general, unit fixed and marginal costs are moderately correlated at most, meaning the dispatch algorithm used will substantively alter which units are operating in a given hour.

Interconnections where total cost reductions exceed marginal cost reductions illustrate cost reductions coming from reducing both fixed and marginal costs. More interconnections reduce both costs under LACD. This reinforces that generation is allocated differently when fixed costs are accounted for.

Our findings provide evidence that generation is allocated differently when fixed costs are ac-

counted for in a least cost dispatch model. If researchers are solely interested in generation cost outcomes, LACD and LMCD show minimal differences and both may be used to produce bounds. In zones more reliant on fossil generation, large differences in emissions may result from generation allocation between the two dispatch algorithms due to different technology and fuel type among units around the margin.

5.3 Factors of Generation Cost Changes

To explore what factors may be driving the generation cost changes we run horse-race regressions of observables on monthly and hourly cost changes. The dependent variable for both are cost reductions, therefore a positive estimated coefficient on the regressor implies larger reductions in generation cost with interconnection. We report results in Table A10 at the hourly time dimension and in Table 4 at the monthly time dimension. Both tell a similar story. Less demand correlation between zones is strongly correlated with more cost reductions from interconnection. The greater the zonal difference between final unit marginal cost is associated with greater cost reductions from interconnection. Excess thermal capacity above demand is also correlated with more cost reduction from interconnection. All of the highlighted variables are estimated with economically meaningful coefficients and are statistically significant. Each of them point to the same mechanical reasons certain interconnection scenarios see larger gains than others. Low demand correlation implies Zone A still has low cost thermal units available when Zone B experiences demand shocks. The gap in final unit marginal costs illustrates that across-zone productivity differs, the more that differs, the more potential for reducing generation costs after interconnection. Thermal generation share of zone total is a strong positive correlate of generation cost reduction hourly, but small and even statistically insignificant at the monthly resolution. In general, greater the zonal difference in productivity (MC), lower demand correlation, and excess thermal generation capacity are associated with greater reductions in generation cost from interconnection.

6 Emissions

Integrating electricity markets reduces aggregate production costs by shifting generation to the most productive units. However, the most productive units may not be the lowest-emitting, so interconnection does not guarantee reduced social costs from emissions. Gonzales et al. (2023) analyzes total emissions changes from Chile's electricity market interconnection but does not ac-

Table 4: Monthly Predictors of Production Cost Reductions from Interconnection

	(1)	(2)
Renewable & Nuclear Share	0.183	
	[-1.24, 0.746]	
Coal Generation Share		-0.708
		[-1.32, 0.314]
Natural Gas Generation Share		-0.0599
		[-0.734, 1.5]
asinh(Mean Hourly Demand)	-0.873*	-0.945**
	[-1.38, 0.0528]	[-1.42, -0.106]
Demand Correlation	-14.2**	-13.9**
	[-21.6, -0.999]	[-21.1, -0.803]
asinh(Demand Variance)	0.0769	0.102
	[-0.0769, 0.255]	[-0.0445, 0.284]
asinh(System MC Variance)	-0.0656	0.00555
	[-0.147, 0.0145]	[-0.13, 0.117]
asinh(Unused Thermal Capacity)	0.881***	0.896***
	[0.525, 1.2]	[0.552, 1.2]
asinh(Marginal MC Spread)	0.769***	0.739***
	[0.533, 1.3]	[0.514, 1.29]
asinh(Marg. MC Spread) $\times$ Demand Corr.	1.03***	1.05***
	[0.623, 1.32]	[0.633, 1.32]
Demand Corr. $\times$ asinh(Demand)	1.13*	1.1*
	[-0.196, 1.88]	[-0.311, 1.82]
Observations	792	792
R^2	0.57	0.57

Notes: The dependent variable is asinh of the total monthly production cost reduction from interconnection ($M). All continuous variables are transformed by the inverse hyperbolic sine (asinh), which behaves like a natural log for large values but is defined for the negative and zero values that occur in cost reductions and several regressors; coefficients are therefore approximately elasticities evaluated at large values. Generation shares and the demand correlation (both bounded in absolute value below one) enter in levels. Each observation is a zone pair $\times$ month for 12 ERCOT interconnection scenarios, July 2018–December 2023, excluding Winter Storm Uri (February 8–22, 2021; $N = 792$). All predictors are monthly means of the corresponding hourly variables (transformed after averaging). Generation shares and cost characteristics are computed from the unconstrained optimal dispatch corresponding to equation (7). No time fixed effects are included. Brackets report 95% confidence intervals from a restricted wild cluster bootstrap (Webb six-point weights, 9,999 replications) clustered on the 12 trade pairs; significance stars are based on the corresponding bootstrap p-values. ***p<0.01, **p<0.05, *p<0.1.

count for where emissions occur after integration. Policymakers need to understand the emission costs borne by the more efficient zone that assumes increased generation from interconnection. We decompose changes in generation and emissions by zone for each interconnection scenario to show how interconnection impacts each zone's fossil generation and emissions. We then trace each plant's emissions through an air quality model to estimate where $PM_{2.5}$ concentrations change and who is exposed.

6.1 Fossil Generation and Carbon Emissions

Our simulated counterfactual evaluates production differences at the unit-by-hour level. To understand which zones bear the burden of higher emissions, we first examine how generation shifts after interconnection. Zones with more productive units relative to their interconnection pair generate more power than prior to interconnection. Changes in total fossil generation are not necessarily symmetric between interconnected zones because combining each zone's nuclear and renewable generation may offset some required dispatchable generation. Emissions may not shift proportionately with generation. More productive units that generate more after interconnection may emit less than the now extra-marginal unit in the interconnected zone. We calculate each unit's CO_2 emissions by hour using its observed unit-by-hour emissions rate (tons/MWh) multiplied by generation assigned to that unit from the dispatch algorithm.

Figure 9 shows that more productive plants are not necessarily lower emitting. The horizontal axis shows change in generation from fossil fueled units and the vertical axis shows change in CO_2 emissions. Zones in the upper-right quadrant represent those whose units are more productive relative to their interconnection pair. The most productive units are in ERCOT North and South. The LACD graph shows that interconnecting ERCOT North and SPP results in ERCOT North generating approximately 53 million MWh more fossil power than without interconnection while SPP generates about 50 million MWh less. SPP's CO_2 emissions fall by about 34 million tons while ERCOT North's rise by about 35 million tons, leaving aggregate CO_2 roughly unchanged, a net increase of about 1 million tons. Table A12 presents these results in table format. In every ERCOT South interconnection, ERCOT South generation increases and total interconnection carbon emissions increase, indicating its units are more productive but not lower-emitting. Aggregate CO_2 rises in nine of the twelve interconnection scenarios. These results align with findings in Gonzales et al. (2023) when renewable investment cannot adjust with increased interconnection.

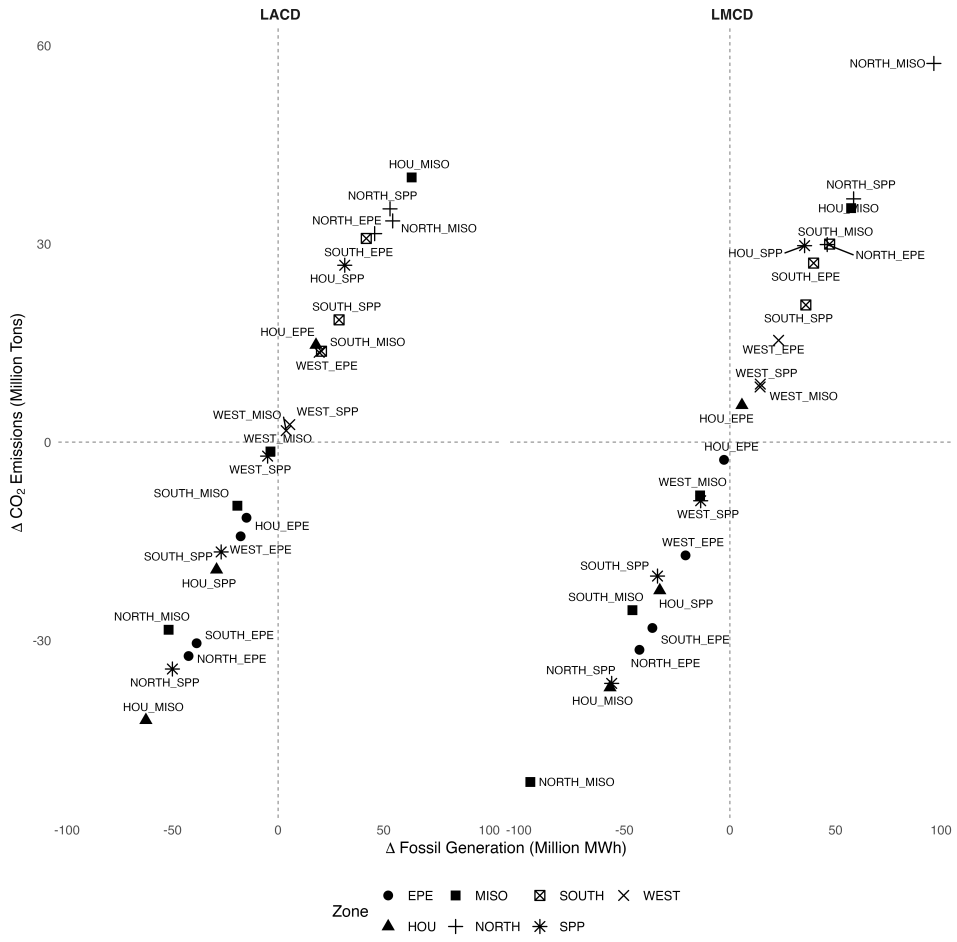


Figure 9: Change in CO_2 Emissions and Fossil Fuel Generation

Notes: This figure displays the changes in electricity generation from fossil fuel sources and CO_2 emissions by interconnection scenario and dispatch type.

