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 $100M 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. We find that some interconnection scenarios decrease the social cost of emissions by up to $360M annually, while others result in higher emissions. In a case study for one proposed interconnection, we show that generation and revenues shift to the Texas zone. We also show that reductions in costs of maintaining reliability are about as much as generation cost reductions.

JEL codes: C53; L94; Q41; Q48
Key Words: interconnection; transmission; electricity supply; least cost dispatch; emissions; 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 to the South serving 90% of the state's population with 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, emissions externality costs, 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] The zone is a geographic designation that is the most spatially granular level electricity demand (load) is observed.

We show that interconnection reduces electricity production costs up to \$100 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. For example, a zone with low cost, high productivity units on average interconnecting with a zone with high cost, low productivity units. 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 market integration results in higher emissions externality costs for all Texas zones except for one, where externality costs drop by up to \$360 million annually. This signals that only one zone in our study has units that are both more productive and lower-emitting on average.

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. 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 differences in production cost changes but very different emissions results from interconnection.

Finally, we show that reliability cost reductions from integration are nearly as large as 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 and increased emissions.

We address a gap in the literature of 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. 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 impacts 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 negative externality 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 very similar across both dispatch algorithms. The relative difference between marginal costs and average costs re-order 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 less 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.

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. Section 7 details firm winners and losers as well as cost of reliability changes for one case study interconnection. Section 8 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' electrical load (FERC, 2022) and operates under oversight from the Public Utility Commission of Texas alone.

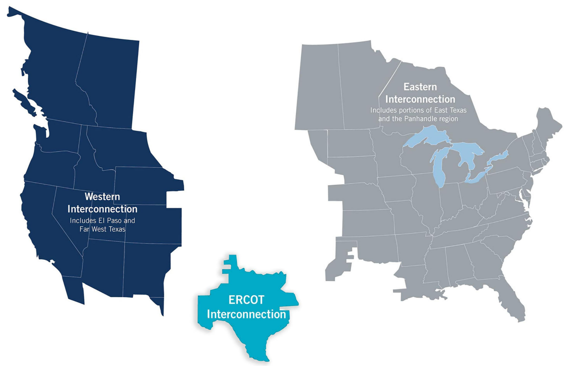
We study four zones within ERCOT and three neighboring zones.[3] A "zone" is the geographic area established by the ISO from which aggregated load data is derived and prices are published. Figure 2 displays the footprint of these seven zones. ERCOT comprises four load zones: West, North, South, and Houston. 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

[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 1: North American Interconnections

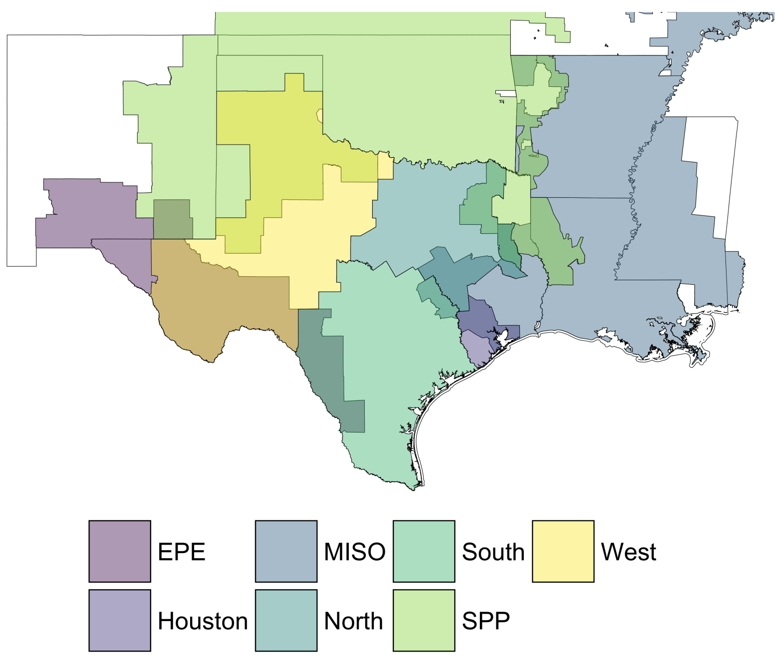


Notes: This figure displays the three interconnections in North America.

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.

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 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 for each of the 677 thermal generating units in our study region as well as all renewable and nuclear generation.[6]

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]

[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.

[7] According to the EPA's eGrid 2021 dataset units under 25 MW makeup 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.

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 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 differing in our baseline specification and show how each unit type was assigned cycle counts 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

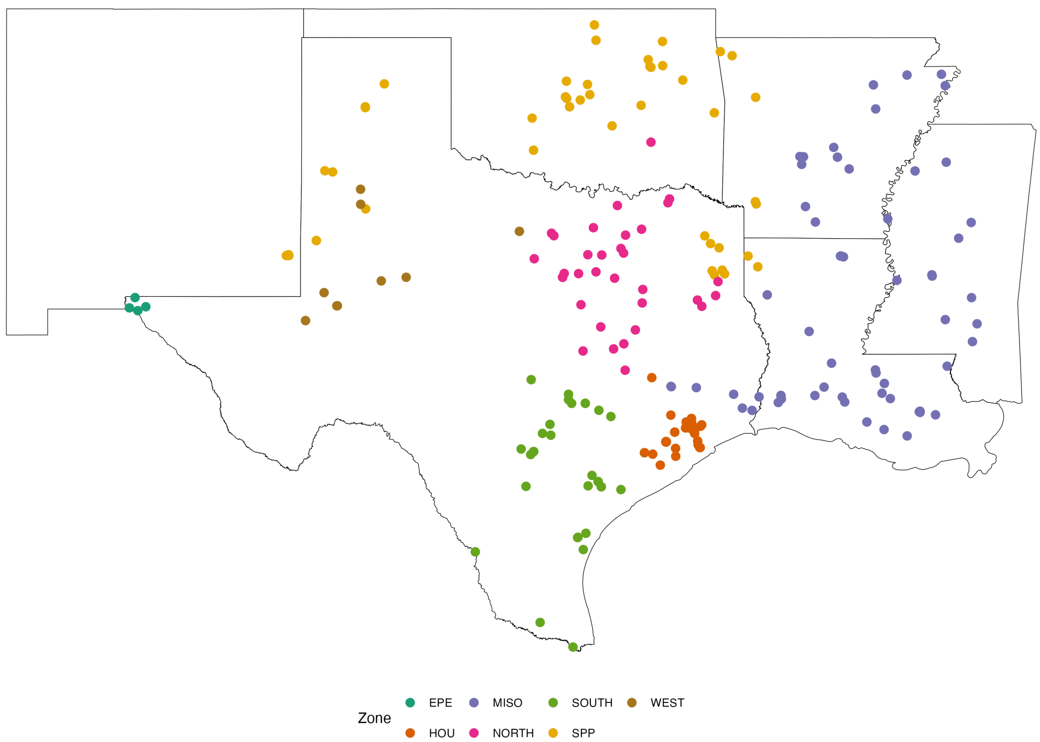
We merge all hourly thermal generating unit-level data by the unique combination of the plant and unit identifier. The panel is unbalanced because of unit entry and exit during our sample period.

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

[10] Robustness checks performed using 25th and 75th percentiles of cycle costs are forthcoming and will be included in the next version of the working paper.

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.

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.

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 [INSERT NUMBER] nuclear units in [INSERT NUMBER] out of [INSERT NUMBER] zones in our sample, it is straightforward to allocate generation to the correct zone.

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 generation by fuel type by the relevant zone share to obtain hourly zone-level generation.[11] This

[11]For example, if SPP reports 100 MWh of wind generation in a particular hour and 10% of SPP's wind generation in

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 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 (MWh). 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 MWh) multiplied by the unit's heat rate, hr_i (in mmBtu per MWh) plus variable operating and maintenance costs om_i (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.

[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.

dollars per MWh).[14] We winsorize marginal costs at the 1st and 99th percentiles to account for a small amount 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 amount of times 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 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. Natural gas units vary more than coal plants in generation costs. The total cycle cost for a coal unit is more than

[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).

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.

four times larger than natural gas on average. On average coal units generate about ten times as much electricity as 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 less 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 heterogeneity in electricity source across zones. Natural gas is the primary fossil fuel source in our sample accounting for 15% to 77% 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 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.

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 reduc-

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	0.29	0.06	0.11	0.60
SOUTH	48216	0.20	0.06	0.04	0.67
SPP	48216	0.30	0.11	0.00	0.68
WEST	19728	0.04	0.05	0.00	0.39
Fossil Other					
HOU	48216	0.04	0.02	0.00	0.11
MISO	48216	0.03	0.01	0.01	0.08
NORTH	48215	0.00	0.00	0.00	0.01
Natural Gas					
EPE	48216	0.45	0.16	0.13	1.00
HOU	48216	0.77	0.06	0.52	0.97
MISO	48216	0.61	0.07	0.28	0.91
NORTH	48216	0.49	0.13	0.00	0.74
SOUTH	48216	0.38	0.13	0.03	0.68
SPP	48216	0.52	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	48210	0.02	0.02	0.00	0.34
HOU	48210	0.01	0.02	0.00	0.19
MISO	48210	0.02	0.01	0.00	0.07
NORTH	48210	0.06	0.05	0.00	0.35
SOUTH	48210	0.21	0.12	0.00	0.64
SPP	48206	0.18	0.12	0.00	0.99
WEST	48210	0.84	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.

tions 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) 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:

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

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:

