

# The Efficiency and Environmental Impacts of Market Organization: Evidence from the Texas Electricity Market

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November 2019

## Abstract

This paper examines the effect of market organization on efficiency and emissions in wholesale electricity markets. Taking advantage of Texas' transition from a decentralized bilateral trading market to a centralized auction market, we find that information aggregation has a positive effect on market efficiency that dominates any change in market power incentives. Specifically, we show that in the nine months following the transition, high-cost generators are displaced by low-cost generators in production, leading to annual cost savings of ~\$59 million relative to the counterfactual. Although the centralized market reduces generation costs, it also has an unintended effect on pollution emissions. For moderate marginal damage estimates, we find the increase in external costs of emissions completely offsets the productive efficiency gain.

**Keywords:** Market Design; Electricity Markets; Congestion Externality; Market Power; Emissions

**JEL Classification Numbers:** L51, L94, Q41, Q51

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# 1 Introduction

How markets are organized is an important determinant of market performance. For many commodities and financial assets, markets can be organized in two basic forms: a decentralized market where transactions are conducted through private negotiations, and a centralized market where trades are intermediated by a central coordinator. For example, stocks and bonds may be traded both over-the-counter and through centralized exchanges. Given the possibility of different market forms, it is important to understand their relative merits. Starting with Wolinsky’s (1990) seminal article, several theoretical studies have modeled different market forms across dimensions such as asymmetric information, search frictions, and market power (e.g., Dewatripont and Maskin (1995), Acharya and Bisin (2014), Glode and Opp (2016)). However, these studies do not provide a clear consensus regarding which market is more efficient, as results depends on the finer details of their models.

This paper adds insight into this question by providing empirical evidence on the relationship between market organization and efficiency. To do so, we focus on the US electric sector. Over the past 20 years, this sector has undergone drastic reform. Seventeen states, plus the District of Columbia, have unbundled electric generation and retail service from transmission and distribution. In these restructured states, the wholesale electricity market takes the form of either a decentralized bilateral trading market or a centralized auction market. While a bilateral trading market relies largely on individual firms to make private transactions and dispatch decisions, a centralized market relies largely on a system operator to make scheduling and dispatch decisions based on generator bids. Among both policy-makers and academics, the question of which market design supports a more efficient and competitive wholesale power market has sparked significant debate (Hogan, 1995).

We focus on the wholesale electricity market in Texas which transitioned from a bilateral trading market to a centralized market on December 1, 2010.<sup>1</sup> We examine how this market redesign affects market efficiency and social welfare. On one hand, a centralized market may improve market efficiency through information aggregation.<sup>2</sup> An important feature of the electricity market is the presence of network externalities. It is difficult for market partic-

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<sup>1</sup>Note that, like many electricity market restructurings and redesigns, Texas’s redesign featured some unique characteristics. Chief among these is that prices were no longer set in a small number of “zones,” but instead at a large number of “nodes.” Redesigns that are closer to Texas’s experience will have greater comparability.

<sup>2</sup>In studying financial markets, Acharya and Bisin (2014) propose a model in which a lack of transparency regarding trade positions leads to a counterparty risk externality. They also conclude that a centralized market improves efficiency by aggregating information about these trades.

ipants to resolve this externality in a bilateral way, due to limited information processed by each participant about others' production schedules. In contrast, a centralized market's system operator can utilize its position to aggregate information from all generating units and minimize bid-based costs. On the other hand, a centralized market may reduce efficiency if it exacerbates firms' incentive to exercise market power. In a multi-unit auction, firms have the incentive to withhold their capacity or submit bids in excess of marginal costs to inflate market-clearing prices. Indeed, evidence of high price-cost margins has been found in other electricity markets.<sup>3</sup> Whether a centralized market yields a more efficient outcome remains an open question. Moreover, changes in market organization may also affect pollution emissions through reallocation of generating quantities among different resources. For social welfare analysis, these environmental impacts should also be taken into account along with the efficiency impact.

The core of this paper exploits hourly unit-level generation data to estimate the effect of the market redesign on generation allocation among units. The overnight change provides an opportunity to estimate the effect without contamination from changes in other aspects of the market such as generation capacity, technology and transmission capacity. These factors stayed the same within a short period preceding and following the redesign. However, demand levels and fuel prices did change even within a short window of time. We therefore rely on an econometric approach relating unit-level generation quantity to demand and fuel prices to create a credible counterfactual of generation outcomes without the market redesign. We estimate this relationship semi-parametrically and separately for the pre-redesign and post-redesign periods, and then use the estimates from the pre-redesign period to construct the counterfactual allocation for the post-redesign period. This approach allows for considerable flexibility and avoids the needs to model the complex grid and firm behavior in detail. With the estimated changes in generation quantity for each unit and their cost and emission information, we calculate the overall cost and emission changes in this market.

The primary finding of this paper is that ERCOT's centralized market redesign improves productive efficiency. The market redesign leads to changes in generation allocation among resources of different marginal costs. As low-cost thermal generators, coal plants as a whole produce 526 more MWh per hour, which is a 3% increase in overall coal capacity utilization.

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<sup>3</sup>See Joskow and Kahn (2002) and Borenstein et al (2002) for evidence of market power in the California market. A growing body of research has also examined the role of transmission constraints and found that congestion adds an additional layer to the complexity of the market and thus opens up more opportunities for gaming. See Cardell et al (1997), Borenstein et al (2000), Joskow and Tirole (2000), Wolak (2015) and Ryan (2017).

The increase is significant at all levels of demand. For mid-cost combined-cycle natural gas generators, generation decreases when demand is low, which is consistent with the increase in coal. But when demand is high, there is no significant change for combined-cycle generators, while the effect on high-cost gas generators, i.e. combustion turbines and steam turbines, emerges. Specifically, generation from steam turbines decreases while generation from combustion turbines increases. Overall, our results show that high-cost generators are displaced by low-cost generators in the centralized market. Accordingly, the average hourly generation cost is estimated to be \$6,749 lower than what would have been, for the nine months post redesign. This amounts to annual cost savings of \$59.1 million, or a 1.5% decrease in total generation costs. These findings suggest that the benefits from information aggregation outweigh potential market power changes associated with the move to a centralized market.

While our results indicate a productive efficiency gain from the transition to a centralized market, we also find a negative environmental impact from this transition. Specifically, we find that the increase in coal-based generation leads to an increase in carbon dioxide ( $\text{CO}_2$ ) emissions by 322 tons per hour or 1.3 percent. Applying different estimates of the social cost of carbon from the EPA (2016), we find that the increase in external costs of  $\text{CO}_2$  emissions completely offsets the private efficiency gain for moderate estimates of the social cost. The market redesign also introduces changes in sulfur dioxide ( $\text{SO}_2$ ) and nitrogen oxides ( $\text{NO}_x$ ) emissions, with large increases in damage from sulfur dioxide. Overall, because external emissions costs were not considered in the market redesign, we find it is welfare-reducing.

This paper builds on and contributes to the market design literature, especially in the context of the electricity industry. Joskow (1997), Joskow (2000), Wilson (2002), and Borenstein and Bushnell (2015) provide an overview of the architecture of this industry and some of the tradeoffs involved in restructuring.<sup>4</sup> Additionally, Kleit and Reitzes (2008), examining federal transmission policy, find that larger and more integrated markets are more efficient. This is in line with the objective of the ERCOT redesign.

More recently, Mansur and White (2012) and Cicala (2017) provide some evidence on the relative performance of different organizational forms. Both studies estimate the gains from trade due to expansion of centralized electricity markets. This paper differs from their work in several important ways. First, we focus on a context where a market transition does

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<sup>4</sup>In particular, Borenstein and Bushnell (2015) note that “studies of plant-level impacts of restructuring have either focused on its impact on regulated plants or were limited to a focus on the few performance variables that continue to be reported for deregulated plants.” We advance the literature by analyzing all plants within ERCOT and aim to comprehensively include marginal costs.

not involve any boundary change. This setting helps rule out the possibility that trading is impeded by administrative barriers across markets other than imperfect information related to network externality. Second, to the best of our knowledge, this is the first paper examining the environmental consequences of electricity market design. As our results suggest, these environmental impacts are critical for welfare evaluation. Third, we use an econometric approach that allows for considerable flexibility and requires no explicit assumptions on firm behavior or the grid. This contrasts with Mansur and White (2012), which assumes away the presence of market power in their framework. Finally, our study provides a more nuanced understanding of the heterogeneous effects of market design across both generators and demand levels.

The rest of the paper is organized as follows. Section 2 presents an overview of the US electricity market. Section 3 provides an example to illustrate how network externality, information aggregation, and market power can impact market efficiency. Section 4 discusses the data while Section 5 presents our empirical strategy. Section 6 presents our findings. We then provide a discussion of the results in Section 7 and conclude in Section 8.

## 2 Background

In this section we provide a brief overview of electricity market features that necessitate the adoption of independent system operators. We also discuss the market design of this industry, including the role of independent system operators under different organizational forms. We then introduce the event this study focuses on – a redesign of the Texas electricity market.

### 2.1 Electricity Market Basics

Electricity markets have several unique characteristics. First, the demand for electricity varies widely from hour to hour and day to day, but it is almost perfectly inelastic in the short-run. Very few consumers are willing and able to adjust their consumption in response to wholesale electricity price fluctuations. Second, electricity cannot be stored in meaningful quantities. This requires constant real-time balance between electricity generation and consumption. Sufficient imbalances between the two can cause brownouts (a drop in electrical frequency), blackouts (complete loss of electrical service), or damage to infrastructure. Third, unlike railroad networks where a supplier can designate a path for delivery, electric power flows through transmission networks according to physical laws (most relevantly,

Kirchhoff’s Laws) rather than from individual sellers to individual buyers. Finally, the entire transmission network must meet certain physical constraints regarding frequency, voltage, and capacity to ensure grid reliability.

Because of these attributes, proper functioning of the electricity market requires coordination among market participants. In the US, the entire electricity market is segmented into smaller power control areas.<sup>5</sup> Within each power control area, an entity known as the “balancing authority” ensures both load-generation balance and reliability of the grid. Traditionally, vertically integrated utilities fulfill the role of balancing authorities. They own both generation and transmission assets, and can therefore rely on internal scheduling and dispatch to deliver power within their exclusive service territories. While power exchanges do take place among utilities, these transactions are usually based upon mutual agreement, with each utility maintaining control over the use of its own transmission facilities.

However, since the late 1990s, several states have restructured their electric sectors and opened wholesale markets to competition. Investor-owned utilities were required to functionally unbundle their wholesale generation assets from their transmission services. To ensure open and non-discriminatory access to transmission services, FERC Order No. 888 suggested adopting Independent System Operators (ISOs) as the balancing authorities for these restructured markets. Several ISOs emerged as a result, including the California ISO, PJM Interconnection, New York ISO, and New England ISO. These ISOs do not own any transmission assets, but exert functional control over their respective regional markets. Currently, there are 9 ISOs operating in North America, as shown in Figure 1.<sup>6</sup>

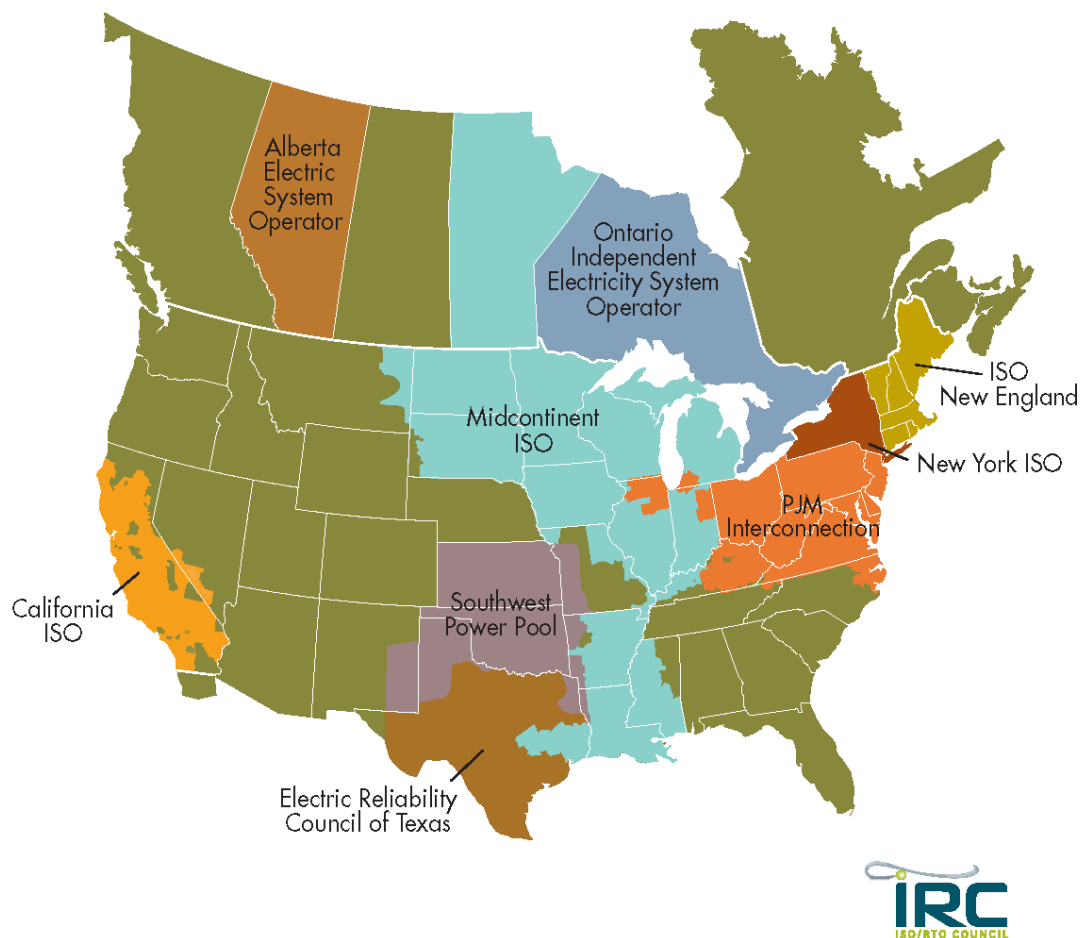
## 2.2 Wholesale Electricity Market Design

Although the organization of each individual wholesale electricity market is different, wholesale markets can be broadly categorized into two types based on the scope of the ISO’s authority and the extent of the market’s centralization.

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<sup>5</sup>A power control area (PCA) is a portion of an integrated power grid for which a single dispatcher has operational control of all electricity generators. PCAs range in size from small municipal utilities such as the City of Columbia, MO, to large power pools such as PJM Interconnection. Generation and transmission facilities are physically interconnected throughout the grid, but controlled locally by each PCA. Since one PCA’s operations affect other PCAs, the US electric industry has developed a complex set of standard operating protocols through the National Electric Reliability Council (NERC) and its eight regional reliability councils.

<sup>6</sup>We consider ISOs and RTOs (Regional Transmission Organizations) to be synonymous.