Table A13 shows results under LMCD. Aggregate CO_2 falls in five interconnections under LMCD (Houston–MISO, North–EPE, South–EPE, West–EPE and West–SPP), compared with three under LACD (Houston–MISO, North–EPE and West–EPE). When dispatched in least average cost order, plants tend to be larger, more carbon-intensive units with lower cycle costs. Researchers who do not account for the fixed costs of cycling would therefore misattribute decreases in carbon emissions in some interconnection scenarios relying on LMCD.

6.2 Social Costs of Emissions

Following Gonzales et al. (2023), we combine unit-by-hour changes in generation from thermal plants with estimates of negative externalities (USD/MWh) by unit type from Greenstone and

Looney (2012) and mean social cost of carbon from Rennert et al. (2022).[17] Aside from CO_2, thermal units emit SO_2, NO_x, and $PM_{2.5}$, which harm human health and create negative externalities for the public in areas where generation occurs.

Interconnection does not necessarily reduce the aggregate social cost of emissions, and whether as well as how much it does depends on the dispatch methodology. Table 5 reports the change in externality cost of emissions for each trade pair under both dispatch methods. The ERCOT Houston–MISO interconnection delivers the largest reduction in emissions cost, $347 million under LACD and $301 million under LMCD, however, this is made up entirely of reductions in CO_2 emissions and the interconnection would see an increase in local non-carbon social costs. Emissions cost reductions scale down substantially for the next-ranked interconnections: only ERCOT North–El Paso Electric and ERCOT West–El Paso Electric also lower emissions cost under both methods, by $157 to $186 million under LACD. Under LMCD emissions cost reductions for these two scenarios are about twice as much.

Table 5: Change in Emissions Cost from Interconnection by Trade Pair and Dispatch Method

		Carbon		Non-carbon		Total		
Zone 1	Zone 2	LACD	LMCD	LACD	LMCD	LACD	LMCD	Rel. Diff. (%)
HOU	MISO	-376.5	-320.9	29.9	19.6	-346.6	-301.3	15.0
WEST	EPE	-124.8	-322.4	-61.0	-126.7	-185.8	-449.2	-58.6
NORTH	EPE	-154.1	-285.9	-3.0	-45.6	-157.0	-331.5	-52.6
SOUTH	EPE	68.7	-193.7	-52.6	-81.6	16.1	-275.3	-105.8
WEST	MISO	56.6	48.9	15.9	7.2	72.5	56.1	29.3
WEST	SPP	96.0	-19.8	13.1	-20.2	109.1	-40.0	-372.3
NORTH	SPP	175.8	53.3	80.3	19.7	256.1	72.9	251.2
SOUTH	SPP	346.4	88.1	34.5	-9.0	380.9	79.1	381.7
HOU	EPE	600.3	535.7	78.0	69.0	678.2	604.7	12.2
SOUTH	MISO	761.4	836.8	125.2	124.4	886.6	961.2	-7.8
NORTH	MISO	937.5	1084.3	207.0	204.5	1144.6	1288.8	-11.2
HOU	SPP	1377.7	1345.8	323.0	295.2	1700.7	1641.0	3.6

Notes: Change (post − pre) in the social cost of emissions ($M), summed across affected jurisdictions; a negative value denotes a reduction. Carbon at the $185/ton SCC (Rennert et al., 2022); non-carbon $10/MWh gas, $34/MWh coal; rates winsorized 1st/99th. *Rel. Diff.* = (LACD − LMCD)/LMCD in percent, large where the LMCD total is near zero.

Table 5 provides evidence that dispatch methodology matters when evaluating emissions changes from interconnections. The sign and magnitude of the emissions-cost change vary widely across dispatch methods. The ERCOT South–El Paso Electric interconnection, for instance, lowers emis-

[17] Greenstone and Looney (2012) estimates the non-carbon external cost is $34 per MWh of coal generation and $10 per MWh of natural gas generation. Rennert et al. (2022) estimate the social cost of carbon to be $185/ton of CO_2.

sions cost by $275 million under LMCD but raises it by $16 million under LACD, and the ERCOT North–El Paso Electric reduction shrinks from $331 million under LMCD to $157 million under LACD. Because the two methods reshuffle the units around the margin, they change which plants absorb displaced generation and therefore the emissions outcome.

Under these fuel-average damages, lower production costs do not guarantee lower emissions costs. Many interconnections that deliver large generation cost savings increase the social cost of emissions. ERCOT North–MISO, the second-largest generation cost reduction, raises social costs of emissions by about $1.14 billion under LACD, and all SPP interconnections combine sizable production cost savings with emissions-cost increases. Houston–SPP alone adds roughly $1.70 billion, more than offsetting its generation cost reductions. Most of these increases are carbon costs, which account for about 82 percent of the increase for North–MISO and 81 percent for Houston–SPP.

6.2.1 Drivers of Emissions Cost Changes and Dispatch Differences

We explore potential factors driving emissions social cost changes by running horse-race regressions of observables on monthly and hourly cost changes from LACD and display these results in Table 6. These regressions provide descriptive evidence and are not intended to be interpreted as causal. The correlates largely mirror the generation cost results. Interconnections between zones with larger gaps in marginal cost between price-setting units and more unused thermal capacity deliver the largest reductions in carbon social costs. The mechanism is the same reshuffling story: when two zones' demand peaks do not coincide and their units differ in cost, interconnection lets more productive units displace generation across the border. Demand correlation follows similarly as in the generation cost regressions; more demand-correlated interconnections see smaller reductions or even increases in carbon costs. One key departure is coal generation. More coal-intensive interconnections realize smaller carbon-cost reductions and, in some cases, increases. The zonal differences that decrease generation costs, do not necessarily reduce social costs of emissions because the generation dispatched is often more carbon-intensive.

We also regress the difference between carbon-cost changes from LACD and LMCD on the same set of observables to better understand what factors contribute to how carbon social costs differ. Results are displayed in Table A14. The gap between the dispatch methods widens in interconnections with weakly correlated demand and ample thermal capacity. Intuitively, incorporating

Table 6: Predictors of Carbon Cost Reductions from Interconnection

	(1)	(2)	(3)	(4)
Renewable & Nuclear Share	0.421		4.18*	
	[-2.65, 1.97]		[-0.535, 7.34]	
Coal Generation Share		-2.19*		-12.1***
		[-4.14, 0.501]		[-17.7, -5.09]
Natural Gas Generation Share		0.0868		-2.32
		[-1.67, 3.27]		[-4.26, 1.54]
asinh(Combined Demand)	-0.398	-0.536	-1.34	-2.43**
	[-1.96, 0.839]	[-1.99, 0.678]	[-3.8, 1.26]	[-4.51, -0.217]
Demand Correlation	-16.6**	-14.9*	-31.5***	-27.2***
	[-39.2, -2.12]	[-35.9, 0.0769]	[-57, -16.2]	[-47, -16]
asinh(Demand Variance)	-0.159	-0.104	-0.366	0.0103
	[-0.65, 0.285]	[-0.585, 0.342]	[-1.42, 0.426]	[-0.835, 0.811]
asinh(System MC Variance)	-0.492***	-0.249	-1.56***	-0.482
	[-0.688, -0.269]	[-0.551, 0.0983]	[-2.2, -0.948]	[-1.05, 0.161]
asinh(Unused Thermal Capacity)	0.392	0.43	1.59**	1.82***
	[-0.314, 1.37]	[-0.219, 1.3]	[0.39, 2.74]	[0.646, 2.82]
asinh(Marginal MC Spread)	0.637***	0.607***	1.49**	1.03**
	[0.333, 0.932]	[0.319, 0.876]	[0.471, 2.65]	[0.0789, 1.94]
asinh(Marg. MC Spread) × Demand Corr.	-0.0426	-0.0589	0.887	1.08*
	[-0.81, 0.99]	[-0.837, 0.975]	[-0.59, 2.11]	[-0.163, 2.11]
Demand Corr. × asinh(Demand)	1.54**	1.39**	2.78***	2.35***
	[0.306, 3.66]	[0.135, 3.29]	[1.32, 5.29]	[1.29, 4.36]
Observations	574,266	574,266	792	792
R^2	0.04	0.04	0.17	0.24

Notes: Columns (1)–(2) are hourly (dependent variable: asinh of the carbon cost reduction, $000s); columns (3)–(4) are monthly ($M). The carbon-cost reduction values the CO_2 reduction from interconnection at $185/ton (Rennert et al., 2022), with emission rates winsorized at the 1st/99th percentile; non-carbon local-pollution costs are assessed separately with the air quality model. Continuous variables enter as asinh transforms (coefficients ≈ elasticities); generation shares and the demand correlation enter in levels. Sample: 12 ERCOT interconnection scenarios, July 2018–December 2023, excluding Winter Storm Uri. Hourly specifications include month, day-of-week and hour fixed effects (not shown); monthly include none. Brackets are 95% wild cluster bootstrap confidence intervals (Webb weights, 9,999 replications) clustered on the 12 trade pairs. ***p<0.01, **p<0.05, *p<0.1.

cycle costs only reorders the margin when there are many marginal units to reorder and real cost differences among them. In zone pairs where demand is tightly correlated and capacity is scarce, the merit order is effectively fixed and the methods yield nearly the same carbon social costs.

