# Market Dispatch and Emissions in U.S. Electricity Markets

## Spatial Reallocation and Operational Efficiency

Sara Asgari* Chris Malloy† Qihong Liu‡

*This draft is part of an ongoing project and is updated regularly. The most recent version is available at:*

saraasgarigouraj.github.io/papers/

**Abstract**

We evaluate whether market-based electricity dispatch improved social welfare during the U.S. deregulation of 1999–2012. Using a decomposition that contrasts observed dispatch with counterfactual least-cost and least-emissions regimes, we find that markets modestly reduced $CO_2$ and $NO_x$ damages through efficiency gains, but sharply increased $SO_2$ damages by expanding trade and shifting generation toward cheap coal. The net effect was an annual increase in environmental damages of $2–11 billion, far exceeding previously documented $3–5 billion in private cost savings. Losses were concentrated in early-adopting, coal-reliant, and merchant-heavy regions. These results show that while markets improved private efficiency, they imposed larger social costs by amplifying externalities, underscoring the need to align wholesale market rules with environmental objectives. (JEL L94, Q41, Q53)

**Keywords:** electricity markets; market dispatch; trade; emissions; externality; welfare

*University of Oklahoma. Email: sara.asgari@ou.edu.
†University of Oklahoma. Email: chris.malloy@ou.edu.
‡University of Oklahoma. Email: qihong.liu@ou.edu.

# I. Introduction

Replacing command-and-control regulation with markets can enhance cost efficiency but also distort outcomes when production externalities are unpriced. If private cost efficiency and social cost efficiency are aligned, markets lower both operating costs and external damages. If they diverge, markets risk reducing costs while amplifying external damages, motivating a key question: does market introduction align private incentives with social costs, thereby providing a better foundation for internalization of externalities than the command-and-control alternative.

The degree to which markets align social and private costs relative to command and control is ambiguous. Markets increase cost efficiency relative to command-and-control regulation by incentivizing more efficient production processes and reallocating production to relatively lower cost firms. The degree to which the cost efficiency associated with market introduction exacerbates or reduces negative production externalities depends on the relationship between private and social marginal cost: If private and social marginal costs are negatively correlated across firms, then market introduction will shift production to lower cost firms that generate large negative production externalities. Conversely, if private and marginal costs are positively correlated across firms, then market introduction could shift production toward low-cost firms with relatively smaller negative production externalities.

We examine how the wave of restructuring of wholesale markets in the US electricity sector, which accounted for 32% of total energy-related $CO_2$, 64% of $SO_2$, and 14% of $NO_X$ emissions nationally in 2022 (Declet-Barreto and Rosenberg, 2022), affected emissions from electricity generation. While the wave of wholesale market restructuring in the US electricity sector has been extensively studied, this is the first study to quantify the spatial reallocation of emissions from electricity generation that resulted from decreased barriers to trading electricity following market reforms.

In U.S. wholesale electricity markets, Cicala (2022) shows that replacing administrative dispatch with market-based dispatch substantially reduced production costs. We extend this evidence by quantifying the environmental consequences of this market-based deregulation. Exploiting the staggered rollout of market dispatch between 1999 and 2012, we estimate its effects on $CO_2$, $SO_2$, and $NO_x$ emissions and translate those changes into monetized damages. Our analysis reveals a central policy tension: markets deliver cost savings but can simultaneously reallocate pollution in ways that increase external damages.

Prior to the 1990s, U.S. electricity was supplied by vertically integrated utilities that combined generation, transmission, and distribution within exclusive service territories. These firms were regulated under rate-of-return rules with guaranteed profit margins (Borenstein and Bushnell, 2015). Dispatch was determined internally to meet forecast demand and reliability requirements, not market prices or marginal cost, leaving weak incentives to minimize operating costs, invest in flexible capacity, or trade across regions.

Beginning in the mid-1990s, federal and state reforms introduced competition into wholesale power markets. Transmission was separated from generation, many utilities divested generation assets, and independent power producers (merchant generators) were allowed to sell directly to utilities. In some states, retail choice was also introduced, allowing competitive suppliers to purchase from generators and resell to end-use customers. To coordinate these new market participants, independent system operators (ISOs) and regional transmission organizations (RTOs) were created to manage regional grids. Most importantly, the scope of dispatch shifted from utility-level scheduling to region-wide *market dispatch*. Instead of each utility running its own plants, ISOs and RTOs conducted centralized auctions in which generators submitted marginal-cost bids, and dispatch was determined by selecting the lowest-cost portfolio of plants across the region to meet demand, thereby optimizing the generation mix at the regional level. Open access to transmission reinforced this shift: while early transactions relied on bilateral contracts, centralized markets quickly replaced them, reducing contracting frictions and transmission bottlenecks. The result was a sharp expansion of routine interregional trade and a fundamental reallocation of generation across space.

These institutional changes transformed the allocation and pricing of electricity. The shift from administrative coordination to market-driven dispatch reshaped incentives for both incumbent utilities and new entrants, with consequences for production efficiency, investment, and the environmental footprint of the sector. Prior research documents substantial cost savings from these reforms (Cicala, 2022; Fell and Kaffine, 2018; Davis and Wolfram, 2012; Fabrizio et al., 2007). By contrast, much less is known about their environmental consequences, how market-based dispatch has affected emissions, and the damages they cause (Bushnell et al., 2017).

Several recent studies, including Chan et al., 2017 and Park and Kaffine, 2025, examined the effects of deregulation on $SO_2$ and $CO_2$ emissions in the US. Chan et al., 2017 use a difference-in-differences research design to provide evidence that, on average, investor-owned coal-fired power plants operated more efficiently after deregulation relative to their counterparts in non-deregulated regions, implying $CO_2$, $SO_2$, and $NO_x$ emissions reductions. Park and Kaffine, 2025 study the channels through which the introduction of the day-ahead wholesale electricity market in the Southwest Power Pool affected $CO_2$ emissions from electricity generation, finding a reduction in emissions primarily through the exit of generators with higher emissions intensities. Our analysis differs from these studies in two key ways. First, we examine a national sample of electricity generators which allows us to decompose effects by type of market reform and estimate how the wide variation in deregulation implementation across states influenced power sector emissions. Second, the channels documented in this paper do not restrict spatial reallocation across regional transmission organizations (such as between the Southwest Power Pool and the Midwest Independent System Operator), allowing for a comprehensive analysis of spatial reallocation following deregulation. Our analysis moves beyond the primary focus on production costs by quantifying the effects of market-based dispatch on emissions and monetized environmental damages. We combine unit-level hourly data on generation and emissions with spatially varying estimates of marginal damages from air pollution. Our empirical strategy builds on and extends the framework in Cicala (2022), allowing us to calculate counterfactual emissions and damages under alternative dispatch orders and to decompose observed outcomes into the mechanisms driving them.

Using a two-way fixed effects research design in a national sample of regional Power Control Areas (PCAs) between 1999 and 2012, our contributions are threefold. First, we estimate three channels through which deregulation affects emissions: (1) changes in operational efficiency, (2) changes in emissions intensities at low cost generation units, and (3) spatial reallocation to units in neighboring regions with different emissions intensities from local generators. Second, we translate estimated changes in emissions following deregulation into damages from exposure using source-specific estimates from Holland et al., 2016, allowing for a direct comparison of damages estimated in this paper to the cost savings from deregulation estimated in Cicala, 2022. This analysis clarifies whether economic and environmental goals are complementary or conflicting under market-based allocation. Third, we document heterogeneity in these effects across power control areas, exploiting variation in adoption timing, market structure, and regulatory institutions that prior work has not systematically studied. Together, these contributions provide the first economy-wide evidence on how market-based dispatch reshaped both costs and pollution in the U.S. electricity sector, and translated pollution impacts into monetized damages.

Our empirical strategy compares counterfactual outcomes under three allocation mechanisms: observed dispatch, least-cost dispatch, and least-emissions dispatch, holding demand and input prices fixed. In each case, we construct a counterfactual merit order—based either on marginal cost or emissions intensity—and sequentially dispatch available units to meet demand. Applying unit-specific emissions rates and generation costs yields total emissions and costs under each regime. This framework allows us to quantify directly the economic and environmental trade-offs implied by different allocation rules. As in Cicala, 2022,

Our findings reveal a clear trade-off. Market dispatch reduced $CO_2$ and $NO_x$ damages, while $SO_2$ damages increased. We find evidence that lower barriers to trade following deregulation spatially reallocated electricity generation to low-cost foreign generators with higher-$NO_x$ and $SO_2$ emissions relative to the local generators who were displaced by trade: on average, inverse hyperbolic sine transformed $NO_x$ and $SO_2$ emissions were both around 0.8 higher relative to autarky following deregulation. Our estimates also imply that, on average, operational efficiency reduced inverse hyperbolic sine-transformed $CO_2$ and $NO_x$ emissions by 0.09 and 0.08, respectively by lowering the emissions intensities of operational generators. Finally, our estimates suggest that, on average, deregulation reduced $CO_2$ emissions intensities and increased $SO_2$ intensities at low-cost generators, strengthening the synergy between cost and $CO_2$ emissions reductions but weakening the synergy between cost and $SO_2$ emissions reductions. In many areas, the rise in $SO_2$ damages more than offsets the declines in $CO_2$ and $NO_x$, producing net increases in external costs. In dollar terms, markets saved \$3–5 billion in production costs but raised environmental damages by \$2–11 billion. The distribution of these effects was uneven: merchant regions and early adopters experienced the largest damage increases, while late adopters saw no significant effect. Strikingly, MISO and PJM—where cost savings were greatest (Cicala, 2022)—also generated the largest increases in damages.

Taken together, the results show that while electricity market reforms generated substantial cost savings, they also created environmental trade-offs that were not central to their original design. Understanding these trade-offs is critical for ongoing debates on market design and the integration of environmental objectives into wholesale market rules.

The remainder of the paper proceeds as follows. Section II. reviews related work. Section III. develops the decomposition of observed emissions into operational inefficiency and the consequences of trade, constructed from counterfactual merit-order dispatch and pollutant-specific intensities. Section IV. describes the data and construction of damage variables. Section V. presents the empirical strategy. Section VI. reports the main findings. Section VII. concludes with policy implications.

## II. Literature Review

The existing literature clusters around three questions: did restructuring improve operational efficiency, did it reshape generation investment, and did it reduce or increase environmental damages? We review these strands to highlight where the evidence is consistent and where it remains incomplete.

## A. Operational Efficiency

Restructuring sharpened dispatch incentives and consistently lowered private costs. At the system level, Cicala (2022) shows that market dispatch cut production costs by 5 percent through larger gains from trade and fewer uneconomic runs. Expansion of RTOs further increased cross-regional trade and improved coordination (Mansur and White, 2012; Bushnell et al., 2017), echoing international evidence: in India, unbundling raised plant availability (Malik et al., 2011), while in England and Wales, privatization cut costs nearly in half and accelerated the coal-to-gas shift (Newberry and Pollitt, 1997).

Plant-level studies reinforce this conclusion. Fabrizio et al. (2007) document cost reductions at investor-owned plants in restructured states. Cicala (2015) finds coal plants freed from costly contracts converged to market fuel prices. Chan et al. (2017) show fuel efficiency improvements, and Douglas (2014) finds ISO dispatch shifted output away from high-cost coal, lowering costs by 2–3 percent. Nuclear plants also improved: F. Zhang (2007) document higher availability, and Davis and Wolfram (2012) show shorter outages increased wholesale value by $2.5 billion annually and cut $CO_2$ by 35 million tons—consistent with our finding that efficiency gains in dispatch reduced $CO_2$ damages.

These gains reflected incentives, not ownership. Bushnell and Wolfram (2005) show that divested and retained plants improved similarly once subject to incentive regulation. Still, restructuring created vulnerabilities: Borenstein et al. (2002) attributes California's crisis to market power, while Borenstein et al. (2012) shows procurement distorted by managerial incentives.

Together, these studies establish that restructuring improved private efficiency, but they measure only costs. Our study extends this work by applying the same efficiency lens to emissions, quantifying whether cost savings coincided with environmental gains or came at the expense of higher damages.

## B. Generation Investment

Restructuring not only changed dispatch incentives but also reshaped generation investment. A surge of nearly 140 GW of mostly gas-fired capacity entered between 1999–2002 (Joskow, 2006).

Asset sales to independent producers increased competition (Ishii and Yan, 2003), though regulatory uncertainty initially depressed investment (Ishii and Yan, 2006).

Policy interactions shaped these outcomes. Fowlie (2010) finds deregulated plants were less likely to adopt capital-intensive abatement, raising damages particularly in densely populated regions. More recently, Doshi and Johnston (2024) show that restructured markets adopted fewer advanced renewable technologies, citing higher financing costs and revenue risk.

This prior work shows that markets altered long-run investment incentives. We isolate a more immediate channel: The operational reallocation of generation across the existing fleet. Our analysis demonstrates that market dispatch—even before any investment response—systematically shifted output toward high-damage units, creating substantial environmental costs. This sharp short-run effect helps explain why the damage increases we document are largest among early adopters.

### C. Environmental Performance

The environmental record is mixed. Bushnell et al. (2017) stresses that private cost savings omit social damages. Brehm and Y. Zhang (2021) show this trade-off directly: centralized dispatch in Texas saved $59 million, but associated emissions erased those gains once damages were valued.