Source: ISO/RTO Council

Figure 1: ISOs Operating in North America

The first type of market design is referred to as the bilateral trading market or Min-ISO. Under a bilateral trading scheme, the role of the ISO is limited and relatively passive (Joskow, 2000). In this market, electricity buyers and sellers engage in private negotiation. The resulting bilaterally-arranged schedules are reported to the ISO. The ISO’s primary role is to then evaluate grid reliability and mitigate any energy imbalances between scheduled generation and real-time demand. This model assumes that most of the resource allocation work is done via bilateral trading, with the ISO playing only a residual balancing role. This model has been adopted by MISO (2001-2005), ERCOT (2002-2010), and CAISO (2001-2009) in the US, and NETA in the UK (2001-current).

The second market design is the centralized auction market, usually called the “electricity pool” or Max-ISO. Under this model, the ISO plays a much more active role in managing

the energy market. Generation resources submit bids to supply energy to the market. The ISO then applies an optimization algorithm to the portfolio of supply offers and finds the allocation with the lowest bid-based cost to achieve balance between supply and demand at every node on the network. This model has been adopted by the northeastern ISOs (NYISO, ISO-NE, PJM), MISO (2005-current), ERCOT (2010-current), and CAISO (2009-current).

## 2.3 The ERCOT Redesign

The Electric Reliability Council of Texas (ERCOT) is a nonprofit corporation certified by the Public Utility Commission of Texas (PUCT) as the independent system operator for the ERCOT region.<sup>7</sup> ERCOT serves 85 percent of Texas' load, 75 percent of Texas' land, and approximately 23 million customers. ERCOT is unique among ISOs: it is the only ISO to also serve the entirety of a North American electricity interconnection. Only limited power exchanges occur between ERCOT and neighboring regions, making it an isolated "electricity island" and thus well suited for the purposes of this study.<sup>8</sup>

On December 1, 2010, after years of planning, ERCOT transitioned from a bilateral trading market to a centralized auction market.<sup>9</sup> This transition transferred most of the scheduling and dispatch responsibilities from individual firms to ERCOT. Firms can rely entirely on markets organized by ERCOT to sell and buy energy. Appendix A.1 provides more details about the scheduling and dispatch procedures under each market design.

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<sup>7</sup>ERCOT was initially formed in 1970 to comply with NERC requirements. In 1995, the Texas Legislature amended the Public Utility Regulatory Act to deregulate the wholesale generation market. They followed this in 1999 by passing Senate Bill 7 (SB7), which deregulated the retail electricity market. Afterwards, PUCT began the process of expanding ERCOT's responsibilities to enable wholesale and retail competition and facilitate efficient use of the power grid by all market participants. On July 31, 2001, ERCOT began to operate as a single balancing authority for the entire ERCOT market, fulfilling the requirements of an ISO as specified in FERC Order No. 888.

<sup>8</sup>ERCOT is not synchronously connected to the Eastern and Western Interconnections. Power can be exchanged only via DC-ties between ERCOT and surrounding regions. There are two commercially operational DC-Ties between ERCOT and the Eastern Interconnection: North (DC\_N) located near Oklaunion and East (DC\_E) located near Monticello. These DC-Ties are capable of transferring a maximum power of 220 and 600 megawatts respectively. There are three additional DC-Ties connecting ERCOT and Mexico. There are no DC-Ties between ERCOT and the Western Interconnection. The overall net interchange accounts for only 0.65 percent of total net generation as of 2010.

<sup>9</sup>The redesign of the market was directed by PUCT in September 2003 with the goal of improving market and operating efficiencies. The initial implementation date was October 1, 2006. However, due to cost overruns and software problems, the market transition was postponed several times. The new market finally launched on December 1, 2010.



### 3 Network Externalities, Information Aggregation and Market Power

This section demonstrates how theoretical predictions about the effect of market design on market organization and efficiency are ambiguous. Using a simple example, we illustrate the concept of a “network externality,” a special form of externality in the electricity market. We then examine how a centralized auction market can solve this externality problem and thus improve market efficiency. However, we also show that a centralized auction market can enhance market power and reduce efficiency.

#### 3.1 Network Externalities

As discussed in Section 2, electricity is transmitted through an interconnected network that is subject to transmission constraints. In particular, networks can become congested. When networks are congested, the amount of electricity from a particular source that can be accommodated by the network can depend on electricity generation quantities from other sources. This creates a special externality problem in the electricity market, where market efficiency is impaired if market participants fail to internalize this externality.

The network externality problem can be illustrated with a simple example. Consider an equilateral triangular network with three generators. These three generators are located at the vertices, A, B and C respectively, with different marginal costs, as shown in Figure 2(a). While the transmission lines between from A to C and B to C are unconstrained, the line from A to B has a capacity limit of 100 megawatts. Point C has demand of 300 megawatts.

To meet the demand at C, the most efficient allocation is to obtain 300 megawatts from generator A, the least costly generator. Actual electricity flows are determined by Kirchhoff’s Law, which states that when there are multiple paths connecting the same orientation and destination, electrons will flow in proportion to each route’s resistance level.<sup>10</sup> Since there are two routes connecting A and C, and one of them is twice as long as the other one, the resistance of the indirect path is twice as high as the resistance of the direct path. Thus, electrons will be split in a 1:2 ratio between the indirect and direct path. Figure 2(a) depicts

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<sup>10</sup>The exact statement of Kirchhoff’s (voltage) law is that the directed sum of the voltage around any closed network is zero. By Ohm’s law, voltage is proportional to current for the same electrical circuit. Let the currents going through line  $\overline{AB}$ ,  $\overline{BC}$  and  $\overline{AC}$  be  $I_{AB}$ ,  $I_{BC}$  and  $I_{AC}$ , respectively. Then the combination of Kirchhoff’s law and Ohm’s law dictates the following relationship:  $I_{AB}+I_{BC}-I_{AC}=0$ . In scenario (a),  $I_{AB}=I_{BC}=\frac{1}{2}I_{AC}$ .

the resulting electrical flows.

Let us now consider a higher load hour, one where demand at point C is 600 megawatts. Notice that the transmission line from A to B is already at its capacity limit. If generator A produces more electricity, some of the additional electrons will flow between A and B, overloading the transmission line, causing damage, and decreasing reliability. Therefore, we must look for an alternative allocation to fulfill the increasing demand.<sup>11</sup> An obvious solution is to obtain additional 300 megawatts from generator C, the second least costly generator, which yields a total generation cost of \$3,900. Figure 2(b) illustrates this situation, which we refer to as the “naïve allocation.”

While this seems to be the best solution at first glance, the naïve allocation overlooks potential complementarities among generation sources in the network. Suppose, instead, that generator B provides 150 megawatts. While B has higher marginal costs than A, it is not only providing electricity – it also alters the resistance of the indirect path from A to C. Thus, it enables greater flows from generator A on the direct path from A to C, without additional flows on the congested path from A to B.<sup>12</sup> Figure 2(c) illustrates the resulting allocation. The resulting total generation cost of \$3,600 is lower than the generation cost under the naïve allocation.

### 3.2 Imperfect Information and Information Aggregation

The above example demonstrates how finding the most efficient allocation requires knowing more than the marginal costs of each generator. We also need to understand the structure of the network and be able to calculate electricity flows over every segment of the transmission network.

Under a bilateral trading market, market participants possess imperfect information that prevents them from identifying network externalities and achieving efficient allocations. Although they likely have a good understand of different generators’ marginal costs, given the similarity of technology across plants and the abundance of public data, they may not know

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<sup>11</sup>One alternative is to close the link from A to B so that power directly flows to consumers at C. However, transmission lines are typically built to maximize reliability and are generally not switched “on” or “off.” If one line fails, the other line(s) will provide an alternative to deliver supplies. Although transmission lines can be disconnected from the grid through a “disconnecter” or “circuit breaker,” these mechanisms are designed for safety and line isolation during service or maintenance, not for regular control of the circuit.

<sup>12</sup>Recall from footnote 10 that  $I_{AB}+I_{BC}-I_{AC}=0$ . This means that we can increase  $I_{AC}$  and hold  $I_{AB}$  constant if  $I_{BC}$  also increases.

others’ privately-negotiated scheduled generation. Moreover, the actual transmission network has hundreds of lines and thousands of nodes. These complexities add to the difficulty of identifying externalities.

While market participants in our simple example would likely learn gradually through repeated interactions, a complete understanding of network externalities is an illusion created by the simplicity of our network example and is unlikely to be repeated in the real world. Identifying externalities in a complex network requires detailed modeling of the grid and considerable computing power. As a result, the network externality problem will struggle to be resolved in a Coasian fashion under a bilateral trading market.<sup>13</sup>

In contrast, under a centralized auction market the ISO aggregates information from generators and takes full charge of scheduling. The optimization algorithm directly takes into account the physical properties of the actual transmission lines and solves for the optimal generation allocation that minimizes bid-based generation costs over the entire network. Since network externalities are directly accounted for in the optimization procedure, the centralized market is superior at resolving the network externality problem. Mansur and White (2012) share the same view on the source efficiency gains.

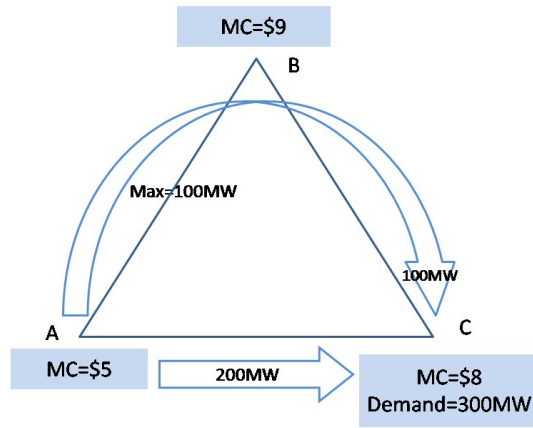
### 3.3 Market Power

The previous example (Figure 2) assumes that marginal costs are observed and used to determine economic dispatch. Since the ability of the ISO to optimize allocations depends on the information submitted by suppliers, inefficiency can also result when firms deliberately withhold their generation capacity or submit bids substantially in excess of their marginal costs. This behavior changes the dispatch order on the supply curve and causes higher-cost generators to be used while lower-cost ones stay idle.<sup>14</sup>

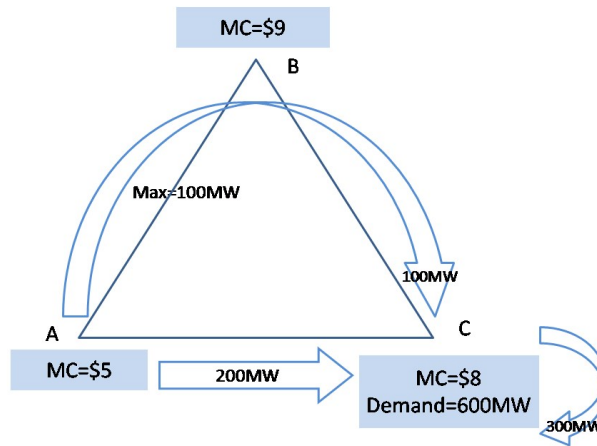
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<sup>13</sup>Although ERCOT can re-dispatch generators in the balancing market, these adjustments do not fully correct inefficiency in the bilateral schedules. In particular, the balancing market only takes care of the imbalance between scheduled generation and demand,  $\sim 5\%$  of the overall generation. The majority of generation is scheduled by market participants. Additionally, if a bilateral schedule is feasible and inefficient, such as the “naïve allocation” in the example, ERCOT will not adjust it in the balancing market. Finally, when ERCOT does change the schedules to resolve power imbalances or congestion, it adjusts generation in a piecemeal fashion (see Appendix A.1). Using a zonal structure rather than considering the grid in its entirety, ERCOT cannot find the most efficient allocation in its adjustment.

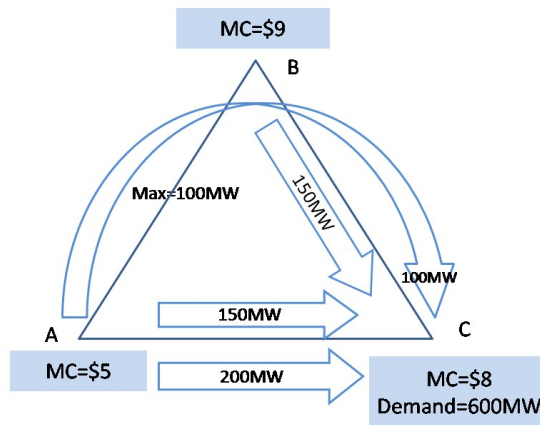
<sup>14</sup>Note that the exploitation of market power does not necessarily indicate efficiency loss. If all firms simply bid twice their marginal costs, they will retain their order in the supply curve and hence incur no efficiency loss, despite the oligopoly rents they will enjoy. Under this scenario, the exercise of market power only causes a transfer of surplus from consumers to suppliers.



(a)



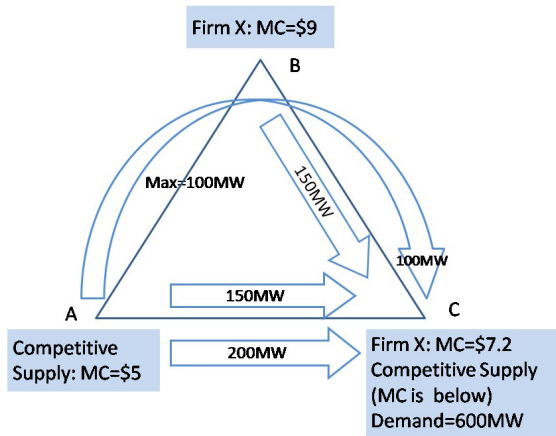
(b)



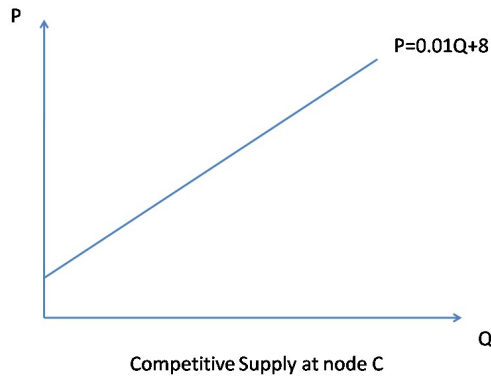
(c)

*Notes:* These figures provide an example illustrating the notion of network externality. Figure (a) shows the optimal allocation when demand is 300 megawatts. Figures (b) and (c) show the “naïve allocation” and the optimal allocation respectively when demand is 600 megawatts. See the text for details.

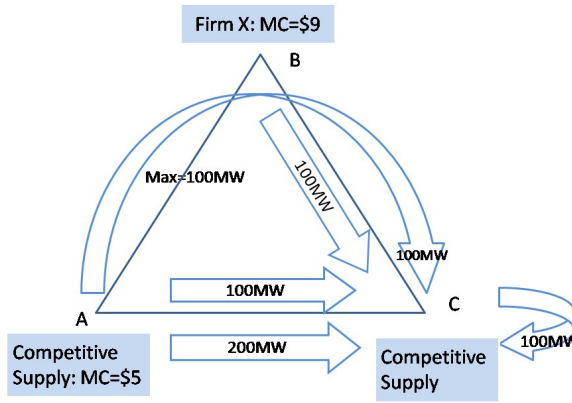
Figure 2: An Example Illustrating Congestion Externalities



(a)



(b)



(c)

Notes: These figures provide an example illustrating the effect of market power. Figure (a) shows the market structure. Firm X has two plants located at nodes B and C. Competitive suppliers are located at nodes A and C. The supply curve of the competitive fringe at node C is given in Figure (b). The power flows drawn in Figure (a) indicate the efficient allocation when Firm X acts competitively and marginal costs are used to minimize the generation cost. Figure (c) presents the outcome when Firm X exercises its unilateral market power. See the text for details.