6.2.2 Health Damages from an Air Quality Model

Fuel-average damages per MWh treat every coal unit, and every gas unit, alike. They do not depend on which plant changes its output, how much SO_2 and NO_x it emits per unit of fuel, where it is located, or how many people live downwind. To capture these, we also estimate $PM_{2.5}$-related health damages with AP4T (Dennin et al., 2025), a census-tract version of the AP4 integrated assessment model (Dennin and Muller, 2025), the latest version of the APEEP model (Muller and Mendelsohn, 2007). AP4T maps annual emissions of SO_2, NO_x, primary $PM_{2.5}$, NH_3 and volatile organic compounds from 1,814 electric generating units, and from all other sources in the 2017 National Emissions Inventory (NEI), to annual mean $PM_{2.5}$ concentrations in 72,538 census tracts in the contiguous United States. It uses Gaussian plume-based source-receptor matrices to model the transport of each pollutant and the formation of secondary ammonium sulfate and ammonium nitrate, and its concentrations are calibrated to EPA Air Quality System monitor data. AP4T converts changes in concentration to premature deaths using tract-level population and baseline mortality rates. For adults aged 30 and older, it applies a log-linear concentration-response function with a relative risk of all-cause mortality of 1.06 per 10 $\mu g/m^3$ of $PM_{2.5}$, from the American Cancer Society cohort (Krewski et al., 2009). For infants, it applies a logistic function with an odds ratio of 1.07 per 10 $\mu g/m^3$ (Woodruff et al., 2006). We value each premature death at $9.97 million in 2020 dollars: the EPA's central value of a statistical life of $7.4 million in 2006 dollars (U.S. Environmental Protection Agency, 2014), adjusted for real income growth to 2017 using an income elasticity of 0.7 (Hammitt and Robinson, 2011; U.S. Environmental Protection Agency, 2016) and for inflation to 2020. Dennin et al. (2025) document the model's concentration-response and valuation modules in detail.

We link the dispatch model to AP4T at the plant level. For each plant in an interconnection pair, we compute the change in its generation from interconnection under LACD with ramping constraints. This is its simulated generation with trade minus its simulated generation without trade, over the sample excluding Winter Storm Uri, the same comparison behind the generation and carbon cost results. We convert this change to a change in heat input using the plant's observed net heat rate. We then scale the plant's 2017 NEI emissions of SO_2, NO_x and primary $PM_{2.5}$ by the

ratio of its counterfactual to baseline heat input. Each plant's emission rate stays at its NEI value; only how much it runs changes. Plants outside the pair, and all other emission sources, are held at baseline. Because the scaling ratio is the change in generation relative to the plant's observed net generation, its heat rate cancels out of the calculation. Errors in reported heat rates alone therefore cannot move the damage estimates (see the Appendix).

Table 7: $PM_{2.5}$ Health Damages (AP4T), Carbon Costs, and Generation Costs from Interconnection, Annual

		$PM_{2.5}$ (AP4T)					
Zone 1	Zone 2	$\Delta PM_{2.5}$ (ng/m^3)	Δ Deaths per year	Δ Health damages	Δ Carbon cost	Δ Total externality	Δ Generation cost
WEST	EPE	-0.57	-7.7	-77	-21	-97	-28
SOUTH	EPE	-0.27	-3.9	-39	12	-26	-47
SOUTH	MISO	-0.15	-1.8	-18	137	118	-38
WEST	SPP	0.18	2.8	27	18	45	-19
WEST	MISO	0.24	3.7	37	10	47	-22
SOUTH	SPP	0.41	5.3	53	62	115	-33
NORTH	EPE	0.31	5.8	58	-27	31	-59
NORTH	SPP	0.46	6.0	60	32	91	-51
NORTH	MISO	0.77	9.4	94	169	263	-74
HOU	EPE	1.12	14.9	149	109	258	-33
HOU	MISO	0.73	16.4	163	-68	95	-83
HOU	SPP	1.51	24.9	249	251	499	-59

Notes: Changes (post − pre interconnection) are in millions of dollars per year unless noted; negative values are reductions. All columns use LACD with ramping and minimum generation constraints, compare simulated dispatch with trade to simulated dispatch without trade, and exclude Winter Storm Uri (February 8–22, 2021). $\Delta PM_{2.5}$ is the national population-weighted change in annual mean concentration across 72,538 census tracts, in nanograms per cubic meter ($1\ ng/m^3 = 0.001\ \mu g/m^3$). Health damages are premature deaths from $PM_{2.5}$ exposure valued at $9.97 million per death. Carbon costs are from Table 5. Generation costs are from Table 3. Carbon and generation costs are each divided by the 5.5-year sample length. Pairs are sorted by the change in health damages.

Table 7 reports the results on an annual basis. In nine of the twelve pairs, interconnection raises national population-weighted $PM_{2.5}$ and premature mortality. The changes are small. Population-weighted $PM_{2.5}$ changes by at most 1.5 ng/m^3, and mortality changes range from 7.7 fewer deaths per year (West–EPE) to 24.9 more (Houston–SPP). Where health damages rise, they rise by $27 to $249 million per year, and the three Houston interconnections have the largest increases. Health damages fall only in West–EPE, South–EPE and South–MISO, by $18 to $77 million per year. In eight pairs, the increase in health damages alone exceeds the generation cost savings. Adding carbon costs, total externality costs rise in ten pairs. In nine of them, the increase exceeds the generation cost savings. Before reliability benefits, only West–EPE, South–EPE and North–EPE lower the sum of generation and externality costs.

Fuel-average and air quality model estimates of local pollution costs agree in sign for ten of the twelve pairs (Table 5). The exceptions are North–EPE, where fuel-average non-carbon costs fall slightly while AP4T damages rise, and South–MISO, where the reverse holds. Where the two agree, the AP4T estimates are 2.5 to 30 times larger in magnitude. This partly reflects their use of each plant's 2017 NEI emission rates, which can overstate emissions at units that added controls after 2017 (see the Appendix). Both measures are driven by a shift of generation toward lower-cost coal and lignite units. In Houston–SPP, Houston natural gas units lose generation to SPP coal plants in Oklahoma and Texas such as Muskogee, Sooner, Tolk and Welsh, and SO_2 emissions rise by 6,600 metric tons per year. In all three ERCOT North pairs, the lignite and coal plants Martin Lake, Limestone and Oak Grove gain generation. In North–SPP, these gains roughly offset reductions at SPP coal plants, and SO_2 falls by 1,200 metric tons per year. Population-weighted $PM_{2.5}$ still rises. The largest reductions are at plants in the Texas Panhandle and Oklahoma, such as Harrington, Tolk and Sooner, while the increases are at plants in East and Central Texas, closer to large populations.

Who bears these damages depends on which side of the interconnection gains generation. In most pairs, $PM_{2.5}$ rises for most Texans. In nine pairs, $PM_{2.5}$ rises in census tracts home to more than 90 percent of the Texas population. In North–MISO and North–SPP, Texas residents account for about 89 percent of the additional deaths. In South–EPE and West–EPE, national damages fall, but $PM_{2.5}$ still rises for 99 and 96 percent of Texans; the national improvement comes from reductions outside Texas. The Houston interconnections differ. In Houston–SPP, nearly all of the additional deaths occur outside Texas, where $PM_{2.5}$ rises for nearly everyone, while 43 percent of Texans see an increase. In Houston–MISO, $PM_{2.5}$ falls for 95 percent of Texans but rises for 73 percent of the population elsewhere.

While total electricity production costs do not differ substantially between dispatch methods, dispatch method choice has larger implications for emissions outcomes. The cost of one MWh of electricity varies little between units around the margin. We demonstrate how reshuffling units around the margin leads to different conclusions about emissions impacts from interconnection. The damage model matters too. Fuel-average damages and an air quality model that tracks each plant's emissions to where people live agree that interconnection raises local pollution costs in most scenarios. The air quality model, however, implies health damages several times larger, large enough in most pairs to exceed the generation cost savings, and it shows that much of the added exposure falls on Texans.