Other evidence points in different directions. Mansur (2007) finds strategic behavior in PJM reduced emissions by 20 percent, while Palmer and Burtraw (2005) stresses that efficiency and trade can either raise or lower emissions depending on the fuel mix. Graff Zivin et al. (2014) highlights sharp spatial and temporal heterogeneity in marginal emissions, and Linn et al. (2013) shows coal price increases improved efficiency and lowered carbon intensity.

Policy and infrastructure matter as well. Fowlie (2009) documents leakage from partial regulation in California. Hausman (2024) shows transmission lines constraints both raise costs and curtail renewables. By contrast, technology shifts and regulation produced large health gains: Holland et al. (2020) estimates $112 billion in annual damage reductions from 2010–2017, disproportionately benefiting disadvantaged communities.

These studies highlight important mechanisms, but all are partial—focusing on single markets, fuels, or pollutants. Our contribution is to unify these strands: we provide the first economy-wide accounting that compares private cost savings from market dispatch to monetized environmental damages, and show how expanded interregional trade reallocated generation in ways that systematically amplified $SO_2$ damages even as $CO_2$ and $NO_x$ declined.

## III. Production Emissions Decomposition

A power control area (PCA) is the basic operating unit of the U.S. grid: a geographic zone in which the system operator balances generation and demand each hour. PCAs are nested within larger reliability regions defined by the North American Electric Reliability Corporation (NERC), which provides the institutional boundary for transmission planning and interregional trade. Within each PCA sit multiple power plants, and within each plant, individual generating units.

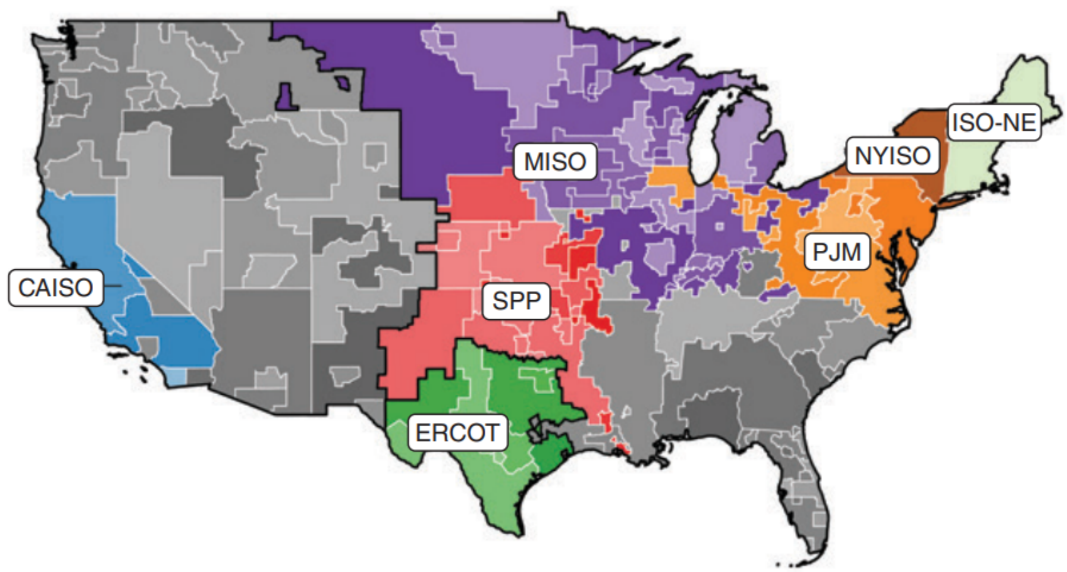



**Figure 1:** U.S. electrical grid as PCAs (2012).

Notes: Thick black lines identify interconnection boundaries. White borders delineate PCAs, and colors denote NERC reliability regions. Source: Cicala (2022).

Across the PCAs shown in Figure 1, each unit is characterized by its technology and primary fuel input (for example, coal, natural gas, nuclear, hydro, or renewables), which together determine its operating costs and emissions profile. Every hour, the operator decides which units to run to meet load. These choices are governed by costs, not emissions. To study the environmental consequences of dispatch, we assign to each unit an *emissions intensity*—tons of $CO_2$ or pounds of $SO_2$ and $NO_x$ per MWh of output. Each PCA in each hour can therefore be represented as a stack of units ordered by cost, with an associated emissions intensity for each unit.

This representation provides the foundation for our decomposition. Building directly on Cicala (2022), we preserve the cost-based merit order while mapping each generating unit to its emissions profile. This allows us to compare three dispatches: (i) the *observed* dispatch, (ii) the *least-cost* counterfactual, and (iii) a *least-emissions* benchmark. Because emissions differ by pollutant, we construct separate least-emissions orders for each pollutant—for example, least-$CO_2$, least-$SO_2$, or least-$NO_x$. The construction is directly analogous to Cicala's cost decomposition and yields an additive accounting identity for emissions.

Index generating units in PCA $p$ at hour $t$ by $i$. For each unit, let $g_{it}$ denote observed generation (MWh), $m_{it}$ observed mass emissions (tons of $CO_2$ or pounds of $SO_2$, $NO_x$), and

$$e_{it} = \frac{m_{it}}{g_{it}}$$

the unit's emissions intensity. By definition, unit–hour emissions are $m_{it} = e_{it} g_{it}$.

Observed emissions in PCA $p$ at hour $t$ are

$$E_{pt}(Q_{pt}) = \sum_{i \in \mathcal{I}_{pt}} m_{it} = \sum_{i \in \mathcal{I}_{pt}} e_{it} g_{it}, \tag{1}$$

where $\mathcal{I}_{pt}$ is the set of units actually dispatched and $Q_{pt} = \sum_{i \in \mathcal{I}_{pt}} g_{it}$ is total generation in $p$ at time $t$.

To construct counterfactuals, we reallocate generation while holding total output fixed at $Q_{pt}$. Units are dispatched in merit order until their capacity $\bar{g}_{it}$ is fully used, with the marginal unit partially loaded to satisfy $Q_{pt}$.

The *least-cost emissions* are the total emissions if generation were dispatched strictly in cost order:

$$E^*_{pt}(Q_{pt}) \;=\; \sum_{i \in C_{pt}} e_{it}\bar{g}_{it}, \tag{2}$$

where $C_{pt}$ is the set of lowest-cost units sufficient to supply $Q_{pt}$, each dispatched up to capacity $\bar{g}_{it}$ with the marginal unit partially loaded as needed. By construction, $E^*_{pt}(Q_{pt})$ represents the implied emissions of $CO_2$, $SO_2$, or $NO_x$ under the least-cost dispatch at output $Q_{pt}$.

The *least-emissions benchmark* is the analogous construction in emissions order:

$$\widehat{E}_{pt}(Q_{pt}) \;=\; \sum_{j \in \mathcal{E}_{pt}} e_{jt}\bar{g}_{jt}, \tag{3}$$

where $\mathcal{E}_{pt}$ is the set of lowest-emission units sufficient to supply $Q_{pt}$, each dispatched up to capacity $\bar{g}_{jt}$ with the marginal unit partially loaded. By construction, $\widehat{E}_{pt}(Q_{pt})$ is the lowest feasible emissions level at output $Q_{pt}$.

Importantly, each pollutant has its own benchmark. Under the least-$CO_2$ order we measure $CO_2$ emissions; under the least-$SO_2$ order we measure $SO_2$ emissions; and under the least-$NO_x$ order we measure $NO_x$ emissions. There is no cross-measurement: each benchmark provides the cleanest feasible dispatch for the specific pollutant.

### A. Operational Efficiency & Emissions Gaps

Following Cicala (2022), the operational efficiency channel is captured by comparing observed emissions to the least-cost benchmark:

$$O_{pt}(Q_{pt}) \;=\; E_{pt}(Q_{pt}) - E^*_{pt}(Q_{pt}), \tag{4}$$

which measures excess emissions from out-of-merit dispatch. Observed outcomes differ from the least-cost benchmark because operators may deviate from strict cost merit order due to transmission constraints, unit outages, or reliability concerns.

Because we additionally construct a least-emissions benchmark, we can refine this measure into two distinct components:

$$O_{pt}(Q_{pt}) = \underbrace{\left[E_{pt}(Q_{pt}) - \widehat{E}_{pt}(Q_{pt})\right]}_{\text{Observed vs. Least-Emission}} - \underbrace{\left[E^{*}_{pt}(Q_{pt}) - \widehat{E}_{pt}(Q_{pt})\right]}_{\text{Least-Cost vs. Least-Emission}}. \tag{5}$$

The first term captures *excess emissions from inefficient operation*: observed dispatch may be higher or lower in emissions than least-cost dispatch, but it will always be weakly higher than the least-emissions benchmark. The second term captures the *structural tradeoff* inherent in cost-based dispatch: when grid operators dispatch strictly by cost, emissions must be weakly higher than if units were dispatched in order of emissions intensity. This term therefore measures the additional pollution generated by prioritizing cost minimization rather than emissions minimization.

This framework delivers a clean decomposition of emissions outcomes under three allocation mechanisms: observed dispatch, least-cost dispatch, and least-emissions dispatch, holding demand and input prices fixed. Comparing these counterfactuals isolates two channels. The first is *inefficient operation*, captured by the gap between observed and least-cost dispatch. The second is the *structural cost–emissions tradeoff*, captured by the gap between least-cost and least-emissions dispatch. Together, these account for how operational decisions within a PCA shape emissions. We now extend the framework to the third and central channel: the effect of trade across PCAs.

### B. Trade Emissions

Transmission links allow power to flow across PCAs, so that generators in exporting regions displace production in importing regions. This reshuffling changes both the level and spatial distribution of emissions.

When it comes to trade, markets operate strictly on costs: electricity flows from lower-cost to higher-cost PCAs, generating a surplus that is always positive in economic terms. The environmental effect, however, depends on the relative fuel mix. If exports substitute for units with higher emissions intensity, total emissions fall; if they substitute for cleaner units, total emissions rise.

This heterogeneity is central to our empirical strategy. To capture both possibilities, we allow for trade effects that can be positive or negative. Since emissions changes from trade may be small, zero, or negative, we transform outcomes using the inverse hyperbolic sine (asinh). Unlike the logarithm, the asinh transformation accommodates zeros and negatives while preserving a log-like interpretation for large values. This enables us to measure proportional effects of trade consistently across PCAs and pollutants.

Let $L_{pt}$ denote load in PCA $p$ at hour $t$ and $Q_{pt}$ the electricity generated. The difference $Q_{pt} - L_{pt}$ is net exports ($> 0$) or net imports ($< 0$). To isolate trade, we compare emissions under autarky ($Q_{pt} = L_{pt}$) with emissions under observed flows.

We define *trade emissions* as

$$T_{pt}(L_{pt}, Q_{pt}) = \underbrace{\left[E^*_{pt}(L_{pt}) - E^*_{pt}(Q_{pt})\right]}_{\text{Autarky vs. observed output}} + \underbrace{e^N_t \left[Q_{pt} - L_{pt}\right]}_{\text{Emissions content of trade}} . \tag{6}$$

where $E^*_{pt}(L_{pt})$ are least–cost emissions from meeting local load, $E^*_{pt}(Q_{pt})$ are least–cost emissions from actual generation, and $e^N_t$ is the average emissions intensity in the surrounding PCA with same NERC region at time $t$. The first term measures how local emissions differ between autarky and observed output. The second assigns emissions to the electricity traded.

In practice, we use regional averages that differ by direction: when a PCA is an importer ($Q_{pt} < L_{pt}$), we apply the average emissions intensity of exporters in its NERC region; when it is an exporter ($Q_{pt} > L_{pt}$), we apply the average intensity of importers. This ensures that emissions from trade are consistently assigned even though the marginal units adjusting to flows are unobserved.

This trade measure separates two forces: (i) the change in local least–cost generation between autarky and observed output, and (ii) the emissions content of traded electricity elsewhere. We compute $T_{pt}(L_{pt}, Q_{pt})$ separately for $CO_2$, $SO_2$, and $NO_x$. Putting everything together from Sections III., A., and B., we can now express observed emissions as a decomposition across operational inefficiency, the cost–emissions tradeoff, and trade effects.

### C. Comprehensive Emissions Decomposition

Following Cicala (2022), we decompose observed outcomes into mutually exclusive and exhaustive components. In our setting, the objects are emissions rather than costs. Let total observed emissions in hour $t$ be

$$E_t(Q_t) \ = \ \sum_p E_{pt}(Q_{pt}),$$

where $Q_t = \sum_p Q_{pt}$ is aggregate generation.

By adding and subtracting least–cost and least–emissions counterfactuals for each PCA, observed emissions can be written as

$$\sum_p E_{pt}(Q_{pt}) = \sum_p \left[E_{pt}(Q_{pt}) - \widehat{E}_{pt}(Q_{pt})\right] - \sum_p \left[E^*_{pt}(Q_{pt}) - \widehat{E}_{pt}(Q_{pt})\right] + \sum_p T_{pt}(L_{pt}, Q_{pt}) + \sum_p R_{pt}.$$

Equivalently, for each PCA:

$$E_{pt}(Q_{pt}) = E_{pt}(Q_{pt}) - \widehat{E}_{pt}(Q_{pt}) - \left(E^*_{pt}(Q_{pt}) - \widehat{E}_{pt}(Q_{pt})\right) + T_{pt}(L_{pt}, Q_{pt}) + R_{pt}. \tag{7}$$

The decomposition separates four channels: (i) observed vs least-emission, (ii) least-cost vs least-emission, (iii) autarky vs observed output, (iv) emissions content of trade. The residual $R_t$ facilitates interpretation but is not measured in our empirical analysis.