Figure 3: An Example Illustrating Market Power

Evidence of such manipulation has been found in ERCOT both pre- and post-redesign. Hortaçsu and Puller (2008) finds evidence of a small amount of market power being exercised in ERCOT pre-redesign. Note that bilateral trading data is not generally available; their findings were in the real-time balancing market when only about 5% of electricity generation is scheduled. Woerman (2018) finds evidence of market power being exercised post-redesign on high-temperature days when transmission lines become more congested. While neither paper is able to quantify the full extent of exercised market power, both papers demonstrate that producers within ERCOT are aware of their market power and have taken the opportunity to exercise it to increase profits. Note that Zarnikau et al. (2014) finds that prices declined 2% following the ERCOT redesign, though it is unclear if this is because of efficiency changes or changes in market power. Additionally, exercised market power has been found in UK and California markets by Wolak and Patrick (2001) and Joskow and Kahn (2002), respectively.

To see how the exercise of market power reduces efficiency, consider an extended version of the previous example. Figure 3(a) shows a situation where a competitive mass of suppliers is located at node A with a constant marginal cost of \$5. Competitive fringe suppliers sit at node C, with the marginal cost curve indicated in Figure 3(b). In addition, Firm X owns two generating units, one at node B and another at node C, with marginal costs of \$9 and \$7.2, respectively. In this example, the competitive suppliers take the strategies of Firm X as given and act as price takers.

Our new situation's efficient allocation has the same production decisions as in Figure 2: we should procure 450 megawatts from suppliers at A and 150 megawatts from Firm X at B. This allocation happens in a centralized auction market where marginal costs are submitted as bids. That is, this will happen if firm X acts competitively. The equilibrium price at point B is \$9 and the profit of Firm X is \$0.

However, Firm X can also take advantage of its unique position in the congested network to increase its profits. By withholding one megawatt at B, two additional megawatts will need to be generated at C. This will increase prices at both B and C. In this situation, Firm X has market power and the ability to make the classic tradeoff between profiting from a higher quantity or profiting from a higher price. Firm X's profit-maximizing solution is to use this market power, supplying 100 megawatts at point B and 0 megawatts at point C. This leaves the competitive fringe firms to meet the remaining demand, as depicted in Figure

3(c).<sup>15</sup> The equilibrium prices at point B and C are \$13 and \$9, respectively, and Firm X's profit is \$400.<sup>16</sup> Relative to the competitive benchmark, Firm X is able to increase its profit by restricting its output, but the resulting allocation is no longer efficient. Total generation costs are \$3,750, which are higher not only than under the efficient allocation, but also total costs under the naïve allocation.<sup>17</sup>

We conclude that the exercise of market power can significantly affect generation allocations. Therefore, whether a centralized market improves efficiency depends on changes in both the management of network externality and the exercise of market power.<sup>18</sup> The following sections empirically examine the effect on efficiency from ERCOT's market redesign.

## 4 Data

This study uses a detailed and comprehensive dataset from a variety of sources. Most data are publicly available. The sample period runs June 1, 2010 to August 31, 2011, covering 6 months before the redesign and 9 months after the redesign.<sup>19</sup>

### 4.1 Generation Data

The primary data we use to determine electricity generation are from ERCOT. For each generating unit under ERCOT's control, we observe the net electrical output in 15-minute intervals.<sup>20</sup> We aggregate net generation to the hourly level to be consistent with the other

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<sup>15</sup>See Appendix A.2 for details.

<sup>16</sup>The outcome is the same if we assume Firm X competes by bidding into the pool. The optimal strategy is to then bid \$13 and \$9 for units at B and C, respectively.

<sup>17</sup>Recall that the naïve allocation is the allocation that results when marginal costs are known but complementarity among generation sources is not taken into account. In this case, the naïve allocation procures 300 megawatts from A and 300 megawatts from Firm X at point C. The resulting generation cost for the naïve allocation is \$3,660.

<sup>18</sup>It would be interesting to directly compare market power between the two market designs. Although data exist for bids submitted in centralized auction markets, price and quantity data on bilateral contracts are rarely available due to the confidential nature of these transactions. As a result, the existing literature remains silent on the issue of market power in bilateral markets.

<sup>19</sup>We exclude dates between February 2, 2011 to February 5, 2011. During this period, a strong arctic front approached Texas, resulting in 20-year temperature lows. According to EIA's 2009 Residential Energy Consumption Survey, about half of Texas residents use electricity for heating. The extreme weather conditions drove up the demand for electricity. At the same time, the extreme cold also affected generation performance. More than 8,000 MW of generation unexpectedly dropped off line (40% are coal generators). The combination of these factors led to rotating outages on the ERCOT grid.

<sup>20</sup>A generating unit is a single turbine along with a boiler and a smokestack. Power plants usually consist of several, independently operating, generating units. For combined cycle natural gas generators, however, the output decision is made jointly for both the combustion turbine and the steam turbine. Therefore, we treat them as one single unit.

data we have. Note that due to glitches experienced by ERCOT, our sample is missing several days of data immediately following the market redesign. It is otherwise complete. Overall, there are 429 units, at 218 power plants, supplying electricity to the grid managed by ERCOT.<sup>21</sup>

To determine ERCOT’s generation portfolio, we supplement ERCOT’s generation data with the EIA’s Annual Electric Generator Report (EIA-860 form) and Power Plant Operation Report (EIA-923 form). Table 1 describes the share of ERCOT’s annual generation quantity and capacity by fuel type. Electricity generation in ERCOT comes almost entirely from coal, natural gas, nuclear, and wind. Other generation sources comprise only 1% of the total generation.

Fuel Type	Share of Capacity(%)		Share of Generation(%)	
	2010	2011	2010	2011
Coal	20.33	20.34	35.15	35.61
Hydroelectric	0.55	0.55	0.28	0.15
Natural Gas	63.80	63.57	44.58	44.59
Combined Cycle	38.49	39.18	37.99	37.96
Combustion Turbine	7.06	7.07	3.52	3.72
Steam Turbine	18.24	17.32	3.07	2.91
Nuclear	5.27	5.27	12.08	10.96
Wind	9.60	9.77	6.90	7.71
Others <sup>22</sup>	0.46	0.50	1.01	0.97

*Notes:* This table reports the share of capacity and the share of generation quantity for different resource types in 2010 and 2011. Data are from EIA-860 forms and EIA-923 forms.

Table 1: Generation Composition in ERCOT: 2010-2011

## 4.2 Generator Characteristics

We obtain plant- and generator-level characteristics from EIA-860 forms, EPA’s Continuous Emissions Monitoring System (CEMS) and eGrid.<sup>23</sup> For each generating unit, we

<sup>21</sup>Not all generating units in the ERCOT territory are subject to ERCOT dispatch. There are firms which provide electricity only on private networks. Nor are all the generating units dispatched by ERCOT located in Texas. In particular, the Kiamichi Energy Facility in Oklahoma provides electricity to ERCOT.

For subsequent analyses, we drop generators whose cumulative generation is less than 15 megawatt hours during the sample period. These units are not economically important.

<sup>22</sup>Others include biomass, petroleum coke, distillate fuel oil, solar, and electricity storage.

<sup>23</sup>All fossil-fuel generating units with at least 25 megawatts of generating capacity report their hourly gross generation, heat inputs, and CO<sub>2</sub>, SO<sub>2</sub>, and NO<sub>x</sub> emissions to the EPA. In our analytical sample, 208 out of 297 thermal generators are covered by CEMS.



observe its ownership, nameplate capacity, fuel type, technology, sector, commercial operating date, operating status, and location, among other information. For generators with information available in CEMS, we also observe their hourly CO<sub>2</sub>, SO<sub>2</sub>, and NO<sub>x</sub> emission quantities, as well as their heat inputs.

For thermal generators, we use these data to measure the average CO<sub>2</sub>, SO<sub>2</sub> and NO<sub>x</sub> emission rates and heat rates. The heat rate is a ratio of thermal energy input against electricity output. It is stable within the operating range of a generator, but can be higher during startups.<sup>24</sup> Heat rates reflect a power plant’s efficiency: lower heat rates correspond to more efficient generators. For generators covered in CEMS, we calculate average heat rates for each unit by dividing total heat inputs (in MMBtus) by total generation (in MWhs) during our time period. For generators not covered in CEMS, we use their plant-level nominal heat rates obtained from the EPA’s eGrid database. To calculate average emission rates, we divide total emission quantities (in short tons or pounds) by total net generation (in MWhs).<sup>25</sup>

	Coal	Natural Gas		
		Combined Cycle	Combustion Turbine	Steam Turbine
Nameplate Capacity (MW)	639.32 (192.85)	414.90 (277.86)	52.42 (47.52)	254.10 (215.74)
Years in Operation	26.49 (11.29)	16.15 (11.11)	14.16 (13.42)	43.64 (8.08)
Heat Rate (MMBtu/MWh)	10.57 (0.51)	7.81 (1.50)	11.99 (4.40)	12.62 (2.64)
CO <sub>2</sub> (Tons/MWh)	1.16 (0.20)	0.51 (0.14)	0.61 (0.33)	0.81 (0.33)
SO <sub>2</sub> (Pounds/MWh)	5.80 (3.86)	0.01 (0.01)	0.02 (0.04)	0.02 (0.03)
NO <sub>x</sub> (Pounds/MWh)	1.36 (0.69)	0.34 (0.26)	2.06 (2.28)	1.74 (1.05)
Median Ramping Time <sup>26</sup>	Over 12H	12H	1H	12H

*Notes:* This table compares the characteristics of different types of thermal generators. The data for nameplate capacity, years in operation, and ramping time come from EIA-860 forms. Heat rates and emission rates are calculated as described in the text. Standard deviations are reported in the parentheses.

Table 2: Summary Statistics

Table 2 presents summary statistics for the thermal generators in our sample. In gen-

<sup>24</sup>More than half of the startup costs are fuel costs incurred to warm up the generator. Startup costs vary by technology and unit size.

<sup>25</sup>We also compare heat and emission rates from eGrid and CEMS and correct for anomalous estimates.

<sup>26</sup>Ramping time is defined as the minimum amount of time required to bring a generator from cold shutdown to full load, and is coded into four categories: 10 minutes, 1 hour, 12 hours and over 12 hours. Because this data was unavailable before 2013, we use the 2013 EIA-860 form.

eral, coal generators tend to be larger, more polluting, and slower to ramp than natural gas generators. Natural gas generators use several different technologies. A combustion turbine, a.k.a. a gas turbine, uses high-pressure gas generated from fuel-burning to drive the turbine. A steam turbine works similarly except it uses water instead of air to drive the turbine. Most steam turbine generators currently in use were built in the 1980s and 1990s and the technology has not changed very much since then. In contrast, combustion turbine technology has become more efficient over time. As a result, there is a wide variation in the heat rates of combustion turbines; the most recent combustion turbine's heat rate is only 25% as large as the oldest unit's heat rate. Because combustion turbines can respond quickly to changing demand, they are often used as peaking plants. The relatively new combined-cycle technology combines these two thermodynamic cycles together to improve the efficiency of energy conversion. They have the lowest average heat rate among natural gas generators.

### 4.3 Electricity Demand

Hourly demand data in eight weather zones are obtained from ERCOT.<sup>27</sup> The data are derived by aggregating meter data and include both transmission and distribution losses. We use demand at the weather zone level to capture any spatial distribution in demand that may impact generation outcomes. In addition, we select a time period that includes both winter and summer months under each market design to capture seasonal or diurnal patterns in demand.

### 4.4 Cost Data

The electricity industry's cost structure is relatively straightforward and well understood. For wind generators, the marginal cost for producing one more MW is essentially zero. For nuclear power plants, the marginal cost can be estimated by adding the marginal fuel cost to the variable operating and maintenance (VOM) cost. We use the EIA (2011)'s fuel cost estimate of \$7.01 and ERCOT (2012)'s VOM estimate of \$5.02 to obtain a marginal cost of \$12.03 for nuclear units. To estimate the marginal cost for thermal generators, we take the standard approach commonly used in the economic literature (Wolfram (1999), Borenstein et al (2002), Mansur (2008)). This methodology is based on the following elements: (1) the heat rate of each generator, (2) fuel prices, (3) VOM costs, (4) emission rates for each generator, and (5) emission allowance prices. Appendix A.3 provides more details on the

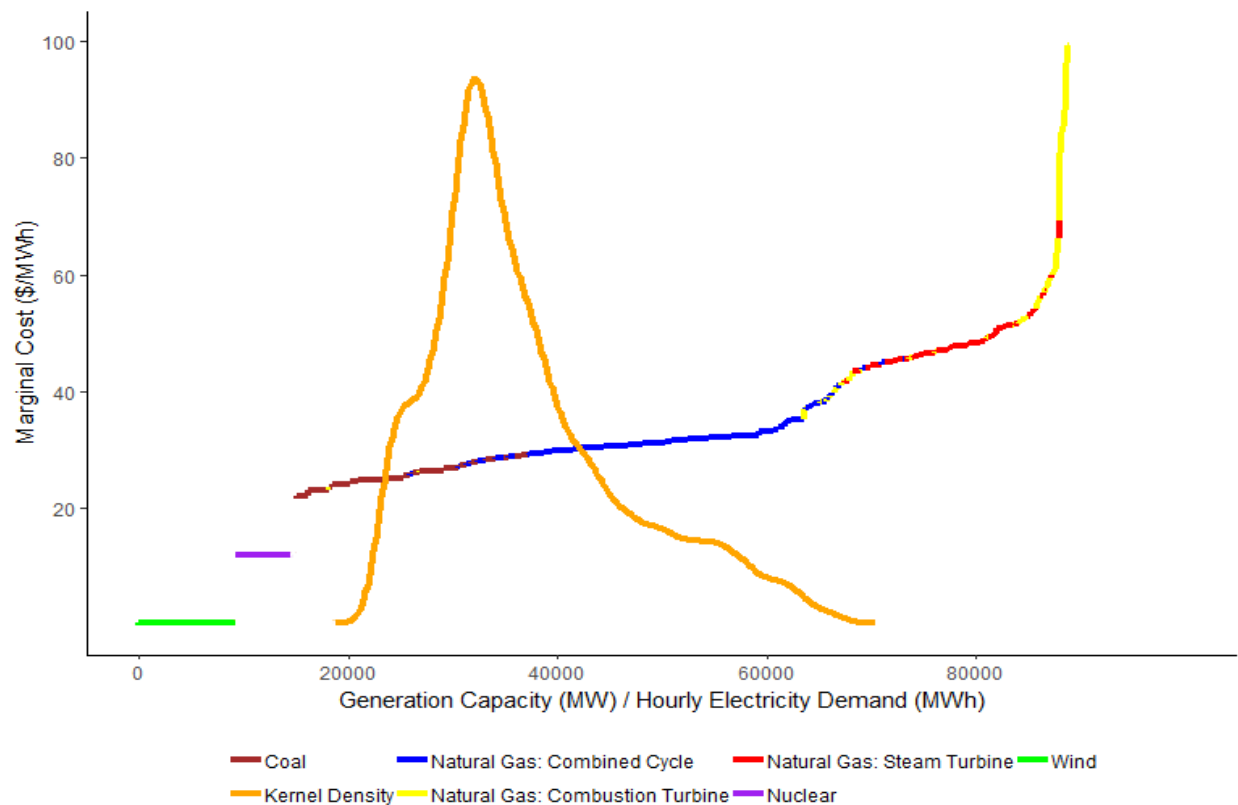
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<sup>27</sup>A weather zone is a geographic region designated by ERCOT in which climatological characteristics are similar for all areas within such a region. There are eight weather zones in ERCOT: coast, west, far west, east, north, north central, southern, and south central.

data sources for (2), (3), and (5). For each thermal generator  $i$  at time  $t$ , its marginal cost is calculated using the following formula:

$$MC_{it} = \text{Heat Rate}_i \times \text{Fuel Price}_{it} + P_{NO_x t} \times NO_{x_i} + P_{SO_2 t} \times SO_{2_i} + VOM_i$$

Figure 4 plots the marginal cost curve using generators' average marginal costs and the observed maximum hourly net generation as a measure of their capacity during the sample period. Note that marginal costs differ by fuel and technology types. Specifically, wind generation and nuclear power generation are cheaper than thermal generation. Among thermal generators, coal generation is in general cheaper than natural gas generation, and combined-cycle generation is cheaper than combustion or steam generation. We also overlay on the same graph the distribution of hourly electricity demand. We see that for most realizations of demand the marginal unit is a coal or a combined-cycle natural gas generator. During peak hours, the marginal unit is generally a combustion or a steam turbine.