7 Winning and Losing Firms

As indicated by Hausman (2025), aggregate reductions in generation costs imply that generation and revenues shift to the most productive units. This shifting results in some firms winning and losing from market integration. Understanding which companies win and lose may reveal barriers to interconnection. We calculate revenue changes from pre-integration to post-integration modeled scenarios for firms. First, we calculate unit revenue as unit generation (MWh) from the LACD algorithm multiplied by the average cost of the unit on the margin. The average cost of the final unit in the supply curve serves as a reasonable proxy for market clearing price when units submit bids equal to marginal cost plus cycle costs spread over the hours of expected run time. We then match generator units to firms using EIA Form 860 and aggregate revenues from generating units to firms over the sample period.

Table 8: Firm Revenue Change from Interconnection: ERCOT vs. External Firms

Zone 1	Zone 2	ERCOT Firms ($B)	External Firms ($B)
SOUTH	EPE	1.41	-1.33
NORTH	EPE	1.32	-1.32
WEST	EPE	0.98	-0.75
SOUTH	SPP	0.79	-0.53
NORTH	SPP	0.44	-0.74
HOU	EPE	0.36	-0.53
WEST	SPP	0.19	0.00
SOUTH	MISO	0.16	-0.10
WEST	MISO	0.08	-0.03
NORTH	MISO	-0.22	-0.47
HOU	SPP	-2.01	1.77
HOU	MISO	-3.52	3.26

Notes: Net change in firm revenue from interconnection ($B) under LACD dispatch, for ERCOT-based versus external (MISO/SPP/EPE) firms; a positive value is a revenue gain. Winter Storm Uri is excluded.

One potential explanation for ERCOT's isolation is the desire to protect domestic firms from outside competition. If firms in neighboring zones are more productive, ERCOT plants would lose generation and therefore revenue from market integration. Table 8 reports total revenue changes for ERCOT and external firms in every interconnection scenario. Across nine of twelve scenarios generation and revenue shift away from firms in neighboring zones to ERCOT firms, indicating that plants just outside of Texas stand to lose from interconnection. As documented in Hausman (2025) and Ham et al. (2026), we also find transmission expansion reduces economic costs, but

incentives are not aligned for low productivity firms. Interestingly, the Houston-MISO scenario sees the largest reduction in generation costs and the largest reductions in ERCOT firm revenues, a decrease of more than $3.5 billion over the sample period. The Houston zone is heavily reliant on natural gas and home to some of the least efficient units in our sample. These particular firms may be aware of how much revenue they stand to lose from interconnection and have thus far benefited from ERCOT's isolation.

8 Reliability: Capacity Avoided by Interconnection

Beyond production and emissions costs, interconnection changes the generation capacity a region must build to keep the lights on. Reliability councils and system operators run annual studies that evaluate whether available capacity at peak demand meets a target reserve margin, and require new capacity when it does not. We adapt this framework to each interconnection scenario and estimate how much new generation capacity interconnection allows each pair to avoid.

ERCOT sets a minimum target reserve margin of 13.75%, meaning available capacity must be at least 1.1375 times peak demand.[18] For each zone's independent baseline, we take the hour of that zone's maximum observed demand over the sample and compute the additional capacity it would need to meet the reserve margin, equal to 1.1375 times its peak demand less its available capacity in that hour. Available capacity comes from the ramp-constrained LACD dispatch: renewable capacity is observed generation, coal capacity reflects ramping constraints and stochastic outages, and natural gas capacity is the observed 99th percentile of generation net of stochastic outages. We repeat the calculation for the interconnected pair at the hour of maximum combined demand. The capacity avoided by interconnection is the sum of the two zones' standalone needs less the combined pair's need; a zone with available capacity already above its reserve requirement has a negative standalone need, that is, surplus capacity. We value avoided capacity at $900,000 per MW, the cost of a new combined-cycle natural gas unit.[19]

Table 9 reports the results for all twelve interconnection scenarios. Interconnection avoids capacity in ten of the twelve pairs, from about 150 MW for Houston-SPP to roughly 4,100 MW for Houston-MISO, worth $135 million to $3.7 billion in deferred construction. Two forces drive these savings. First, zone peaks are not perfectly coincident, so a pair's combined peak demand is lower

[18] From the 2023 ERCOT Resource Adequacy report.

[19] Source: EIA construction cost data for electric generators installed in 2023.

Table 9: Reliability: Generation Capacity Avoided by Interconnection

Interconnection	ERCOT Zone Reserve Gap (MW)	External Zone Reserve Gap (MW)	Combined Reserve Gap (MW)	Capacity Avoided (MW)	Avoided Capacity Cost (Millions)
HOU–MISO	8,184	-2,365	4,061	4,124	$3,711
NORTH–MISO	4,838	-2,365	980	3,858	$3,472
WEST–SPP	-7,215	3,539	-6,301	3,539	$3,185
HOU–EPE	8,184	-1,647	5,385	2,799	$2,519
NORTH–EPE	4,838	-1,647	2,183	2,655	$2,390
SOUTH–MISO	2,437	-2,365	-1,129	2,437	$2,193
SOUTH–SPP	2,437	3,539	3,619	2,357	$2,121
SOUTH–EPE	2,437	-1,647	89	2,348	$2,113
NORTH–SPP	4,838	3,539	8,078	299	$269
HOU–SPP	8,184	3,539	11,573	150	$135
WEST–MISO	-7,215	-2,365	-11,922	–	–
WEST–EPE	-7,215	-1,647	-8,705	–	–

Notes: A zone's reserve gap is the generation capacity it needs to meet ERCOT's 13.75% reserve margin at its peak demand hour; a negative value denotes surplus capacity above the margin. Capacity avoided is the new capacity the interconnected pair need not build: each zone's positive gap (a surplus counts as zero) less the pair's combined gap, valued at $900,000/MW for a new combined-cycle gas unit (EIA 2023). A dash marks pairs where both zones hold surplus, so no capacity is avoided. Winter Storm Uri is excluded.

than the sum of its members' individual peaks, and less reserve capacity is required. Second, zones differ in how tightly capacity binds at their own peaks: ERCOT North, South, and Houston would each need substantial new capacity in isolation (about 4,800, 2,400, and 8,200 MW), while ERCOT West, MISO, and El Paso Electric already hold surplus capacity. Interconnection lets a surplus zone cover part of a needy partner's shortfall, so the largest savings come from pairing a capacity-short ERCOT zone with a surplus neighbor, such as Houston or North with MISO. The exceptions are West-MISO and West-EPE, where both zones already hold surplus and interconnection avoids no new capacity.

These reliability savings are as large as, or larger than the generation cost savings in Section 5. Houston-MISO and North-MISO, the two largest generation cost reducers at roughly $458 and $408 million, avoid about $3.7 billion and $3.5 billion in capacity, respectively. The pattern is consistent with Hausman (2025), which suggests that the reliability benefits of interconnection can exceed its allocative efficiency gains. Because we value only the capacity needed to meet a fixed reserve margin, and do not price the lost load that would occur when that margin is breached, these figures are a lower bound on the reliability value of interconnection. Identifying the prevented lost load in each hour and multiplying by the value of lost load likely yields a substantially larger number.

9 Conclusion

Interconnecting Houston or ERCOT North with MISO provides the largest reductions in generation costs, but in most scenarios higher emissions costs more than offset the savings. We arrive at this conclusion by extending the least marginal cost dispatch model to include fixed cycle costs. We simulate generation dispatch for ERCOT regions interconnecting with a neighboring zone using rich data across a five and a half year sample period. Over this sample period, electricity markets are undergoing rapid change as the share of generation from renewables is growing and the climate is becoming variable, providing a relevant window for understanding the context for expanding transmission interconnection. We show that least average cost and least marginal cost dispatch do not result in substantially different estimates of generation cost reductions. However, the two different models suggest different generation allocation, resulting in more interconnection scenarios under LACD seeing cost reductions by reducing both fixed costs and marginal costs than under LMCD. We provide evidence that our novel dispatch algorithm better matches observed generation profiles. Both models predict identical ranking of reductions in generation cost by interconnection but differ in magnitude of reduction. We show that interconnecting either of Texas's two largest regions with MISO would result in the largest reductions in generation cost. The two dispatch methods offer differing results when evaluating emissions impacts. The generation allocated to the infra-marginal units under LACD tends to be more carbon-intensive than those under LMCD leading to very different conclusions regarding emissions impacts for a few interconnections.

First, we build a temporally and spatially rich data set combining several disparate sources that characterizes electricity production in Texas and neighboring zones. We extend the least cost dispatch algorithm in two ways. Where Cicala (2022) and Hausman (2025) rely on dispatching generating units by marginal cost, we incorporate cycle costs to build a measure of unit average cost. We show that including cycle costs improves dispatch performance by nearly 16%. We also use zone-level autarky to evaluate reductions in generation costs from interconnection between zones that belong to larger interconnections. We show that interconnection results in reductions in generation costs of more than $400 million over the sample for the largest interconnection scenarios.