## IV. Data

Our analysis relies on a unit–hour panel spanning 1999–2012, a period that covers the onset of electricity market restructuring and its widespread adoption. The dataset draws on two main sources: (i) electricity market operations data that provide the backbone for counterfactual dispatch analysis, and (ii) environmental data that extend these operations into emissions and damages.

The first source is Cicala (2022), who compile hourly data on U.S. generation, marginal costs, and system load from multiple federal agencies. These data provide the backbone for constructing least-cost dispatch counterfactuals. Fossil-fuel generation originates from Energy Information Administration (EIA) Forms 767 and 923, hydropower from operator reports or streamflow estimates, non-hydro renewables from Form 923 combined with hourly climate data, and nuclear generation from Nuclear Regulatory Commission (NRC) records. Marginal costs are built from fuel prices, technology-specific heat rates, and operations and maintenance (O&M) costs, including pollution permit prices where relevant. Following standard practice, we assume zero marginal costs for non-hydro renewables. Hourly load data come from Federal Energy Regulatory Commission (FERC) Form 714, with gaps imputed using LASSO regression.

The second source extends these operational data with environmental outcomes. We link each generating unit to the EPA's Continuous Emissions Monitoring System (CEMS), which provides hourly emissions of $CO_2$ (tons), $SO_2$, and $NO_x$ (pounds) for large fossil units. The EPA's Power Sector Data Crosswalk allows consistent matching between CEMS units and the Cicala dataset. Together, these sources yield a unit–hour dataset that connects dispatch, costs, emissions, and damages.

Coverage gaps in CEMS require imputation. Smaller units not subject to monitoring, or large units in hours when they are offline, lack direct emissions intensities. We fill these gaps using a hierarchy of averages from comparable CEMS units in the same PCA, fuel type, and month, progressively broadening to NERC–fuel–month when needed. When no comparable unit is available, we use engineering-based estimates derived from unit-specific heat rates and fuel-specific emissions coefficients:

$$\mathrm{EI}_{it}^{f} = HR_{it} \times \sum_{f} \left( FS_{it}^{f} \times EF^{f} \right), \tag{8}$$

where $HR_{it}$ is the unit's heat rate (MMBtu/MWh), $FS_{it}^{f}$ the share of fuel $f$ in its input mix, and $EF^{f}$ the fuel-specific emissions factor (lbs/MMBtu). These engineering estimates are converted to output-based units of tons/MWh for $CO_2$ and lbs/MWh for $SO_2$ and $NO_x$. To limit the influence of extreme values, all emissions intensities are winsorized at the 99th percentile.

Finally, we monetize emissions to construct hourly damage variables. These yield pollutant-specific and total damages at the PCA–hour level, our main outcomes.

### A. Emission Damages

Following Fell et al. (2021), we compute damages by multiplying unit-level emissions by county-specific marginal damages from Holland et al. (2016). $CO_2$ is priced at \$39 per ton (the U.S. Interagency Working Group's social cost of carbon), while $SO_2$ and $NO_x$ use county-level values from Holland et al. (2016). This approach provides pollutant-specific damages and aggregates to total damages at the PCA–hour level.

Formally, damages for unit $i$ in county $c$ at hour $t$ are

$$d_{it}^{p} = e_{it} \times g_{it} \times \mathrm{MD}_{c}^{p}, \tag{9}$$

where $e_{it}$ is emissions intensity (tons/MWh for $CO_2$, lbs/MWh for $SO_2$ and $NO_x$), $g_{it}$ is generation (MWh), and $\mathrm{MD}_c^p$ is the marginal damage per unit of pollutant $p$.

Aggregating across units yields PCA-level damages:

$$D_{pt}^{p} = \sum_{i \in p} d_{it}^{p},$$

and the total across pollutants:

$$D_{pt}^{\mathrm{Total}} = D_{pt}^{\mathrm{CO_2}} + D_{pt}^{\mathrm{SO_2}} + D_{pt}^{\mathrm{NO}_x}. \tag{10}$$

This construction not only provides a measure of overall damages but also allows us to identify the pollutant driving those damages, distinguishing global climate costs ($CO_2$) from local health damages ($SO_2$, $NO_x$).

## V. Empirical Strategy

Electricity markets in the United States were created and expanded at different times across regions, as local utilities ceded operational control to independent system operators (ISOs) or regional transmission organizations (RTOs). The central institutional change was the adoption of centralized, market-based dispatch. These adoption events are discrete and well documented, and their staggered timing across power control areas (PCAs) yields a natural difference-in-differences design: PCAs that have not yet restructured serve as contemporaneous controls for adopters.

Building on the emissions decomposition in Section III., we (i) separate operational inefficiency from the structural cost–emissions tradeoff, and (ii) assign an emissions content to traded electricity using contemporaneous, region-specific average intensities (direction-specific for imports vs. exports). Thus, imports are not treated as emissions-free and exports are not treated as environmentally costless; traded MWh carry pollutant-specific emissions by construction. Mapping these emissions into damages with spatially varying marginal damages further ensures that reallocation across PCAs is consistently valued in environmental terms.

The challenge is instead to account for time-varying local fundamentals—fuel prices, load, and installed capacity—that shape dispatch in each PCA. Following Cicala (2022), we therefore control for exogenous merit-order fundamentals: the least-cost benchmark $C^*_{pt}(Q_{pt})$, and the least-emissions benchmark $E^*_{pt}(Q_{pt})$ for the pollutant under study. These depend only on installed capacity, heat rates, fuel prices, and load, not on realized dispatch.

Our baseline specification is

$$y_{pt} = \alpha + \beta_1 \text{Treated}_{pt} + \beta_2 \log L_{pt} + \beta_3 \log C^*_{pt}(Q_{pt}) + \beta_4 \log E^*_{pt}(Q_{pt}) + \beta_5 \chi_{pt} + \gamma_{pm} + \delta_{tr} + \varepsilon_{pt}, \quad (11)$$

where $y_{pt}$ is the asinh-transformed outcome for PCA $p$ in hour $t$: observed emissions, damages, or one of the decomposition components. The treatment indicator $\text{Treated}_{pt}$ equals one after market dispatch begins in $p$, capturing the short-run effect of restructuring.

Equation (11) includes three sets of controls. First, we flexibly control for demand with $\log L_{pt}$, allowing load to scale emissions outcomes in a nonlinear way. Second, we include $C^*_{pt}(Q_{pt})$, the least-cost cost of meeting observed production under strict merit order, to capture contemporaneous cost fundamentals driven by capacity, heat rates, and fuel prices. Third, we include $E^*_{pt}(Q_{pt})$, the pollutant-specific least-emissions requirement for producing $Q_{pt}$ under the cleanest feasible merit order. For example, when the dependent variable is $CO_2$, we control for $\log E^{*CO_2}_{pt}(Q_{pt})$; when it is $SO_2$, for $\log E^{*SO_2}_{pt}(Q_{pt})$; and likewise for $NO_x$. This ensures that estimated treatment effects are not confounded by differences in abatement opportunities across PCAs' generating fleets.

The vector $\chi_{pt}$ contains annual event-time indicators for periods within two years before and after adoption, so that treatment effects are identified from short-run adjustments around the adoption window rather than long-run trends. To account for potential contamination of the control group, we also include indicators for whether a PCA borders a market that has adopted dispatch, capturing spillovers from new trading opportunities.

Fixed effects absorb additional variation. PCA-by-month fixed effects ($\gamma_{pm}$) capture seasonal patterns that differ across PCAs, such as scheduled maintenance or hydrological cycles. Date–hour-by-region fixed effects ($\delta_{tr}$) absorb high-frequency shocks common to all PCAs within a NERC region, such as fuel price spikes or weather events. All regressions weight by mean PCA load in 1999 to prevent small PCAs from dominating the estimates, and standard errors are clustered by PCA-month to allow for serial correlation and seasonal collinearity.

We also control for market adoption by neighboring PCAs to account for spatial spillovers. For each PCA's first- and second-closest neighbors, we include indicators for whether the neighbor adopted recently (1–24 months prior), adopted longer ago (¿24 months prior), or will adopt in the future (¿24 months later). This ensures our estimates capture only the direct effect of a PCA's own market adoption, net of confounding spillovers from geographically proximate treated areas.

The coefficient $\beta_1$ is the average treatment effect on the treated (ATT): the change in emissions or damages for adopting PCAs in the two years after market-based dispatch, net of local demand, cost fundamentals, abatement opportunities, spillovers, and common shocks.

Before turning to results, we document how market and non-market PCAs differ at baseline.

Table 1 reports averages for key outcomes in 1999, the year when restructuring began. Market PCAs start out systematically dirtier on $SO_2$, and their observed dispatch is further from the least-emissions benchmark. By contrast, differences in $CO_2$ and $NO_x$ are more modest. These patterns highlight why controlling for least-cost and least-emissions counterfactuals is essential: without these benchmarks, differences in underlying fleet composition could be mistaken for causal effects of market adoption

Table 1 shows that markets and non-markets look remarkably similar on average in terms of load, generation, and $CO_2$ emissions. In both 1999 and 2012, treated and untreated PCAs generated roughly the same electricity and exhibited comparable $CO_2$ levels. Where differences do emerge is in damages: in 1999, markets exhibited about $660k higher damages than non-markets. Notably, this gap does not appear in raw $SO_2$ emissions, which are statistically similar across groups, underscoring the importance of using location-specific damage values. By 2012, total damages had fallen sharply across the board, but remained about $185k higher in markets.

Capacity patterns underscore these compositional differences. By 2012, market PCAs had shifted more heavily into gas and non-utility capacity and were far more merchant-oriented (61 percent vs. 39 percent). Non-markets, by contrast, retained more traditional utility ownership and a slightly larger coal share. These differences are not dramatic in magnitudes but point to persistent structural variation in generation fleets and institutional design. They highlight why our identification strategy conditions on least-cost and least-emissions benchmarks: absent these controls, estimated treatment effects could simply reflect markets starting out slightly dirtier and adopting different capacity mixes over time.

**Table 1:** Summary Statistics by Market Adoption Status

| | 1999 | | | 2012 | | |
|---|---|---|---|---|---|---|
| | Markets | Non-Markets | Diff | Markets | Non-Markets | Diff |
| *Panel A. Quantities and Costs* | | | | | | |
| Load (GWh) | 10.98 | 9.94 | 1.03 | 11.83 | 10.94 | 0.90 |
| | [8.72] | [7.45] | (0.90) | [9.24] | [8.20] | (0.98) |
| Generation (GWh) | 10.50 | 10.49 | 0.01 | 11.08 | 11.63 | –0.54 |
| | [8.59] | [7.93] | (0.94) | [8.98] | [8.90] | (1.02) |
| Observed Cost ($k) | 137.26 | 122.76 | 14.50 | 184.81 | 209.47 | –24.66 |
| | [122.22] | [108.98] | (12.65) | [163.25] | [189.44] | (20.60) |
| Total Damage ($k) | 2389.15 | 1731.91 | 657.24** | 675.94 | 491.35 | 184.59** |
| | [3009.23] | [1891.40] | (305.21) | [734.44] | [538.36] | (75.53) |
| *Panel B. Emissions* | | | | | | |
| $CO_2$ (k tons) | 7.01 | 6.88 | 0.13 | 5.68 | 6.00 | –0.32 |
| | [5.72] | [6.32] | (0.72) | [4.70] | [5.46] | (0.60) |
| $SO_2$ (k lbs) | 87.00 | 77.46 | 9.54 | 19.66 | 16.01 | 3.66 |
| | [102.75] | [91.23] | (11.86) | [22.46] | [20.74] | (2.55) |
| $NO_x$ (k lbs) | 29.77 | 33.59 | –3.82 | 8.20 | 8.53 | –0.33 |
| | [29.76] | [31.65] | (3.53) | [8.89] | [7.10] | (0.92) |
| *Panel C. Gains from Trade* | | | | | | |
| $CO_2$ | 0.40 | 0.39 | 0.01 | 0.47 | 0.46 | 0.01 |
| | [1.09] | [1.18] | (0.09) | [1.03] | [1.32] | (0.10) |
| $SO_2$ | 1.64 | –1.17 | 2.81*** | 1.09 | 0.34 | 0.75*** |
| | [16.12] | [10.37] | (0.84) | [6.09] | [3.38] | (0.29) |
| $NO_x$ | 0.57 | 0.95 | –0.38 | 0.33 | 1.03 | –0.70*** |
| | [4.45] | [4.13] | (0.27) | [2.43] | [3.86] | (0.23) |
| *Panel D. Observed vs. Least Emission* | | | | | | |
| $CO_2$ | 2.31 | 1.50 | 0.81*** | 2.03 | 2.43 | -0.41 |
| | [2.77] | [1.20] | (0.26) | [1.90] | [2.25] | (0.25) |
| $SO_2$ | 65.14 | 45.07 | 20.08** | 18.81 | 15.61 | 3.19 |
| | [84.12] | [47.52] | (8.50) | [21.65] | [20.69] | (2.53) |
| $NO_x$ | 14.33 | 15.38 | -1.05 | 6.18 | 6.70 | -0.52 |
| | [13.51] | [14.28] | (1.64) | [7.13] | [5.59] | (0.77) |
| *Panel E. Least Cost vs. Least Emission* | | | | | | |
| $CO_2$ | 1.64 | 0.94 | 0.71*** | 0.95 | 0.84 | 0.11 |
| | [2.16] | [0.73] | (0.20) | [0.97] | [1.06] | (0.11) |
| $SO_2$ | 54.86 | 33.69 | 21.16*** | 12.74 | 4.87 | 7.88*** |
| | [78.72] | [37.44] | (7.68) | [16.79] | [8.72] | (1.30) |
| $NO_x$ | 10.74 | 12.38 | -1.64 | 2.84 | 2.26 | 0.58** |
| | [10.38] | [12.82] | (1.42) | [3.40] | [2.86] | (0.29) |
| *Panel F. Capacity and Shares* | | | | | | |
| Total Capacity (GW) | 19.69 | 16.50 | 3.19* | 23.70 | 23.17 | 0.53 |
| | [16.20] | [11.76] | (1.65) | [18.22] | [18.03] | (2.17) |
| Coal (GW) | 7.45 | 7.78 | –0.33 | 6.86 | 7.20 | –0.33 |
| | [7.29] | [8.13] | (0.97) | [6.89] | [7.34] | (0.89) |
| Gas (GW) | 4.96 | 3.24 | 1.72*** | 10.40 | 10.72 | –0.32 |
| | [4.71] | [3.94] | (0.44) | [7.64] | [9.45] | (1.00) |
| Merchant Share (2012, %) | | | | 0.61 | 0.39 | 0.22*** |
| | | | | [0.30] | [0.24] | (0.02) |
| Retail Share (2012, %) | | | | 0.33 | 0.23 | 0.10*** |
| | | | | [0.22] | [0.26] | (0.03) |
| PCAs | 60 | 38 | | 60 | 38 | |

*Notes:* Values weighted by PCA mean load in 1999. Damages in thousands of 2011 USD. Standard deviations in brackets; differences in parentheses.