*Notes:* This figure plots the marginal cost curve using generators' average marginal costs and observed maximum hourly net generation as their capacity for the sample period (June 1, 2010 - August 31, 2011, excluding a few days in December and February). It also shows the kernel density of the total hourly electricity demand for the same period. See text for additional details.

Figure 4: Marginal Cost Curve and the Demand Distribution

## 5 Empirical Strategy

This section introduces the econometric approach we use to quantify changes in generation allocation due to the ERCOT market redesign. We begin by discussing market efficiency in electricity generation. We then discuss our measurement of changes in market efficiency and detail our empirical approach.

### 5.1 Market Design and the Marginal Cost Curve

We treat electricity demand as perfectly inelastic in the short-run. Due to the lack of real-time pricing, demand swings are driven entirely by non-pecuniary forces like temperature changes. Given the need to balance generation with demand at every second, there is no inefficiency from quantity distortion under either market design. Thus, any change in market efficiency will be reflected as a change in the generation cost needed to serve the same demand.

The marginal cost curve in Figure 5 represents the theoretically efficient supply based on installed generator capacity, each generator’s marginal cost, and the physical constraints imposed by the network. Note that this may be slightly different from the installed-capacity marginal cost curve in Figure 4. The least-costly allocation will involve some generation that is out of the merit order if it is infeasible to only utilize the least-costly units (due to, e.g., transmission constraints). Section 3 shows that it will sometimes be lower-cost to call a unit to help meet  $n$  megawatts of demand, even though the unit is not among the  $n$  cheapest megawatts in terms of installed capacity.<sup>28</sup>

The choice of market design will influence how far the actual MC curve deviates from the theoretically efficient MC curve. Electricity market design may cause out-of-merit order costs for two primary reasons. First, market participants may fail to identify or resolve network externalities. Second, they may influence the market by exercising market power (see Section 3.3). Our study does not focus on out-of-merit costs per se, as in Borenstein et al (2002). Instead, we focus on the difference in out-of-merit costs between the two different designs.

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<sup>28</sup>Other reasons for out-of-order operations include generator outages and dynamic constraints. Plants periodically go off-line for maintenance and occasionally experience forced shutdowns, causing more expensive units to fill the gap. In addition, start-up time and ramping costs play a role in determining the most economical dispatch, as shown by Mansur (2008) and Reguant (2014). Hence, the mere presence of out-of-merit costs does not necessarily indicate efficiency loss.

In Figure 5, the grey area represents out-of-merit costs under the bilateral trading market. When ERCOT moved from a bilateral market, they did so with the belief that the centralized market would do a better job of resolving network externalities. This change likely also affected the amount of market power that firms are able exercised. Figure 5 is consistent with ERCOT's expectations and shows the centralized market bringing the actual MC curve closer to the theoretically efficient MC curve, reducing out-of-merit costs.<sup>29</sup> Correspondingly, the slashed-pattern area measures the efficiency gain in this hypothetical example. Note that it is also possible out-of-merit costs increased under the redesign. We now turn to empirically measuring the magnitude (and sign) of the assumed productive efficiency gain.

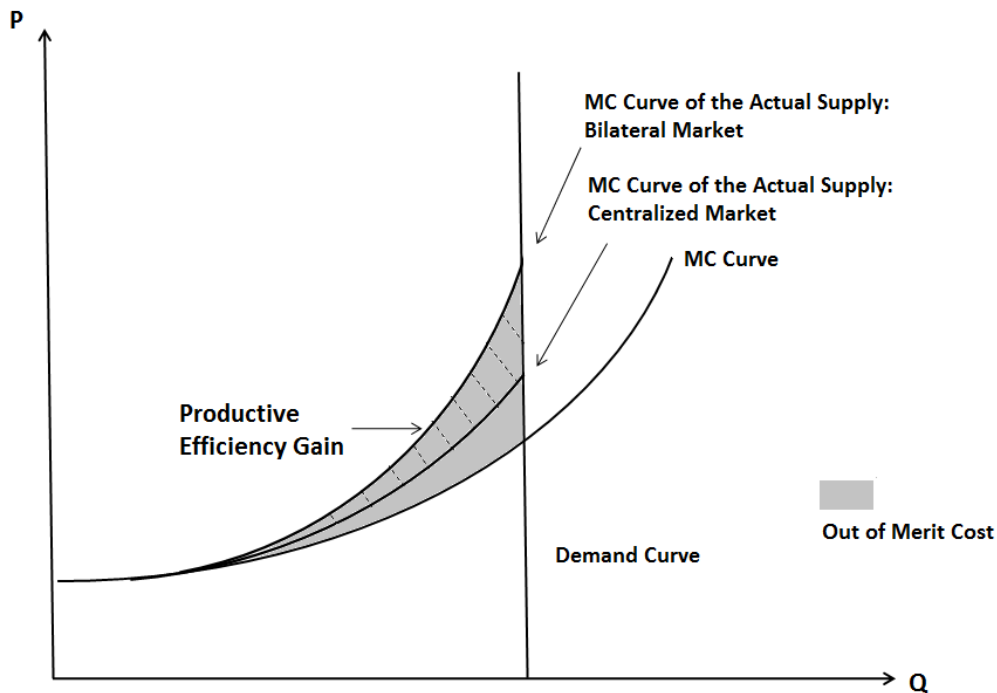


Figure 5: An Illustration of a Hypothetical Efficiency Gain Under the Centralized Market

## 5.2 Estimating Generation Cost Changes

To measure changes in generation costs, we need to create a credible counterfactual of what would have happened if ERCOT didn't redesign its market. We cannot simply compare

<sup>29</sup>Note that the true lowest cost supply curve would also account for real-world constraints such as transmission constraints, ramping constraints, and minimum run times. These will exist under either market design. Figure 5 assumes them away for expositional purposes.

pre- and post-redesign generation costs. While this approach will give us an approximate answer, it relies on there being few changes in the market during the relatively short period preceding and following the redesign. Indeed, Appendix A.4 shows that while the ranges of demand levels, fuel prices, and market capacity are comparable pre- and post-, average demand levels are higher pre-redesign.

We therefore rely on an econometric approach that estimates a flexible function of generation quantity on market demand and fuel prices for each generating unit separately before and after the market redesign. We use these estimates to construct counterfactual generation quantities which form the basis for the calculation of changes in overall generation costs and emissions. If the centralized market results in an improvement in market efficiency, we should expect an increase in electricity generation from lower-cost generators and a decrease in electricity generation from higher-cost generators, conditional on the same market demand and fuel prices. Figure 6 illustrates this situation. Hence, we can measure the change in generation quantity for each generator by first estimating these generation curves. This approach is similar to the one used by Davis and Hausman (2016).<sup>30</sup>

We treat wind power and nuclear power as non-dispatchable units unaffected by the market redesign. For wind turbines, generation quantity is largely determined by the availability of the wind, though it may be curtailed by ERCOT when transmission is congested. Although the market redesign can potentially improve the integration of wind power and thus reduce the incidence of curtailments, we do not find evidence supporting such a claim.<sup>31</sup> For nuclear power generators, their low marginal costs and limited capacity to follow load mean that they almost always run at full capacity. Therefore, the rest of our analysis will focus on thermal generators.

Let  $ThermalDemand_{jt}$  be the residual demand for thermal generation, after subtracting generation from wind, nuclear, and other sources, in weather zone  $j$  at time  $t$ .<sup>32</sup> We then separate  $ThermalDemand$  in each zone into 12 mutually exclusive equal-frequency bins.<sup>33</sup>

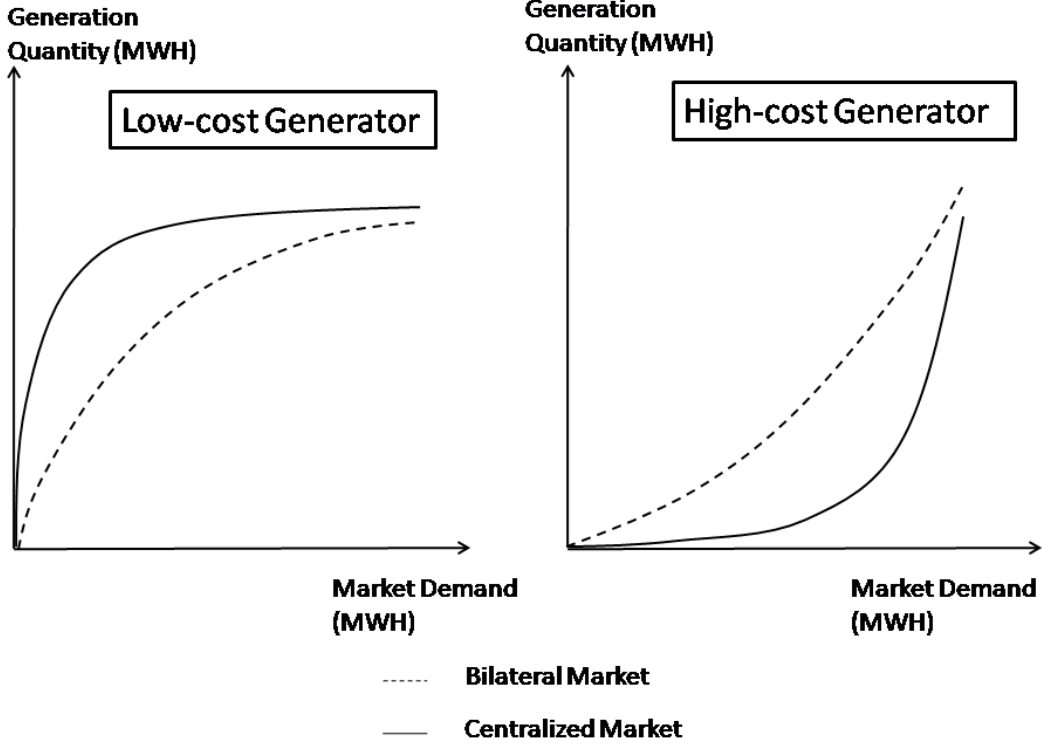
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<sup>30</sup>An alternative is to use an engineering model to simulate the market. This requires modeling the electric grid in detail and making strong assumptions regarding firms' information sets and strategic behavior. This is a difficult task given the complex nature of the transmission network and competitive dynamics.

<sup>31</sup>See Appendix A.5 for more details.

<sup>32</sup>Other generators include biomass, petroleum coke, distillate fuel oil, solar, and electricity storage. These generation sources provide a very small percentage of ERCOT's generation.

<sup>33</sup>The optimal number of bins is selected by using the leave-one-out cross validation technique. Specifically, given the number of bins, we estimate the corresponding model on (N-1) observations (hours) and predict outcomes for the remaining observation. We repeat the process for all N combinations and calculate the prediction errors. We experimented with different numbers of bins and chose the one that minimizes the



Notes: Assuming constant fuel prices, this figure provides an example of changes in generation curves for generators of low versus high costs if the centralized market improves efficiency.

Figure 6: An Illustration of Changes in Generation Curves for Generators of Different Costs

Let  $b_{jk}$  ( $j=1,\dots,8$ ;  $k=1,\dots,12$ ) denote the left end point of bin  $k$  for demand in weather zone  $j$ . Define

$$B_{jk}(ThermalDemand_{jt}) = \begin{cases} ThermalDemand_{jt} - b_{jk} & \text{if } ThermalDemand_{jt} > b_{jk} \\ 0 & \text{if } ThermalDemand_{jt} \leq b_{jk} \end{cases}$$

For each thermal generator  $i$ , we estimate a continuous piecewise linear model with respect to demand at each weather zone for the pre- and post-redesign periods respectively:

$$Gen_{it} = \beta_{0i} + \sum_{j=1}^8 \sum_{k=1}^{12} \beta_{ijk} B_{jk}(ThermalDemand_{jt}) + \phi_{ih} + \delta_{iw} + \alpha_{1i} P_{NG-Coal,t} + \alpha_{2i} P_{NG-Coal,t}^2 + \epsilon_{it} \quad (1)$$

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mean squared error.

We include hour-of-day fixed effects  $\phi_{ih}$  and day-of-week fixed effects  $\delta_{iw}$ . We also control for the effect of fuel prices on the switch between coal and natural gas generation by including a quadratic form of the price difference between coal and natural gas.<sup>34</sup> All coefficients are generator specific and different before and after the market transition. Overall, there are 10,646 hourly observations in our sample. For each generator, we estimate 256 coefficients, resulting in a total of 76,032 coefficients for the 297 generating units in the sample. Our counterfactual uses estimates from the pre-redesign period and calculates the change in generation quantity for each generator  $i$  at each hour  $t$  in the post-redesign period.<sup>35</sup> Mathematically,

$$\Delta\text{Gen}_{it} = (\hat{\text{Gen}}_{it} \mid \hat{\boldsymbol{\theta}}_i^{post}, \mathbf{X}_t^{post}) - (\hat{\text{Gen}}_{it} \mid \hat{\boldsymbol{\theta}}_i^{pre}, \mathbf{X}_t^{post})$$

Standard errors are estimated using the simple block wild bootstrapping method where a “block” consists of 24 hours of a calendar day. This method allows for arbitrary correlations across generators as well as serial correlations for up to 24 hours.

## 6 Results

This section first presents estimated average hourly changes in generation quantity. It then examines how changes in generation vary with changes in demand and fuel prices. In light of the heterogeneity of costs across generators, we aggregate the results according to their fuel and technology types.

### 6.1 Effect of the Market Redesign on Generation Quantity

Table 3 reports estimated changes in generation quantity averaged over all hours in the post-redesign period. The baseline column shows the results using Equation 1. On average, coal generation increased by 513.3 MWh per hour while natural gas generation decreased by a similar amount. Because coal was usually cheaper than gas, this finding is suggestive that ERCOT’s centralized market uses lower-cost resources than the bilateral trading market. In the context of ERCOT’s overall average generation of 19,819 MW, this increase is roughly equivalent to a 2.5% of total generation. Within natural gas generators, the

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<sup>34</sup>Including higher-order polynomials of the fuel price difference yields similar results. We also perform ridge regressions as an alternative specification to address overfitting concerns. Results are qualitatively and quantitatively similar.

<sup>35</sup>Note that we are *not* comparing costs with the theoretical static efficiency benchmark outlined by the “MC” curve in Figure 5.



decrease in generation comes from both combined-cycle and steam-turbine generators. Interestingly, combustion turbine generators experienced an increase in production after the redesign, though they do not have the lowest marginal costs. This increased usage could be explained by their ability to quickly adjust production to serve peak loads. A more nuanced discussion of these changes occurs later in this section.

Fuel Type	Baseline Model	Alternative Models				
		(1)	(2)	(3)	(4)	(5)
Coal	513.3 (73.8)	526.3 (69.7)	511.9 (74.6)	509.9 (79.6)	530.0 (76.5)	482.7 (67.9)
Natural Gas: CC	-329.6 (60.1)	-324.7 (58.3)	-329.3 (58.9)	-333.3 (61.3)	-365.3 (58.7)	-399.4 (52.0)
Natural Gas: CT	110.6 (16.4)	89.8 (13.9)	110.3 (16.2)	119.2 (15.2)	117.8 (16.7)	99.0 (15.3)
Natural Gas: ST	-295.9 (30.1)	-294.5 (29.9)	-294.5 (30.5)	-303.4 (30.9)	-275.9 (30.4)	-336.0 (29.5)
Quadratic Fuel Price Difference	Y	Y	Y	Y	N	Y
Quartic Fuel Price Difference	N	N	N	N	Y	N
Quadratic Temperature	N	Y	N	N	N	N
Standard Deviation of Demand	N	N	Y	N	N	N
One-hour Lagged Demand	N	N	N	Y	N	N
Truncation	N	N	N	N	N	Y

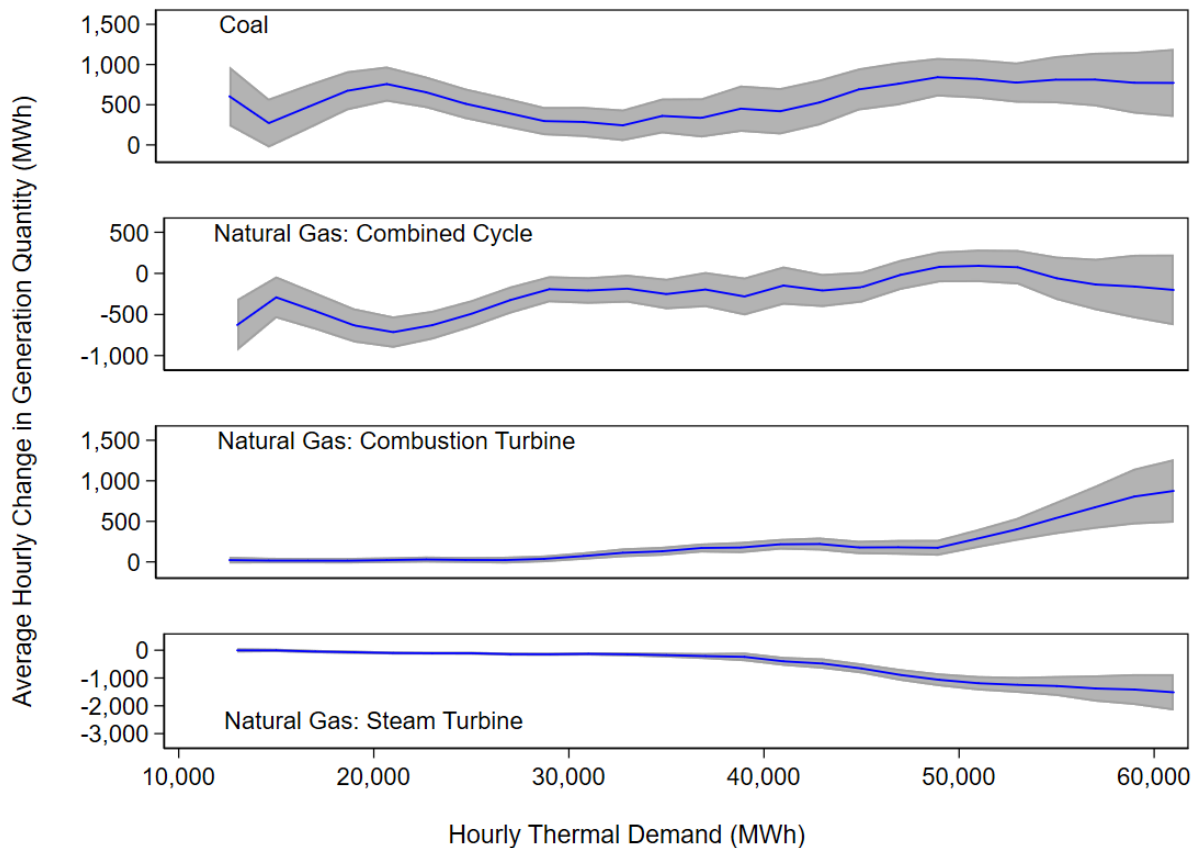
*Notes:* This table reports estimates of average hourly changes in generation quantities measured in MWh, using Equation 1 and several alternative models. For all models, hour and day-of-week fixed effects are included. The sample consists of 10,464 hourly observations and 297 generating units. Standard errors reported in the parentheses are estimated using the simple block wild bootstrapping method.

Table 3: Effect of the Market Redesign on Average Generation Quantities

We run several alternative specifications to check the robustness of our results. First, since ambient temperature may affect thermal generators' efficiency, we re-run our analysis including a quadratic form of temperature in column (1).<sup>36</sup> Second, because generators differ in their ability to adjust output in response to load fluctuations, we include daily variance of demand and one-hour lagged demand in columns (2) and (3), respectively. Third, column (4) experiments with a higher order polynomial of the fuel price gap. Finally, column (5) truncates predicted quantities that are below zero or beyond generators' nameplate capacities. Note that while about 25% of the predictions are truncated, less than 5% of these are more than 5 MWh away from their thresholds. Although the magnitudes differ slightly

<sup>36</sup>Temperature data are collected from National Centers for Environmental Information (NCEI)'s Integrated Surface Database. We use average hourly temperature of the three largest cities in Texas (Houston, Dallas, and San Antonio).

across specifications, the overall pattern is consistent with our baseline results. In addition, Appendix A.4 includes two placebo tests and finds that these changes are not observed in years without market redesigns.



*Notes:* These figures plot the average hourly changes in generation quantity at different demand levels. The prices of natural gas and coal are fixed at their post-redesign averages, i.e. \$4.17/MMBtu for natural gas and \$2.17/MMBtu for coal. The grey area indicates 95% confidence intervals.

Figure 7: Average Hourly Changes in Generation Quantity by Demand Levels

Next, we examine how average hourly changes in generation quantity vary with demand levels, assuming average post-redesign fuel prices. Figure 7 plots changes for different fuel and technology types. For coal generation, the increase persists across all demand levels, but tends to be larger when demand is higher. Note that the increase is also larger when thermal demand is at about 20,000 MW, the point at where coal and combined-cycle natural gas split on the marginal cost curve (at average post-redesign fuel prices).<sup>37</sup> Our results

<sup>37</sup>Unlike Figure 4, we only show thermal demand in Figure 7. In Figure 4, coal and combined-cycle natural gas split around an overall load of 35,000 MW.

show that the decrease in combined-cycle natural gas generation also changes with demand. Specifically, the decrease is greater when demand is relatively low. When demand is high, the decrease in combined-cycle natural gas generation is insignificant. This makes sense, as this technology is relatively cheap compared to steam turbine technology.

The change in combustion and steam turbine usage patterns is interesting. When demand is low, these two resources are less likely to be used. Consequently, the market redesign has little effect on their generation levels. Under high demand levels, however, combustion turbine generation increases and steam turbine generation decreases. The increase in combustion turbine generation is likely due to its relatively low marginal costs compared to steam turbines, as well as its ability to ramp up and down quickly.<sup>38</sup> This allows combustion turbines to offset steam turbine generation in cases when coal or combined-cycle natural gas generators are unable to. Overall, these results appear to reinforce the role of cost in determining generation outcomes in the centralized market.

Finally, Figure 8 examines changes in generation quantity at different fuel prices, assuming average post-redesign demand levels. Coal generation results have an interesting inverse-U shape. Switching is greatest at intermediate price gaps between coal and natural gas. At higher price gaps, there was likely less room to switch – coal was already being predominantly used. At lower price gaps, it is likely cheaper to use natural gas and there is less room for improvement under the centralized market. This pattern is supported by changes in combined-cycle natural gas generation. With marginal costs close to coal, combined-cycle generators experience changes in the opposite direction to those of coal. In contrast, the fuel price difference has a relatively small effect on combustion and steam turbine generation as these generators are further away from coal on the marginal cost curve.

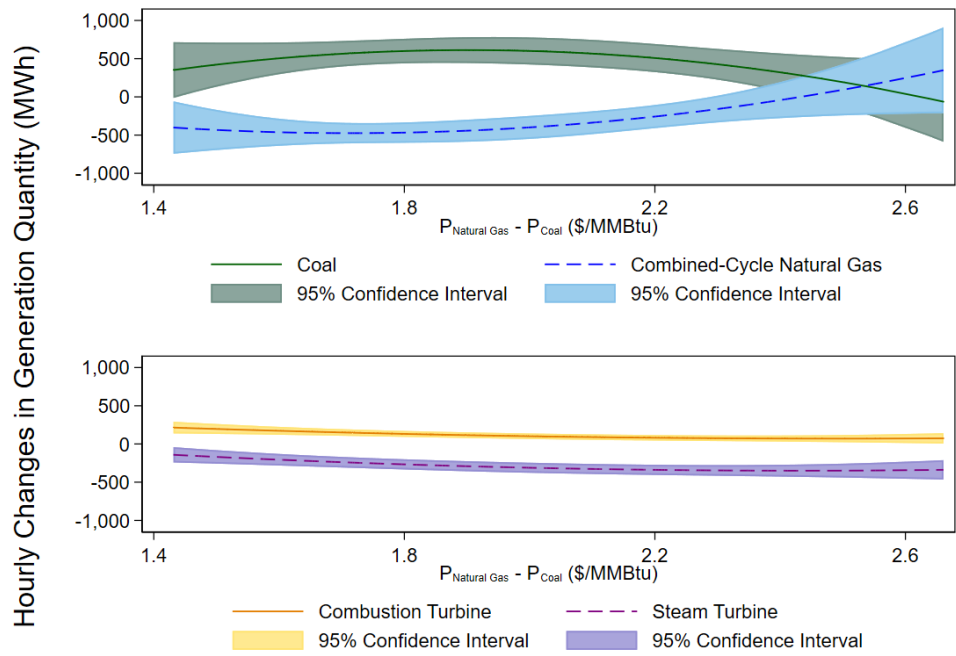
## 6.2 Effect of the Market Redesign on Generation Cost

To calculate the changes in generation cost due to the market redesign, we use each generator’s estimated quantity changes from the previous section and their average marginal costs in the post-redesign period. The overall change in generation cost at hour  $t$  is the sum of changes from all the generators, i.e.,

$$\Delta Cost_t = \sum_i \Delta Gen_{it} * MC_i$$

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<sup>38</sup>Combustion turbines and steam turbines do overlap substantially on the marginal cost curve (Figure 4), with combustion turbines having more variance in their marginal costs than steam turbines.



*Notes:* This figure shows the hourly changes in generation quantity over the price differences between natural gas and coal. Demand at each zone is assumed to be at its post-redesign average, which adds up to 31,196 MW for the overall thermal demand. The shaded area indicates 95% confidence intervals.

Figure 8: Hourly Changes in Generation Quantity and Fuel Price Differences

Averaging across all hours, the cost reduction is estimated to be \$6,749 per hour with a bootstrapped standard error of \$1,105 for the nine months in the post-redesign period. The reduction is roughly 1.5% of the average total hourly generation cost. Although these changes vary on an hourly basis, the generation cost is estimated to be lower than what it would have been without the market redesign for about 70% of all hours.<sup>39</sup>

### 6.3 Market Redesign Effect on Emissions and External Costs

Although the centralized market leads to a significant reduction in generation costs, it also affects social welfare through changes in emissions. From a social perspective, any private efficiency gain must be weighed against changes in external costs of emissions.

Given the available data, we focus on three pollutants: CO<sub>2</sub>, SO<sub>2</sub> and NO<sub>x</sub>. To estimate changes in emissions of each pollutant, we again use estimated changes in electricity generation quantity and each generator’s emission rates. For pollutant  $j$ , we calculate the change in emission quantity in hour  $t$  as the sum of emission changes from all the generators, i.e.,

$$\Delta \text{Emission Quantity}_{jt} = \sum_i \Delta \text{Gen}_{it} * \text{Emission Rate}_{ij}$$

The second column in Table 4 reports the average hourly changes in emission quantities. On average, CO<sub>2</sub> emissions increase by 322 metric tons per hour or 1.3 percent. This rise in CO<sub>2</sub> emissions is not surprising given the increased usage of coal generators in the centralized market. On average, coal power plants emit 1.16 tons of CO<sub>2</sub> per MWh, while natural gas plants emit only 0.65 tons of CO<sub>2</sub> per MWh. For SO<sub>2</sub> and NO<sub>x</sub>, we find that emissions decrease by 0.254 and 0.225 tons per hour, respectively. Notably, SO<sub>2</sub> emissions decrease despite the fact that coal generators on average emit far more SO<sub>2</sub> than natural gas generators. This decrease is a result of generation changes within coal plants. SO<sub>2</sub> emission rates from coal generators are dispersed, ranging from 0.1 pounds/MWh to 14.8 pounds/MWh. This variation reflects coal power plants’ heterogeneous compliance strategies for environ-

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<sup>39</sup>This approach assumes no start-up costs and constant marginal costs. An alternative approach is to run regressions similar to Equation 1, but with a different dependent variable – the heat inputs. This captures nonlinearities in fuel usage over the operational range of a generator. With the estimated changes in heat inputs, we can apply fuel prices to derive changes in fuel costs. This approach, though, does not take into account other cost components, such as emission allowance costs and VOM. To address this issue, we estimate non-fuel cost changes using results from the original generation regressions and the non-fuel portion of each generator’s marginal cost. The resulting estimate for the overall cost reduction averages \$8,367 per hour for the nine months post redesign. The primary limitation of this approach is that only generators covered in CEMS data have heat input information. Indeed, using our preferred approach we see that non-CEMS plants have cost increases of roughly \$1,522/hour. The two approaches, therefore, yield similar results.

mental regulations. Different coal plants will have different types of SO<sub>2</sub> controls (or none at all!) and make different choices about what types of coal to use. As a result, when high SO<sub>2</sub>-emitters are displaced by low SO<sub>2</sub>-emitters within coal generators, overall SO<sub>2</sub> emission levels can decrease. Note that this change is not significant, given the relatively large standard errors.

In a similar way, we obtain the changes in external costs associated with these emission changes. For pollutant  $j$ , the change in the external cost at hour  $t$  is calculated as follows:

$$\Delta\text{External Cost}_{jt} = \sum_i \Delta\text{Gen}_{it} * \text{Emission Rate}_{ij} * \text{Marginal Damage}_{ij}$$

To calculate the monetary damage cost of emissions, we use two data sources. For CO<sub>2</sub>, we use EPA (2016) estimates on the social cost of carbon that are designed for use in regulatory analysis. For one metric ton of CO<sub>2</sub> emitted in 2011, the social cost ranges from \$10 to \$51 in 2007 dollars, largely depending on the assumed discount rate. We convert 2007 dollars to 2011 dollars to make the values comparable with generation cost estimates. For SO<sub>2</sub> and NO<sub>x</sub>, we use Jaramillo and Muller (2016)'s marginal damage estimates. Unlike CO<sub>2</sub> which is a uniformly mixed pollutant, SO<sub>2</sub> and NO<sub>x</sub> have relatively localized geographic impacts. Therefore, these estimates are spatially differentiated at the county level. For SO<sub>2</sub>, the marginal damage ranges across counties from \$8,416 to \$41,960 per metric ton. For NO<sub>x</sub>, the marginal damage ranges across counties from \$1,435 to \$7,785 per metric ton.

Pollutant	ΔEmission Quantity (Tons/Hour)	Marginal Damage (2011\$/Ton)	ΔExternal Cost (2011\$/Hour)
		11	3,546 (571)
CO <sub>2</sub>	322.4 (51.9)	35	11,284 (1,817)
		56	18,054 (2,906)
SO <sub>2</sub>	-0.254 (0.23)	8,416 - 41,960	11,097 (4,670)
NO <sub>x</sub>	-0.225 (0.05)	1,435 - 7,785	-1,866 (281)

*Notes:* This table reports average hourly changes in emission quantities and the associated changes in external costs. Standard errors reported in parentheses are estimated using the simple block wild bootstrapping method.

Table 4: Average Hourly Changes in Emission Quantities and External Costs

The rightmost column in Table 4 reports the average hourly changes in the external costs of the three pollutants. Changes in external costs of CO<sub>2</sub> emissions range from \$3,546, to \$18,054 per hour, depending on the social cost of carbon. Changes to external costs of SO<sub>2</sub>

and  $\text{NO}_x$  emissions are estimated to be \$11,097 and -\$1,866 per hour respectively. Taken together, these results show that the overall change in emission costs exceeds the private generation cost savings of \$6,749 per hour.<sup>40</sup> When interpreting the results, two caveats should be kept in mind.

First, power plants may internalize some of the external costs due to cap and trade programs. In Texas, while  $\text{CO}_2$  emissions are not regulated,  $\text{SO}_2$  and  $\text{NO}_x$  are subject to cap and trade programs. This internalization should not significantly impact our results, since the average allowance prices for  $\text{SO}_2$  and  $\text{NO}_x$  during the sample period are only \$8.4 and \$274.5 per ton, respectively. This is a very small fraction of actual damages.

A second caveat is that we implicitly assume any environmental damage incurred by changes in  $\text{SO}_2$  and  $\text{NO}_x$  emissions is confined to Texas. That is, no changes in emission levels are created outside of Texas as a result of this market redesign. If, however, the cap and trade programs are binding, then by constraint, emission increases in Texas would create emission reductions somewhere outside of Texas, resulting in no aggregate change in emission levels. Furthermore, even without aggregate changes in emission quantity, the redistribution of the pollutants may still affect overall environmental costs, given the spatially heterogeneous nature of the marginal damages. A thorough analysis of this spillover effect is beyond the scope of this paper. Nevertheless, even without considering the impact of either  $\text{SO}_2$  or  $\text{NO}_x$ , we find that the increase in the external cost of  $\text{CO}_2$  emissions itself completely offsets the private efficiency gain, as long as the marginal damage of  $\text{CO}_2$  is greater than \$20.93 per ton.

## 7 Discussion

Our results show that both generation cost reductions and external cost increases are statistically significant and economically large. In this section, we first compare our results with the predicted savings expected by ERCOT and then discuss whether the redesign was

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<sup>40</sup>We also estimate changes in emissions using Equation 1 with emissions as the dependent variable. This approach's main advantage is that it will capture emissions changes due to changes in ramping. The primary disadvantages are that it will erroneously ascribe, e.g., changes in  $\text{SO}_2$  control technology to the redesign and that we only have CEMS information for 208 of the units. If we use a 'mixed' approach that uses estimates with emissions as the dependent variable, replacing these with our main estimates in the event of a pollution control change, we find that results are similar. Changes in  $\text{CO}_2$  emissions are 367 tons/hour, changes in  $\text{SO}_2$  damages are \$20,146/hour, and changes in  $\text{NO}_x$  damages are -\$839/hour. We interpret these results as very similar to our primary estimates – of the same magnitude and larger than the cost savings from the redesign.

warranted on a cost-benefit basis.

Prior to the implementation of the new market design, the Public Utility Commission of Texas retained several consulting firms (Tabors Caramanis & Associates (TCA) in 2004, and CRA International and Resero Consulting (CRA/Resero) in 2008) to conduct cost-benefit analyses of the new market design. These studies used the GE MAPS simulation model that includes a full transmission representation of ERCOT but assumes no market power. Annual production cost reductions were ex-ante estimated to be \$66.8 million in 2003 dollars and \$48.0 million in 2008 dollars, respectively. Furthermore, a back-cast using bids submitted during a market trial suggested that 2008 production costs would have been lower by \$90 to \$180 million, had the centralized market design been in place at that time (ERCOT, 2011a). In the previous section, we find average hourly cost savings are \$6,749, or \$59.1 million annually. Our findings are in the range of the aforementioned estimates. The relative similarity between our estimates and engineering estimates suggests that changes in market power following the redesign were relatively modest.

<b>Benefit</b>	
Generation Cost Saving(\$m/year)	59.1 (Authors' Calculation)
Ancillary Services Cost Saving(\$m/year)	34.0 (ERCOT, 2011a)
Savings from Improved Generation Siting(\$m/year)	35.1 (CRA/Resero, 2008)
<b>Cost</b>	
One-time Implementation Cost(\$m)	548.6 (ERCOT, 2011b)
Incremental Operational Costs(\$m/year)	14.8 (CRA/Resero, 2008)
Environmental Cost(\$m/year)	111.9-239.0 (Author's Calculation)

*Notes:* This table lists the benefits and costs of ERCOT's market redesign. All numbers are in 2011 dollars.

Table 5: The Cost-Benefit Analysis of ERCOT's Market Redesign

We can also examine whether the market redesign was warranted using a cost-benefit analysis. The transition to the centralized market provides a number of benefits in addition to the decrease in generation cost. Specifically, the centralized market is expected to reduce annual ancillary service costs by \$34 million per year.<sup>41</sup> Additionally, in the long run, the centralized market can lead to improvement in siting of new resources through more transparent locational marginal prices. CRA/Resero (2008) estimates this benefit to be \$35.1 million per year. However, this transition also carries several costs, principally the external costs from increasing emission levels, but also a one-time implementation cost of

<sup>41</sup>Ancillary services are those services necessary to maintain grid stability and support continuous balance between supply and demand. Note that the very unusual winter storm caused extra ancillary costs in excess of \$75 million. These estimates exclude that event.



\$548.6 million as well as yearly recurring expenses of \$14.8 million. Table 5 summarizes these costs and benefits. Taken together, the picture that emerges is that the redesign will be cost effective over the first 10 years of operation if the discount rate is 16% or less and we exclude environmental costs. However, the market redesign creates a social welfare loss when environmental impacts are taken into account.<sup>42</sup>

## 8 Conclusion

This paper examines the effect of the Texas electricity market redesign on both market efficiency and social welfare. To do so, we use a flexible semi-parametric approach to estimate changes in generation allocation among different types of generators. We then use these estimates to quantify associated changes in production costs and emissions. Our results show the market redesign improves market efficiency, suggesting that the informational benefits created by a centralized market outweigh any change in market power incentives. Currently, a centralized market design is the norm for all deregulated electricity markets in the US. This paper provides evidence supporting the practice on an efficiency basis. Worldwide, there are still regions that either have not restructured their electricity markets or have adopted a bilateral trading model. Texas’s experience provides a useful reference for regions considering moving to a centralized market. Given that our estimates are based on market conditions in Texas and include some Texas-specific changes, one natural extension would be to conduct cross-market comparisons to better understand market-specific drivers that may impact the direction and magnitude of efficiency changes.

While our results attest to the superiority of the centralized market design in terms of efficiency, we also find that the transition to a centralized market increases emission levels. The conflict between efficiency improvements and pollution mitigation is a result of the disparity between private and social costs, rather than flaws in the design per se. Enacting pollution taxes or appropriate emission caps is one possible way to resolve this conflict. In recent years, the idea of an ISO-administered “carbon adder” – a price on carbon added to

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<sup>42</sup>An important caveat is that this extrapolation is based on the market conditions between June 1, 2010 to August 31, 2011. During subsequent years, natural gas prices have dropped from about \$4/MMBtu to less than \$2/MMBtu and continue to fluctuate. This decrease in natural gas prices has led to widespread substitution of natural gas for coal (Cullen and Mansur, 2017 and Brehm, 2019). On the one hand, since some natural gas power plants, especially the combined-cycle plants, are ahead of coal in the merit order, we may not see as much displacement of natural gas generation by coal generation in the later years as in 2011. Hence, the environmental cost may be substantially lower in the later years than the estimates shown here. On the other hand, private cost savings from the market redesign may also be lower, given smaller differences in marginal costs among generators.

generators' bids – has been proposed as an alternative way to reduce carbon emissions. We find that the environmental costs associated with increasing emissions is not trivial. In fact, when those costs are taken into account, the redesign no longer passes a cost-benefit test. This finding highlights the need to take environmental impacts into account when we make decisions in energy markets.

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# Appendix

## A.1 ERCOT Market Operation

This section provides details on market processes under the bilateral trading market and the centralized auction market.

### A.1.1 Scheduling and Dispatch Under the Bilateral Trading Market

Before the redesign, ERCOT was a bilateral trading market. Market operations consisted of two major phases:<sup>43</sup>

1. Day-ahead scheduling process

Load serving entities and generation resources negotiated privately with each other to buy and sell energy. Resulting bilateral contracts specified the transfer of electricity at negotiated terms, including duration, price, and time of delivery. In the day-ahead period, market participants were required to submit their “balanced schedules” to the ERCOT ISO through Qualified Scheduling Entities (QSEs, qualified by ERCOT to submit schedules for a portfolio of generators and power purchasers). These schedules specified the origins and destinations of power flows by congestion zone for each 15-minute settlement interval.<sup>44</sup>

Scheduled resource production should not deviate from the forecasted demand beyond an established range. ERCOT analyzed the day-ahead schedules and notified QSEs of anticipated inter-zonal congestion. Market participants were allowed to adjust their schedules to relieve the forecasted congestion. Once the schedules were accepted by ERCOT, generators were “physically” committed to produce the scheduled quantity unless instructed to increase or decrease their production in the balancing market. Any uninstructed deviation exceeding 1.5% or 5 MWh of a QSE’s schedule resulted in a penalty payment (Sioshansi and Hurlbut, 2010). 95% of overall generation is scheduled through this process.

2. Real-time balancing market

During the day-ahead scheduling process, generation resources also submitted bal-

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<sup>43</sup>There was also an adjustment period between the day-ahead period and the operating period.

<sup>44</sup>ERCOT divides its territory into 4 congestion zones. A congestion zone is a group of electrical buses with similar shift factors on commercially significant constraints. Dividing the entire grid into several congestion zones simplifies the modeling of the network.

ancing energy bids for adjusting generation relative to their scheduled quantities. In real-time, ERCOT managed energy imbalance and transmission congestion between zones by intersecting the bidding functions separately for each zone. For intra-zonal congestion, ERCOT deployed resources based on generic fuel cost factors and shift factors to resolve local transmission constraints.

### A.1.2 Scheduling and Dispatch Under the Centralized Auction Market

Under the centralized market design, market participants put their generation resources at the disposal of ERCOT. Resources are centrally dispatched to minimize generation costs. The operation of the centralized auction market also consists of two phases.

#### 1. Day-ahead operation

In the day-ahead period, market participants submit offers to sell energy for each hour of the operating day. Supply offers may contain three parts: a startup offer, a minimum-energy offer, and an energy offer curve. Participation in the day-ahead energy market is voluntary and does not physically commit a resource to come on-line. In 2011, day-ahead purchases accounted for approximately 40 percent of real-time load (Potomac Economics, 2012). After completion of the day-ahead energy market, ERCOT executes a reliability unit commitment process to ensure that it has enough capacity committed to serve forecasted load for the operating day.

#### 2. Real-time operation

While bilateral trades and the day-ahead energy market transfer *financial* responsibility among QSEs, ERCOT’s Security Constrained Economic Dispatch (SCED) program actually dispatches resources in real time. SCED represents the electrical system and includes critical information on characteristics, ratings, and operational limits of all elements of the transmission grid. On-line resources are dispatched in economic order according to submitted energy offer curves. The execution of SCED results in locational marginal prices at approximately 4,000 nodes.<sup>45</sup>

## A.2 Proof of Firm X’s Optimal Strategy

Denote the quantities Firm X supplies at node B and C as  $Q_B$  and  $Q_C$ . The supply coming from node A is  $300 + Q_B$ . Hence, the residual demand for Firm X at node C is  $Q_C = 600 - (300 + Q_B) - Q_B - 100(P_C - 8) = 1100 - 2Q_B - 100P_C$ . Equivalently,  $P_C = 11 - 0.02Q_B - 0.01Q_C$ . To obtain  $P_B$ , note that if we increase production at both A

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<sup>45</sup>Hence, the centralized market is also known as the “nodal market.”



and B by 1 MW each, production at C can be reduced by 2 MW to meet the same level of demand at C. The resulting prices, therefore, satisfy the relationship  $P_A + P_B = 2P_C$ . Firm X's problem is:

$$\max_{Q_B \geq 0, Q_C \geq 0} (11 - 0.02Q_B - 0.01Q_C - 7.2) * Q_C + [2 * (11 - 0.02Q_B - 0.01Q_C) - 5 - 9] * Q_B$$

The kuhn-Tucker conditions with respect to  $Q_B$  and  $Q_C$  are

$$\begin{aligned} \frac{\partial}{\partial Q_B} &= 8 - 0.08Q_B - 0.04Q_C \leq 0 \\ \frac{\partial}{\partial Q_C} &= 3.8 - 0.04Q_B - 0.02Q_C \leq 0 \end{aligned}$$

Obviously, the equalities will not hold for both conditions. We must have

$$\begin{aligned} \frac{\partial}{\partial Q_B} &= 0 \\ \frac{\partial}{\partial Q_C} &< 0 \end{aligned}$$

Hence, the profit-maximizing quantities are  $Q_B^* = 100$ ,  $Q_C^* = 0$ .

## A.3 Data Appendix

### A.3.1 Coal Prices

The majority of a power plant's coal is purchased through long-term contracts. Therefore, we use monthly plant-level coal receipt cost data from EIA-923 forms as the relevant coal prices. While spot market coal prices could be used to approximate opportunity costs for coal plants, we use contract prices for two reasons. First, there is evidence that the pass-through from spot market price to contract price for coal is fairly long and incomplete. Chu et al (2015) find that a 1% change in the coal spot price leads to only an approximately 0.11% change in the contract prices received by power plants even after 12 months. Second, power plants consistently pay a sizable premium for contract coal over spot coal. This suggests that there are industrial or institutional barriers to taking advantage of the cheaper spot coal. Joskow (1987) and Jha (2014) attribute this phenomenon to transaction-cost economics and regulatory-induced risk aversion, respectively.

Fuel receipt cost data are publicly available for regulated plants. There are 16 coal plants in ERCOT, 6 of which are regulated. For deregulated plants, we approximate the

coal prices in the following way. Power plants in Texas purchase two types of coal: lignite from Texas and sub-bituminous coal from the powder river basin in Wyoming. Only two regulated plants purchase lignite. Since lignite is produced within Texas, we assume that the transportation costs are relatively small while the content of the coal matters more for the price. Hence, we use the coal prices paid by plant Pirkey to approximate prices for deregulated plants, since the characteristics of coal purchased by Pirkey are close to the average lignite being purchased. However, transportation costs are likely to be important for sub-bituminous coal. Therefore, we match every deregulated plant to its closest regulated neighbor and use the matched plant’s coal price as its price. We are able to find a match for every deregulated plant within 100 miles. In the very few cases where no price data are available for a certain month, we use the average price of the months preceding and following that month instead. Table A1 summarizes matching outcomes. The final price for each plant is the quantity-weighted monthly receipt price.

Regulation Status	Coal Plant	Fuel Type	Matched Coal Plant
Deregulated	Big Brown	SUB	Gibbons Creek
		LIG	Pirkey
	Coletto Creek	SUB	J T Deely
		Limestone	SUB
	Martin Lake	LIG	Pirkey
		SUB	Welsh
	Monticello	LIG	Pirkey
		SUB	Welsh
	Oak Grove	LIG	Pirkey
		Sandow No 4	LIG
	Sandow No 5	LIG	Pirkey
		Twin Oaks Power One	LIG
	W A Parish	SUB	Fayette Power Project
	Regulated	Gibbons Creek	SUB
Fayette Power Project		SUB	
J K Spruce		SUB	
J T Deely		SUB	
Oklaunion		SUB	
San Miguel		LIG	

*Notes:* This table shows the matching results for coal plants in ERCOT. As explained in the text, each deregulated plant is matched to a regulated plant that purchases the same type of coal.

Table A1: Matching Outcomes for Coal Plants in ERCOT

### **A.3.2 Natural Gas Prices**

Daily natural gas spot prices are collected from SNL Financial. We use prices at the Agua Dulce, Katy, Waha, and Carthage hubs for units in the South, Houston, West, and North zones, respectively. Prices at the four hubs track each other very closely.

### **A.3.3 Variable Operation and Maintenance Costs (VOM)**

Variable O&M costs include scheduled and forced outage maintenance, water supply costs, and environmental equipment maintenance. We use standard VOM costs published by ERCOT (ERCOT, 2012). These costs differ by fuel and technology type. For coal, combined-cycle natural gas, natural gas combustion turbine, and steam turbine, VOM costs are \$5.02, \$3.19, \$3.94 and \$7.08 per MWh (in 2009 dollars), respectively.

### **A.3.4 Emission Allowance Prices**

Power plants in ERCOT are subject to four programs: the Acid Rain Program (ARP), the Clean Air Interstate Rule (CAIR) annual SO<sub>2</sub> program, the Clean Air Interstate Rule (CAIR) annual NO<sub>x</sub> program, and the Mass Emissions Cap & Trade (MECT) annual NO<sub>x</sub> program. The ARP, established under Title IV of the 1990 Clean Air Act (CAA) Amendments, requires major emission reductions of SO<sub>2</sub> and NO<sub>x</sub>, the primary precursors of acid rain, from the power sector. It is a nationwide program affecting large fossil fuel-fired power plants across the country. CAIR was finalized in 2005, and took effect in 2009 for NO<sub>x</sub> and 2010 for SO<sub>2</sub>. The CAIR SO<sub>2</sub> and NO<sub>x</sub> annual programs require further reductions for large electricity generating units in 28 eastern states including Texas. Houston-area plants are subject to MECT, a local NO<sub>x</sub> program designed to bring the region back into attainment under the Clean Air Act.

Not all generating units are affected by these four programs. To determine each generating units' coverage status, we use information provided by the EPA's Air Markets Program Data (AMPD) and cross check our data with the Code of Federal Regulations Parts 72 and 96 (40 CFR Part 72 and Part 96). We have also reached out directly to the Texas Commission on Environmental Quality for information about MECT's coverage.

All programs are cap-and-trade programs designed to allow power plants to find the cheapest possible reductions among covered sources to meet the overarching cap. For each ton of SO<sub>2</sub> emitted, ARP compliance requires the surrender of 1 ARP allowance, while CAIR compliance requires an additional ARP allowance of prompt vintage. For each ton

of  $\text{NO}_x$  emitted, 1  $\text{NO}_x$  annual allowance has to be deducted. Generally, these allowances are traded among companies and individuals through brokers. We acquired daily  $\text{SO}_2$  and  $\text{NO}_x$  allowance price indexes from a leading over-the-counter energy brokerage firm based in Texas. We use the last trading price each day as the relevant price. For non-trading days, we approximate the price by taking the average price from the trading days preceding and following that day. For MECT, only about 2.5 trades happen per month; we use average annual permit prices published by the Texas Commission on Environmental Quality.

Relative to fuel costs, emission permit costs are quite low. For coal power plants, emission permit costs are only about 0.6% of marginal costs. For natural gas generators, the percentage is about 0.15%.

### **A.3.5 Wholesale Electricity Price Data**

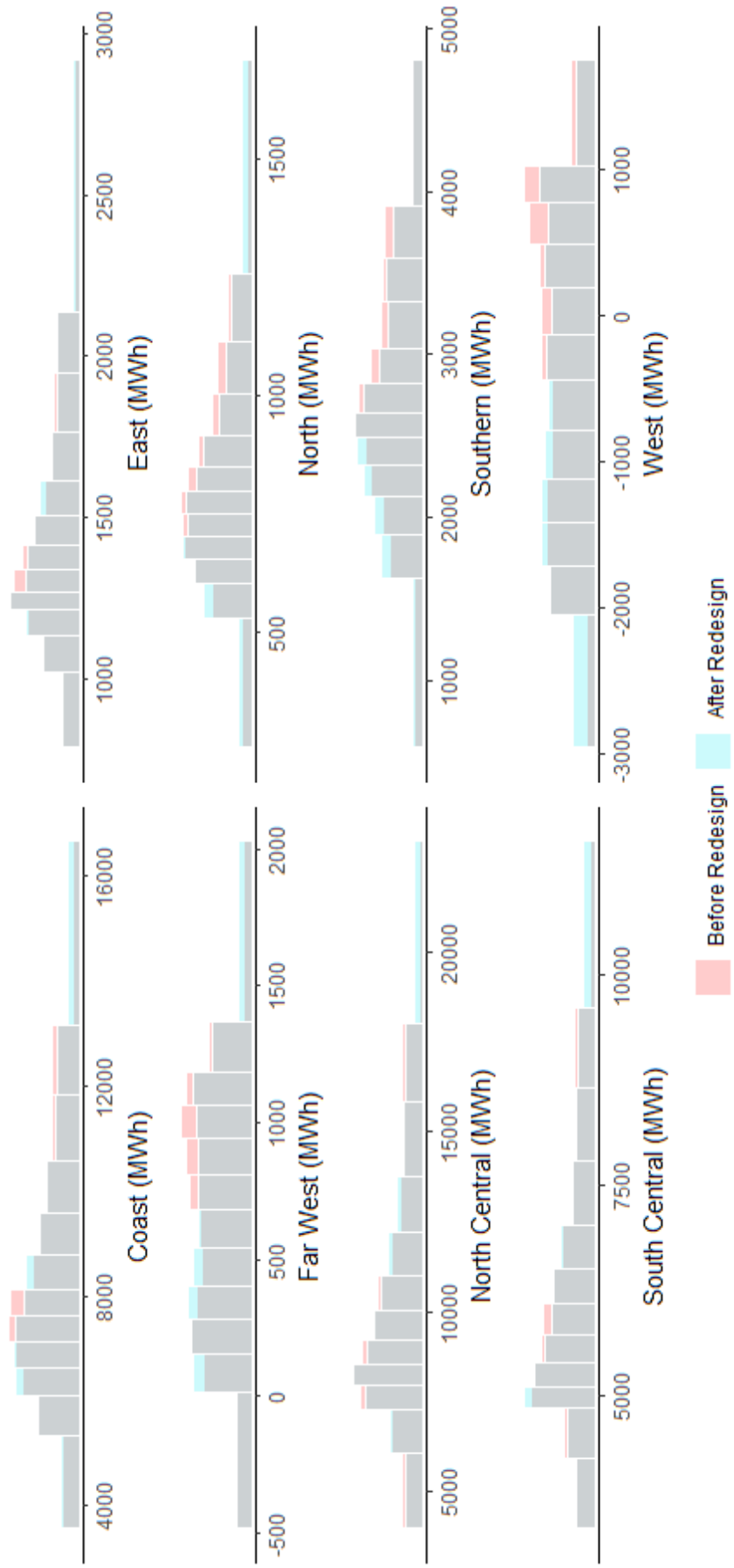
From ERCOT, we also collect real-time post-redesign electricity prices at four hubs: Houston, North, South and West. A hub's price is the simple average of the locational marginal prices (LMPs) of nodes within that hub.<sup>46</sup> When there is no congestion, hub prices are the same throughout the system. However, if congestion exists, LMPs differ from node to node, as do the hub prices. Therefore, we define an hour to be congested if the electricity prices at the four hubs are not the same. Congestion is quite common in our sample. About 60% of hours in the post-redesign sample period are congested.

## **A.4 Additional Results and Robustness Checks**

This section contains additional evidence that supports our empirical approach's validity and the robustness of the findings. First, we show that although the market conditions pre- and post-redesign are not identical, they are quite comparable: the span of demand at each zone overlaps substantially; changes in fuel prices are moderate; and entry or exit of generators does not exert a significant impact on the market. Second, we conduct placebo tests to show that observed changes pre- and post-redesign are not seen in other years.

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<sup>46</sup>Locational marginal prices (LMPs) are prices at a given network node based on the cost of delivering the next MW of energy to that node. For example, if there is a need for 10 MW at a network node, the LMP is determined by the cost of delivering the 11th MW.



Notes: These figures show the histograms of hourly thermal demands at eight weather zones separately for pre-redesign and post-redesign periods. The pre-redesign period runs from June 1, 2010 to November 30, 2010. The post-redesign period runs from December 1, 2010 to August 31, 2011. Demand at each zone is divided into 12 equal-frequency bins based on the entire sample.

Figure A1: Histogram of Hourly Thermal Demand By Weather Zone

#### A.4.1 Comparison of Demand

Figure A1 compares the distributions of demand at all eight weather zones pre- and post-redesign. To be consistent with the main specification, demand at each zone is divided into 12 equal-frequency bins based on the entire sample so that the number of observations falling into each bin is the same. Comparing the distributions before and after the redesign, we see that they all have observations in each bin. The common support enables the estimation of the parameters for each bin both pre- and post-redesign.

#### A.4.2 Comparison of Fuel Prices

Changes in fuel prices are the only factor that could substantially affect generators' marginal costs. Other factors either do not change over time or constitute a very small portion of marginal costs. In order to attribute the changes in generation to market redesign, it is essential to examine how fuel prices changed during the sample period.

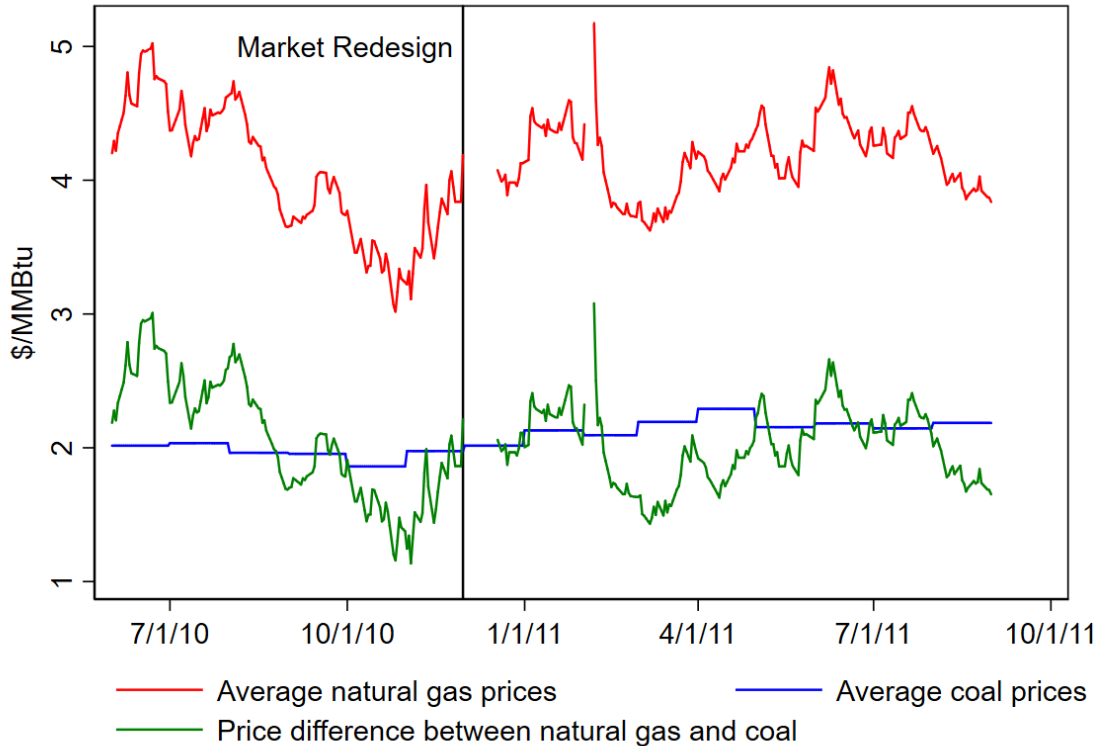
Figure A2 plots the movement of coal prices and natural gas prices during the sample period.<sup>47</sup> Overall, the magnitudes of the price changes for both natural gas and coal are quite small. On average, coal and natural gas prices during the post-redesign period increase by 18.8 cents/MMBtu (10%) and 12.9 cents/MMBtu (3%) respectively, compared to the pre-redesign period. The range of price differentials is similar pre- and post-redesign.