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

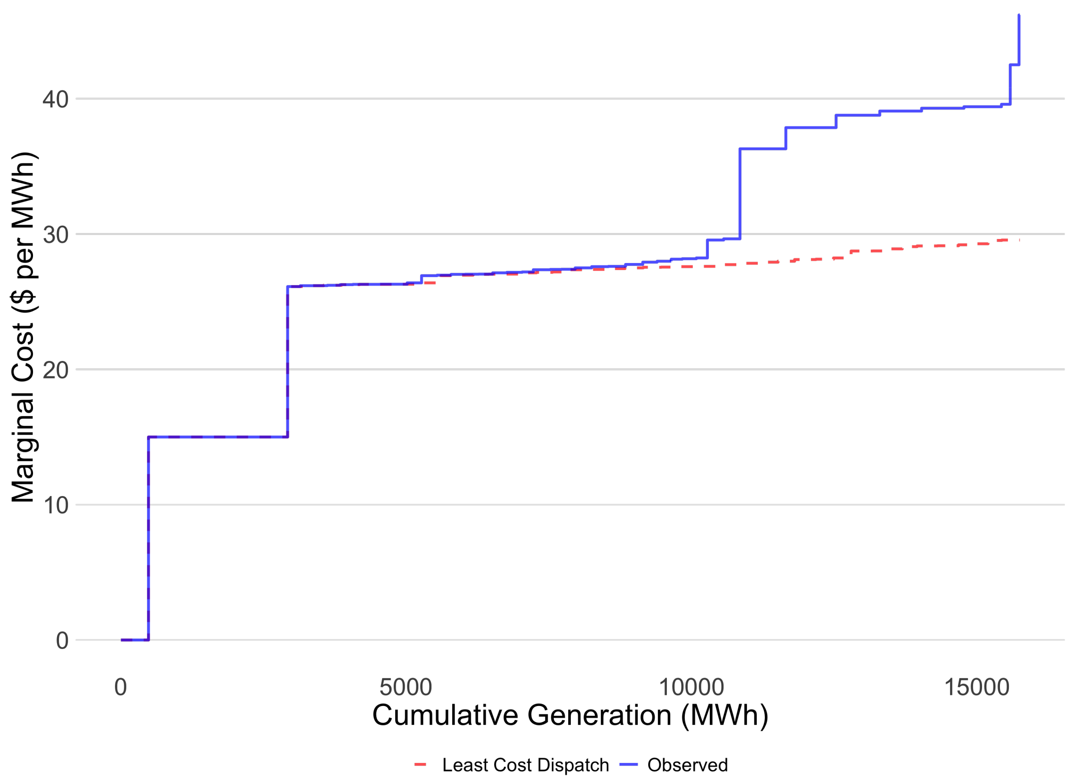
where $g^{\star}_{i,z,t}$ are the equilibrium quantities that solve equation (2). Figure 4 shows an example of marginal cost curves for ERCOT North for a single hour. We choose the hour in which observed generation in ERCOT North is closest to the zone's mean observed generation.

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

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.

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

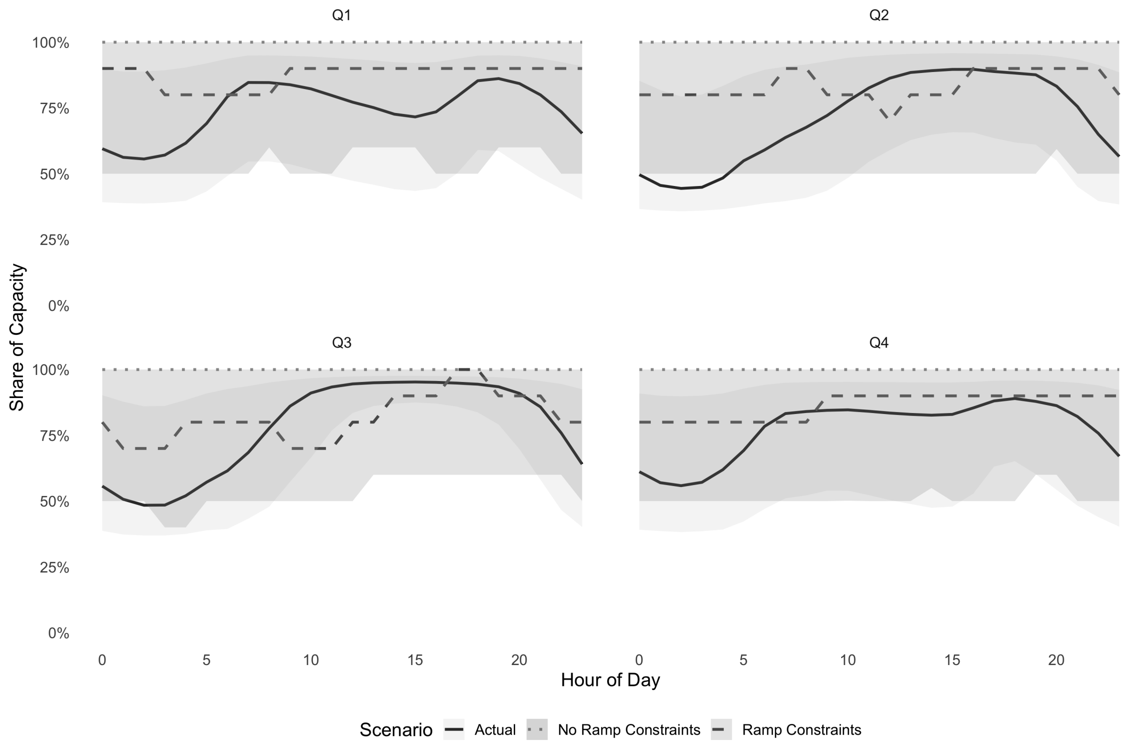
Following Gonzales et al. (2023), we incorporate ramping and minimum generation requirements. Estimating these parameters is beyond the scope of our study, so we use existing empirical evidence (Reguant, 2014; Borrero et al., 2024). We constrain coal units to generate a minimum of 40% of their capacity 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 shows coal generation as the share of units' capacity across hour of day split by quarter of year. Including ramping and minimum generation constraints disciplines 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. Figure A1 in the Appendix shows the same graphic under LMCD. 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

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



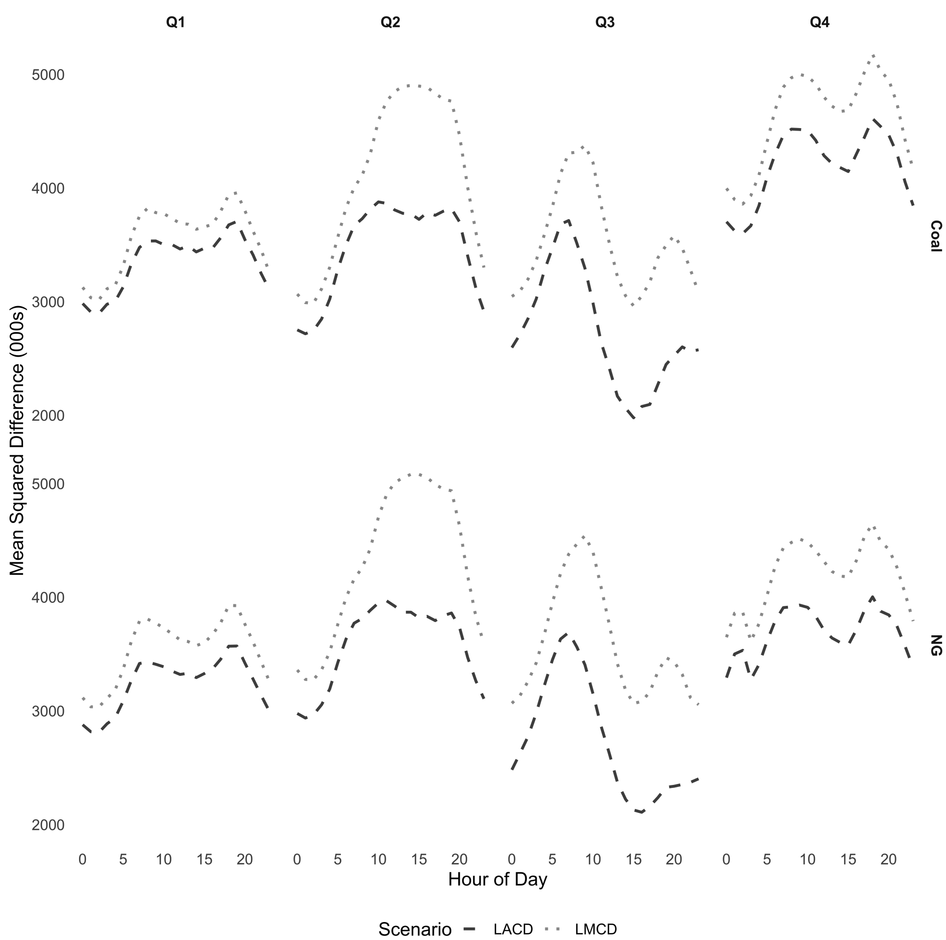
Notes: This figure displays the median and interquartile range of generation as a share of capacity for all coal units across hour of day, split out by quarter of year.

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. Appendix Figure A2 displays the hour-by-hour average differences in generation by fuel type for each dispatch method compared to observed. The curve corresponding to LACD average differences follows the same pattern as LMCD but is closer to zero. Incorporating generator fixed cycle costs of start up and shut down results in a more realistic generation mix online in any hour.

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 A3 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 price of a MW 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 significantly 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.

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. 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. Dotted lines are mean squared differences from LMCD.

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:

$$\begin{aligned} \min_{g_{i,p,t}} \left(\sum_{i \in (1,2,..,I_p)} ac_{i,t} g_{i,p,t} \right) \quad s.t. \quad & \sum_{i \in (1,2,..,I_p)} g_{i,p,t} = obs\_gen_{p,t}; \\ & g_{i,p,t} \leq C_{i,t} \quad \forall i; \end{aligned} \tag{7}$$

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. 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. Table A3 displays the same information using dispatch algorithms without ramping or minimum generation constraints. Total cost changes differ minimally between dispatch methods with or without ramp constraints. Reshuffling units between dispatch methods has little impact on total production cost because in most hours units around the margin are within 50 cents of each other in marginal or average cost. This reordering may mean 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.