## VI. Results

Tables 2, 3, and 4 present the estimated short-run impacts of deregulation on $CO_2$, $SO_2$, and $NO_x$ emissions during the 24 months following adoption of market dispatch. Column 1 reports the effect on observed emissions, Column 2 isolates the contribution of gains from trade relative to autarky, Column 3 compares observed emissions to the least-emissions counterfactual, and Column 4 measures the gap between least-cost and least-emissions dispatch. We estimate all models using the inverse hyperbolic sine (asinh) transformation of our outcome variables. Standard errors are clustered at the PCA-month level and shown in parentheses. Each specification includes the full set of controls from equation (11), and Appendix A.2 reports robustness to alternative empirical models.

Table 2 shows that asinh-transformed $CO_2$ emissions declined by 0.05 on average in the 24 months following deregulation (Column 1). This reduction is driven by statistically significant improvements in operational efficiency (Column 3), which also narrowed the gap between least-cost and least-emissions dispatch (Column 4). These findings indicate that deregulation aligned cost savings with reductions in $CO_2$. By contrast, the effect of trade on emissions is positive but imprecisely estimated (Column 2), suggesting modest savings relative to autarky that are not precisely identified.

**Table 2:** Effect of Market Dispatch on $CO_2$ (Tons)

| | Observed $CO_2$ | Gains from Trade | Observed vs Least-$CO_2$ | Least-Cost vs Least-$CO_2$ |
|---|---|---|---|---|
| Mkt Effect | -0.049*** | 0.163 | -0.087*** | -0.060** |
| | (0.007) | (0.124) | (0.013) | (0.028) |
| Intercept | 9.067*** | 2.567*** | 7.896*** | 7.505*** |
| | (0.004) | (0.077) | (0.009) | (0.016) |
| Log($L_{pt}$) | Yes | Yes | Yes | Yes |
| Log($C^*_{pt}(L_{pt})$) | Yes | Yes | Yes | Yes |
| Log($CO2^*_{pt}(L_{pt})$) | Yes | Yes | Yes | Yes |
| PCA×Month-of-Year FE | Yes | Yes | Yes | Yes |
| Region×Date×Hour FE | Yes | Yes | Yes | Yes |
| Event-time dummies | Yes | Yes | Yes | Yes |
| Neighbor markets | Yes | Yes | Yes | Yes |
| Clusters | 16,464 | 16,464 | 16,464 | 16,464 |
| PCAs | 98 | 98 | 98 | 98 |
| Mean | 2,942 | 150 | 991 | 858 |
| $R^2$ | 0.951 | 0.551 | 0.935 | 0.852 |
| Observations | 12,028,128 | 12,028,128 | 12,028,128 | 12,028,128 |

*Notes:* Outcomes are expressed in asinh units. Standard errors clustered at the PCA–month level in parentheses. Log($L_{pt}$), log merit-order cost $C^*_{pt}(L_{pt})$, and log merit-order emissions $CO2^*_{pt}(L_{pt})$ enter with separate slopes by PCA–month of year. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table 3 indicates that deregulation reduced observed $NO_x$ emissions on average (Column 1). This net decline masks offsetting mechanisms. Trade reallocates production toward lower-cost but more $NO_x$-intensive generators, raising emissions relative to autarky (Gains from Trade). At the same time, operational efficiency improves significantly, lowering emissions by –0.08 in asinh units. Because the efficiency gap between observed and least-emissions dispatch (5,000 pounds) is far larger than the trade gap (288 pounds), efficiency gains dominate, yielding an overall reduction. The gap between least-cost and least-emissions dispatch widens slightly, but the effect is statistically insignificant.

**Table 3:** Effect of Market Dispatch on $NO_x$ (lbs)

| | Observed $NO_x$ | Gains from Trade | Observed vs Least-$NO_x$ | Least-Cost vs Least-$NO_x$ |
|---|---|---|---|---|
| Mkt Effect | -0.047*** | -0.763*** | -0.078*** | 0.051 |
| | (0.012) | (0.235) | (0.017) | (0.033) |
| Intercept | 9.869*** | 1.148*** | 9.451*** | 9.045*** |
| | (0.008) | (0.118) | (0.010) | (0.021) |
| Log($L_{pt}$) | Yes | Yes | Yes | Yes |
| Log($C^*_{pt}(L_{pt})$) | Yes | Yes | Yes | Yes |
| Log($NO_x{}^*_{pt}(L_{pt})$) | Yes | Yes | Yes | Yes |
| PCA×Month-of-Year FE | Yes | Yes | Yes | Yes |
| Region×Date×Hour FE | Yes | Yes | Yes | Yes |
| Event-time dummies | Yes | Yes | Yes | Yes |
| Neighbor markets | Yes | Yes | Yes | Yes |
| Clusters | 16,464 | 16,464 | 16,464 | 16,464 |
| PCAs | 98 | 98 | 98 | 98 |
| Mean | 8,347 | 288 | 5,034 | 4,489 |
| $R^2$ | 0.937 | 0.502 | 0.908 | 0.822 |
| Observations | 12,028,128 | 12,028,128 | 12,028,128 | 12,028,128 |

*Notes:* Outcomes are expressed in asinh units. Standard errors clustered at the PCA–month level in parentheses. Log($L_{pt}$), log merit-order cost $C^*_{pt}(L_{pt})$, and log merit-order emissions $NO_x{}^*_{pt}(L_{pt})$ enter with separate slopes by PCA–month of year. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

In contrast to the declines in $CO_2$ and $NO_x$, Table 4 shows that deregulation raised $SO_2$ emissions. On average, asinh-transformed $SO_2$ emissions increased by 0.09 in the 24 months following market dispatch. This rise reflects a shift in production from local, lower-intensity generators to low-cost but more $SO_2$-intensive plants in other regions, driving emissions from trade up by 0.8 relative to autarky (Column 2). The operational efficiency channel is small and statistically insignificant. Moreover, deregulation widened the gap between least-cost and least-emissions dispatch by 0.12, indicating that cost savings came at the expense of higher $SO_2$. These findings underscore the importance of accounting for interregional electricity flows when evaluating the environmental consequences of market reforms.

Our finding that $SO_2$ emissions rose in the 24 months after deregulation contrasts with Chan et al. (2017), who report efficiency gains and lower emissions at coal plants. The difference reflects both scope and horizon. Chan et al. (2017) focus on plant-level outcomes, without accounting for the general equilibrium effects of market dispatch on trading patterns and emissions in non-market states. By contrast, our design captures interregional reallocation of generation, where cost savings came from shifting toward $SO_2$-intensive coal. We also estimate short-run effects, while their results reflect longer-run adjustments in efficiency and capacity utilization. These distinctions help explain why our estimates imply divergence between cost and emissions, while theirs imply convergence.

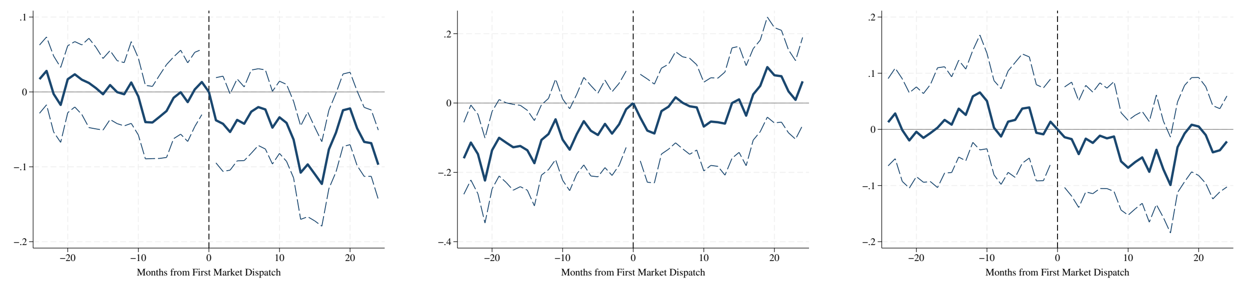
**Table 4:** Effect of Market Dispatch on $SO_2$ (lbs)

| | Observed $SO_2$ | Gains from Trade | Observed vs Least-$SO_2$ | Least-Cost vs Least-$SO_2$ |
|---|---|---|---|---|
| Mkt Effect | 0.087*** | -0.799*** | 0.026 | 0.120*** |
| | (0.017) | (0.212) | (0.018) | (0.041) |
| Intercept | 10.472*** | -0.016 | 10.314*** | 9.896*** |
| | (0.011) | (0.117) | (0.012) | (0.028) |
| Log($L_{pt}$) | Yes | Yes | Yes | Yes |
| Log($C^*_{pt}(L_{pt})$) | Yes | Yes | Yes | Yes |
| Log($SO_2{}^*_{pt}(L_{pt})$) | Yes | Yes | Yes | Yes |
| PCA×Month-of-Year FE | Yes | Yes | Yes | Yes |
| Region×Date×Hour FE | Yes | Yes | Yes | Yes |
| Event-time dummies | Yes | Yes | Yes | Yes |
| Neighbor markets | Yes | Yes | Yes | Yes |
| Clusters | 16,464 | 16,464 | 16,464 | 16,464 |
| PCAs | 98 | 98 | 98 | 98 |
| Mean | 20,580 | 39.7 | 16,798 | 14,877 |
| $R^2$ | 0.934 | 0.466 | 0.926 | 0.844 |
| Observations | 12,028,128 | 12,028,128 | 12,028,128 | 12,028,128 |

*Notes:* Outcomes are expressed in asinh units. Standard errors clustered at the PCA–month level in parentheses. Log($L_{pt}$), log merit-order cost $C^*_{pt}(L_{pt})$, and log merit-order emissions $SO_2{}^*_{pt}(L_{pt})$ enter with separate slopes by PCA–month of year. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Our difference-in-differences design relies on the parallel trends assumption: absent adoption, treated and untreated PCAs would have evolved similarly. The rich set of fixed effects and structural controls in Equation (11) makes this assumption plausible by absorbing common shocks and adjusting for local fundamentals, but it cannot guarantee it. To assess validity, we estimate event-study specifications that trace dynamic treatment effects in the 24 months before and after adoption. Figure 2 reports dynamic treatment effects for observed emissions. Event–study results for decomposition channels and damages are reported in the Appendix A.3.

For $CO_2$ (Panel A), pre-treatment coefficients are flat and statistically indistinguishable from zero, consistent with parallel trends. Following adoption, $CO_2$ declines modestly, reflecting efficiency gains in dispatch. For $SO_2$ (Panel B), small upward pre-trends remain even after controls, suggesting that markets started slightly dirtier. Post-adoption, the divergence grows as dispatch shifts toward

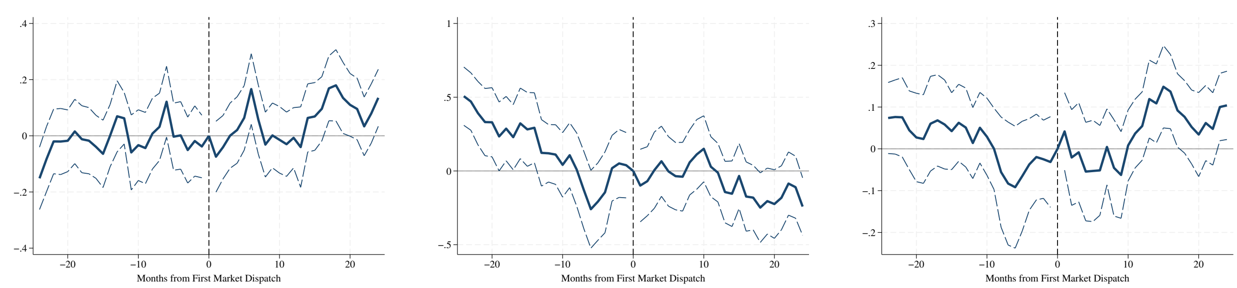



Panel A. Observed $CO_2$ Panel B. Observed $SO_2$ Panel C. Observed $NO_x$

**Figure 2:** Event–study estimates of observed emissions.

coal units with higher sulfur intensity. For $NO_x$ (Panel C), pre-treatment dynamics are largely flat, though somewhat noisier than $CO_2$. After adoption, $NO_x$ falls slightly, driven by improvements in operational efficiency.