The comparability of fuel prices pre- and post-redesign provides reassuring evidence that our results are not driven by price trends. Furthermore, we directly include a quadratic form of the price difference between natural gas and coal in the baseline model to capture effects caused by relative changes in fuel prices. We find it unlikely that relative changes in fuel prices are the cause of the switch between coal and natural gas generation. In particular, the coal price increases more than the natural gas price during the post-redesign period. This would make coal generators less appealing, but our results instead find that coal displaces natural gas generation by significant amounts in the post-redesign period.

As a robustness check, we focus on only natural gas generators and run similar regressions as Equation 1 using demand for natural gas generation instead of thermal generation as the explanatory variable. Within natural gas generators, marginal cost order is essentially determined by heat rates and unaffected by the change of natural gas prices. Therefore, relative changes in generation within them is not confounded by fuel price movements. Results from

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<sup>47</sup>To be consistent with the estimation sample, we exclude dates between December 1, 2010 to December 17, 2010 (absence of ERCOT data) and dates between February 2, 2011 and February 5, 2011 (anomalous winter storm).



*Notes:* This figure shows the time series of average coal prices and natural gas prices as well as the price gap between coal and natural gas during the sample period. The period runs from June 1, 2010 to August 31, 2011 and excludes December 1, 2010 to December 17, 2010 and February 2, 2011 to February 5, 2011. The vertical line indicates when the market redesign took effect.

Figure A2: Average Coal and Natural Gas Prices During the Sample Period

these regressions support the main findings: generation from cheaper resources (combined-cycle generators and combustion turbines) increases while generation from costlier resources (steam turbines) decreases.

#### A.4.3 Entry and Exit of Thermal Generators

Estimation restricts the sample to all thermal generating units that continually operated during the sample period. Three thermal units either entered or exited the market during this period. Two steam turbines, with capacities of 800 and 115 MW, exited the market prior to the market redesign. One combined-cycle natural gas plant, with a capacity of 640 MW, entered the market on March 16, 2011. These events pose the question of whether the observed changes in generation are caused by the entries or exits of these units. Although it is difficult to separate out their impact, we believe it is unlikely to be the case. Average hourly generation quantities from these three units while they were operating were only 69.9, 4.7 and 127.9 MWh, respectively. Their generation accounts for less than 0.1% of the total

thermal generation. Given these low magnitudes, we conclude that our results cannot be explained by their entry and exit.

Plant Name	Entry/Exit	Time	Technology	Capacity (MW)	Average Marginal Cost(\$)	Average Hourly Generation (MWh)
Tradinghouse	Exit	Sep 19, 2010	Natural gas: steam turbine	800	43.5	69.86
Permian Basin	Exit	Nov 21, 2010	Natural gas: steam turbine	115	49.4	4.72
Jack County	Entry	Mar 16, 2011	Natural gas: combined cycle	640	32.5	127.90

*Notes:* This table lists the thermal generators that have entered or exited the market during the sample period. Data are from EIA-860 forms. Entry and exit dates are also cross-checked with CEMS data and web sources.

Table A2: List of Entering and Exiting Generators

#### A.4.4 Placebo Tests

Finally, we perform placebo tests to show that the magnitudes our results are indeed unusual and not seen in other years. For this exercise, we consider two hypothetical scenarios where a redesign occurred on December 1, 2009 or December 1, 2011 and repeat the analyses. We focus on a very short time period – two months centered around the (real or pseudo) implementation date of the market redesign. Given the short time frame, we are confident that there are no significant changes in capacity, cost, or other aspects of the market. We run regressions similar to Equation 1. However, given fewer observations, we simplify the analysis by using thermal demand for all of Texas instead of the demand in each zone, and fit a constant line within each bin. We also estimate the regressions at a more aggregate level by fuel and technology types. For type  $i$  at hour  $t$ , the estimation equation takes the following form:

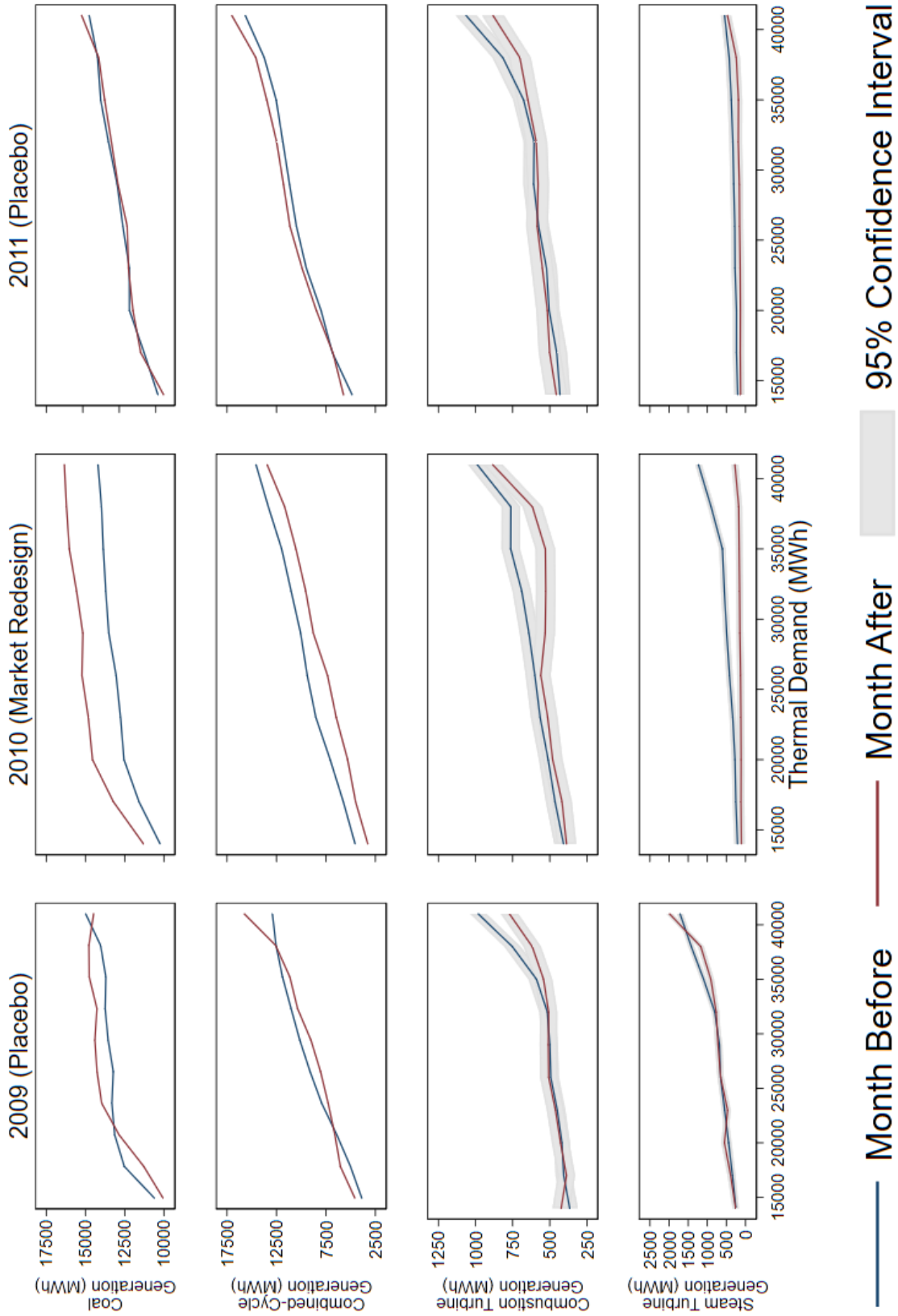
$$\text{Gen}_{it} = \sum_{k=1}^{12} \beta_{ik} \text{Bin}_k(\text{ThermalDemand}_t) + \epsilon_{it}$$

where  $\text{Bin}_k$  is equal to one if the thermal demand falls into that bin and zero otherwise.

Figure A3 reports the results for the four categories: coal, combined-cycle natural gas, natural gas combustion turbines, and steam turbines. We can see that the changes in 2010 are not seen in other years. For coal and combined-cycle natural gas, the “before” and “after” generation lines are intertwined and close to each other. Only in 2010 when there is a real redesign do we see significant gaps between these two lines. For combustion and steam turbines, the parameters are estimated less precisely. For steam turbines, there is



evidence of a significant effect of market redesign when demand is over 20,000 MWh. Again, Figure A3 shows that this is not seen in other years. For combustion turbines, the changes in 2010 are not very different from changes in 2009 and 2011. Overall, the 95% confidence intervals of the two generation lines overlap for 2010. However, this does not contradict the earlier findings that generation from combustion turbines increases, because the increase in our main results only occurs during high demand hours. Figure 7 shows that the effect starts to appear when the thermal demand exceeds 50,000 MWh. Given that the demand in November and December never reaches 50,000 MWh, it is unsurprising that the effect of market redesign on combustion turbines is not salient.

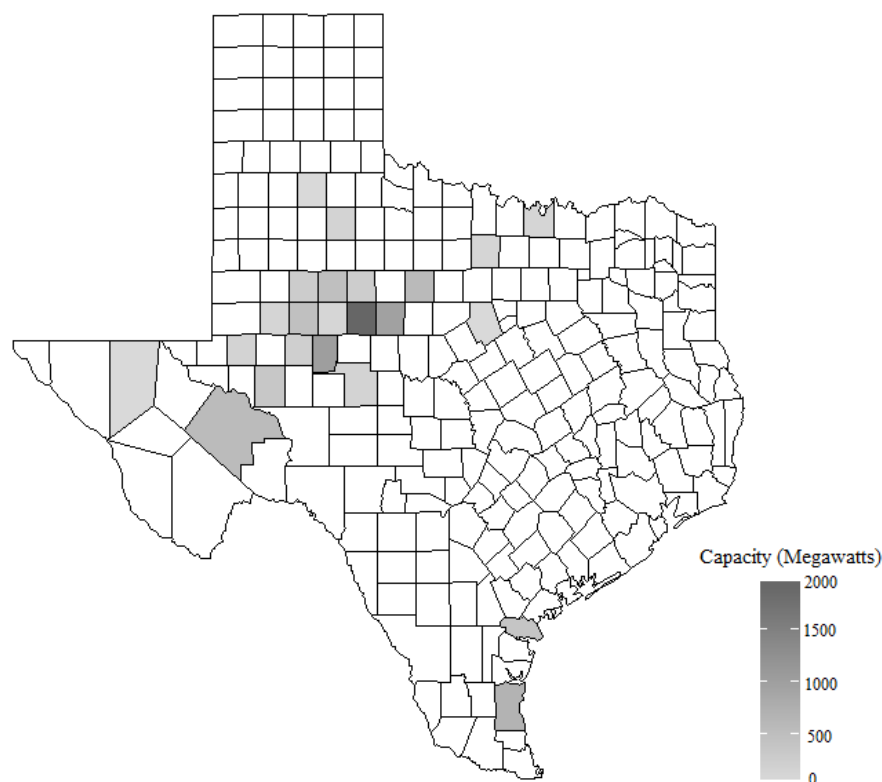


Note: These figures report results from the placebo tests.

Figure A3: Results of Placebo Tests

## A.5 The Effect of the Market Redesign on Wind Generation

Wind energy has a significant presence in the ERCOT region. As of 2010, installed wind capacity in ERCOT amounted to 9,363 MW, representing 9.45% of the overall generating capacity. Figure A3 demonstrates that the majority of the wind farms are located in western Texas, with the remainder in the southern portion of the state.



*Notes:* This figure is constructed by the authors using data from the 2010 EIA-860 forms.

Figure A4: Installed Wind Capacity in ERCOT: 2010

Wind power is determined by the availability of wind resources. Specifically, a wind turbine's potential generation is proportional to its cross-sectional area as well as the cube of wind speed. Wind is non-dispatchable in the sense that wind speed cannot be changed at will. However, cases do occur in which potential wind generation is not fully used. This happens largely because of limited transmission capacity between western Texas where the most abundant wind resources are, and eastern Texas where most electricity demand is located. In some cases, wind generation must be curtailed to avoid overloading congested

transmission lines.<sup>48</sup> Therefore, it is natural to ask if the market redesign resulted in less curtailment and better wind resource integration.

Without data on the frequency of wind curtailments, we rely on a regression approach to examine the effect of market redesign on wind generation. The idea is that wind output is determined mostly by wind speed. If there is no effect, we should expect to see that the observed wind output curve stays more or less the same pre- and post-redesign. However, if the redesign leads to better integration of wind resources, we should see a significant gap for wind outputs given the same wind speed and other market conditions before and after the redesign. During the sample period, 350 MW of additional wind capacity was added. To address increased capacity, we restrict our sample to the subset of wind farms that were already in operation as of June 1, 2010. We conduct the analysis at the weather zone level. For zone  $i$  at hour  $t$ , we estimate the following regression:

$$GEN_{it} = \theta_i After_t + \sum_{k=1}^3 \alpha_{ik} WSP_{it}^{(k)} + \sum_{k=1}^8 \beta_{ik} Demand_{kt} + \delta_h + \epsilon_{it}$$

where  $GEN_{it}$  is the aggregated wind generation quantity in zone  $i$  at hour  $t$ .  $After$  is a dummy that indicates the post-redesign period.  $WSP$  is the average wind speed cubed.<sup>49</sup> We also include demand in all eight weather zones as well as hourly fixed effects. Newey-West standard errors are calculated using 24-hour lags.

Table A3 shows the results of the coefficients for  $After$  at the five weather zones which have non-zero installed wind capacity. Although there appear to be increases in generation when only wind speed is included in the model, this effect goes away as more controls are added. In the full model, there is no evidence of a significant increase in wind generation after the redesign. If anything, the results seem to suggest that wind generation is lower in some regions post-redesign.

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<sup>48</sup>See Sioshansi and Hurlbut (2010) for an extensive discussion of ERCOT market protocols with respect to wind generation.

<sup>49</sup>Wind speed data are collected from National Centers for Environmental Information(NCEI)'s Integrated Surface Database. One station is selected from each county where wind farms exist and data are available. The average wind speed for each zone is calculated by taking the simple average of the stations within that zone.

Weather Zone	Model (1)	Model (2)	Model (3)
Far West	53.01** (24.03)	31.30 (23.35)	-19.98 (26.15)
North	21.54*** (5.17)	18.34*** (4.76)	2.94 (5.57)
North Central	26.72*** (9.95)	12.42 (9.18)	-26.19** (12.10)
Southern	7.68 (8.97)	8.42 (9.05)	-13.56 (12.03)
West	23.97 (36.28)	-44.42 (30.45)	-129.56*** (36.04)
Cube of WSP	Y	Y	Y
Hour	N	Y	Y
Demand	N	N	Y

*Notes:* Newey-West standard errors are reported in the parentheses.

\*\*\* Significant at the 1% confidence level

\*\* Significant at the 5% confidence level

Table A3: Effect of the Market Redesign on Wind Generation