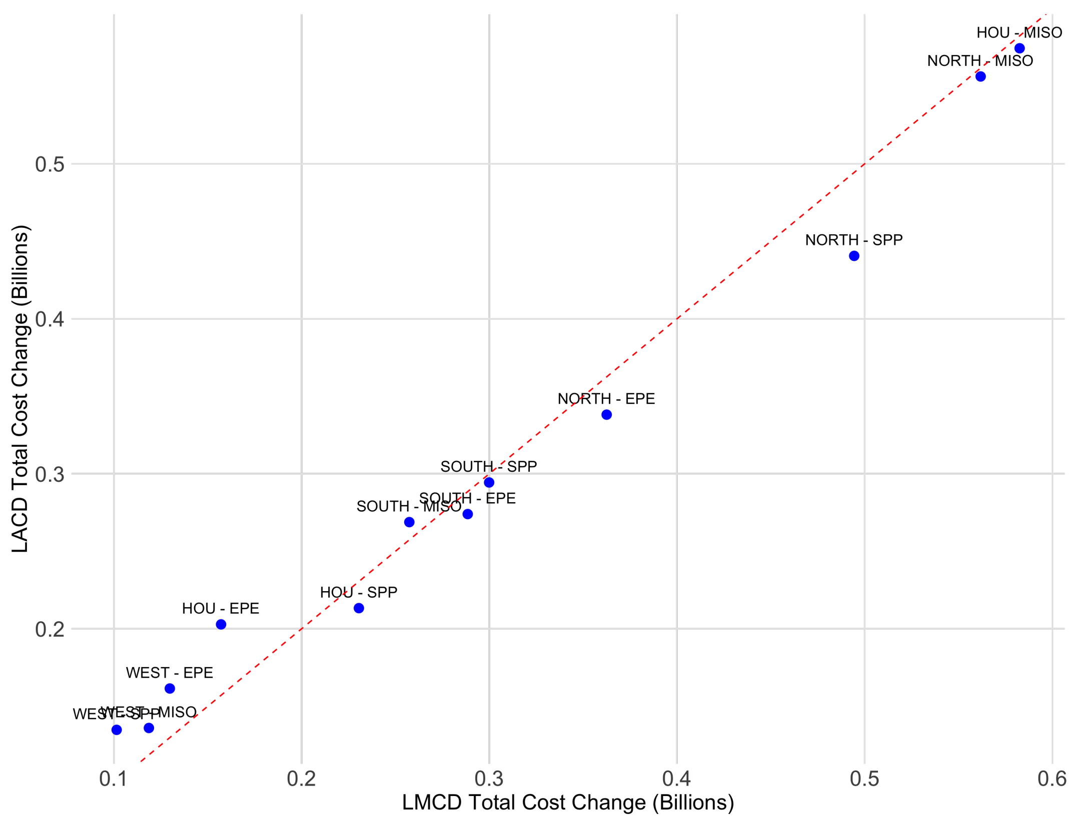
Table 3: Interconnection Total Cost Change w/ Ramp Constraints

Zone 1	Zone 2	LACD Total Cost Change (Billions)	LMCD Total Cost Change (Billions)
HOU	MISO	0.57	0.58
NORTH	MISO	0.56	0.56
NORTH	SPP	0.44	0.49
NORTH	EPE	0.34	0.36
SOUTH	SPP	0.29	0.30
SOUTH	EPE	0.27	0.29
SOUTH	MISO	0.27	0.26
HOU	SPP	0.21	0.23
HOU	EPE	0.20	0.16
WEST	EPE	0.16	0.13
WEST	MISO	0.14	0.12
WEST	SPP	0.13	0.10

The three interconnection scenarios with the largest reductions in generation cost result in decreases of about $500 million. This represents a 0.4% to 2.2% decrease in total generation costs as shown in Table A4. The three interconnection pairs with the largest reductions are also the three largest in volume of electricity produced. Combined average hourly zone generation in each of these interconnection scenarios is about 35,000 MWh. The three 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 may also have small relative efficiency differences between their units. The Appendix includes analogous results tables for each dispatch method with and without ramp constraints, showing that total cost changes do not differ substantially when ramping constraints are introduced.

Figure 7 shows that changes in total generation costs differ slightly under LACD versus LMCD. The most economical generating units constitute the "baseload" under both dispatch models and produce at capacity in both models. Slight differences arise from reshuffling generators at the margin. The difference in generating a single megawatt of electricity between the marginal unit and the next is often less than 50 cents under both LMCD and LACD. The marginal unit produces below capacity to meet remaining generation needed in that hour. The small per megawatt cost difference between the marginal unit and the first unit above the margin combined with low production at the margin explain why we observe small differences in total generation cost reductions between LACD and LMCD. Total cost changes tend to be larger under LMCD for bigger, more fossil-intensive interconnections. The opposite holds for smaller, more renewable-intensive interconnections, which generate larger total cost changes under LACD.

Figure 7: 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.

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 $z_1, z_2 \in p$

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

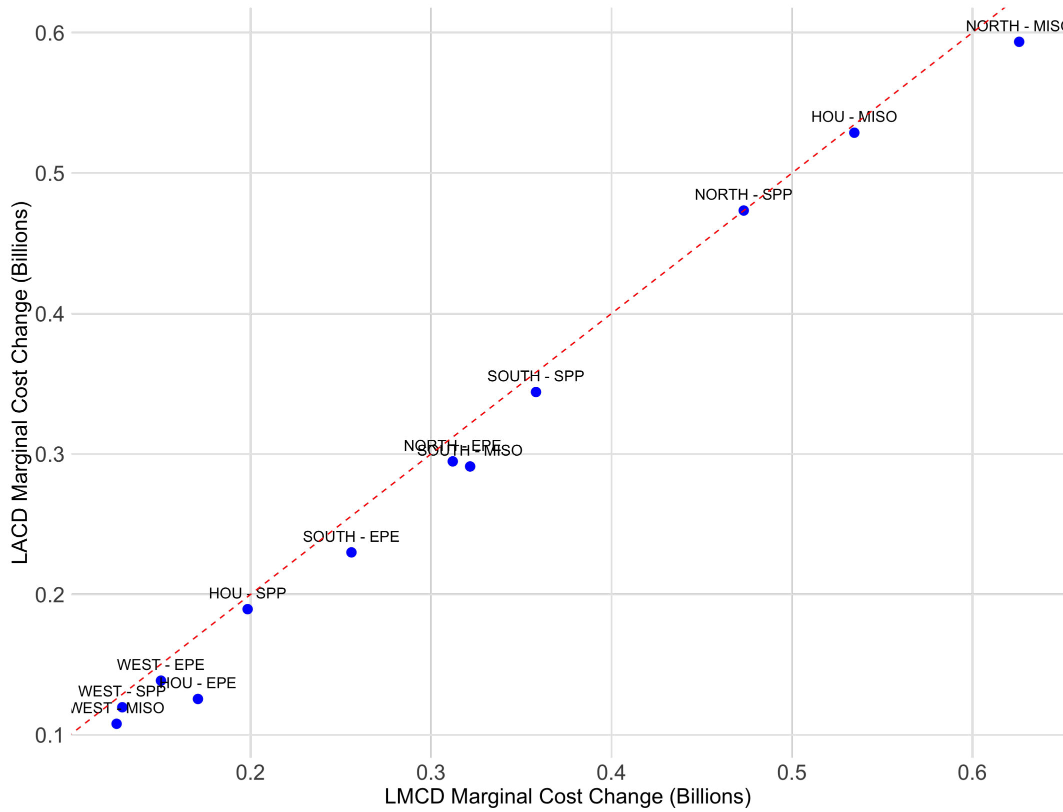
where $g^{\dagger\dagger}_{i,z,t}, g^{\ddagger\ddagger}_{i,z,t}$ are the quantities that solve the least cost dispatch algorithms for independent zones z_1, z_2 and $g^{**}_{i,p,t}$ are the quantities that solve the least cost dispatch algorithms under interconnection. Figure 8 shows generation marginal cost changes from each interconnection scenario using LACD and LMCD. Differences in marginal cost reductions between dispatch algorithms range from \$5 to \$40 million in 11 of the 12 interconnections.[16] Although these differences are small relative to total electricity generation cost, they follow the same direction for all interconnection scenarios. Comparing Figures 7 and 8, 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.

Marginal costs decrease \$110 to \$590 million 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 A5, this represents a 0.3% to 2% 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 three 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 identi-

[16] Table A8 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 total cost changes between dispatch methods.

cal 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 A10 and A11 show that zone pairs Hou-EPE, 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. Under LMCD, 7 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 four 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.

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 accounted 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.

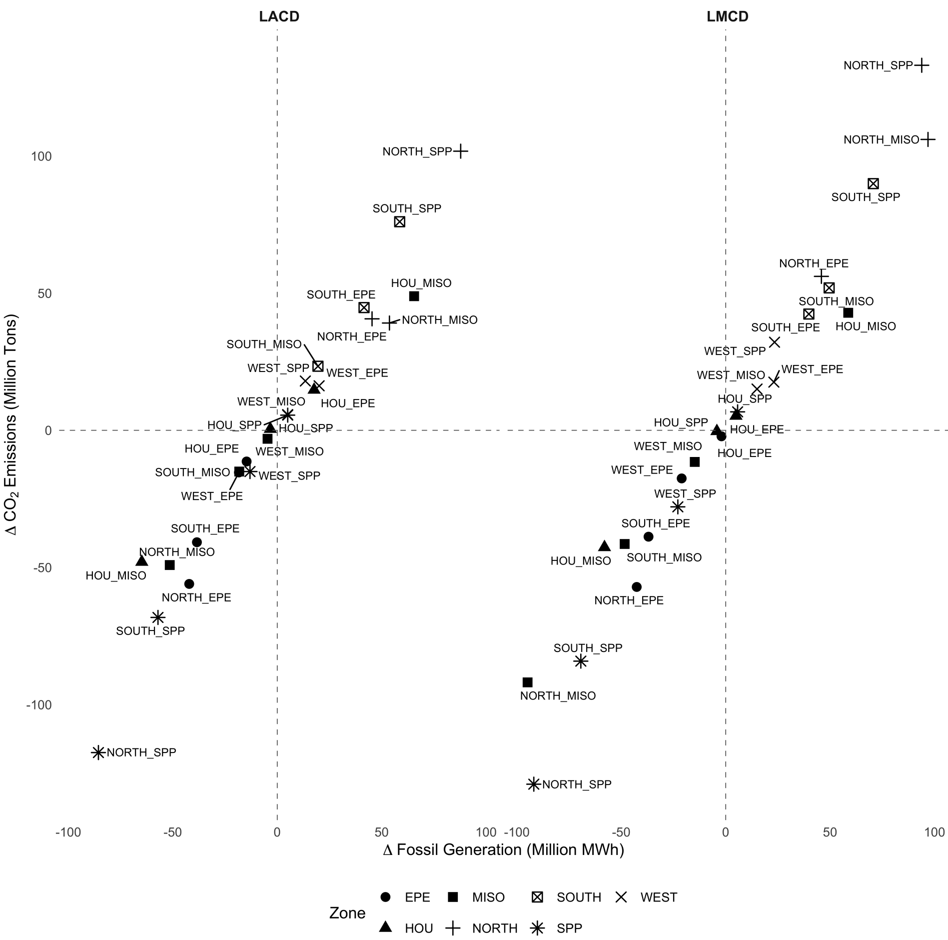
6 Emissions

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 account for where emissions occur after integration. Policy makers 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.