To shed light on mechanisms, we turn to generation mix dynamics. Figure 3 plots event studies of generation shares by coal, gas, and nuclear. Coal share (Panel A) is stable in the pre-period but rises sharply in the two years after adoption. Gas share (Panel B) shows the mirror image: flat before reform, then contracting persistently post-adoption. Nuclear share (Panel C) trends are relatively flat before reform but increase gradually thereafter. These dynamics are consistent with the regression estimates in Table 5: coal, nuclear, and renewables expand after restructuring, while gas and oil contract.




Panel A. Coal Generation Share Panel B. Gas Generation Share Panel C. Nuclear Generation Share

**Figure 3:** Event–study estimates of generation mix dynamics.

**Table 5:** Effect of Market Dispatch on Generation Fuel Share

| | Coal | Gas | Oil | Nuclear | Renewables |
|---|---|---|---|---|---|
| Mkt Effect | 0.051*** | -0.120*** | -0.056** | 0.028* | 0.157*** |
| | (0.018) | (0.036) | (0.028) | (0.016) | (0.020) |
| Intercept | 4.081*** | 1.971*** | 0.096*** | 2.950*** | 1.735*** |
| | (0.011) | (0.019) | (0.010) | (0.007) | (0.010) |
| Log($L_{pt}$) | Yes | Yes | Yes | Yes | Yes |
| Log($C^*_{pt}(L_{pt})$) | Yes | Yes | Yes | Yes | Yes |
| Log($CO_2{}^*_{pt}(L_{pt})$) | Yes | Yes | Yes | Yes | Yes |
| Log($SO_2{}^*_{pt}(L_{pt})$) | Yes | Yes | Yes | Yes | Yes |
| Log($NO_x{}^*_{pt}(L_{pt})$) | Yes | Yes | Yes | Yes | Yes |
| PCA×Month-of-Year FE | Yes | Yes | Yes | Yes | Yes |
| Region×Date×Hour FE | Yes | Yes | Yes | Yes | Yes |
| Event-time dummies | Yes | Yes | Yes | Yes | Yes |
| Neighbor markets | Yes | Yes | Yes | Yes | Yes |
| Clusters | 16,464 | 16,464 | 16,464 | 16,464 | 16,464 |
| PCAs | 98 | 98 | 98 | 98 | 98 |
| Mean | 61.986 | 15.815 | 0.414 | 12.183 | 9.434 |
| $R^2$ | 0.906 | 0.872 | 0.719 | 0.991 | 0.943 |
| Observations | 12,022,807 | 12,022,807 | 12,022,807 | 12,022,807 | 12,022,807 |

*Notes:* Outcomes are expressed in asinh units. Standard errors clustered at the PCA–month level in parentheses. Controls are estimated with PCA–month-of-year specific slopes. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table 5 shows that market adoption shifted the generation mix: coal, nuclear, and renewables expanded, while gas and oil contracted. This compositional shift is central for understanding the emissions results. In particular, the post-adoption increase in coal generation helps explain why $SO_2$ diverges from $CO_2$ and $NO_x$.

Turning from mechanisms to impacts, Table 6 shows deregulation raised total damages by about 0.04 asinh units per PCA–hour. This aggregate effect masks sharp heterogeneity across pollutants. Damages from $SO_2$ rose by 0.11 asinh units, reflecting the shift toward coal-intensive output. By contrast, damages from $CO_2$ and $NO_x$ fell modestly, by 0.05 and 0.03 asinh units, respectively. Because $SO_2$ damages dominate the pollution profile, their increase more than offsets the reductions in other pollutants, producing a clear net rise in total damages.

**Table 6:** Effect of Market Dispatch on Emission Damages (2011 USD)

| | $CO_2$ Damages | $SO_2$ Damages | $NO_x$ Damages | Total Damages |
|---|---|---|---|---|
| Mkt Effect | -0.046*** | 0.111*** | -0.034*** | 0.036*** |
| | (0.007) | (0.017) | (0.011) | (0.012) |
| Intercept | 12.723*** | 13.281*** | 10.531*** | 13.955*** |
| | (0.004) | (0.011) | (0.008) | (0.008) |
| $\text{Log}(L_{pt})$ | Yes | Yes | Yes | Yes |
| $\text{Log}(C^*_{pt}(L_{pt}))$ | Yes | Yes | Yes | Yes |
| $\text{Log}(\text{CO}_2{}^*_{pt}(L_{pt}))$ | Yes | – | – | Yes |
| $\text{Log}(\text{SO}_2{}^*_{pt}(L_{pt}))$ | – | Yes | – | Yes |
| $\text{Log}(\text{NO}_x{}^*_{pt}(L_{pt}))$ | – | – | Yes | Yes |
| PCA×Month-of-Year FE | Yes | Yes | Yes | Yes |
| Region×Date×Hour FE | Yes | Yes | Yes | Yes |
| Event-time dummies | Yes | Yes | Yes | Yes |
| Neighbor markets | Yes | Yes | Yes | Yes |
| Clusters | 16,464 | 16,464 | 16,464 | 16,464 |
| PCAs | 98 | 98 | 98 | 98 |
| Mean | 115,000 | 412,000 | 20,200 | 547,000 |
| $R^2$ | 0.926 | 0.942 | 0.945 | 0.950 |
| Observations | 12,028,128 | 12,028,128 | 12,028,128 | 12,028,128 |

*Notes:* Outcomes are expressed in asinh units. Standard errors clustered at the PCA–month level in parentheses. Controls are estimated with PCA–month-of-year specific slopes. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

As shown in Table 6, after adoption, damages rise by about 0.036 in asinh units, conditional on controls. Because outcomes are modeled in inverse-hyperbolic-sine (IHS) units, the treatment effect on the dollar scale depends on each observation's baseline level, shaped by fixed effects and covariates, and must therefore be back–transformed. We compute the ATT by predicting IHS damages with and without treatment for each adopting PCA–hour, back-transforming both with $\sinh(\cdot)$, taking their difference in dollars, and averaging across treated observations using 1999 load weights consistent with the regression design. Unweighted ATTs, which place equal weight on each PCA, are reported in Appendix Table X and yield similar results.

This procedure yields an ATT of roughly \$21,331 per adopting PCA–hour, equivalent to a 3.9 percent increase relative to the baseline mean of \$546,584. By 2012, the ATT falls to about \$3,272 per adopting PCA–hour, or 0.6 percent of baseline. Annualizing, damages rose by approximately \$11 billion per year in the early years of restructuring (\$21,331 × 8,760 × 60), but only about \$1.7

billion by 2012.

This decline reflects the steep drop in baseline damages, particularly from $SO_2$, as shown in Table 1. The early increase in damages stems from a shift in dispatch toward coal units with higher sulfur intensity, a byproduct of cost–minimization. Over time, however, the grid's fuel mix evolved: gas capacity expanded rapidly, and regulatory controls reduced the sulfur content of coal generation. These changes lowered the marginal damage of dispatch decisions, so that even though markets continued to favor cheap coal, the absolute dollar effect on damages diminished sharply. The trajectory underscores the central role of fuel mix frictions: markets could not easily substitute toward gas in the early years, amplifying $SO_2$ damages, but as gas entry reduced those frictions, the environmental cost of competitive dispatch became much smaller.

Importantly, the annualized dollar effects are robust to how damages are normalized. Using the overall sample mean damages ($547k) yields an estimate of about 4 percent, or $11 billion annually early in the sample, declining to about $1.7 billion by 2012. Using instead the adopter–year means ($2.39 million in 1999 and $676k in 2012) gives relative effects of 0.9 percent and 0.5 percent, respectively, but the implied annual aggregates are nearly identical: about $11.2 billion in 1999 and $1.7 billion in 2012. This stability reflects the offsetting relationship between baseline damages and the treatment effect: when damages were high, the proportional effect was modest, while as baseline damages fell with sulfur controls, the proportional effect shrank but remained large in dollar terms.

In sum, our results highlight a central tradeoff. Market dispatch lowered $CO_2$ and $NO_x$ through efficiency gains, but the trade channel shifted production toward cheaper, coal–intensive plants, driving up $SO_2$. In the early years, when coal's sulfur intensity was highest, this reallocation dominated. As gas capacity expanded and pollution controls tightened, the cost of trade diminished, underscoring how fuel–mix frictions shape the environmental consequences of competitive dispatch.

Because outcomes are modeled in inverse–hyperbolic–sine (IHS) units, a constant treatment effect on the IHS scale does not translate into a constant dollar effect: by the nonlinearity of $\sinh(\cdot)$, the dollar impact depends on each observation's baseline level (which embeds fixed effects and covariates). We therefore obtain the ATT on the response scale by predicting IHS damages with and without treatment for each adopting PCA–hour, back–transforming both with sinh(·), taking the dollar difference, and then averaging across treated observations using 1999 load weights (the same design weights used in estimation). Unweighted ATTs, which give each PCA equal weight, are reported in Appendix Table X and are similar in magnitude. Using this procedure, the overall ATT equals about $21,331 per adopting PCA–hour when averaging unweighted, and $50,714 per adopting PCA–hour when averaging with 1999 load weights; the latter is our preferred, design–consistent estimate. A Duan–style retransformation that carries the IHS residual through both treated and untreated predictions yields virtually identical results.

### A. Heterogeneity

As has been documented in Borenstein and Bushnell (2015), the scope and design of deregulation varied widely across the United States. In the Northeast, Texas, and California, generation was opened more fully to independent power producers, yielding much larger shares of output from non-utility (merchant) generators. By contrast, many southeastern states continued to rely on utility-owned generation. This distinction mattered for incentives: in merchant-heavy regions, generators bore the full risk of market prices and leaned heavily on cheap coal when fuel costs favored it. In utility-dominated regions, where firms could still recover costs from ratepayers, those incentives were muted.

Texas also went further in restructuring the retail sector, more fully separating generation and transmission from sales. This produced a greater share of transactions through competitive retail marketers. Retail choice shifted risk and wholesale price volatility directly onto consumers, while utilities were left primarily as wires companies. The effect was largely on the demand side: retailers procured power in wholesale markets and passed prices through to end users, increasing demand responsiveness to volatility but doing little to change how generators chose fuels or operated plants.

Because deregulation was not a single uniform policy but a patchwork of institutional designs, examining heterogeneity is essential. Table 7 disaggregates the effects of market dispatch by adoption timing, merchant intensity, retail restructuring, and ISO region. This lens helps explain why the environmental consequences of deregulation diverged so sharply across markets. Independent System Operators (ISOs)—the regional entities that run wholesale markets—differ not only in geography and fuel mix but also in institutional structure. The Electric Reliability Council of Texas (ERCOT), the Midcontinent Independent System Operator (MISO), and the Pennsylvania–New Jersey–Maryland Interconnection (PJM) are merchant-heavy and coal-dependent, while ISO New England (ISO-NE), the New York Independent System Operator (NYISO), and the Southwest Power Pool (SPP) rely more on cleaner fuels and face weaker merchant incentives. The combination of merchant and retail shares with regional ISO differences is central to understanding why damages rose sharply in some markets but remained negligible in others.

**Table 7:** Heterogeneity by Market Characteristics on asinh(Total Damages)

| | Estimate |
|---|---|
| **A. Adoption Timing** | |
| Early adopter × Market dispatch | −0.038** |
| | (0.017) |
| Late adopter × Market dispatch | −0.109*** |
| | (0.022) |
| Market dispatch | 0.108*** |
| | (0.017) |
| **B. Merchant Share** | |
| Merchant state × Market dispatch | 0.066*** |
| | (0.025) |
| Market dispatch | −0.001 |
| | (0.025) |
| **C. Retail Share** | |
| Retail restructuring × Market dispatch | 0.021 |
| | (0.015) |
| Market dispatch | 0.045*** |
| | (0.016) |
| **D. By ISO** | |
| ERCOT (Texas) | 0.062*** |
| | (0.020) |
| ISO New England | 0.044 |
| | (0.042) |
| NYISO | −0.010 |
| | (0.028) |
| MISO | 0.115*** |
| | (0.015) |
| PJM | 0.104*** |
| | (0.016) |
| SPP | −0.027 |
| | (0.020) |

*Notes:* Each panel reports a separate weighted regression with the same controls and fixed effects as the main tables. Controls include PCA–month-specific slopes for load, cost, and least-emissions load fundamentals ($CO_2$, $SO_2$, $NO_x$). Standard errors are clustered at the PCA–month level. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

For our heterogeneity analysis we classify PCAs into three adoption groups based on the year they introduced market dispatch. Early adopters are those restructured in 2004 or earlier. The largest wave of reform occurred in 2005–2006, which we treat as the reference category. Late adopters are those restructured in 2007 or later. Panel A of Table 7 shows that early adopters (2004 or earlier) and the large 2005–2006 wave experienced significant increases in damages following deregulation. By contrast, late adopters (2007 or later) show no net effect. This result is not because the interaction is negative, but because the baseline effect is positive and almost exactly cancels the interaction term, leaving the total impact close to zero. In other words, by the time late adopters restructured, the grid had already shifted toward cleaner fuels. The fracking boom and rising renewables eroded coal's cost advantage, so market incentives no longer translated into higher emissions.