We show that decreases in generation costs come from reducing both cycle costs and marginal costs for some interconnections while other interconnection scenarios increase fixed cycle costs and substantially decrease marginal costs. This finding differs from LMCD to LACD highlighting that incorporating fixed cycle costs reallocates generation among marginal units. This fact is important

to consider when evaluating individual generator response to increased transmission. In reality, operators consider cycle costs when bidding to sell electricity to the grid and incorporating these cycle costs may shift dispatch results closer to observed output without incorporating dynamics or more complex physical and transmission constraints.

Emissions impacts are more sensitive to dispatch methodology than generation costs. We show how LACD tends to shift generation to more carbon-intensive units around the margin. Therefore, relying on LMCD may result in more optimistic estimates of the change in carbon costs from interconnection. We also measure local pollution damages with an air quality model that accounts for which plants change their output, where they are, and who breathes their emissions. Interconnection raises $PM_{2.5}$ mortality in nine of twelve scenarios, because it shifts generation toward low-cost coal and lignite units. Fuel-average damages per MWh point in the same direction for most scenarios, but understate the magnitude. In eight scenarios, the increase in health damages alone exceeds the generation cost savings, and in nine, $PM_{2.5}$ rises for more than 90 percent of Texans.

We document revenue changes for firms in each interconnection scenario. Across a majority of scenarios, aggregate revenue in neighboring zones falls while revenues to Texas firms increase. This evidence disputes the argument that Texas is the sole party opposing grid integration. We also document how reliability cost savings are at least as great as generation cost savings from interconnection. Understanding how much each zone benefits from integration can inform how the costs of transmission could be shared.

Our findings have both policy and research methodology implications. We document the value of increased interconnection which could provide guidance for policymakers evaluating options to decrease electricity costs. We also show that researchers interested in measuring generation cost changes can get similar results from LACD and LMCD. However, very different conclusions can be reached when evaluating emissions changes, both across dispatch methods and across damage models. We argue that LACD disciplines coal generation better than LMCD and can provide more reliable estimates of emissions impacts. We also document the potential political economy barriers to interconnection when firms in zones outside of Texas stand to lose substantial revenue.

Future research could expand on our work in several ways. Our study could be extended by looking at how dynamic investment in generation capacity responds to interconnection. Some inefficient generators would become obsolete when zones are able to trade while others will produce at greater capacity factors and firms may be incentivized to invest in lower marginal cost units. Future research could also benefit from the design of a compensation scheme to equate the costs

and benefits of interconnection. Because the added $PM_{2.5}$ exposure falls largely on residents near the coal and lignite units that gain generation, often in Texas, such a scheme would need to cover residents as well as firms. Pairing interconnection with emission controls or retirements at those units could also change its health impacts. Understanding how both zones could be made better off from grid integration would inform the discussion on how the public is being compensated for increased negative externalities. Finally, it would be beneficial to analyze the total private and social costs of building transmission infrastructure to holistically inform the policy discussion.

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Appendix

Table A1: Cycle Costs by Fuel and Technology

		Cycle Cost ($/MWh capacity)		
Fuel	Technology/Size	Low (25th)	Median	High (75th)
Coal	Small Sub Critical (<300 MWh)	87	147	286
Coal	Large Sub Critical [300,850)	63	105	124
Coal	Super Critical (≥850)	73	104	120
Natural Gas	Combined Cycle	46	79	101
Natural Gas	Combustion Turbine (≥ 55 MWh)	31	103	118
Natural Gas	Combustion Turbine (< 55 MWh)	12	32	61
Natural Gas	Steam	54	75	89
Oil, Wood, etc.		54	75	89

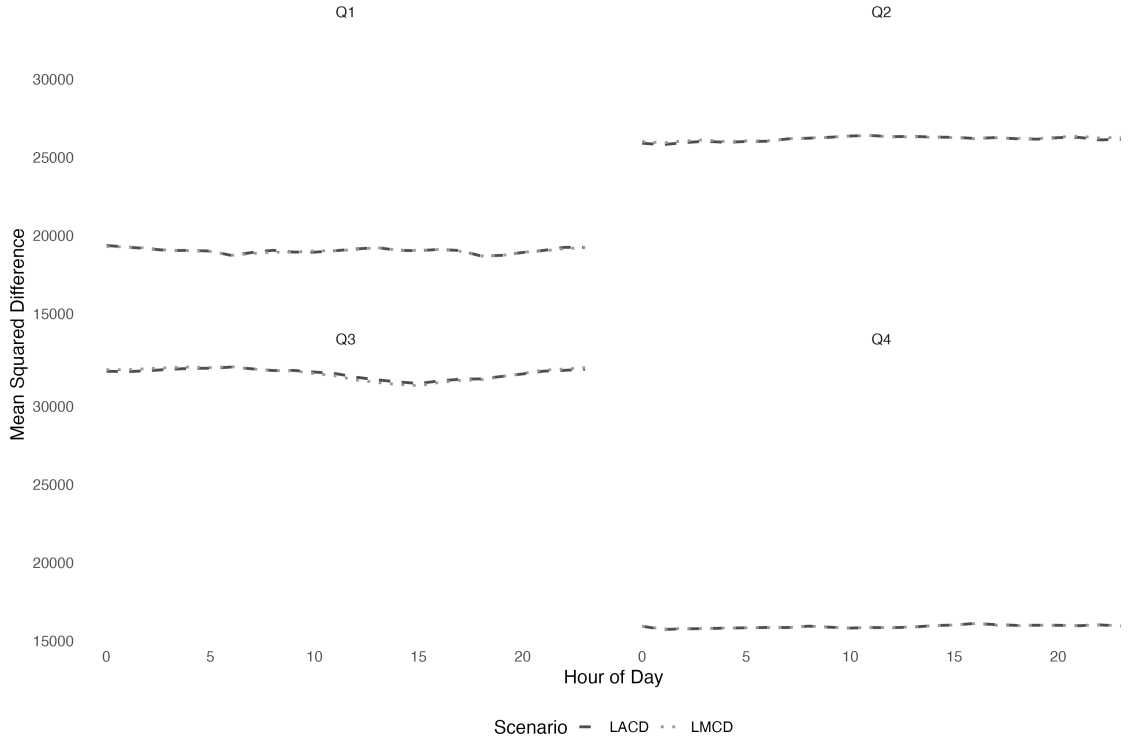
Notes: Cold-start cycle cost per MWh of capacity by fuel and technology from Kumar et al. (2012) (Table 1-1). The baseline dispatch uses the median; the 25th and 75th percentiles are used as the low and high bounds in the cycle-cost robustness checks.

Table A2: Dispatch Model Improvement over LMCD in Coal Capacity Factor and Generation Mix

		Baseline		Low AC		High AC	
	LMCD	LACD					
Metric	LMCD	Baseline	% Impr.	Low AC	% Impr.	High AC	% Impr.
Coal Capacity Factor							
Capacity Factor — MSD	823.69	600.32	27.1%	1,090.32	-32.4%	897.79	-9%
Capacity Factor — MAD	19.47	16.37	15.9%	24.64	-26.5%	21.86	-12.2%
Generation Mix							
Coal Generation — MSD (000s MWh^2)	3,889.3	3,347.2	13.9%	3,527.3	9.3%	3,244.7	16.6%
Coal Generation — MAD (MWh)	1,522.7	1,402.3	7.9%	1,449.2	4.8%	1,376.8	9.6%
NG Generation — MSD (000s MWh^2)	3,588.4	3,077.6	14.2%	3,246.4	9.5%	3,030.9	15.5%
NG Generation — MAD (MWh)	1,406.1	1,293.0	8%	1,337.4	4.9%	1,276.1	9.2%

Notes: MSD: mean squared difference; MAD: mean absolute difference. Both metrics are computed relative to observed generation and capacity factors. Percentage improvement is calculated as (LMCD − Model)/LMCD × 100, where positive values indicate smaller errors than LMCD.

Figure A1: Difference from Observed Final Marginal Cost LACD vs LMCD



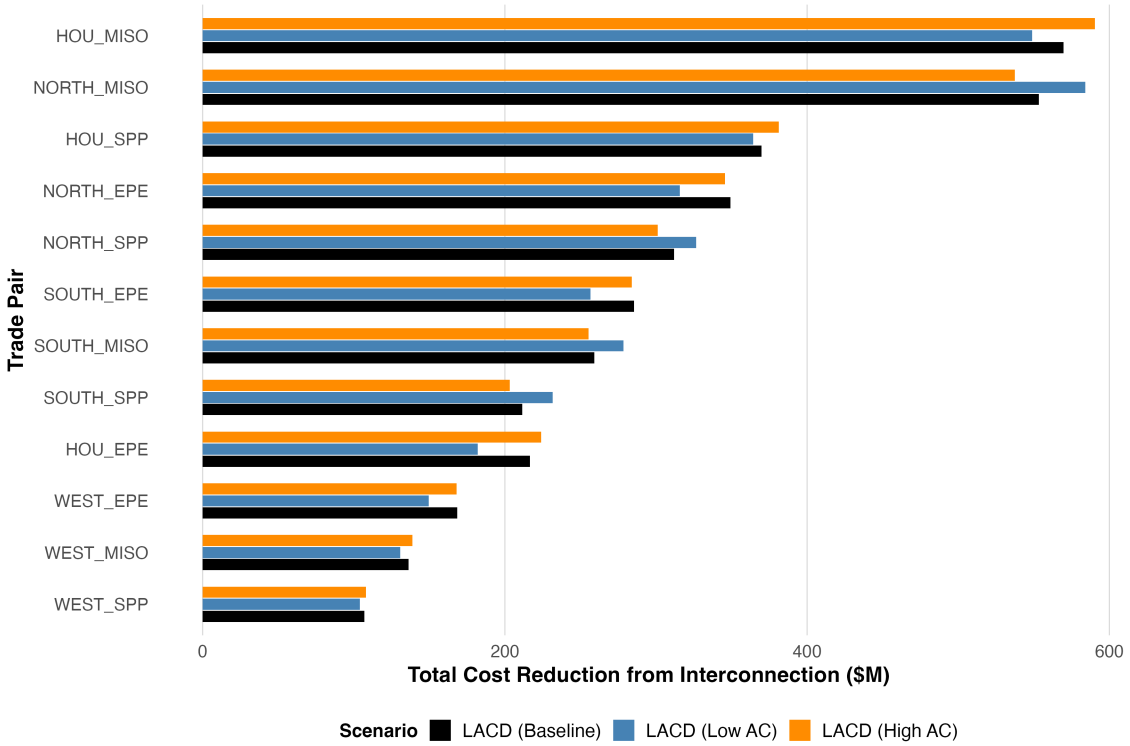
Notes: Figure displays the mean squared differences of the marginal cost of the final unit with positive generation comparing simulation dispatch to observed. The mean squared difference is calculated for each zone hour-by-hour and displayed by hour of day and month of quarter 2. Dashed lines are the mean squared differences from LACD. Dotted lines are mean squared differences from LMCD.

Table A3: Total Cost Change (LACD w/ Ramp Constraints)

Zone 1	Zone 2	Total Constrained Generation Costs (Millions)	LACD Total Cost Change (Millions)	Percent Reduction Generation Costs
HOU	MISO	51113	458	0.90%
NORTH	MISO	57565	408	0.71%
HOU	SPP	31864	325	1.02%
NORTH	EPE	27990	322	1.15%
NORTH	SPP	38316	278	0.72%
SOUTH	EPE	20367	261	1.28%
SOUTH	MISO	49943	210	0.42%
SOUTH	SPP	30693	181	0.59%
HOU	EPE	21538	179	0.83%
WEST	EPE	7250	155	2.14%
WEST	MISO	36825	123	0.33%
WEST	SPP	17576	105	0.60%

Notes: Total production cost reduction from interconnection under least-average-cost dispatch (LACD), with ramp constraints, in millions of dollars. *Percent Reduction* is the reduction as a share of the combined pre-interconnection cost. Winter Storm Uri is excluded.

Figure A2: Total Cost Reduction LACD - Cycling Cost Robustness



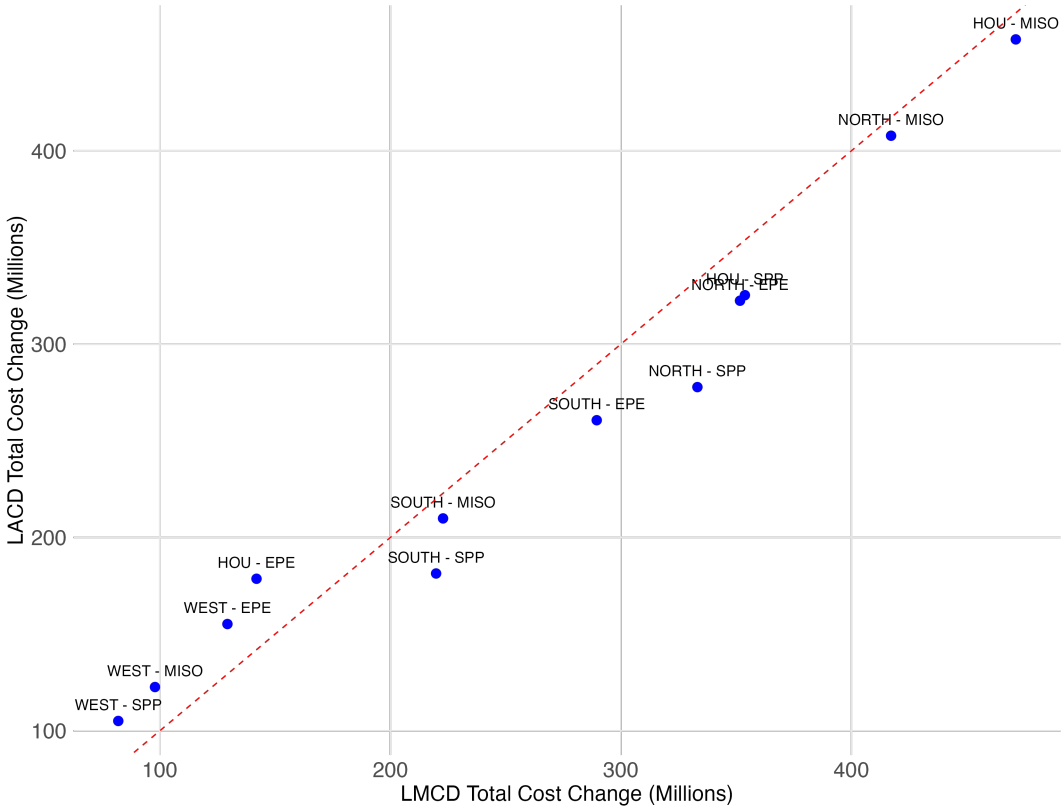
Notes: Figure displays the total cost change across interconnection scenarios from 25th, 50th (baseline), and 75th percentile NREL cycling cost estimates.

Table A4: Marginal Cost Change (LACD w/ Ramp Constraints)

Zone 1	Zone 2	Constrained Marginal Costs (Millions)	LACD Marginal Cost Change (Millions)	Percent Reduction Marginal Costs
NORTH	MISO	55530	447	0.81%
HOU	MISO	49830	413	0.83%
HOU	SPP	30955	308	0.99%
NORTH	SPP	36653	283	0.77%
NORTH	EPE	26757	275	1.03%
SOUTH	MISO	48284	242	0.50%
SOUTH	SPP	29408	213	0.73%
SOUTH	EPE	19511	212	1.09%
WEST	EPE	6932	127	1.84%
HOU	EPE	21058	98	0.46%
WEST	MISO	35704	89	0.25%
WEST	SPP	16829	76	0.45%

Notes: System marginal cost reduction from interconnection under least-average-cost dispatch (LACD), with ramp constraints, in millions of dollars. *Percent Reduction* is the reduction as a share of the combined pre-interconnection marginal cost. Winter Storm Uri is excluded.

Figure A3: Interconnection Total Cost Change w/ Ramp Constraints



Notes: This figure displays the total cost changes by interconnection scenario under LACD vs LMCD. Both dispatch methods include ramping and minimum generation constraints. The dashed line is 45-degrees representing equal total cost changes between dispatch methods.

Table A5: Total Cost Change (LMCD w/ Ramp Constraints)

Zone 1	Zone 2	Total Constrained Generation Costs (Millions)	LMCD Total Cost Change (Millions)	Percent Reduction Generation Costs
HOU	MISO	51113	471	0.92%
NORTH	MISO	57565	417	0.72%
HOU	SPP	31864	354	1.11%
NORTH	EPE	27990	352	1.26%
NORTH	SPP	38316	333	0.87%
SOUTH	EPE	20367	290	1.42%
SOUTH	MISO	49943	223	0.45%
SOUTH	SPP	30693	220	0.72%
HOU	EPE	21538	142	0.66%
WEST	EPE	7250	129	1.78%
WEST	MISO	36825	98	0.27%
WEST	SPP	17576	82	0.47%

Notes: Total production cost reduction from interconnection under least-marginal-cost dispatch (LMCD), with ramp constraints, in millions of dollars. *Percent Reduction* is the reduction as a share of the combined pre-interconnection cost. Winter Storm Uri is excluded.

Table A6: Marginal Cost Change (LMCD w/ Ramp Constraints)

Zone 1	Zone 2	Constrained Marginal Costs (Millions)	LMCD Marginal Cost Change (Millions)	Percent Reduction Marginal Costs
NORTH	MISO	55530	486	0.87%
HOU	MISO	49830	418	0.84%
HOU	SPP	30955	316	1.02%
NORTH	EPE	26757	299	1.12%
NORTH	SPP	36653	293	0.80%
SOUTH	MISO	48284	261	0.54%
SOUTH	EPE	19511	243	1.24%
SOUTH	SPP	29408	222	0.75%
WEST	EPE	6932	146	2.10%
HOU	EPE	21058	141	0.67%
WEST	MISO	35704	105	0.30%
WEST	SPP	16829	88	0.53%

Notes: System marginal cost reduction from interconnection under least-marginal-cost dispatch (LMCD), with ramp constraints, in millions of dollars. *Percent Reduction* is the reduction as a share of the combined pre-interconnection marginal cost. Winter Storm Uri is excluded.

Table A7: Interconnection Marginal Cost Change

Zone 1	Zone 2	LACD Marginal Cost Change (Millions)	LMCD Marginal Cost Change (Millions)
NORTH	MISO	447	486
HOU	MISO	413	418
HOU	SPP	308	316
NORTH	SPP	283	293
NORTH	EPE	275	299
SOUTH	MISO	242	261
SOUTH	SPP	213	222
SOUTH	EPE	212	243
WEST	EPE	127	146
HOU	EPE	98	141
WEST	MISO	89	105
WEST	SPP	76	88

Notes: Change in system marginal cost from interconnection ($M), summed across both jurisdictions, with ramp constraints; a positive value is a reduction. LACD/LMCD: least-average-/least-marginal-cost dispatch. Winter Storm Uri is excluded.

Table A8: Total vs Marginal Cost Change Interconnection (LACD w/ Ramp Constraints)

Zone 1	Zone 2	Total Cost Change (Millions)	Marginal Cost Change (Millions)	MC Change Greater?
HOU	MISO	458	413	No
NORTH	MISO	408	447	Yes
HOU	SPP	325	308	No
NORTH	EPE	322	275	No
NORTH	SPP	278	283	Yes
SOUTH	EPE	261	212	No
SOUTH	MISO	210	242	Yes
SOUTH	SPP	181	213	Yes
HOU	EPE	179	98	No
WEST	EPE	155	127	No
WEST	MISO	123	89	No
WEST	SPP	105	76	No

Notes: Total production cost change versus system marginal cost change from interconnection under least-average-cost dispatch (LACD), with ramp constraints, in millions of dollars. *MC Change Greater?* flags pairs where the marginal cost change exceeds the total cost change. Winter Storm Uri is excluded.

Table A9: Total vs Marginal Cost Change Interconnection (LMCD w/ Ramp Constraints)

Zone 1	Zone 2	Total Cost Change (Millions)	Marginal Cost Change (Millions)	MC Change Greater?
HOU	MISO	471	418	No
NORTH	MISO	417	486	Yes
HOU	SPP	354	316	No
NORTH	EPE	352	299	No
NORTH	SPP	333	293	No
SOUTH	EPE	290	243	No
SOUTH	MISO	223	261	Yes
SOUTH	SPP	220	222	Yes
HOU	EPE	142	141	No
WEST	EPE	129	146	Yes
WEST	MISO	98	105	Yes
WEST	SPP	82	88	Yes

Notes: Total production cost change versus system marginal cost change from interconnection under least-marginal-cost dispatch (LMCD), with ramp constraints, in millions of dollars. *MC Change Greater?* flags pairs where the marginal cost change exceeds the total cost change. Winter Storm Uri is excluded.

Table A10: Hourly Predictors of Production Cost Reductions from Interconnection

	(1)	(2)
Renewable & Nuclear Share	-1.42***	
	[-2.65, -0.756]	
Coal Generation Share		1.46***
		[0.605, 2.6]
Natural Gas Generation Share		1.4***
		[0.654, 2.85]
asinh(Combined Demand)	-0.214	-0.21
	[-0.741, 0.41]	[-0.78, 0.404]
Demand Correlation	-9.85**	-9.89*
	[-19.8, -0.117]	[-19.7, 0.193]
asinh(Demand Variance)	0.0967	0.0953
	[-0.127, 0.332]	[-0.124, 0.339]
asinh(System MC Variance)	0.0932**	0.0869*
	[0.0131, 0.186]	[-0.0157, 0.212]
asinh(Unused Thermal Capacity)	0.312*	0.312*
	[-0.0321, 0.728]	[-0.0524, 0.732]
asinh(Marginal MC Spread)	0.582***	0.582***
	[0.449, 0.723]	[0.448, 0.722]
asinh(Marg. MC Spread) × Demand Corr.	0.394***	0.395***
	[0.102, 0.748]	[0.108, 0.733]
Demand Corr. × asinh(Demand)	0.844*	0.847*
	[-0.0382, 1.76]	[-0.0663, 1.73]
Observations	574,266	574,266
R^2	0.15	0.15

Notes: The dependent variable is asinh of the hourly production cost reduction from interconnection ($000s). All continuous variables are transformed by the inverse hyperbolic sine (asinh), which behaves like a natural log for large values but is defined for the negative and zero values that occur in cost reductions and several regressors; coefficients are therefore approximately elasticities evaluated at large values. Generation shares and the demand correlation (both bounded in absolute value below one) enter in levels. Each observation is a zone pair × hour for 12 ERCOT interconnection scenarios, July 2018–December 2023, excluding Winter Storm Uri (February 8–22, 2021; $N = 574{,}266$). Generation shares, cost characteristics, and dispatch margin variables are computed from the unconstrained optimal dispatch corresponding to equation (7), which minimizes combined average cost absent ramp constraints. *Demand Correlation* is the within-month hourly correlation of zone demands. *Demand Variance* is the within-month variance of combined hourly demand. *System MC Variance* is the variance of unit-level marginal costs across all dispatched units in both zones. *Unused Thermal Capacity* is total available thermal capacity less total zone demand. All specifications include month-of-year, day-of-week, and hour-of-day fixed effects (not shown). Brackets report 95% confidence intervals from a restricted wild cluster bootstrap (Webb six-point weights, 9,999 replications) clustered on the 12 trade pairs; significance stars are based on the corresponding bootstrap *p*-values. ***p<0.01, **p<0.05, *p<0.1.

Table A11: Correlation between Unit-Level Fixed and Marginal Costs

	N	Mean FC	Mean MC	Pearson r	Spearman ρ	Gen-wt. r
Panel A: By fuel type						
Coal	57	0.39	38.4	0.379***	0.148	0.264
Natural Gas	578	6.09	61.5	0.343***	0.575	0.318
Other	10	1.47	106.1	0.341	0.612	0.126
Panel B: By zone						
NORTH	91	7.13	52.1	0.649***	0.669	0.496
SOUTH	98	5.35	65.4	0.512***	0.733	0.313
HOU	118	6.43	69.4	0.717***	0.632	0.327
WEST	24	11.20	59.8	0.916***	0.910	0.916
EPE	37	4.63	45.4	0.540***	0.457	0.395
SPP	122	4.57	68.2	0.120	0.474	0.228
MISO	155	4.03	51.9	0.492***	0.429	0.093
All units	645	5.51	60.2	0.349***	0.565	0.242

Notes: Each observation is a thermal generating unit. *Fixed cost* is the unit's average cycling (start-up) cost per MWh; *marginal cost* is its generation-weighted mean hourly marginal cost (fuel plus O&M, winsorized at the 1st/99th percentiles); both in $/MWh. Renewable and nuclear units, and units with a capacity factor below 1%, are excluded. *Pearson r* and *Spearman ρ* weight units equally; *Gen-wt. r* weights each unit by its total generation. Stars are from the Pearson correlation test: $^{***}p<0.01$, $^{**}p<0.05$, $^{*}p<0.1$.

Table A12: Carbon Emissions and Fossil Generation - LACD

	Carbon Emissions (Million Tons)			Fossil Gen. (Million MWh)		
Zone	CO_2 Pre	CO_2 Post	Δ CO_2	Fossil Pre	Fossil Post	Δ Gen
Hou - EPE						
EPE	90.44	78.99	-11.45	121.32	106.36	-14.96
HOU	238.11	252.81	14.69	374.49	392.45	17.96
Total	328.55	331.80	3.24	495.81	498.81	3.00
Hou - MISO						
HOU	233.20	191.13	-42.08	374.49	311.87	-62.62
MISO	441.82	481.86	40.04	753.68	816.96	63.28
Total	675.02	672.99	-2.04	1128.17	1128.83	0.66
Hou - SPP						
HOU	237.86	218.55	-19.31	374.49	345.35	-29.14
SPP	296.08	322.83	26.76	391.80	423.38	31.58
Total	533.94	541.39	7.45	766.29	768.73	2.43
North - EPE						
EPE	87.11	54.73	-32.37	121.32	78.91	-42.41
NORTH	359.56	391.10	31.54	601.14	646.88	45.75
Total	446.67	445.83	-0.83	722.46	725.80	3.34
North - MISO						
MISO	428.71	400.31	-28.40	753.68	701.81	-51.86
NORTH	358.95	392.41	33.47	601.14	655.43	54.29
Total	787.66	792.72	5.07	1354.82	1357.24	2.43
North - SPP						
NORTH	363.93	399.22	35.29	601.14	654.17	53.03
SPP	290.28	255.94	-34.34	391.80	341.74	-50.07
Total	654.21	655.16	0.95	992.94	995.90	2.96
South - EPE						
EPE	88.56	58.12	-30.44	121.32	82.73	-38.59
SOUTH	225.35	256.16	30.81	358.32	400.11	41.79
Total	313.90	314.27	0.37	479.64	482.83	3.20
South - MISO						
MISO	433.47	423.84	-9.63	753.68	734.39	-19.29
SOUTH	222.95	236.69	13.75	358.32	378.87	20.56
Total	656.41	660.53	4.12	1111.99	1113.26	1.27
South - SPP						
SOUTH	227.17	245.66	18.49	358.32	387.21	28.90
SPP	293.30	276.67	-16.62	391.80	364.84	-26.96
Total	520.46	522.34	1.87	750.12	752.05	1.93
West - EPE						
EPE	89.31	75.05	-14.26	121.32	103.58	-17.74
WEST	31.06	44.64	13.58	60.05	79.53	19.47
Total	120.37	119.70	-0.67	181.37	183.11	1.73
West - MISO						
MISO	433.44	432.02	-1.42	753.68	750.07	-3.61
WEST	30.42	32.15	1.73	60.05	63.91	3.85
Total	463.86	464.17	0.31	813.73	813.98	0.24
West - SPP						
SPP	294.72	292.60	-2.12	391.80	386.84	-4.97
WEST	31.25	33.89	2.64	60.05	65.58	5.53
Total	325.97	326.49	0.52	451.86	452.42	0.56

Notes: CO_2 emissions (million short tons) and fossil generation (million MWh) by zone, before and after interconnection under LACD with ramp constraints; Δ is post − pre. Winter Storm Uri is excluded.

Table A13: Carbon Emissions and Fossil Generation - LMCD

	Carbon Emissions (Million Tons)			Fossil Gen. (Million MWh)		
Zone	CO_2 Pre	CO_2 Post	Δ CO_2	Fossil Pre	Fossil Post	Δ Gen
Hou - EPE						
EPE	88.43	85.74	-2.69	121.56	118.76	-2.79
HOU	236.04	241.62	5.58	374.61	380.30	5.70
Total	324.47	327.36	2.90	496.16	499.07	2.90
Hou - MISO						
HOU	230.26	193.13	-37.13	374.61	317.81	-56.79
MISO	439.80	475.19	35.40	753.71	811.14	57.42
Total	670.06	668.32	-1.73	1128.32	1128.95	0.63
Hou - SPP						
HOU	235.70	213.25	-22.44	374.61	341.38	-33.23
SPP	289.82	319.54	29.72	392.15	427.53	35.38
Total	525.52	532.80	7.27	766.76	768.91	2.15
North - EPE						
EPE	84.30	52.87	-31.43	121.56	78.71	-42.85
NORTH	352.12	382.01	29.89	601.59	647.68	46.09
Total	436.42	434.88	-1.55	723.15	726.39	3.24
North - MISO						
MISO	425.89	374.46	-51.43	753.71	659.17	-94.54
NORTH	351.43	408.72	57.29	601.59	698.21	96.62
Total	777.32	783.18	5.86	1355.30	1357.38	2.07
North - SPP						
NORTH	356.83	393.63	36.80	601.59	660.20	58.61
SPP	283.12	246.60	-36.51	392.15	336.14	-56.01
Total	639.95	640.23	0.29	993.74	996.33	2.59
South - EPE						
EPE	85.98	57.85	-28.13	121.56	84.83	-36.73
SOUTH	221.78	248.86	27.08	358.59	398.25	39.65
Total	307.75	306.71	-1.05	480.15	483.08	2.93
South - MISO						
MISO	430.87	405.43	-25.43	753.71	707.54	-46.18
SOUTH	218.89	248.84	29.96	358.59	405.84	47.25
Total	649.75	654.28	4.52	1112.31	1113.38	1.07
South - SPP						
SOUTH	223.99	244.74	20.75	358.59	394.57	35.97
SPP	286.37	266.10	-20.27	392.15	357.85	-34.30
Total	510.36	510.84	0.48	750.75	752.42	1.67
West - EPE						
EPE	86.94	69.79	-17.14	121.56	100.53	-21.02
WEST	30.51	45.91	15.40	60.17	83.23	23.06
Total	117.45	115.71	-1.74	181.73	183.77	2.04
West - MISO						
MISO	430.83	422.76	-8.07	753.71	739.59	-14.12
WEST	29.83	38.17	8.34	60.17	74.48	14.31
Total	460.66	460.93	0.26	813.88	814.07	0.18
West - SPP						
SPP	288.11	279.23	-8.88	392.15	378.30	-13.85
WEST	30.71	39.48	8.77	60.17	74.57	14.40
Total	318.82	318.72	-0.11	452.32	452.88	0.55

Notes: CO_2 emissions (million short tons) and fossil generation (million MWh) by zone, before and after interconnection under LMCD with ramp constraints; Δ is post − pre. Winter Storm Uri is excluded.

Table A14: Predictors of the LACD−LMCD Difference in Carbon Cost Reduction (asinh)

	(1)	(2)	(3)	(4)
Renewable & Nuclear Share	-0.268		0.172	
	[-1.04, 0.494]		[-2.06, 2.58]	
Coal Generation Share		1.24**		-0.451
		[0.0302, 2.76]		[-3.75, 3.04]
Natural Gas Generation Share		-0.00997		-0.107
		[-0.907, 0.896]		[-2.59, 2.26]
asinh(Combined Demand)	-0.227	-0.151	-1.09	-1.13
	[-1.36, 0.216]	[-1.3, 0.344]	[-3.67, 0.757]	[-3.55, 0.842]
Demand Correlation	-7.49**	-8.38**	-19.3***	-19.1***
	[-20.9, -1.21]	[-23.4, -1.61]	[-50.2, -3.69]	[-49.6, -3.57]
asinh(Demand Variance)	0.0000429	-0.03	-0.0155	-0.00232
	—	[-0.228, 0.134]	[-0.41, 0.325]	—
asinh(System MC Variance)	0.0909	-0.0425	0.236	0.274
	[-0.0314, 0.197]	[-0.209, 0.0827]	[-0.188, 0.687]	[-0.266, 0.749]
asinh(Unused Thermal Capacity)	0.308**	0.287**	1.18***	1.19***
	[0.0686, 0.613]	[0.00651, 0.647]	[0.45, 1.98]	[0.425, 1.93]
asinh(Marginal MC Spread)	0.104**	0.12***	0.102	0.0856
	[0.0147, 0.19]	[0.0356, 0.206]	[-0.671, 0.748]	[-0.588, 0.696]
asinh(Marg. MC Spread) × Demand Corr.	-0.0524	-0.0435	0.0662	0.073
	[-0.204, 0.124]	[-0.196, 0.133]	[-0.304, 0.656]	[-0.297, 0.619]
Demand Corr. × asinh(Demand)	0.718**	0.797***	1.79**	1.78**
	[0.14, 1.97]	[0.176, 2.18]	[0.276, 4.77]	[0.32, 4.8]
Observations	574,266	574,266	792	792
R^2	0.01	0.01	0.06	0.06

Notes: The dependent variable is asinh of the difference in the carbon cost reduction between dispatch methods, $\Delta_{\text{LACD}} - \Delta_{\text{LMCD}}$ (columns (1)–(2) hourly, \$000s; (3)–(4) monthly, \$M); CO_2 is valued at \$185/ton with rates winsorized at the 1st/99th percentile, non-carbon costs analyzed separately via the air quality model. Continuous explanatory variables are asinh-transformed; generation shares and the demand correlation enter in levels. 12 ERCOT scenarios, July 2018–December 2023, excluding Winter Storm Uri; hourly columns include month, day-of-week, and hour fixed effects. Brackets are 95% wild cluster bootstrap confidence intervals (Webb weights, 9,999 replications) clustered on the 12 trade pairs. ***p<0.01, **p<0.05, *p<0.1. A confidence interval shown as — could not be inverted by the bootstrap (the coefficient is statistically indistinguishable from zero); the significance stars from the bootstrap p-value still apply.

AP4T Health Damages: Robustness and Caveats

Heat rates. For each plant, the AP4T scaling ratio equals one plus its change in generation divided by its observed net generation, so its reported heat rate cancels out. Where a plant's simulated reduction exceeds its observed generation, which happens for 0 to 6 plants per pair, we set its counterfactual heat input to zero.

Emission rates. Each plant's emission rate is held at its 2017 NEI value, so its response to interconnection is scaled on its 2017 rate. Units that installed controls or switched fuels after 2017 may have their changes in emissions overstated. This matters most for SO_2 from the coal and lignite units that gain generation.

Other caveats. Damages are long-run annual averages and do not reflect hourly or seasonal variation in meteorology or in emission rates. They include premature mortality from $PM_{2.5}$ only, not morbidity or ozone. Health damages value deaths at \$9.97 million each, while carbon costs use \$185 per ton of CO_2. Plants in the dispatch model that cannot be matched to an NEI facility (0 to 19 per pair) are held at baseline.