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 not 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: 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.

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, South, and West. Emissions shift disproportionately to generation. The LACD graph shows that interconnecting ERCOT North and SPP results in ERCOT North generating approximately 87 million

MWh more than without interconnection while SPP generates 85 million MWh less. This results in SPP emitting about 117 million tons less CO_2 and ERCOT North emitting an additional 100 million tons for the same power generated. Table A12 presents these data in table format. ERCOT North is the only zone where each interconnection scenario generates more electricity while aggregate CO_2 emissions fall. These results align with findings in Gonzales et al. (2023) when renewable investment cannot adjust with increased interconnection.

Table A13 shows results differ substantially under LMCD. Only the ERCOT North and El Paso Electric interconnection reduces CO_2 emissions under LMCD. This pattern indicates that the lowest marginal cost units are generally more CO_2 intensive. Under LACD, more generation is allocated to slightly less carbon intensive units. When dispatched in least average cost order, plants around the margin tend to be newer natural gas-fired units with slightly higher marginal costs and lower cycle costs relative to marginal natural gas units dispatched in least marginal cost order.

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 social cost of carbon from Carleton and Greenstone (2021).[17] Aside from CO_2, thermal units emit SO_2, NO_x, and PM2.5, which harm human health and create negative externalities for the public in areas where generation occurs.

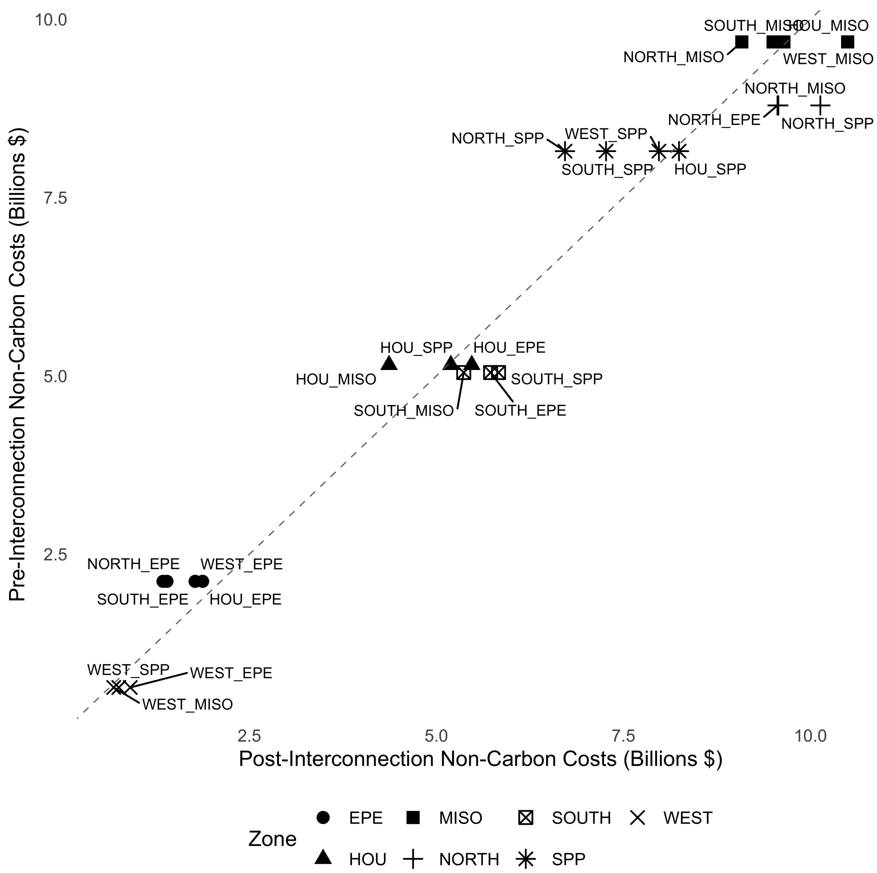
Interconnection does not necessarily result in lower aggregate social costs from electricity generation. ERCOT North is the only zone that sees lower total external costs from generation across its interconnection scenarios. Table A14 shows reductions in aggregate negative externality costs range from \$1.07 to \$2.06 billion for interconnections with ERCOT North. All other interconnections see increases in total external costs ranging from \$40 million to \$1.2 billion. SPP has very unproductive and carbon-intensive units relative to its interconnection pairs. In each scenario, CO_2 emissions decline more sharply in SPP than emissions increase in the other zone.

Figure 10 shows how non-carbon social costs of emissions shift to zones under each integration counterfactual. Although total social externality costs decline in some scenarios, local pollutant shifts matter for grid integration. Interconnections with ERCOT North reduce aggregate emissions

[17] Greenstone and Looney (2012) estimates the non-carbon external cost is \$34 per MWh of carbon generation and \$10 per MWh of natural gas generation. Carleton and Greenstone (2021) estimate the social cost of carbon to be \$125/ton of CO_2.

externality costs, but non-carbon local pollutants shift to ERCOT North. Zones below the dashed 45-degree line incur greater externality costs from local pollutants such as SO_2, NO_x, and PM2.5. Understanding who bears the burden of increased local pollution determines what parties finance additional transmission or receive compensation for shifting pollution.

Figure 10: Pre vs. Post-Interconnection Non-Carbon Externality Costs LACD



Notes: Figure displays social externality costs from non-carbon pollutants before and after interconnection. The dashed 45-degree line represents equal values pre and post interconnection.

SPP generates the highest coal generation external costs, and each interconnection scenario shows sharp decreases in generation from its coal units. Figure A6 shows three of four points above the 45-degree line, indicating coal generation shifts away from SPP under interconnection. This demonstrates how SPP's coal units are substantially less productive than those in ERCOT North, largely contributing to the interconnection's reduction in external costs. Coal generation declines slightly overall with the SPP and ERCOT North interconnection. However, coal generators in ERCOT North that increase generation are less carbon-intensive than those in SPP. El Paso Electric also has less productive coal units than its interconnection pairs.

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.

7 Case Study: ERCOT North and SPP

We analyze the ERCOT North and SPP interconnection pair, which has the largest gains from interconnection as measured by generation cost and emissions externality cost reductions. First, we show how generation shifts to different plants and revenues accrue to different firms after integration. 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.

Next, we estimate reliability cost savings from market integration. ERCOT has set a minimum target reserve margin of 13.75%. Reserve capacity of at least 13.75% of peak demand must be available to serve electric needs in the event of unexpectedly high demand or unplanned outages.[18] If the reserve requirement is not met, more generation capacity must be installed. We use modeled data from the LACD algorithm to determine how much additional generation capacity is avoided by integrating markets.

7.1 Winning and Losing Firms

We calculate revenue changes from pre-integration to post-integration modeled scenarios for firms in ERCOT North and SPP zones. 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.

As shown in Appendix Table A12, fossil generation in SPP decreases by over 85 million MWh

[18] From the 2023 ERCOT Resource Adequacy report.

when integrated with ERCOT North. The three firms losing the most revenue from interconnection lose over $2.8 billion over the sample period and all belong to SPP. The least efficient generating units belong to Oklahoma Gas & Electric Co., Southwestern Public Service Co., and Southwestern Electric Power Co. Much of the generation in an interconnected scenario shifts to units in ERCOT North. These large revenue losses for SPP firms challenge the view that ERCOT is the only party that may oppose grid integration.

The three firms with the largest revenue increases from interconnection gain roughly $1.5 billion. Asymmetry in revenue changes is driven by significantly lower marginal unit average cost under grid integration and generation capacity. In the baseline scenario without integration, the average cost ($/MWh) of the final unit is $47.28 per MWh in SPP and $44.01 per MWh in ERCOT North. After interconnection, the average final unit average cost is $44.63 per MWh. In autarky, we assume only within-zone generators meet observed generation totals for the zone and hour.

7.2 Reliability: Cost of New Capacity

We measure the change in reliability cost using modeled generation capacity data from the dispatch algorithm. Reliability councils and system operators run studies annually to evaluate available reserve capacity at peak demand. We adapt this framework and measure available capacity in the hour of highest observed demand for pre- and post-integration counterfactuals. For the independent zone baseline, we sum available capacity for that zone in the hour of the zone's maximum observed demand over the sample. Available capacity is determined by the LACD where renewable capacity is observed generation, coal capacity is dictated by ramping constraints and stochastic outages, and natural gas available capacity is determined by observed 99th percentile of generation and stochastic outages. The same procedure for calculating available capacity is used for the interconnection pair with the hour of maximum observed combined demand.

We calculate reserve capacity needed in those maximum demand hours using ERCOT's 13.75% reserve margin requirement above peak demand. Rows 1 and 2 in Table 4 show how much additional capacity would be needed to meet this requirement for ERCOT North and SPP at respective peak demand hours. Row 3 shows how much additional capacity would be needed in the integrated counterfactual at peak demand. Integration avoids the construction of 451MW of additional capacity. At $900,000/MW for a new combined cycle natural gas unit, interconnection saves roughly $400 million.[19]

Table 4: Capacity Needed to Meet Reserve Margin at Peak Demand

Jurisdiction	New Capacity Needed (MWh)
NORTH	5604
SPP	2188
NORTH_SPP	7341

Notes: This table shows the amount of additional capacity needed to satisfy the reserve margin requirement at maximum observed demand. The first rows are calculated for each zone in autarky and the last row is calculated for the interconnection counterfactual.

This is one measure of reliability cost change that remains within the dispatch algorithm framework. Identifying the sum of prevented lost load from interconnection in each hour and multiplying by the value of lost load would likely yield a much greater dollar value for reliability gains. What we have estimated is a lower bound for reliability benefits from interconnection.

8 Conclusion

Which Texas interconnections would result in the largest reductions in generation and negative externality costs? To shed light on this question, we extend 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 similar reductions in generation cost and 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

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

under LACD tend to be less carbon-intensive than those under LMCD leading to very different conclusions of 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 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 $500 million dollars 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 for selling 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 lower carbon-intensive units around the margin. Therefore, relying on LMCD may result in underestimates of the change in external costs from interconnection. We show that in our geographic region of study, only interconnections involving ERCOT North would provide reductions in total external costs. These reductions are substantial, however, at two to four times greater than the reductions in production cost.

We provide a case study of one interconnection counterfactual and document firm revenue changes from interconnection. In the ERCOT North and SPP integration scenario, three firms in SPP would lose a cumulative $1.5 billion in revenue over the sample window. 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. 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 a zone outside of Texas could stand to lose substantial revenue.

Future research could expand on our work in several ways. Our study could be extended by looking at dynamic investment in generation capacity responds from 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. The most productive zones incur higher concentrations of local pollutants from increased production. Understanding how both zones could be made better off from grid integration would inform the discussion on how the public is being compensated from the increased negative externality. 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

Fuel	Technology/Size	Cycle Cost ($/MWh capacity)
Coal	Small Sub Critical (<300 MWh)	147
Coal	Large Sub Critical [300,850)	105
Coal	Super Critical ($\geq$850)	104
Natural Gas	Combined Cycle	79
Natural Gas	Combustion Turbine ($\geq$ 55 MWh)	103
Natural Gas	Combustion Turbine ($<$ 55 MWh)	32
Natural Gas	Steam	75
Oil, Wood, etc.		75

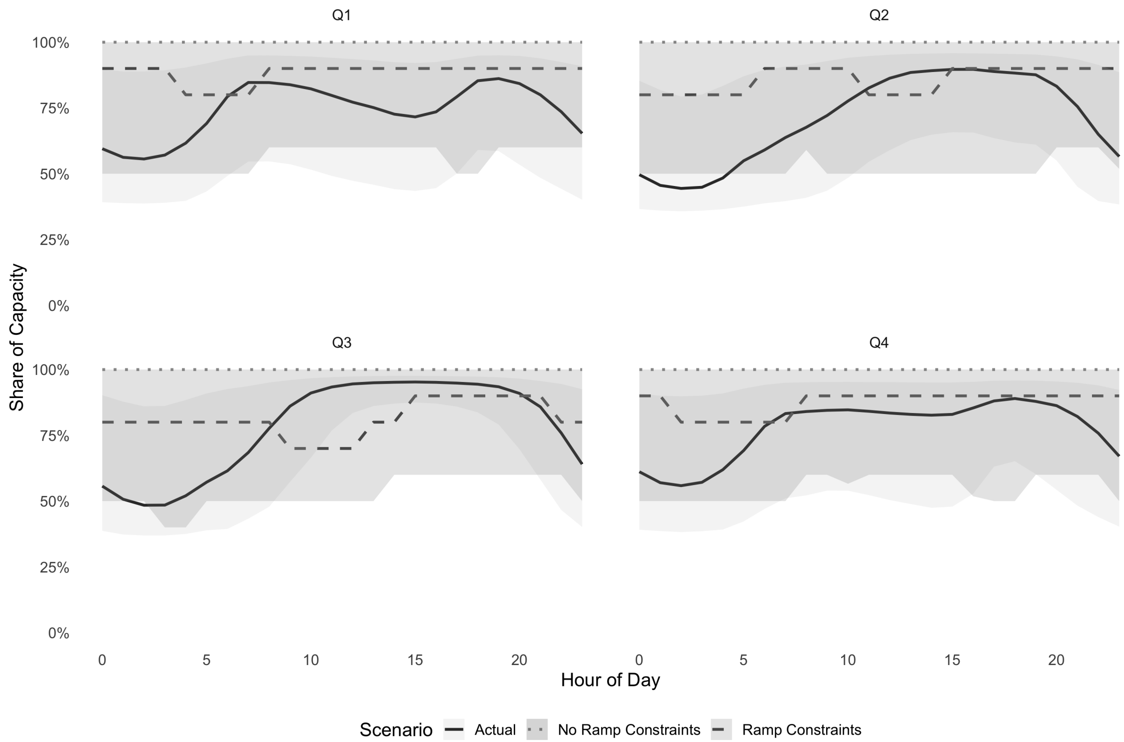
Notes: This table shows the cycle cost per MWh of capacity used for each fuel and technology type for thermal generating units.

Table A2: Generation-Weighted Capacity Factor Simulation vs. Observed

	LMCD	LACD	Difference	T-Statistic
Avg Absolute Diff	18.78	15.61	3.18	62.14
MSE	762	535	227	54.32
SSE	36,756,106	25,803,046	10,953,060	
Zero Gen Hours	5,547	3,520	2,027	

Notes: Table shows summary statistics and relevant t-statistics describing how coal unit capacity factors differ from observed in each dispatch model. Zero gen hours refers to hours of data with zero total coal generation. The observed data has no hours with zero total coal generation.

Figure A1: Coal Capacity Factor Conditional on Positive Generation (LMCD)



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.

Table A3: Interconnection Total Cost Change

Zone 1	Zone 2	LACD Total Cost Change (Billions)	LMCD Total Cost Change (Billions)
HOU	MISO	0.56	0.56
NORTH	MISO	0.55	0.55
HOU	SPP	0.49	0.50
NORTH	EPE	0.44	0.43
SOUTH	EPE	0.36	0.35
NORTH	SPP	0.36	0.39
HOU	EPE	0.33	0.26
SOUTH	MISO	0.27	0.25
SOUTH	SPP	0.25	0.25
WEST	EPE	0.21	0.18
WEST	MISO	0.15	0.12
WEST	SPP	0.14	0.11

Notes: This table shows shows the reduction in total generation costs represented by Equation 8 under each interconnection scenario. All results presented are in reductions and so all are shown as positive.

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

Zone 1	Zone 2	Total Observed Generation Costs (Billions)	LACD Total Cost Change (Billions)	Percent Reduction Generation Costs
HOU	MISO	51.55	0.57	1.11%
NORTH	MISO	57.91	0.56	0.96%
NORTH	SPP	38.42	0.44	1.15%
NORTH	EPE	28.19	0.34	1.20%
SOUTH	SPP	30.71	0.29	0.96%
SOUTH	EPE	20.49	0.27	1.34%
SOUTH	MISO	50.21	0.27	0.54%
HOU	SPP	32.06	0.21	0.67%
HOU	EPE	21.83	0.20	0.93%
WEST	EPE	7.28	0.16	2.22%
WEST	MISO	37.00	0.14	0.37%
WEST	SPP	17.51	0.13	0.77%

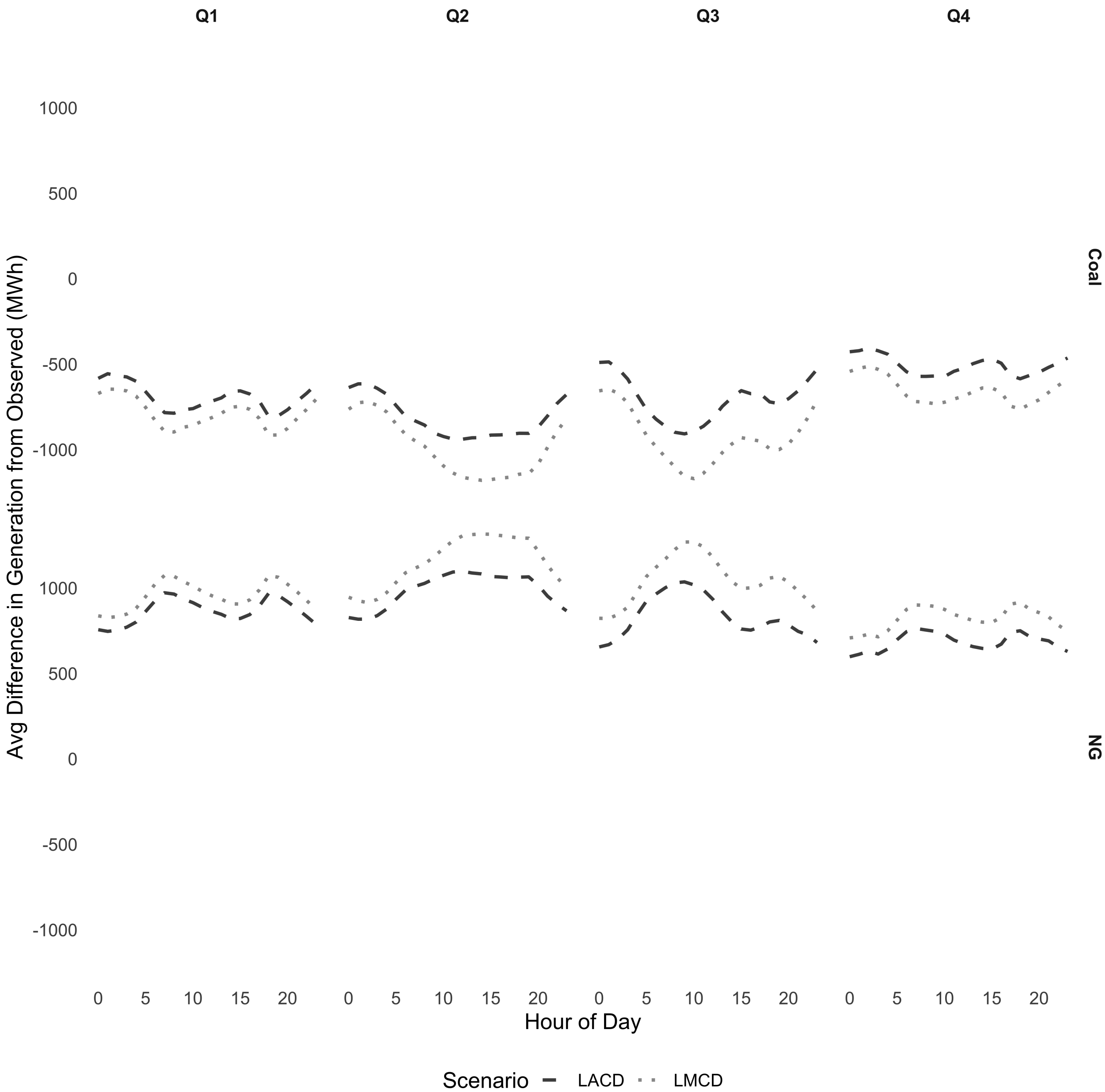
Notes: This table shows the change in total generation costs under LACD. Column 5 shows this change relative to the total generation costs observed.

Table A5: Marginal Cost Change (LACD w/ Ramp Constraints)

Zone 1	Zone 2	Observed Marginal Costs (Billions)	LACD Marginal Cost Change (Billions)	Percent Reduction Marginal Costs
NORTH	MISO	55.86	0.59	1.06%
HOU	MISO	50.25	0.53	1.05%
NORTH	SPP	36.74	0.47	1.29%
SOUTH	SPP	29.43	0.34	1.17%
NORTH	EPE	26.96	0.29	1.09%
SOUTH	MISO	48.54	0.29	0.60%
SOUTH	EPE	19.65	0.23	1.17%
HOU	SPP	31.13	0.19	0.61%
WEST	EPE	6.97	0.14	1.99%
HOU	EPE	21.35	0.13	0.59%
WEST	SPP	16.75	0.12	0.71%
WEST	MISO	35.87	0.11	0.30%

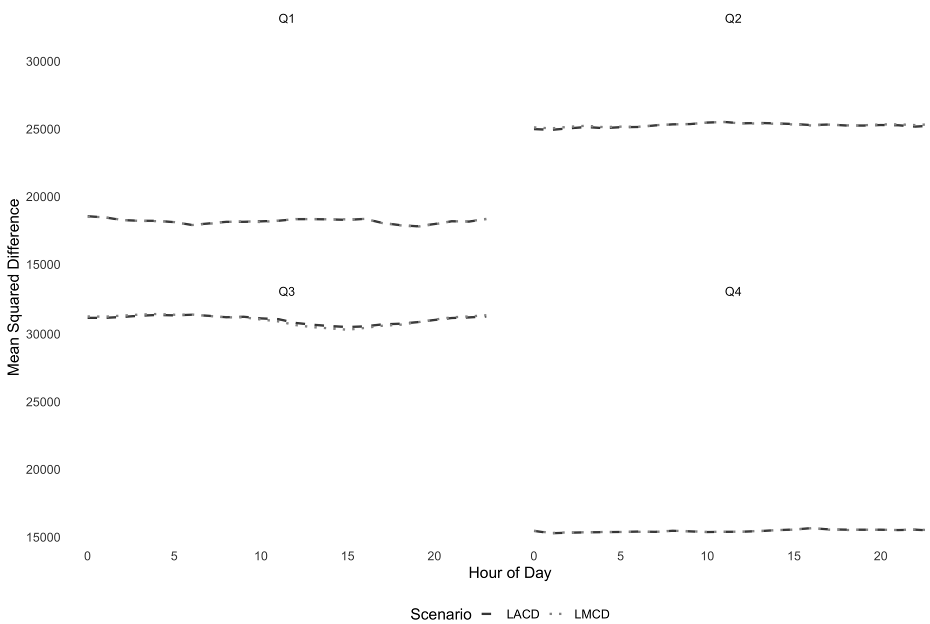
Notes: This table shows the change in marginal costs under LACD. Column 5 shows this change relative to the marginal costs observed.

Figure A2: Average Generation Difference from Observed LACD vs LMCD



Notes: Figure displays the average differences of total generation by fuel type comparing simulation dispatch to observed. The total generation by fuel type is calculated hour-by-hour and displayed by hour of day and month of quarter 2. Dashed lines are the average differences from LACD. Dotted lines are average differences from LMCD.

Figure A3: Difference from Observed Final Marginal Cost LACD vs LMCD



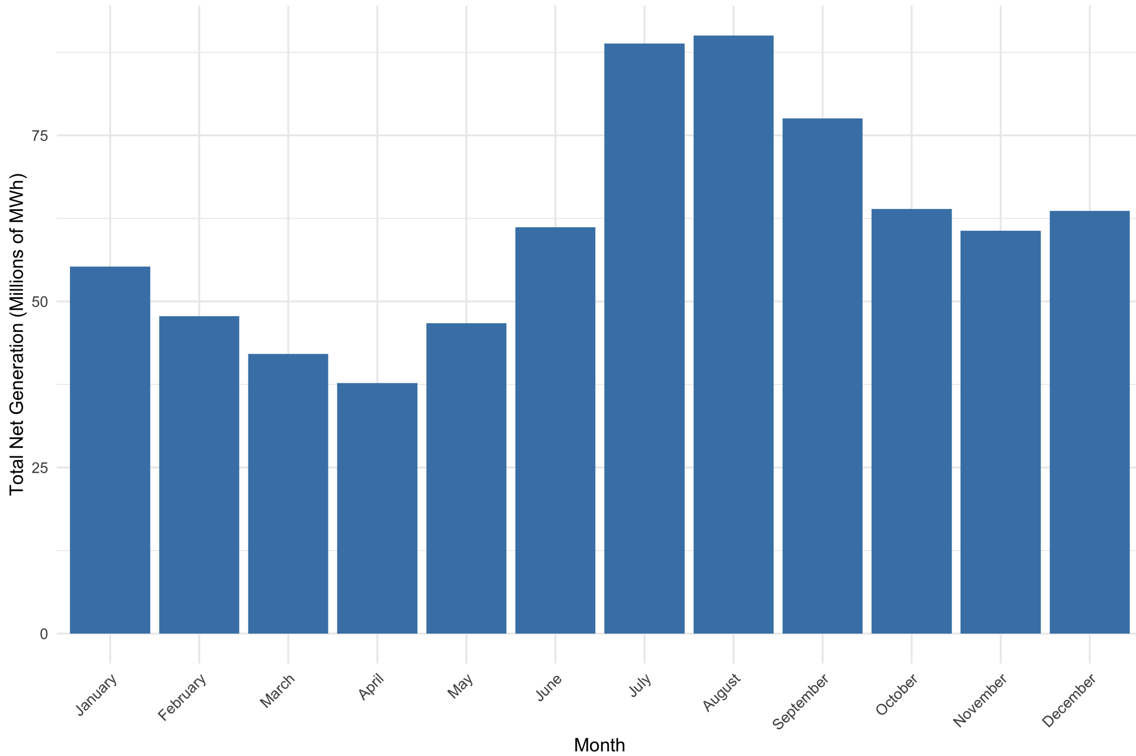
Notes: Figure displays the mean squared differences of the marginal cost of the final unit with positive generation comparing simulation dispatch to observed. The mean squared difference is calculated for each zone hour-by-hour and displayed by hour of day and month of quarter 2. Dashed lines are the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

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

Zone 1	Zone 2	Total Observed Generation Costs (Billions)	LMCD Total Cost Change (Billions)	Percent Reduction Generation Costs
HOU	MISO	51.55	0.58	1.13%
NORTH	MISO	57.91	0.56	0.97%
NORTH	SPP	38.42	0.49	1.29%
NORTH	EPE	28.19	0.36	1.29%
SOUTH	SPP	30.71	0.30	0.98%
SOUTH	EPE	20.49	0.29	1.41%
SOUTH	MISO	50.21	0.26	0.51%
HOU	SPP	32.06	0.23	0.72%
HOU	EPE	21.83	0.16	0.72%
WEST	EPE	7.28	0.13	1.78%
WEST	MISO	37.00	0.12	0.32%
WEST	SPP	17.51	0.10	0.58%

Notes: This table shows the change in total generation costs under LMCD. Column 5 shows this change relative to the total generation costs observed.

Figure A4: Total Observed Coal Generation by Month of Year



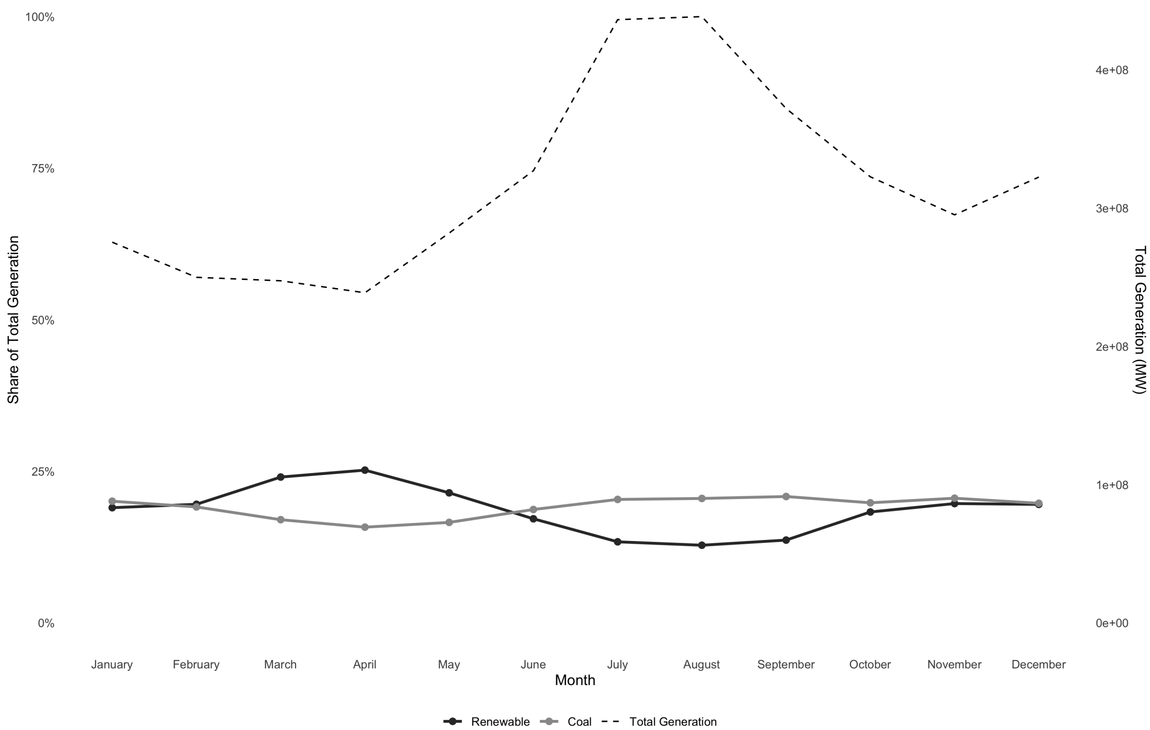
Notes: Figure displays the total generation (MWh) by coal-fired units by month of year.

Table A7: Marginal Cost Change (LMCD w/ Ramp Constraints)

Zone 1	Zone 2	Observed Marginal Costs (Billions)	LMCD Marginal Cost Change (Billions)	Percent Reduction Marginal Costs
NORTH	MISO	55.86	0.63	1.12%
HOU	MISO	50.25	0.53	1.06%
NORTH	SPP	36.74	0.47	1.29%
SOUTH	SPP	29.43	0.36	1.22%
SOUTH	MISO	48.54	0.32	0.66%
NORTH	EPE	26.96	0.31	1.16%
SOUTH	EPE	19.65	0.26	1.30%
HOU	SPP	31.13	0.20	0.64%
HOU	EPE	21.35	0.17	0.80%
WEST	EPE	6.97	0.15	2.16%
WEST	SPP	16.75	0.13	0.77%
WEST	MISO	35.87	0.13	0.35%

Notes: This table shows the change in marginal costs under LMCD. Column 5 shows this change relative to the marginal costs observed.

Figure A5: Total Generation and Shares from Coal and Renewables



Notes: Figure displays the shares of generation from coal units and renewable sources by month of year with units (% of total generation) displayed on the left vertical axis. Total generation by month of year is plotted with units (MWh) on the right vertical axis.

Table A8: Interconnection Marginal Cost Change w/ Ramp Constraints

Zone 1	Zone 2	LACD Marginal Cost Change (Billions)	LMCD Marginal Cost Change (Billions)
NORTH	MISO	0.59	0.63
HOU	MISO	0.53	0.53
NORTH	SPP	0.47	0.47
SOUTH	SPP	0.34	0.36
NORTH	EPE	0.29	0.31
SOUTH	MISO	0.29	0.32
SOUTH	EPE	0.23	0.26
HOU	SPP	0.19	0.20
WEST	EPE	0.14	0.15
HOU	EPE	0.13	0.17
WEST	SPP	0.12	0.13
WEST	MISO	0.11	0.13

Notes: This table shows shows the reduction in generation marginal costs represented by Equation 9 under each interconnection scenario. All results presented are in reductions and so all are shown as positive.

Table A9: Interconnection Marginal Cost Change

Zone 1	Zone 2	LACD Marginal Cost Change (Billions)	LMCD Marginal Cost Change (Billions)
NORTH	MISO	0.61	0.63
HOU	MISO	0.52	0.52
HOU	SPP	0.48	0.47
NORTH	EPE	0.41	0.40
NORTH	SPP	0.38	0.36
SOUTH	EPE	0.34	0.34
SOUTH	MISO	0.30	0.32
SOUTH	SPP	0.28	0.28
HOU	EPE	0.27	0.29
WEST	EPE	0.20	0.21
WEST	MISO	0.13	0.13
WEST	SPP	0.12	0.12

Notes: This table shows shows the reduction in generation marginal costs represented by Equation 9 under each interconnection scenario. All results presented are in reductions and so all are shown as positive.

Table A10: Total vs Marginal Cost Change Interconnection (LACD w/ Ramp Constraints)

Zone 1	Zone 2	Total Cost Change (Billions)	Marginal Cost Change (Billions)	MC Change Greater?
HOU	MISO	0.57	0.53	No
NORTH	MISO	0.56	0.59	Yes
NORTH	SPP	0.44	0.47	Yes
NORTH	EPE	0.34	0.29	No
SOUTH	SPP	0.29	0.34	Yes
SOUTH	EPE	0.27	0.23	No
SOUTH	MISO	0.27	0.29	Yes
HOU	SPP	0.21	0.19	No
HOU	EPE	0.20	0.13	No
WEST	EPE	0.16	0.14	No
WEST	MISO	0.14	0.11	No
WEST	SPP	0.13	0.12	No

Notes: This table compares the change in marginal costs to total generation costs from interconnection under LACD. The final column displays whether the change in marginal costs exceeded the total generation cost change from interconnection.

Table A11: Total vs Marginal Cost Change Interconnection (LMCD w/ Ramp Constraints)

Zone 1	Zone 2	Total Cost Change (Billions)	Marginal Cost Change (Billions)	MC Change Greater?
HOU	MISO	0.58	0.53	No
NORTH	MISO	0.56	0.63	Yes
NORTH	SPP	0.49	0.47	No
NORTH	EPE	0.36	0.31	No
SOUTH	SPP	0.30	0.36	Yes
SOUTH	EPE	0.29	0.26	No
SOUTH	MISO	0.26	0.32	Yes
HOU	SPP	0.23	0.20	No
HOU	EPE	0.16	0.17	Yes
WEST	EPE	0.13	0.15	Yes
WEST	MISO	0.12	0.13	Yes
WEST	SPP	0.10	0.13	Yes

Notes: This table compares the change in marginal costs to total generation costs from interconnection under LMCD. The final column displays whether the change in marginal costs exceeded the total generation cost change from interconnection.

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	91.13	79.77	-11.36	121.57	106.89	-14.68
HOU	240.97	255.73	14.75	377.08	394.72	17.63
Total	332.10	335.50	3.39	498.66	501.61	2.96
Hou - MISO						
HOU	258.67	210.67	-48.00	377.08	312.21	-64.87
MISO	503.71	552.62	48.90	754.45	819.97	65.52
Total	762.38	763.28	0.90	1131.53	1132.18	0.65
Hou - SPP						
HOU	282.18	282.66	0.47	377.08	373.75	-3.33
SPP	431.43	436.96	5.53	451.62	456.62	5.00
Total	713.61	719.62	6.01	828.71	830.37	1.66
North - EPE						
EPE	134.31	78.30	-56.01	121.57	79.41	-42.17
NORTH	585.96	626.61	40.65	601.90	647.28	45.38
Total	720.27	704.91	-15.36	723.47	726.69	3.22
North - MISO						
MISO	655.01	605.89	-49.12	754.45	702.96	-51.49
NORTH	525.40	564.52	39.12	601.90	655.61	53.71
Total	1180.42	1170.41	-10.00	1356.35	1358.57	2.22
North - SPP						
NORTH	592.77	694.54	101.78	601.90	689.73	87.82
SPP	534.69	417.19	-117.50	451.62	365.99	-85.64
Total	1127.46	1111.74	-15.72	1053.53	1055.71	2.18
South - EPE						
EPE	110.82	70.02	-40.80	121.57	83.10	-38.48
SOUTH	282.16	326.91	44.75	347.69	389.23	41.55
Total	392.98	396.93	3.94	469.26	472.33	3.07
South - MISO						
MISO	573.01	557.98	-15.03	754.45	736.24	-18.21
SOUTH	273.21	296.57	23.36	347.69	367.17	19.48
Total	846.22	854.56	8.33	1102.13	1103.41	1.27
South - SPP						
SOUTH	310.94	387.00	76.05	347.69	406.30	58.62
SPP	483.24	415.01	-68.23	451.62	394.50	-57.12
Total	794.18	802.00	7.82	799.31	800.80	1.49
West - EPE						
EPE	91.60	76.24	-15.36	121.57	103.20	-18.37
WEST	30.97	47.20	16.23	58.64	78.68	20.04
Total	122.57	123.44	0.87	180.21	181.88	1.67
West - MISO						
MISO	526.75	523.66	-3.09	754.45	749.79	-4.66
WEST	33.93	39.66	5.74	58.64	63.61	4.97
Total	560.68	563.33	2.64	813.09	813.40	0.31
West - SPP						
SPP	472.68	457.65	-15.03	451.62	438.56	-13.06
WEST	39.04	57.02	17.98	58.64	72.08	13.44
Total	511.72	514.67	2.95	510.27	510.64	0.37

Notes: This table shows each zone's CO_2 emissions and total fossil unit generation pre and post-interconnection for each integration counterfactual under least average cost dispatch.

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	89.02	86.83	-2.19	121.78	119.76	-2.02
HOU	238.89	244.14	5.25	377.17	382.08	4.90
Total	327.91	330.97	3.07	498.95	501.84	2.89
Hou - MISO						
HOU	259.01	216.36	-42.65	377.17	319.13	-58.05
MISO	505.33	548.19	42.85	754.47	813.13	58.67
Total	764.35	764.55	0.20	1131.64	1132.26	0.62
Hou - SPP						
HOU	285.77	285.42	-0.35	377.17	372.94	-4.23
SPP	426.08	432.81	6.73	451.94	457.64	5.70
Total	711.85	718.24	6.39	829.11	830.58	1.47
North - EPE						
EPE	140.57	83.45	-57.11	121.78	79.17	-42.61
NORTH	581.64	637.77	56.13	602.28	648.10	45.82
Total	722.21	721.22	-0.99	724.06	727.27	3.21
North - MISO						
MISO	665.06	573.16	-91.90	754.47	659.60	-94.87
NORTH	516.39	622.45	106.06	602.28	699.15	96.87
Total	1181.45	1195.61	14.16	1356.74	1358.74	2.00
North - SPP						
NORTH	588.80	721.90	133.10	602.28	696.15	93.87
SPP	540.65	411.62	-129.03	451.94	360.05	-91.89
Total	1129.45	1133.52	4.07	1054.21	1056.19	1.98
South - EPE						
EPE	112.46	73.67	-38.79	121.78	84.82	-36.96
SOUTH	288.62	331.01	42.40	347.98	387.80	39.81
Total	401.07	404.68	3.61	469.77	472.62	2.86
South - MISO						
MISO	578.45	537.01	-41.45	754.47	706.08	-48.38
SOUTH	278.13	330.06	51.93	347.98	397.51	49.53
Total	856.58	867.06	10.48	1102.45	1103.60	1.15
South - SPP						
SOUTH	321.79	411.74	89.94	347.98	418.66	70.67
SPP	483.49	399.33	-84.16	451.94	382.56	-69.37
Total	805.28	811.06	5.79	799.92	801.22	1.30
West - EPE						
EPE	89.35	71.81	-17.54	121.78	100.70	-21.09
WEST	30.11	47.68	17.57	58.77	81.82	23.06
Total	119.46	119.50	0.03	180.55	182.52	1.97
West - MISO						
MISO	529.48	517.95	-11.53	754.47	739.64	-14.82
WEST	33.32	48.37	15.05	58.77	73.77	15.00
Total	562.80	566.33	3.53	813.23	813.41	0.18
West - SPP						
SPP	471.15	443.25	-27.90	451.94	429.02	-22.92
WEST	38.85	70.99	32.13	58.77	82.15	23.38
Total	510.00	514.23	4.23	510.70	511.17	0.46

Notes: This table shows each zone's CO_2 emissions and total fossil unit generation pre and post-interconnection for each integration counterfactual under least marginal cost dispatch.

Table A14: Change in Social Cost of Fossil Generation Emissions - LACD (in billions $)

Zone	Δ CO_2	Δ NG Non-carbon	Δ Coal Non-carbon	Δ Total
Hou - EPE				
EPE	-1.42	-0.11	-0.14	-1.66
HOU	1.84	0.12	0.20	2.16
Total	0.42	0.01	0.06	0.50
Hou - MISO				
HOU	-6.00	-0.59	-0.20	-6.79
MISO	6.11	0.59	0.23	6.93
Total	0.11	0.00	0.03	0.14
Hou - SPP				
HOU	0.06	-0.06	0.10	0.10
SPP	0.69	0.03	0.06	0.78
Total	0.75	-0.03	0.16	0.88
North - EPE				
EPE	-7.00	-0.27	-0.50	-7.77
NORTH	5.08	0.32	0.44	5.85
Total	-1.92	0.05	-0.05	-1.93
North - MISO				
MISO	-6.14	-0.48	-0.12	-6.74
NORTH	4.89	0.44	0.34	5.67
Total	-1.25	-0.04	0.22	-1.07
North - SPP				
NORTH	12.72	0.69	0.65	14.06
SPP	-14.69	-0.62	-0.82	-16.12
Total	-1.97	0.07	-0.16	-2.06
South - EPE				
EPE	-5.10	-0.24	-0.48	-5.82
SOUTH	5.59	0.31	0.37	6.27
Total	0.49	0.06	-0.10	0.45
South - MISO				
MISO	-1.88	-0.18	0.00	-2.06
SOUTH	2.92	0.14	0.18	3.24
Total	1.04	-0.04	0.17	1.18
South - SPP				
SOUTH	9.51	0.50	0.28	10.29
SPP	-8.53	-0.44	-0.44	-9.41
Total	0.98	0.06	-0.16	0.88
West - EPE				
EPE	-1.92	-0.12	-0.23	-2.26
WEST	2.03	0.17	0.11	2.31
Total	0.11	0.05	-0.12	0.04
West - MISO				
MISO	-0.39	-0.05	0.01	-0.42
WEST	0.72	0.05	0.01	0.77
Total	0.33	0.00	0.02	0.35
West - SPP				
SPP	-1.88	-0.11	-0.07	-2.06
WEST	2.25	0.14	-0.02	2.37
Total	0.37	0.03	-0.08	0.32

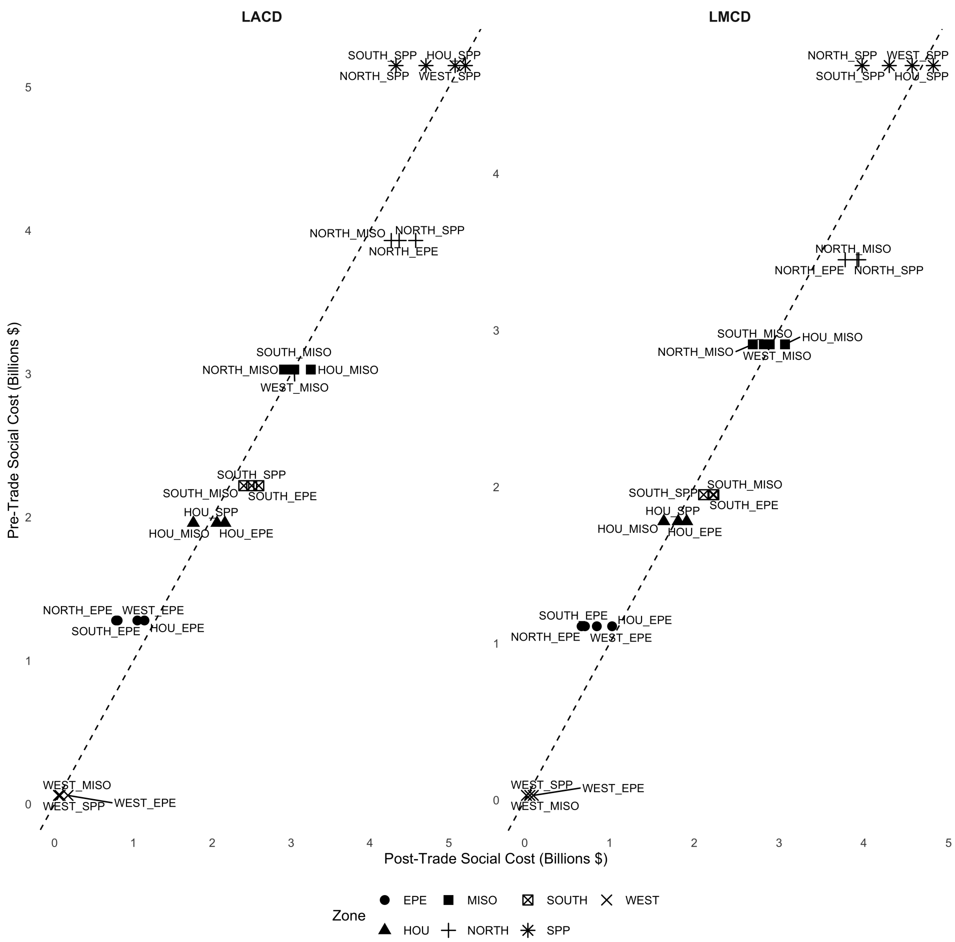
Notes: This table shows the change in social costs of emissions from interconnection by interconnection and zone. Modeled data comes from LACD methodology.

Table A15: Change in Social Cost of Fossil Generation Emissions - LMCD (in billions $)

Zone	Δ CO_2	Δ NG Non-carbon	Δ Coal Non-carbon	Δ Total
Hou - EPE				
EPE	-0.27	0.00	-0.08	-0.35
HOU	0.66	0.01	0.13	0.80
Total	0.38	0.01	0.05	0.45
Hou - MISO				
HOU	-5.33	-0.54	-0.13	-6.01
MISO	5.36	0.54	0.16	6.05
Total	0.03	0.00	0.02	0.05
Hou - SPP				
HOU	-0.04	-0.05	0.03	-0.06
SPP	0.84	0.02	0.13	0.99
Total	0.80	-0.03	0.16	0.93
North - EPE				
EPE	-7.14	-0.30	-0.44	-7.88
NORTH	7.02	0.36	0.33	7.71
Total	-0.12	0.06	-0.11	-0.17
North - MISO				
MISO	-11.49	-0.88	-0.22	-12.59
NORTH	13.26	0.83	0.47	14.56
Total	1.77	-0.05	0.25	1.96
North - SPP				
NORTH	16.64	0.80	0.49	17.92
SPP	-16.13	-0.71	-0.71	-17.55
Total	0.51	0.08	-0.22	0.37
South - EPE				
EPE	-4.85	-0.25	-0.40	-5.50
SOUTH	5.30	0.32	0.27	5.89
Total	0.45	0.07	-0.13	0.39
South - MISO				
MISO	-5.18	-0.46	-0.09	-5.73
SOUTH	6.49	0.41	0.28	7.18
Total	1.31	-0.04	0.18	1.45
South - SPP				
SOUTH	11.24	0.66	0.15	12.06
SPP	-10.52	-0.58	-0.39	-11.49
Total	0.72	0.08	-0.24	0.57
West - EPE				
EPE	-2.19	-0.13	-0.26	-2.59
WEST	2.20	0.21	0.07	2.47
Total	0.00	0.08	-0.19	-0.11
West - MISO				
MISO	-1.44	-0.14	-0.03	-1.61
WEST	1.88	0.14	0.03	2.05
Total	0.44	0.00	0.01	0.45
West - SPP				
SPP	-3.49	-0.19	-0.12	-3.80
WEST	4.02	0.24	0.00	4.25
Total	0.53	0.04	-0.13	0.44

Notes: This table shows the change in social costs of emissions from interconnection by interconnection and zone. Modeled data comes from LMCD methodology.

Figure A6: Pre vs. Post-Interconnection Non-carbon External Cost of Coal Generation



Notes: This figure displays the non-carbon external costs of coal generation in each zone by interconnection and dispatch method. The dashed 45-degree line represents equal values pre and post interconnection.