Panels B and C of Table 7 show that damage effects are concentrated in merchant-heavy regions. In areas where independent producers face full market risk, market dispatch raises damages by 0.07 asinh units, or about 6–7 percent, a precisely estimated and economically significant effect. In non-merchant regions, where utilities retain cost recovery through regulation, the effect is statistically indistinguishable from zero.

Retail choice exhibits no independent impact. The interaction term is small and imprecise, indicating that competitive retail supply did not amplify environmental costs. The modest positive effect observed in retail states reflects the baseline adoption effect, not retail restructuring itself.

Finally, Panel D highlights stark regional differences. Damages rose by about 0.11 asinh units in MISO and 0.10 in PJM—roughly 10–11 percent increases—both classic merchant-heavy, coal-reliant systems. ERCOT shows a smaller but still meaningful increase of around 6 percent. Strikingly, these are the very same ISOs where Cicala (2022) finds the largest private cost savings from deregulation. In other words, the regions that benefited most on the cost side also bore the largest increases in external damages. By contrast, ISO-NE, NYISO, and SPP exhibit effects that are small and statistically indistinguishable from zero, consistent with their cleaner fuel mixes and less merchant-intensive ownership structures. The pattern is consistent and telling: market dispatch amplified social costs exactly where it delivered the greatest efficiency gains, highlighting the central tradeoff between private and external outcomes.

## VII. Conclusion

Market restructuring in U.S. electricity delivered on its central promise: operating costs fell by about five percent of variable costs (Cicala, 2022). Yet these private savings came at a much higher social cost. External damages rose by three to four percent of baseline levels. In dollar terms, annual cost savings of only \$3–5 billion were offset by an additional \$2–11 billion in pollution damages, driven overwhelmingly by sulfur dioxide.

The core tradeoff is clear: competitive markets reallocated generation toward cheap but sulfur-intensive coal. Efficiency gains lowered $CO_2$ and $NO_x$, yet the damage channel was dominated by $SO_2$, where the health costs of sulfur emissions swamped private cost savings. Markets cut costs, but the savings were purchased with higher damages—adding about \$11 billion in annual pollution costs in the early 2000s and nearly \$2 billion a decade later.

The dominant driver of rising damages was the trade channel, which more than erased the efficiency gains from eliminating out-of-merit generation. Markets did improve operational efficiency, modestly reducing $CO_2$ and $NO_x$. But integration expanded cross-PCA flows, reallocating generation toward the lowest-cost units—disproportionately coal plants. This shift sharply increased $SO_2$, adding about \$11 billion in annual damages in the early 2000s and nearly \$2 billion a decade later. Thus, the very mechanism that delivered private cost savings through trade also produced large environmental losses. The result is a clear welfare reversal: markets lowered costs for producers but imposed far greater costs on society.

The broader lesson is straightforward: market liberalization reallocates resources more efficiently on private margins, but efficiency does not translate into welfare when pollution remains unpriced. To deliver genuine gains, market design must be paired with environmental policy—through carbon pricing, differentiated pollution fees, or dispatch rules that reflect local damages. Otherwise, restructuring risks a perverse outcome: cheaper power on the books, but higher costs to society.

Although our estimates cover 1999–2012, the lesson endures. Today's system is cleaner: coal has declined, gas and renewables have expanded, and federal and state rules have reduced sulfur dioxide and nitrogen oxides. Under this baseline, the incremental damage effects of market dispatch are likely smaller. But carbon remains unpriced, and dispatch still ignores spatial variation in damages. Efficiency gains from market liberalization cannot be mistaken for welfare gains unless environmental externalities are explicitly internalized.

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# Appendix A

## 1Extended Analysis of Deregulation on Economic and Environmental Outcomes

### A.1 Replication of Cicala (2022)

**Table A.1:** Effect of Deregulation on log(Quantities)

A. $Log$(Trade Volume)

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Market Dispatch | 0.168*** | 0.149*** | 0.226*** | 0.245*** |
| | (0.033) | (0.033) | (0.031) | (0.032) |
| $1^{st}$ Neighbor Market Dispatch | | | | 0.060* |
| | | | | (0.036) |
| $2^{nd}$ Neighbor Market Dispatch | | | | 0.009 |
| | | | | (0.032) |
| $Log(L_{pt})$ | | Yes | Yes | Yes |
| $Log(C^*_{pt}(L_{pt}))$ | | | Yes | Yes |
| Clusters | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 |
| $R^2$ | 0.537 | 0.568 | 0.584 | 0.585 |
| Obs. | 12004719 | 12004719 | 12004719 | 12004719 |

B. $Log$(MWh Out of Merit)

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Market Dispatch | -0.075*** | -0.077*** | -0.059*** | -0.059*** |
| | (0.013) | (0.013) | (0.013) | (0.014) |
| $1^{st}$ Neighbor Market Dispatch | | | | -0.012 |
| | | | | (0.016) |
| $2^{nd}$ Neighbor Market Dispatch | | | | 0.021 |
| | | | | (0.014) |
| $Log(L_{pt})$ | | Yes | Yes | Yes |
| $Log(C^*_{pt}(L_{pt}))$ | | | Yes | Yes |
| Clusters | 16443 | 16443 | 16443 | 16443 |
| PCAs | 98 | 98 | 98 | 98 |
| $R^2$ | 0.890 | 0.896 | 0.901 | 0.902 |
| Obs. | 11631620 | 11631620 | 11631620 | 11631620 |

**Table A.2:** Effect of Deregulation on log(Costs), part 1

| A. $Log$(Observed Costs) | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Market Dispatch | –0.082*** | –0.075*** | –0.071*** | –0.076*** |
| | (0.012) | (0.011) | (0.009) | (0.009) |
| $1^{st}$ Neighbor | | | | 0.018** |
| Market Dispatch | | | | (0.009) |
| $2^{nd}$ Neighbor | | | | 0.010 |
| Market Dispatch | | | | (0.008) |
| $Log(L_{pt})$ | | Yes | Yes | Yes |
| $Log(C^*_{pt}(L_{pt}))$ | | | Yes | Yes |
| Clusters | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 |
| $R^2$ | 0.946 | 0.955 | 0.963 | 0.963 |
| Obs. | 11996769 | 11996769 | 11996769 | 11996769 |

| B. $Log$(Gains from Trade) | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Market Dispatch | 0.487*** | 0.501*** | 0.535*** | 0.520*** |
| | (0.070) | (0.071) | (0.067) | (0.066) |
| $1^{st}$ Neighbor | | | | 0.074 |
| Market Dispatch | | | | (0.076) |
| $2^{nd}$ Neighbor | | | | 0.008 |
| Market Dispatch | | | | (0.071) |
| $Log(L_{pt})$ | | Yes | Yes | Yes |
| $Log(C^*_{pt}(L_{pt}))$ | | | Yes | Yes |
| Clusters | 16412 | 16412 | 16412 | 16412 |
| PCAs | 98 | 98 | 98 | 98 |
| $R^2$ | 0.497 | 0.556 | 0.581 | 0.582 |
| Obs. | 8480621 | 8480621 | 8480621 | 8480621 |

**Table A.3:** Effect of Deregulation on log(Costs), part 2

C. $Log$(Out of Merit Costs)

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| Market Dispatch | –0.112*** | –0.100*** | –0.113*** | –0.137*** |
| | (0.027) | (0.027) | (0.024) | (0.025) |
| $1^{st}$ Neighbor | | | | –0.030 |
| Market Dispatch | | | | (0.030) |
| $2^{nd}$ Neighbor | | | | 0.034 |
| Market Dispatch | | | | (0.025) |
| $Log(L_{pt})$ | | Yes | Yes | Yes |
| $Log(C^*_{pt}(L_{pt}))$ | | | Yes | Yes |
| Clusters | 16441 | 16441 | 16441 | 16441 |
| PCAs | 98 | 98 | 98 | 98 |
| $R^2$ | 0.857 | 0.866 | 0.876 | 0.876 |
| Obs. | 11621656 | 11621656 | 11621656 | 11621656 |

Note: All specifications include PCA-Month of Year and Region-Date-Hour fixed effects. Controls for the logarithm of load $L_{pt}$ and its merit order cost $C^*_{pt}(L_{pt})$ are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. * p¡0.1, ** p¡0.05, *** p¡0.01

## A.2 Sensitivity of Main Estimates to Changes in Empirical Model

### A.2.1 $CO_2$, asinh (tons)

**Table A.4:** Observed generation $CO_2$ emissions (tons)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.004 | 0.065*** | 0.080*** | 0.032*** | 0.032*** | -0.043*** | -0.049*** | -0.049*** |
| | (0.033) | (0.007) | (0.006) | (0.005) | (0.005) | (0.006) | (0.007) | (0.007) |
| Intercept | 9.080*** | 9.076*** | 9.075*** | 9.078*** | 9.078*** | 9.084*** | 9.084*** | 9.067*** |
| | (0.013) | (0.002) | (0.002) | (0.002) | (0.002) | (0.002) | (0.001) | (0.004) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 2942.362 | 2942.362 | 2942.362 | 2942.362 | 2942.362 | 2942.362 | 2942.362 | 2942.362 |
| $R^2$ | 0.000 | 0.930 | 0.935 | 0.939 | 0.939 | 0.942 | 0.951 | 0.951 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.5:** Gains From Trade, $CO_2$ (tons)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.738*** | 0.707*** | 0.890*** | 0.637*** | 0.637*** | -0.010 | 0.204* | 0.163 |
| | (0.152) | (0.091) | (0.086) | (0.085) | (0.085) | (0.097) | (0.116) | (0.124) |
| Intercept | 2.724*** | 2.726*** | 2.712*** | 2.732*** | 2.732*** | 2.781*** | 2.764*** | 2.567*** |
| | (0.045) | (0.026) | (0.024) | (0.023) | (0.023) | (0.023) | (0.019) | (0.077) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 150.492 | 150.492 | 150.492 | 150.492 | 150.492 | 150.492 | 150.492 | 150.492 |
| $R^2$ | 0.001 | 0.394 | 0.415 | 0.433 | 0.433 | 0.436 | 0.551 | 0.551 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.6:** Observed vs. Least $CO_2$ (tons)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.012 | 0.126*** | 0.116*** | 0.049*** | 0.049*** | -0.056*** | -0.101*** | -0.087*** |
| | (0.039) | (0.011) | (0.011) | (0.009) | (0.009) | (0.011) | (0.013) | (0.013) |
| Intercept | 7.914*** | 7.906*** | 7.906*** | 7.911*** | 7.911*** | 7.919*** | 7.923*** | 7.896*** |
| | (0.017) | (0.004) | (0.004) | (0.003) | (0.003) | (0.003) | (0.002) | (0.009) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 991.331 | 991.331 | 991.331 | 991.331 | 991.331 | 991.331 | 991.331 | 991.331 |
| $R^2$ | 0.000 | 0.880 | 0.898 | 0.920 | 0.920 | 0.923 | 0.935 | 0.935 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.7:** Least Cost vs. Least $CO_2$ (tons)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.183*** | 0.250*** | 0.273*** | 0.174*** | 0.174*** | -0.072*** | -0.077*** | -0.060** |
| | (0.044) | (0.021) | (0.022) | (0.021) | (0.021) | (0.026) | (0.028) | (0.028) |
| Intercept | 7.545*** | 7.539*** | 7.538*** | 7.545*** | 7.545*** | 7.564*** | 7.564*** | 7.505*** |
| | (0.020) | (0.010) | (0.009) | (0.008) | (0.008) | (0.007) | (0.005) | (0.016) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 857.833 | 857.833 | 857.833 | 857.833 | 857.833 | 857.833 | 857.833 | 857.833 |
| $R^2$ | 0.001 | 0.705 | 0.736 | 0.760 | 0.760 | 0.789 | 0.852 | 0.852 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

### A.2.2 $SO_2$, asinh (pounds)

**Table A.8:** Observed generation $SO_2$ (pounds)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.366*** | 0.332*** | 0.424*** | 0.168*** | 0.168*** | -0.108*** | 0.084*** | 0.087*** |
| | (0.061) | (0.022) | (0.023) | (0.015) | (0.015) | (0.014) | (0.016) | (0.017) |
| Intercept | 10.532*** | 10.535*** | 10.528*** | 10.547*** | 10.547*** | 10.568*** | 10.554*** | 10.472*** |
| | (0.024) | (0.009) | (0.009) | (0.007) | (0.007) | (0.005) | (0.004) | (0.011) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 20580.319 | 20580.319 | 20580.319 | 20580.319 | 20580.319 | 20580.319 | 20580.319 | 20580.319 |
| $R^2$ | 0.002 | 0.841 | 0.859 | 0.888 | 0.888 | 0.908 | 0.934 | 0.934 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.9:** Gains From Trade, $SO_2$ (pounds)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.741*** | 0.134 | 0.435*** | -0.067 | -0.067 | -0.646*** | -0.561*** | -0.799*** |
| | (0.276) | (0.155) | (0.149) | (0.137) | (0.137) | (0.170) | (0.205) | (0.212) |
| Intercept | 0.288*** | 0.334*** | 0.312*** | 0.350*** | 0.350*** | 0.394*** | 0.387*** | -0.016 |
| | (0.068) | (0.043) | (0.041) | (0.039) | (0.039) | (0.039) | (0.033) | (0.117) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 39.748 | 39.748 | 39.748 | 39.748 | 39.748 | 39.748 | 39.748 | 39.748 |
| $R^2$ | 0.001 | 0.296 | 0.317 | 0.342 | 0.342 | 0.344 | 0.465 | 0.466 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.10:** Observed vs. Least $SO_2$ (pounds)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.385*** | 0.352*** | 0.421*** | 0.193*** | 0.193*** | -0.103*** | 0.021 | 0.026 |
| | (0.060) | (0.021) | (0.022) | (0.015) | (0.015) | (0.015) | (0.018) | (0.018) |
| Intercept | 10.357*** | 10.360*** | 10.355*** | 10.372*** | 10.372*** | 10.394*** | 10.385*** | 10.314*** |
| | (0.025) | (0.009) | (0.008) | (0.007) | (0.007) | (0.005) | (0.004) | (0.012) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 16797.921 | 16797.921 | 16797.921 | 16797.921 | 16797.921 | 16797.921 | 16797.921 | 16797.921 |
| $R^2$ | 0.003 | 0.847 | 0.860 | 0.884 | 0.884 | 0.903 | 0.926 | 0.926 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

Table A.11: Least Cost vs. Least $SO_2$ (pounds)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.674*** | 0.561*** | 0.736*** | 0.454*** | 0.454*** | -0.131*** | 0.137*** | 0.120*** |
| | (0.067) | (0.034) | (0.044) | (0.043) | (0.043) | (0.035) | (0.039) | (0.041) |
| Intercept | 9.923*** | 9.931*** | 9.918*** | 9.939*** | 9.939*** | 9.984*** | 9.963*** | 9.896*** |
| | (0.033) | (0.020) | (0.018) | (0.016) | (0.016) | (0.013) | (0.009) | (0.028) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 14877.107 | 14877.107 | 14877.107 | 14877.107 | 14877.107 | 14877.107 | 14877.107 | 14877.107 |
| $R^2$ | 0.005 | 0.590 | 0.634 | 0.686 | 0.686 | 0.747 | 0.844 | 0.844 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

### A.2.3 $NO_x$, asinh (pounds)

**Table A.12:** Observed generation $NO_x$ (pounds)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.120*** | 0.265*** | 0.361*** | 0.094*** | 0.094*** | -0.169*** | -0.037*** | -0.047*** |
| | (0.042) | (0.018) | (0.017) | (0.010) | (0.010) | (0.010) | (0.012) | (0.012) |
| Intercept | 9.898*** | 9.887*** | 9.879*** | 9.900*** | 9.900*** | 9.920*** | 9.909*** | 9.869*** |
| | (0.017) | (0.007) | (0.006) | (0.004) | (0.004) | (0.003) | (0.002) | (0.008) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 8347.355 | 8347.355 | 8347.355 | 8347.355 | 8347.355 | 8347.355 | 8347.355 | 8347.355 |
| $R^2$ | 0.001 | 0.801 | 0.837 | 0.904 | 0.904 | 0.918 | 0.937 | 0.937 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.13:** Gains from Trade $NO_x$ (pounds)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | -0.325 | -0.376*** | -0.294** | -0.400*** | -0.400*** | -0.262 | -0.871*** | -0.763*** |
| | (0.264) | (0.143) | (0.150) | (0.143) | (0.143) | (0.185) | (0.234) | (0.235) |
| Intercept | 1.291*** | 1.295*** | 1.289*** | 1.297*** | 1.297*** | 1.287*** | 1.333*** | 1.148*** |
| | (0.062) | (0.036) | (0.033) | (0.030) | (0.030) | (0.032) | (0.030) | (0.118) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 288.280 | 288.280 | 288.280 | 288.280 | 288.280 | 288.280 | 288.280 | 288.280 |
| $R^2$ | 0.000 | 0.350 | 0.372 | 0.396 | 0.396 | 0.399 | 0.502 | 0.502 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.14:** Observed vs Least $NO_x$, $NO_x$ (pounds)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.108** | 0.288*** | 0.353*** | 0.138*** | 0.138*** | -0.166*** | -0.071*** | -0.078*** |
| | (0.043) | (0.015) | (0.015) | (0.012) | (0.012) | (0.013) | (0.017) | (0.017) |
| Intercept | 9.442*** | 9.428*** | 9.424*** | 9.440*** | 9.440*** | 9.463*** | 9.456*** | 9.451*** |
| | (0.017) | (0.006) | (0.006) | (0.004) | (0.004) | (0.004) | (0.003) | (0.010) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 5034.021 | 5034.021 | 5034.021 | 5034.021 | 5034.021 | 5034.021 | 5034.021 | 5034.021 |
| $R^2$ | 0.000 | 0.812 | 0.831 | 0.868 | 0.868 | 0.884 | 0.908 | 0.908 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.15:** Least Cost vs Least $NO_x$, $NO_x$ (pounds)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.289*** | 0.412*** | 0.554*** | 0.200*** | 0.200*** | -0.154*** | 0.069** | 0.051 |
| | (0.048) | (0.023) | (0.028) | (0.022) | (0.022) | (0.029) | (0.032) | (0.033) |
| Intercept | 9.064*** | 9.055*** | 9.044*** | 9.071*** | 9.071*** | 9.098*** | 9.081*** | 9.045*** |
| | (0.022) | (0.013) | (0.012) | (0.010) | (0.010) | (0.008) | (0.006) | (0.021) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 4488.705 | 4488.705 | 4488.705 | 4488.705 | 4488.705 | 4488.705 | 4488.705 | 4488.705 |
| $R^2$ | 0.002 | 0.575 | 0.617 | 0.702 | 0.702 | 0.741 | 0.822 | 0.822 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

### A.2.4 Fuel Shares, asinh

**Table A.16:** Coal Generation Share

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.395*** | 0.218*** | 0.265*** | 0.046*** | 0.046*** | -0.042** | 0.062*** | 0.051*** |
| | (0.040) | (0.017) | (0.020) | (0.014) | (0.014) | (0.017) | (0.018) | (0.018) |
| Intercept | 4.096*** | 4.110*** | 4.106*** | 4.123*** | 4.123*** | 4.129*** | 4.122*** | 4.081*** |
| | (0.016) | (0.009) | (0.008) | (0.006) | (0.006) | (0.005) | (0.003) | (0.011) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 61.986 | 61.986 | 61.986 | 61.986 | 61.986 | 61.986 | 61.986 | 61.986 |
| $R^2$ | 0.006 | 0.707 | 0.733 | 0.828 | 0.828 | 0.851 | 0.906 | 0.906 |
| Obs. | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.17:** Gas Generation Share

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | -0.315*** | -0.233*** | -0.299*** | -0.114*** | -0.114*** | 0.043 | -0.143*** | -0.120*** |
| | (0.077) | (0.029) | (0.034) | (0.032) | (0.032) | (0.030) | (0.034) | (0.036) |
| Intercept | 1.999*** | 1.993*** | 1.998*** | 1.984*** | 1.984*** | 1.972*** | 1.987*** | 1.971*** |
| | (0.024) | (0.015) | (0.014) | (0.010) | (0.010) | (0.009) | (0.006) | (0.019) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 15.815 | 15.815 | 15.815 | 15.815 | 15.815 | 15.815 | 15.815 | 15.815 |
| $R^2$ | 0.002 | 0.658 | 0.686 | 0.770 | 0.770 | 0.784 | 0.872 | 0.872 |
| Obs. | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.18:** Oil Generation Share

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.197*** | 0.199*** | 0.227*** | -0.040* | -0.040* | -0.122*** | -0.065** | -0.056** |
| | (0.041) | (0.032) | (0.033) | (0.020) | (0.020) | (0.029) | (0.026) | (0.028) |
| Intercept | 0.131*** | 0.130*** | 0.128*** | 0.149*** | 0.149*** | 0.155*** | 0.150*** | 0.096*** |
| | (0.007) | (0.006) | (0.006) | (0.004) | (0.004) | (0.004) | (0.004) | (0.010) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 0.414 | 0.414 | 0.414 | 0.414 | 0.414 | 0.414 | 0.414 | 0.414 |
| $R^2$ | 0.007 | 0.297 | 0.336 | 0.591 | 0.591 | 0.604 | 0.718 | 0.719 |
| Obs. | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.19:** Nuclear Generation Share

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | -0.038 | 0.046*** | 0.047*** | -0.012 | -0.012 | 0.016 | 0.034** | 0.028* |
| | (0.065) | (0.010) | (0.011) | (0.009) | (0.009) | (0.012) | (0.016) | (0.016) |
| Intercept | 2.937*** | 2.931*** | 2.931*** | 2.936*** | 2.936*** | 2.933*** | 2.932*** | 2.950*** |
| | (0.020) | (0.005) | (0.004) | (0.002) | (0.002) | (0.002) | (0.002) | (0.007) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 12.183 | 12.183 | 12.183 | 12.183 | 12.183 | 12.183 | 12.183 | 12.183 |
| $R^2$ | 0.000 | 0.970 | 0.972 | 0.988 | 0.988 | 0.989 | 0.991 | 0.991 |
| Obs. | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.20:** Renewables Generation Share

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | -0.313*** | -0.141*** | -0.174*** | -0.070*** | -0.070*** | 0.102*** | 0.151*** | 0.157*** |
| | (0.059) | (0.016) | (0.018) | (0.013) | (0.013) | (0.015) | (0.019) | (0.020) |
| Intercept | 1.700*** | 1.687*** | 1.690*** | 1.682*** | 1.682*** | 1.669*** | 1.665*** | 1.735*** |
| | (0.016) | (0.005) | (0.005) | (0.003) | (0.003) | (0.003) | (0.003) | (0.010) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 9.434 | 9.434 | 9.434 | 9.434 | 9.434 | 9.434 | 9.434 | 9.434 |
| $R^2$ | 0.003 | 0.847 | 0.859 | 0.923 | 0.923 | 0.926 | 0.943 | 0.943 |
| Obs. | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 | 12022807 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

### A.2.5 Damages, asinh

**Table A.21:** Observed Total Damage

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.212*** | 0.223*** | 0.295*** | 0.042*** | 0.042*** | -0.082*** | 0.048*** | 0.036*** |
| | (0.052) | (0.015) | (0.015) | (0.008) | (0.008) | (0.008) | (0.011) | (0.012) |
| Intercept | 14.020*** | 14.020*** | 14.014*** | 14.033*** | 14.033*** | 14.043*** | 14.033*** | 13.955*** |
| | (0.021) | (0.006) | (0.006) | (0.003) | (0.003) | (0.003) | (0.002) | (0.008) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 5.47e+05 | 5.47e+05 | 5.47e+05 | 5.47e+05 | 5.47e+05 | 5.47e+05 | 5.47e+05 | 5.47e+05 |
| $R^2$ | 0.001 | 0.880 | 0.894 | 0.931 | 0.931 | 0.936 | 0.950 | 0.950 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.22:** Observed $CO_2$ Damage

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.009 | 0.065*** | 0.081*** | 0.032*** | 0.032*** | -0.042*** | -0.045*** | -0.046*** |
| | (0.033) | (0.007) | (0.006) | (0.005) | (0.005) | (0.006) | (0.007) | (0.007) |
| Intercept | 12.738*** | 12.734*** | 12.733*** | 12.737*** | 12.737*** | 12.742*** | 12.743*** | 12.723*** |
| | (0.013) | (0.002) | (0.002) | (0.002) | (0.002) | (0.002) | (0.002) | (0.004) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 1.15e+05 | 1.15e+05 | 1.15e+05 | 1.15e+05 | 1.15e+05 | 1.15e+05 | 1.15e+05 | 1.15e+05 |
| $R^2$ | 0.000 | 0.902 | 0.909 | 0.913 | 0.913 | 0.915 | 0.926 | 0.926 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.23:** Observed $SO_2$ Damage

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.428*** | 0.324*** | 0.429*** | 0.170*** | 0.170*** | -0.106*** | 0.109*** | 0.111*** |
| | (0.064) | (0.022) | (0.023) | (0.014) | (0.014) | (0.014) | (0.016) | (0.017) |
| Intercept | 13.359*** | 13.367*** | 13.359*** | 13.378*** | 13.378*** | 13.399*** | 13.383*** | 13.281*** |
| | (0.027) | (0.009) | (0.009) | (0.007) | (0.007) | (0.005) | (0.004) | (0.011) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 4.12e+05 | 4.12e+05 | 4.12e+05 | 4.12e+05 | 4.12e+05 | 4.12e+05 | 4.12e+05 | 4.12e+05 |
| $R^2$ | 0.003 | 0.864 | 0.879 | 0.903 | 0.903 | 0.919 | 0.942 | 0.942 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

**Table A.24:** Observed $NO_x$ Damage

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.167*** | 0.247*** | 0.344*** | 0.083*** | 0.083*** | -0.176*** | -0.025** | -0.034*** |
| | (0.048) | (0.018) | (0.017) | (0.009) | (0.009) | (0.010) | (0.011) | (0.011) |
| Intercept | 10.562*** | 10.556*** | 10.549*** | 10.569*** | 10.569*** | 10.588*** | 10.577*** | 10.531*** |
| | (0.018) | (0.007) | (0.006) | (0.003) | (0.003) | (0.003) | (0.002) | (0.008) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 20238.248 | 20238.248 | 20238.248 | 20238.248 | 20238.248 | 20238.248 | 20238.248 | 20238.248 |
| $R^2$ | 0.001 | 0.835 | 0.864 | 0.917 | 0.917 | 0.928 | 0.945 | 0.945 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

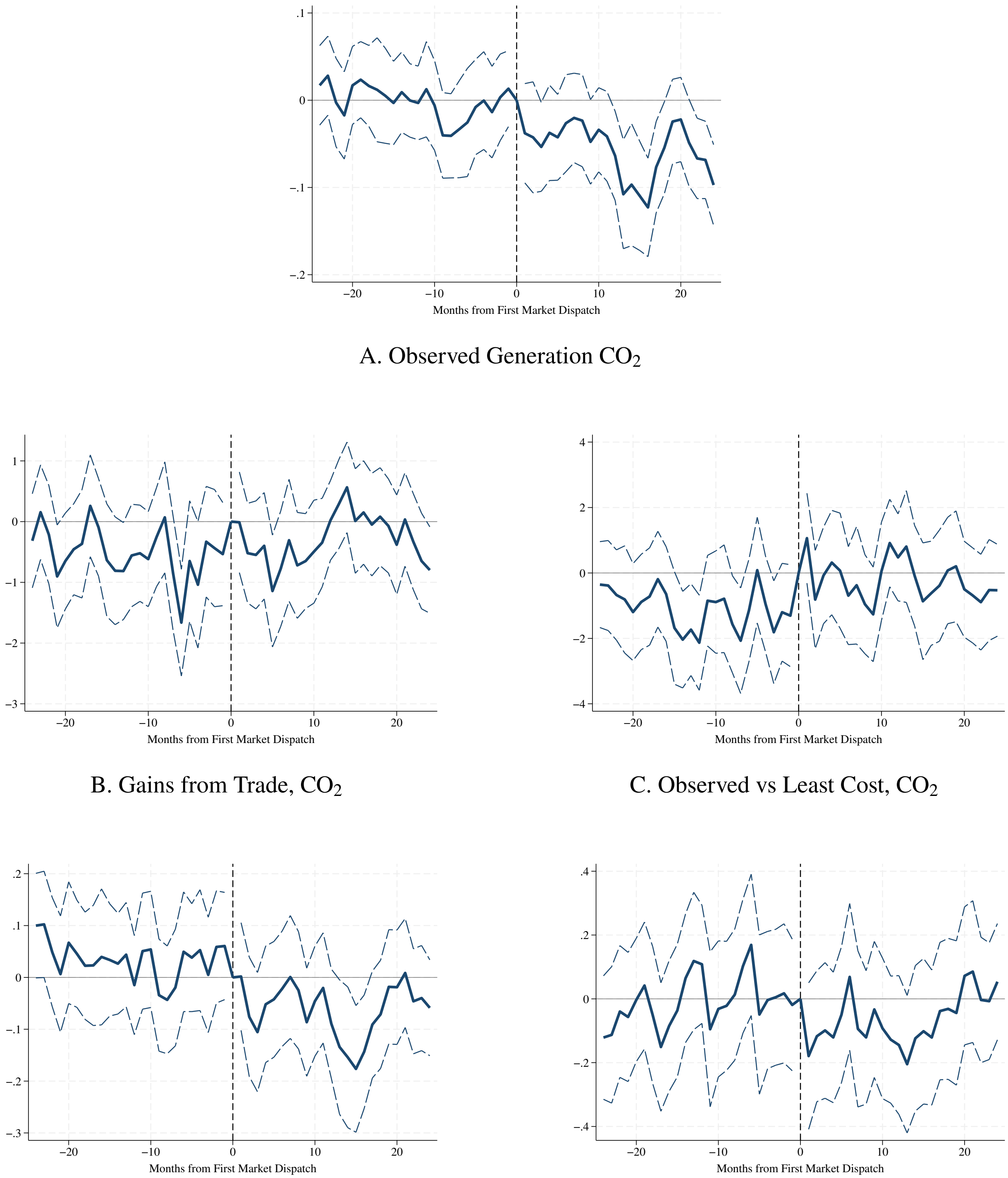
**Table A.25:** Observed Total Damage

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Market Dispatch | 0.212*** | 0.223*** | 0.295*** | 0.042*** | 0.042*** | -0.082*** | 0.048*** | 0.036*** |
| | (0.052) | (0.015) | (0.015) | (0.008) | (0.008) | (0.008) | (0.011) | (0.012) |
| Intercept | 14.020*** | 14.020*** | 14.014*** | 14.033*** | 14.033*** | 14.043*** | 14.033*** | 13.955*** |
| | (0.021) | (0.006) | (0.006) | (0.003) | (0.003) | (0.003) | (0.002) | (0.008) |
| $Log(L_{pt})$ | | X | X | X | X | X | X | X |
| $Log(C^*_{pt}(L_{pt}))$ | | | X | X | X | X | X | X |
| $Log(E^*_{pt}(L_{pt}))$ | | | | X | X | X | X | X |
| PCA-Month | | | | | X | X | X | X |
| Treatment-Dummy | | | | | | X | X | X |
| Datetime-Region | | | | | | | X | X |
| neighbor-mkts | | | | | | | | X |
| Clusters | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 | 16464 |
| PCAs | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| Mean | 5.47e+05 | 5.47e+05 | 5.47e+05 | 5.47e+05 | 5.47e+05 | 5.47e+05 | 5.47e+05 | 5.47e+05 |
| $R^2$ | 0.001 | 0.880 | 0.894 | 0.931 | 0.931 | 0.936 | 0.950 | 0.950 |
| Obs. | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 | 12028128 |

Controls for the logarithm of load ($L_{pt}$), its merit order cost ($C^*_{pt}(L_{pt})$) and its emission merit order emission ($E^*_{pt}(L_{pt})$)are estimated with separate slopes by PCA-Month of Year. Standard errors clustered by PCA-Month in parentheses. All models use 1999 load weights and cluster by PCA Month of the Year. * p¡0.1, ** p¡0.05, *** p¡0.01

## A.3 Additional Event Study Figures

**Figure A.1:** Effect of Deregulation on $CO_2$ Emissions by Time to Event




A. Observed Generation $CO_2$

B. Gains from Trade, $CO_2$

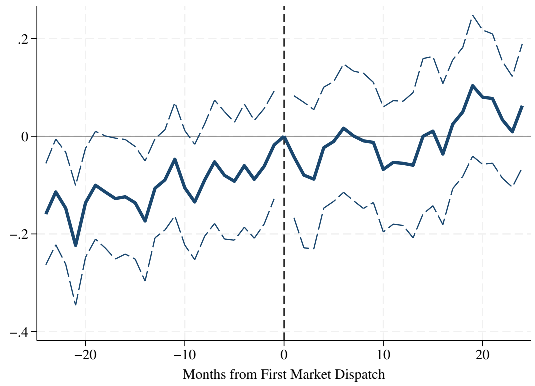
C. Observed vs Least Cost, $CO_2$

D. Observed vs Least $CO_2$, $CO_2$

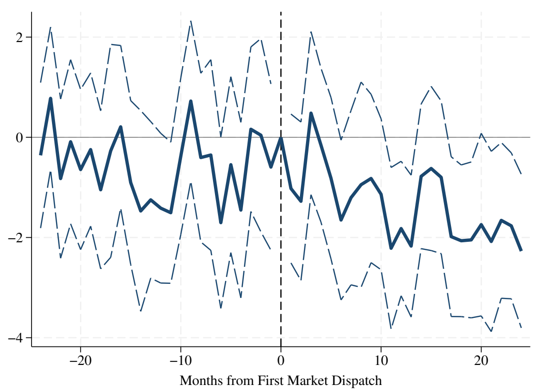
E. Least Cost vs Least $CO_2$, $CO_2$

Notes:

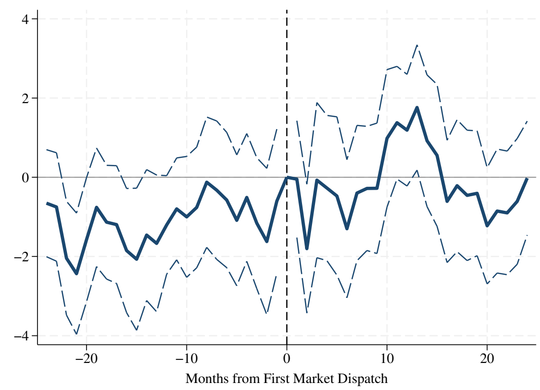
**Figure A.2:** Effect of Deregulation on $SO_2$ Emissions by Time to Event



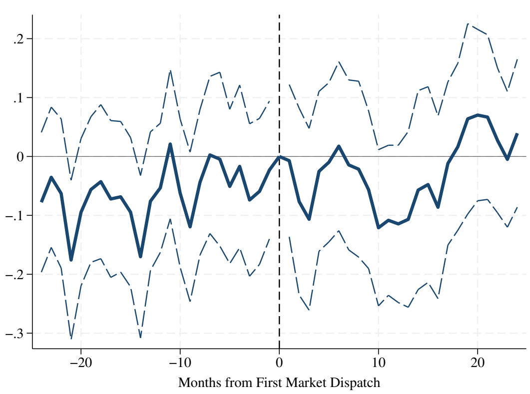

A. Observed Generation $SO_2$



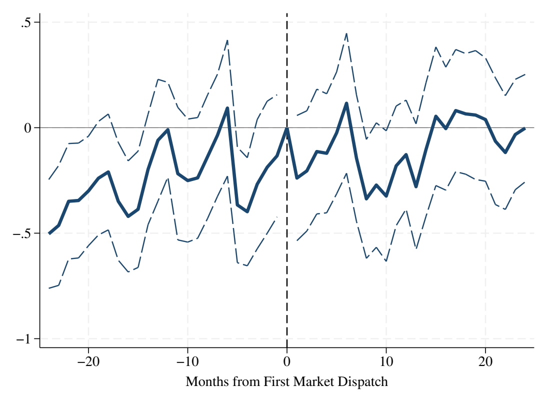

B. Gains from Trade $SO_2$




C. Observed vs Least Cost, $SO_2$



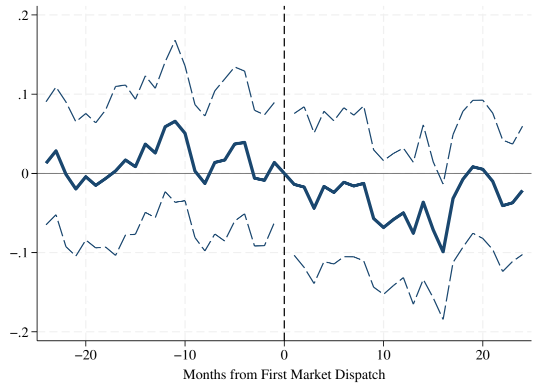

D. Observed vs Least $SO_2$, $SO_2$



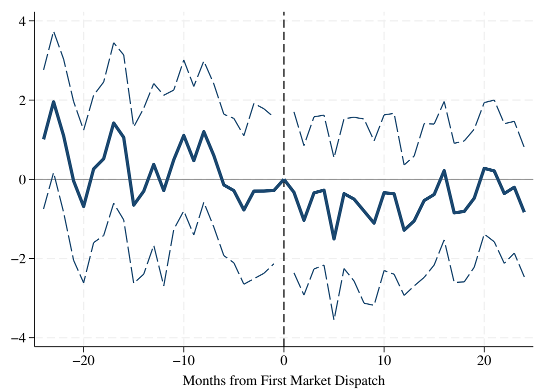

E. Least Cost vs Least $SO_2$, $SO_2$

Notes:

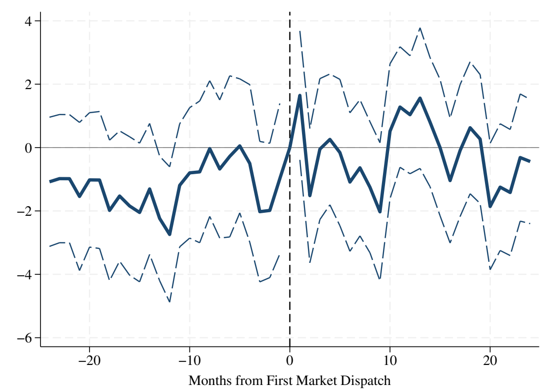
**Figure A.3:** Effect of Deregulation on $NO_x$ Emissions by Time to Event



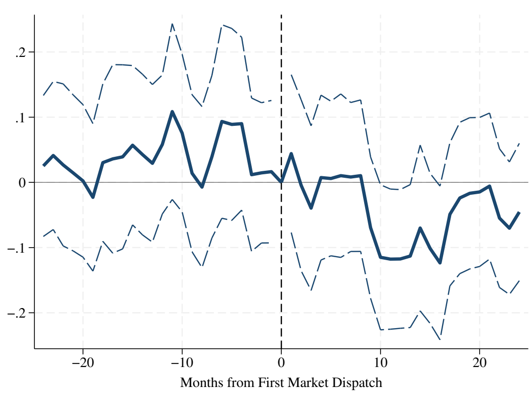

A. Observed Generation $NO_x$



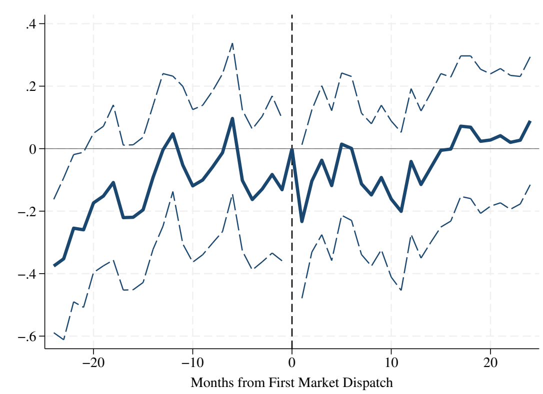

B. Gains from Trade $NO_x$




C. Observed vs Least Cost, $NO_x$




D. Observed vs Least $NO_x$, $NO_x$




E. Least Cost vs Least $NO_x$, $NO_x$

Notes: