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

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Abstract

This paper examines the impact of market organization on efficiency and emissions in the wholesale electricity market. Taking advantage of Texas' transition from a decentralized bilateral trading market to a centralized auction market, I find that information aggregation has a positive effect on market efficiency that dominates any change in market power incentives. Specifically, I show that, in the nine months following the transition, high-cost generators are displaced by low-cost generators in production, leading to a total cost saving of $30.7 million relative to the counterfactual. Although the centralized market reduces generation costs, it also has an unintended effect on pollution emissions. For moderate estimates of marginal damages, I 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 it 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, I focus on the US electric sector. Over the past 20 years, this sector has undergone drastic reform, as 17 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 policymakers and academics, the question of which market design supports a more efficient and competitive wholesale power market has sparked significant debate (Hogan, 1995).

To address this question, I focus on the wholesale electricity market in Texas which transitioned from a bilateral trading market to a centralized market on December 1, 2010. I examine how this market redesign affects market efficiency and social welfare. On one hand, a centralized market may improve market efficiency through information aggregation.[1] An important feature of the electricity market is the presence of network externality. It is difficult for market participants to resolve this externality in a bilateral way, due to limited information processed by each participant about others' production schedules. By contrast, in a centralized market, a system operator can utilize its central position to aggregate infor-

[1] 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.

mation from all generating units and minimize the 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 their marginal costs to inflate the market-clearing prices. Indeed, evidence of high price-cost margins has been found in other electricity markets.[2] Therefore, whether a centralized market yields a more efficient outcome remains an open question. Moreover, changes in market organization may also affect 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. I 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. I 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, I calculate the overall cost and emission changes in this market.

The primary finding of this paper is that the centralized market 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 511 more MWh per hour, which is a 3% increase in overall coal capacity utilization. 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,

[2]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).

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, my 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 \$5,062 lower than what would have been, for the nine months post redesign. This amounts to annual cost savings of \$44.3 million, or a 0.5% decrease in the total generation cost. These findings suggest that the benefits from information aggregation outweigh potential market power changes associated with the move to a centralized market.

While my results indicate a productive efficiency gain from the transition to a centralized market, I also find a negative environmental impact from this transition. Specifically, I find that the increase in coal-based generation leads to an increase in carbon dioxide (CO_2) emissions by 351 tons per hour or 1.3 percent. Applying different estimates of the social cost of carbon from the EPA (2016), I find that the increase in external costs of 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 (SO_2) and nitrogen oxides (NO_x) emissions. Overall, the market redesign is welfare-reducing if the external costs of emissions are taken into account.

This paper builds on and contributes to the market design literature, especially in the context of the electricity industry. While Joskow (2000) and Wilson (2002) provide an overview of the architecture of this industry, there is little empirical evidence on the relative performance of different organizational forms with the exception of Mansur and White (2012) and Cicala (2017). 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, I focus on a context where a market transition does 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 my knowledge, this is the first paper examining the environmental consequences of electricity market design. As my results suggest, these environmental impacts are critical for welfare evaluation. Third, I use an econometric approach that allows for considerable flexibility and requires no explicit assumptions on firm behavior or the grid. This is in contrast with Mansur and White (2012) which assumes away the presence of market power in their framework. Finally, my 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 my empirical strategy. In Section 6, I present my findings. I provide a discussion of the results in Section 7 and conclude in Section 8.

2 Background

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

2.1 Basics of the Electricity Market

Compared to other commodities, electricity has several unique characteristics. First, the demand for electricity varies widely from hour to hour and day to day, but is almost perfectly inelastic in the short-run. That is, very few consumers are willing to or able to adjust their consumption in response to fluctuation in wholesale electricity prices. Second, electricity cannot be stored in meaningful quantities. This requires a constant real-time balance between electricity generation and consumption. Sufficient imbalances between the two can cause brownouts (a drop in electrical frequency) or blackouts (complete loss of electrical service). Third, unlike railroad networks where a supplier can designate a path for delivery, electric power flows through transmission networks according to physical laws (Kirchhoff's Laws) rather than the laws of financial contracting. Finally, the entire transmission network must meet certain physical constraints regarding frequency, voltage and capacity to ensure grid reliability.

Because of the above attributes, the proper functioning of the electricity market calls for coordination among market participants. In the US, the entire electricity market is segmented into smaller power control areas.[3] Within each power control area, an entity known

[3] A power control area (PCA) is a portion of an integrated power grid for which a single dispatcher has operational control of all electric 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 by each PCA. Since the operations of these facilities have an impact on facilities in remote control areas, the US electric industry has developed a complex set of standard operating protocols through the National Electric Reliability Council (NERC) and

as the "balancing authority" ensures both the load-generation balance and the reliability of the grid. Traditionally, vertically integrated utilities fulfill the role of balancing authorities. They own both generation and transmission assets, and hence can 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 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.[4]

2.2 Market Design of the Wholesale Electricity Market

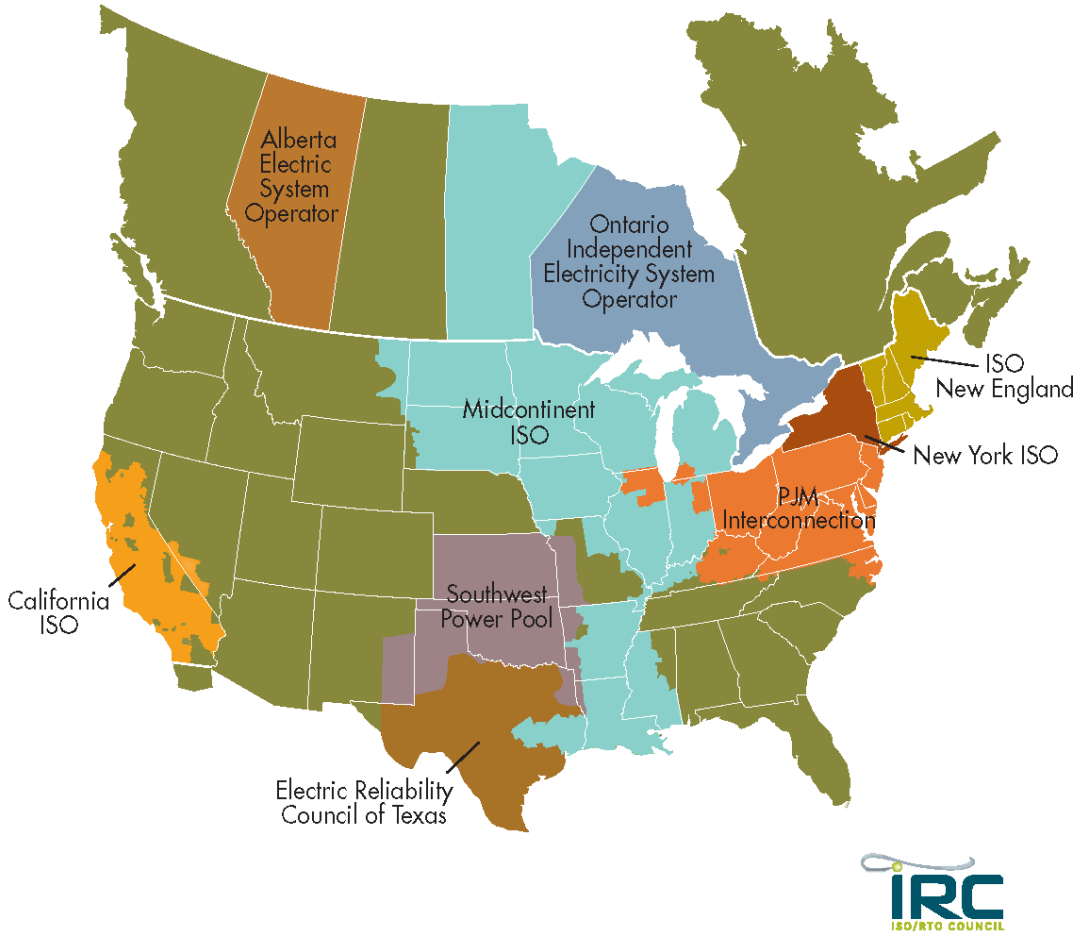
Although the organization of each wholesale electricity market is different, the various markets can be broadly categorized into two types based on the scope of the ISO's authority and the extent of the market's centralization.

The first market design is referred to as the bilateral trading market or Min-ISO. Under the 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 evaluates grid reliability and mitigates any energy imbalance 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

its eight regional reliability councils.

[4]Here, I consider ISO and RTO (Regional Transmission Organization) as synonyms.



Source: ISO/RTO Council

Figure 1: ISOs Operating in North America

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 find 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.[5] ERCOT serves 85 percent of Texas' load, 75 percent of Texas' land, and approximately 23 million customers. ERCOT is unique in that it is one of the three interconnections in North America. 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.[6]

On December 1, 2010, after years of planing, ERCOT transitioned from a bilateral trading market to a centralized auction market.[7] This transition entailed transferring most of the scheduling and dispatch responsibility from individual firms to ERCOT. Firms can rely entirely on the markets organized by ERCOT to sell and buy energy. In Appendix A.1, I provide more details about the scheduling and dispatch procedures under each market design.

3 Network Externality, Information Aggregation and Market Power

It may not be immediately clear which market scheme will produce a more efficient outcome. In this section, I examine the theoretical predictions regarding market organization and efficiency, and find that the result is indeed ambiguous. Using a simple example, I first illustrate the concept of network externality, a special form of externality in the electricity market. Then I examine how a centralized auction market can solve this externality problem and thus improve market efficiency. Finally, I show that a centralized auction market may also reduce efficiency if market power is taken into account.

[5]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, and later in 1999 passed Senate Bill 7 (SB7) to deregulate the retail electric 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 888.

[6]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.

[7]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 was finally launched on December 1, 2010.

3.1 Network Externality

As mentioned in Section 2, electricity is transmitted through an interconnected network that is subject to transmission constraints. In particular, networks can become congested. Once a network is congested, the amount of electricity that can be accommodated by the network from a particular source may depend on how much electricity is generated by other sources. This creates a special externality problem in the electricity market. Market efficiency may be 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. All three transmission lines are identical, except that the line between A and B has a capacity limit of 100 megawatts. At point C, there is also a 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. The actual flow is guided by Kirchhoff's Law which states that when there are multiple paths connecting the same orientation and destination, electrons will flow along the least resistant route.[8] 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 the resulting electrical flows.

Now imagine that the demand at C is increased to 600 megawatts. At this point, the transmission line between A and B reaches its capacity limit. If generator A simply produces more electricity, some of the additional electrons will naturally flow between A and B, causing damages to the transmission line and thus reliability issues. Therefore, we must look for an alternative allocation to fulfill the increasing demand.[9] An obvious solution is to obtain additional 300 megawatts from generator C, the second least costly generator, which

[8] 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: $I_{AB}+I_{BC}-I_{AC}=0$. Under scenario (a), $I_{AB}=I_{BC}=\frac{1}{2}I_{AC}$.

[9] One may wonder why we do not close down the link between A and B so that power can flow directly to consumers at C. Transmission lines like this are typically built for reliability reasons. For example, in case one path fails, the other provides an alternative to deliver supplies. Although transmission lines can be disconnected from the grid through a "disconnecter" or a "circuit breaker," these options are usually not intended for normal control of the circuit, but only for protection and safety isolation during service or maintenance.

yields a total generation cost of \$3900. Figure 2.b illustrates this situation, which I refer to as the "naive allocation".

While at first glance this seems to be the best solution, the naive allocation is actually not the most efficient because it overlooks potential complementarities among generation sources in the network. Suppose we have generator B provide 150 megawatts. This at first seems to be an inefficient arrangement, since B is the most expensive generator. But generation from B alters the resistance of the indirect path from A to C. Thus, it enables greater flow from generator A through the direct path between A and C without adding extra flow through the congested path between A and B.[10] Figure 2.c illustrates the resulting allocation. The total generation cost is \$3600, which is lower than the generation cost under the naive allocation.

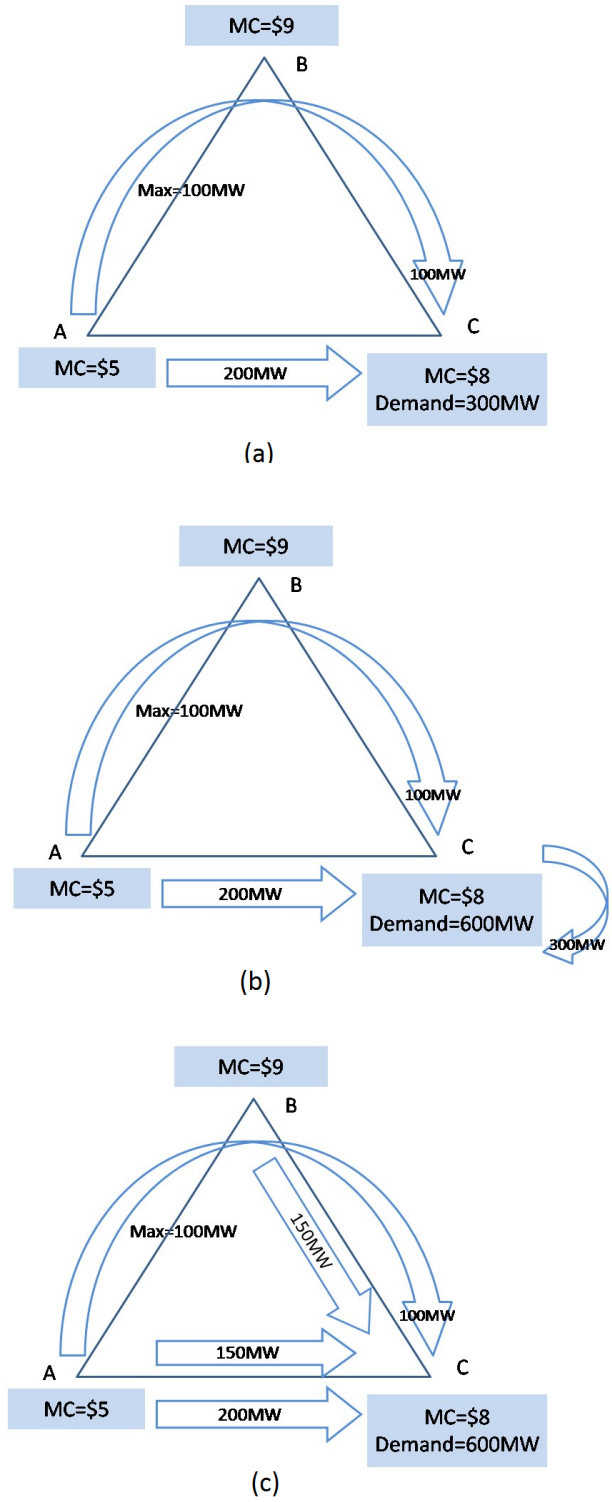
3.2 Imperfect Information and Information Aggregation

The above example shows that finding the most efficient allocation requires knowing the marginal costs of the generators and the structure of the network, as well as being able to calculate electric 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 may have a good idea of different generators' marginal costs, given the similarity of the technology and the abundance of public data, they may not know others' scheduled generation since these are privately negotiated. Moreover, the actual transmission network has hundreds of lines with thousands of nodes. This complexity adds to the difficulty of identifying externalities. While it seems that market participants may learn gradually through repeated interactions, it is an illusion created by the simplicity of the network in the example. Identifying externalities in a complex network requires detailed modeling of the grid and considerable computing power. As a result, the externality problem cannot be resolved in a Coasian fashion under a bilateral trading market.[11]

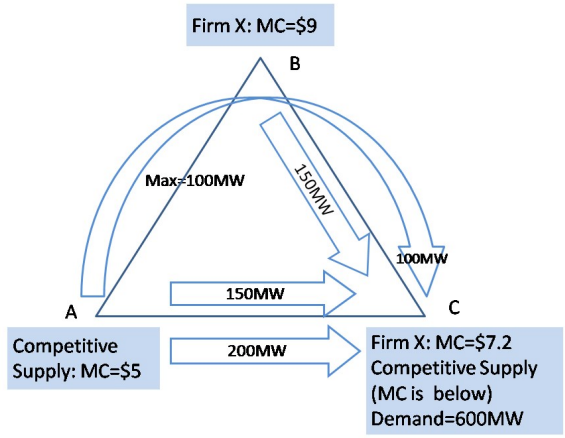
[10] Recall that in footnote 8, we have $I_{AB}+I_{BC}-I_{AC}=0$. This means that we can have a higher I_{AC} by increasing I_{BC} with the same I_{AB}.

[11] Although ERCOT can re-dispatch generators in the balancing market, the adjustments do not fully correct inefficiency in the bilateral schedules, for several reasons. First, the balancing market only takes care of the imbalance between scheduled generation and demand, which is about only 5% of the overall generation, while the majority are scheduled by market participants. Second, if a bilateral schedule is feasible and yet inefficient, such as the "naive allocation" in the example, ERCOT will not change it in the balancing market. Finally, when ERCOT does change the schedules to resolve power imbalance or congestion, it adjusts generation in a piecemeal fashion, as explained in 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.

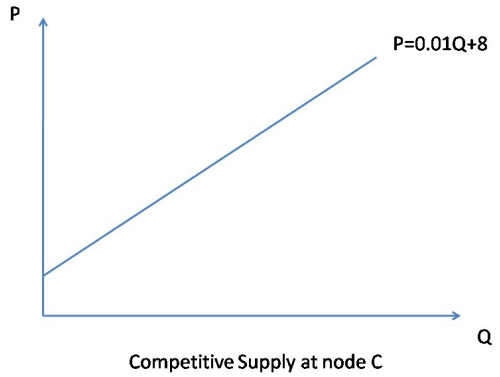


Notes: These figures provide an example illustrating the notion of network externality. Figure (a) shows the optimal allocation when demand is 300 megawatts. Figures (b) and (c) show the "naive allocation" and the optimal allocation respectively when demand is 600 megawatts. See the text for details.

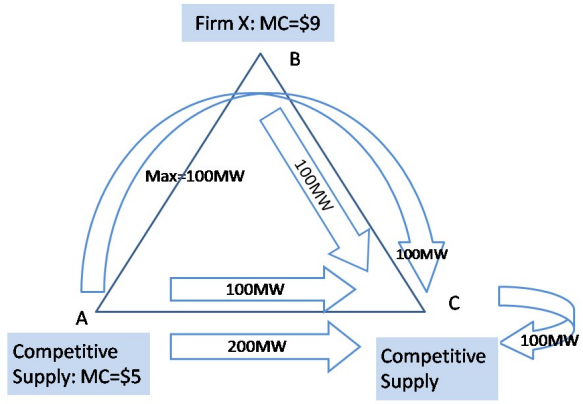
Figure 2: An Example Illustrating Congestion Externalities



(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

By 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 problem. Mansur and White (2012) share the same view on the source of efficiency gain.

3.3 Market Power

In the previous example, I assume 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 result when firms deliberately withhold their generation capacity or submit bids substantially in excess of their marginal costs. Such behavior changes the dispatch order on the supple curve and causes high-cost generators to be used while low-cost ones stay idle.[12] Evidence of such manipulation has been found in the 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. As shown in Figure 3.a, there is a mass of competitive suppliers located at node A with a constant marginal cost of \$5. A competitive fringe supplier sits 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.

Under this setup, the most efficient allocation remains unchanged: we should procure 450 megawatts from suppliers at A and 150 megawatts from Firm X at B. This will be the resulting allocation in a centralized auction market when marginal costs are submitted as bids, or equivalently firm X is acting competitively. The equilibrium price at point B is \$9 and the profit of Firm X is \$0.

[12]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.

However, suppose Firm X wishes to take advantage of its unique position in the congested network to increase its profit. If it withholds one megawatt at B, this means two additional megawatts must be generated at C, increasing prices at both B and C. In this case, Firm X has to make a classic tradeoff between profiting from a higher quantity versus a higher price. Assume Firm X uses the quantities it supplies as leverage. At the optimum, Firm X should supply 100 megawatts at point B, and 0 megawatts at point C, leaving the competitive fringe firm to meet the remaining demand, as depicted in Figure 3.c.[13]. The equilibrium prices at point B and C are \$13 and \$9, respectively, and Firm X's profit is \$400.[14] 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. The total generation cost becomes \$3750, which is higher than not only the cost under the efficient allocation, but also the cost under the naive allocation.[15]

This example shows that the exercise of market power can significantly affect generation allocation. Therefore, whether a centralized market improves efficiency depends on changes in both the management of network externality and the exercise of market power.[16] In the next sections, I will empirically examine the efficiency effect of ERCOT's market redesign.

4 Data

For this study, I compiled a detailed and comprehensive dataset from a variety of sources. Most of the 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.[17]

[13]See Appendix A.2 for details.

[14]The outcome will be the same if I assume Firm X competes by bidding into the pool. The optimal strategy then is to bid \$13 and \$9 for units at B and C, respectively.

[15]Recall that the naive allocation is the allocation when marginal costs are known but complementarity among generation sources is not taken into account. In this case, the naive allocation will procure 300 megawatts from A and 300 megawatts from Firm X at point C. The resulting generation cost for the naive allocation is \$3660.

[16]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 market power issue in the bilateral trading setting.

[17]I exclude dates between February 2, 2011 to February 5, 2011. During this period, a strong arctic front approached Texas and resulted in the lowest temperature in 20 years. 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.

4.1 Generation Data

The primary data I use to determine electricity generation are from ERCOT. For each generating unit under ERCOT's control, I observe the net electrical output in 15-minute intervals.[18] I aggregate net generation at the hourly level to be consistent with the other data I have. Note that my sample is missing several days of data immediately following the market redesign, due to glitches experienced by ERCOT in that period, but is otherwise complete. Overall, there are 429 units, at 218 power plants, supplying electricity to the grid managed by ERCOT.[19]

To determine ERCOT's generation portfolio, I supplement ERCOT's generation data with 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, with the rest comprising only 1% of the total generation.

Fuel Type	Share of Capacity(%)		Share of Generation(%)	
	2010	2011	2010	2011
Coal	19.95	20.34	35.15	35.61
Hydroelectric	0.58	0.55	0.28	0.15
Natural Gas	64.36	63.55	44.59	44.60
Combined Cycle	37.99	39.17	38.00	37.97
Combustion Turbine	7.13	7.06	3.52	3.72
Steam Turbine	19.24	17.32	3.07	2.91
Nuclear	5.17	5.27	12.08	10.96
Wind	9.45	9.79	6.90	7.71
Others[20]	0.49	0.50	1.00	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 come from EIA-860 forms and EIA-923 forms.

Table 1: Generation Composition in ERCOT: 2010-2011

[18] A generating unit is a single turbine along with a boiler and a smokestack. A power plant usually consists 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, I treat them as one single unit.

[19] Not all the 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 is located in Oklahoma.

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

4.2 Generator Characteristics

I obtain plant- and generator-level characteristics from EIA-860 forms, EPA's Continuous Emissions Monitoring System (CEMS) and eGrid.[21] For each generating unit, I 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, I also observe their hourly CO_2, SO_2 and NO_x emission quantities and heat inputs.

For thermal generators, I use these data to measure the average CO_2, SO_2 and NO_x emission rates and heat rates. Heat rate is the ratio of thermal energy input against electricity output. It is stable within the operating range of a generator, but can be higher during startups.[22]Heat rate reflects power plant's efficiency: the lower the heat rate is, the more efficient a generator is. For generators covered in CEMS, I estimate the average heat rate for each unit by using the slope of regressions of heat inputs (in MMBtus) on net generation (in MWhs). For generators not covered in CEMS, I use their plant-level nominal heat rates obtained from the EPA's eGrid database. To calculate average emission rates, I divide total emission quantities (in short tons or pounds) by total net generation (in MWhs).

Table 2 presents the summary statistics for the thermal generators in my sample. In general, coal generators tend to be larger, more polluting and slower in ramping than natural gas generators. Natural gas generators use several different technologies. A combustion turbine, a.k.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. The technology has not seen much improvement since then. By 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 heat rate of the most recent turbine is only one fourth of that of the oldest one. Besides, combustion turbines can also respond quickly to changing demand. Therefore, they are often used as peaking plants. The relatively new

[20]Others include biomass, petroleum coke, distillate fuel oil, solar and electricity storage.

[21]All fossil-fuel generating units with at least 25 megawatts of generating capacity have to report their hourly gross generation, heat inputs, and CO_2, SO_2, and NO_x emissions to the EPA. In the sample, 218 out of 300 thermal generators are covered by CEMS.

[22]More than half of the startup costs are fuel costs incurred in warming up the generator. The startup cost varies by technology and unit size.

[23]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. I obtain this information from the 2013 EIA-860 form, since it is available only after 2013.

	Coal	Natural Gas		
		Combined Cycle	Combustion Turbine	Steam Turbine
Nameplate Capacity(MW)	638.61	414.79	72.53	254.10
	(192.96)	(277.91)	(44.13)	(215.74)
Years in Operation	26.00	16.15	19.50	43.64
	(11.38)	(11.11)	(12.63)	(8.08)
Heat Rate(MMBtu/MWh)	9.55	7.38	11.90	10.99
	(0.62)	(1.35)	(4.26)	(2.82)
CO_2(Ton/MWh)	1.16	0.51	0.72	0.80
	(0.20)	(0.13)	(0.29)	(0.33)
SO_2(Pound/MWh)	5.80	0.01	0.03	0.02
	(3.86)	(0.02)	(0.05)	(0.03)
NO_x(Pound/MWh)	1.36	0.34	2.24	1.76
	(0.69)	(0.26)	(2.61)	(1.06)
Median Ramping Time[23]	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. The heat rates and emission rates are calculated by the author as described in the text. Standard deviations are reported in the parentheses.

Table 2: Summary Statistics

combined-cycle technology combines these two thermodynamic cycles together to improve the efficiency of energy conversion. As a result, they have the smallest average heat rate among natural gas generators.

4.3 Electricity Demand

The hourly demand data at eight weather zones are obtained from ERCOT.[24] The data is derived by aggregating meter data and includes both transmission and distribution losses. I use demand at the weather zone level to capture any spatial distribution in demand that may impact generation outcomes. In addition, I select a time period that includes both winter and summer months under each market design to capture any seasonal or diurnal patterns in demand.

4.4 Cost Data

The cost structure in the electricity industry is relatively straightforward and well understood. For wind generators, the marginal cost for producing 1 more MW is essentially zero. For nuclear power plants, the marginal cost can be estimated by adding up the fu-

[24] 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: coast, west, far west, east, north, north central, southern and south central.

el cost and the variable operating and maintenance cost. I 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, I 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) variable operating and maintenance costs (VOM), (4) the emission rates of each generator, and (5) emission allowance prices. Appendix A.3 provides more details on the data sources of elements (2), (3) and (5). For each thermal generator i at time t, its marginal cost is calculated using the following formula:

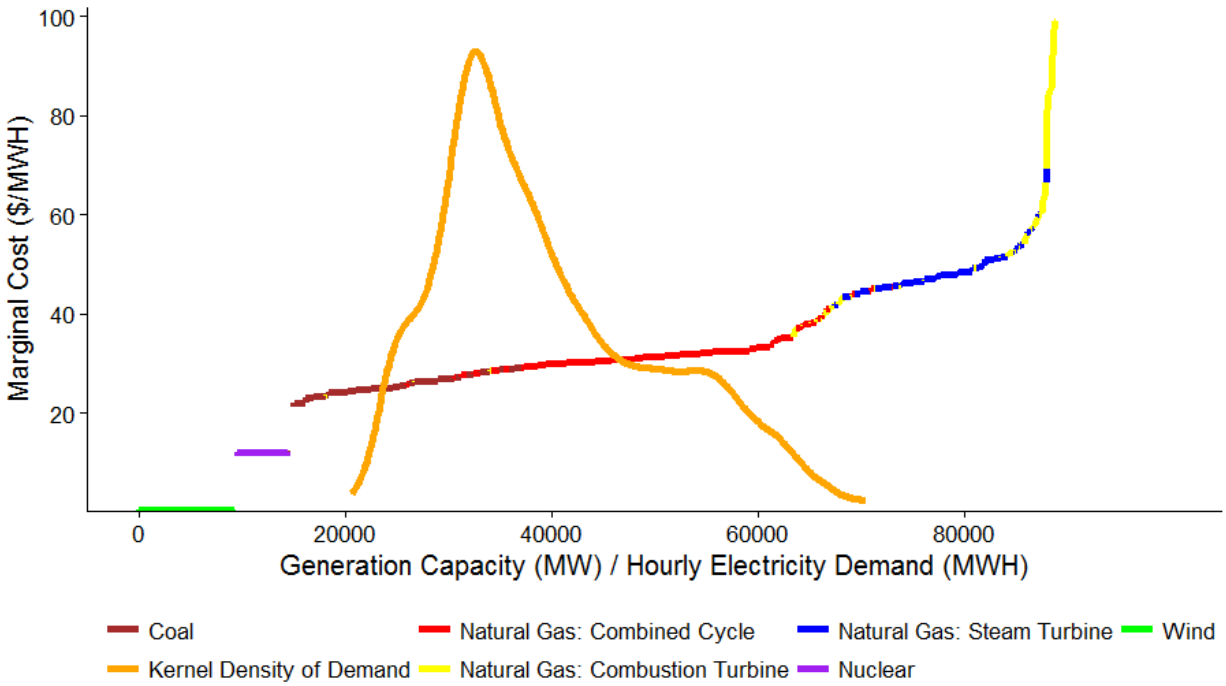
$$\mathrm{MC_{it}}=\text{Heat Rate}_\mathrm{i}\times\text{Fuel Price}_\mathrm{it}+\mathrm{Pno_{xt}}\times\mathrm{NOx_i}+\mathrm{Pso_{2t}}\times\mathrm{SO_{2i}}+\mathrm{VOM_i}$$

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. I also overlay on the same graph the distribution of hourly electricity demand. We can see that the marginal unit is a coal or a combined-cycle natural gas generator for most realizations of demand, while during peak hours it is a combustion or a steam turbine.

5 Empirical Strategy

In this section, I introduce the econometric approach I use to quantify the changes in generation allocation due to the market redesign. I begin by discussing how market efficiency is measured in electricity generation.

Figure 5 illustrates a hypothetical efficiency change. Following the literature, I treat electricity demand as perfectly inelastic in the short-run. Demand swings are driven entirely by exogenous forces, such as temperature or human activity. 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 MC curve in the graph represents the theoretical efficient supply based on installed generator capacity and each generator's marginal cost. However, the actual supply will deviate from this curve. A generator operates



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). It also shows the kernel density of the total hourly electricity demand for the same period. See the text for details.

Figure 4: Marginal Cost Curve and Distribution of Demand

out of the "merit order" if it is called on to help meet n megawatts of demand even though it is not the n cheapest megawatts in terms of installed capacity. Out-of-merit cost is measured as the additional production cost relative to the cost of dispatching the cheapest units. In Figure 5, the grey area represents out-of-merit costs under the bilateral trading market. An electricity market may incur out-of-merit costs for a number of reasons. First, transmission constraints may make it infeasible to utilize only the least-costly units.[25] Second, market participants may fail to identify and resolve network externalities. Third, they may also influence the market by exercising market power, as explained in Section 3. In my study, I do not focus on out-of-merit costs per se, as does Borenstein et al (2002). Instead, I focus on the difference in out-of-merit costs between the two different designs. In Figure 5, the centralized market brings the supply closer to the MC curve, reducing out-of-merit costs. Correspondingly, the slashed-pattern area measures the efficiency gain in this hypothetical

[25]Other reasons 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, the 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.

example.

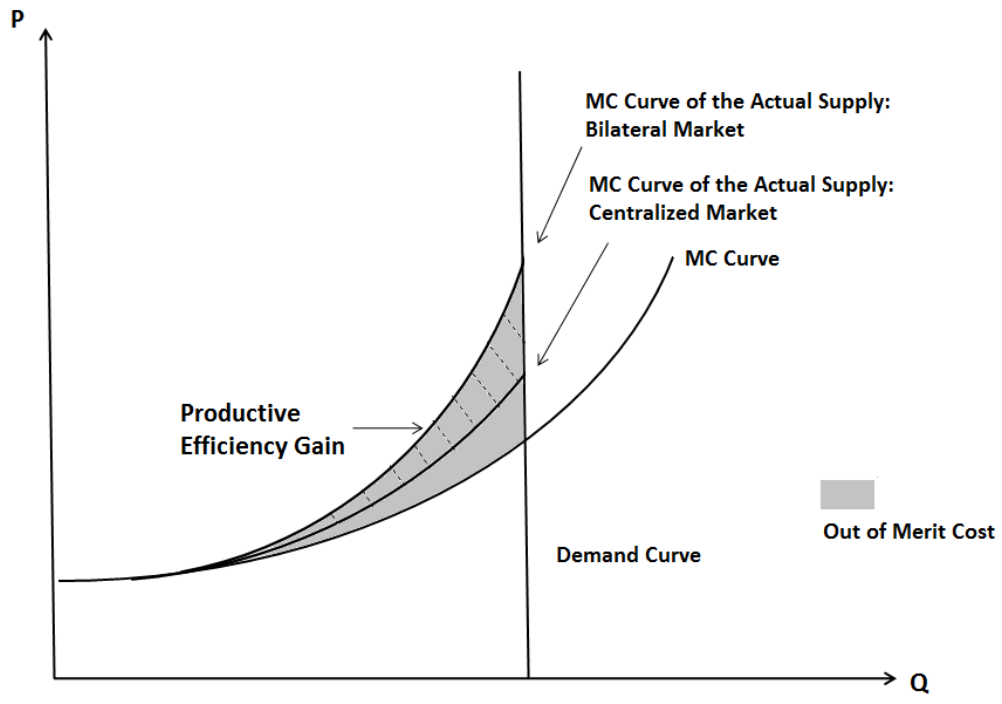
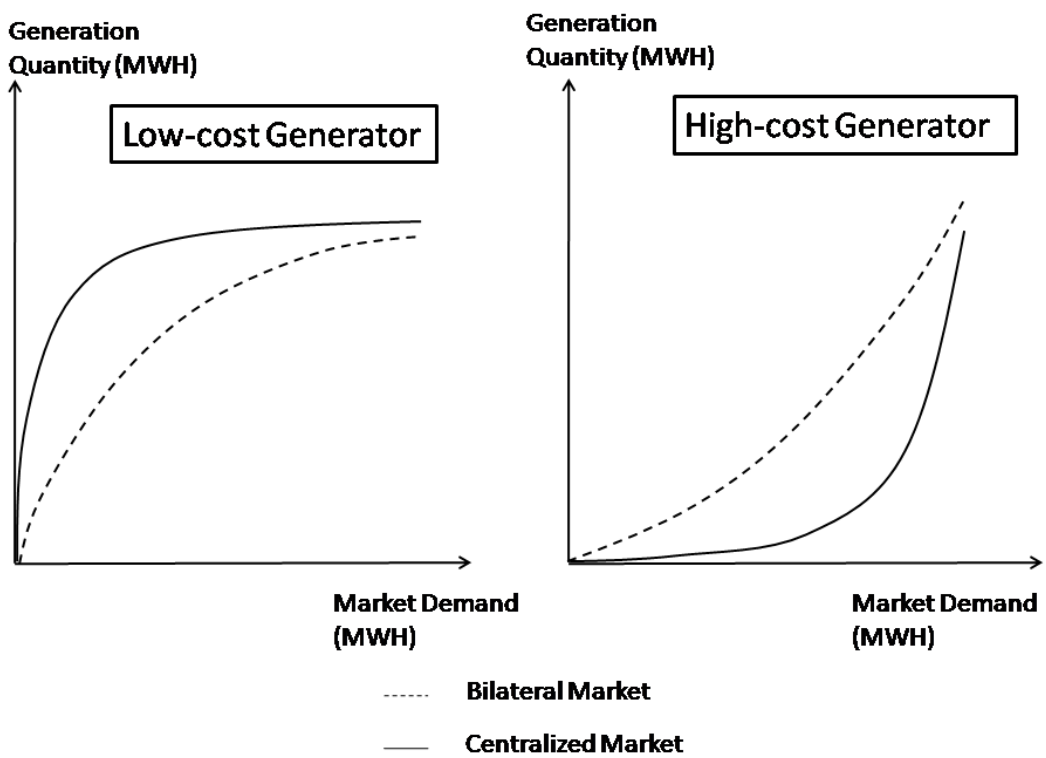


Figure 5: An Illustration of A Hypothetical Efficiency Gain Under the Centralized Market

In order to measure the changes in generation costs, I need to create a credible counterfactual of what the outcome would be had ERCOT not redesigned its market. Creating this counterfactual poses several challenges. First, a market simulation with an engineering model would require modeling the electrical 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 as well as the competitive dynamics. Second, doing a pre/post comparison of generation costs might seem plausible as there are few changes in the market during the relatively short period preceding and following the redesign. Indeed, in Appendix A.4, I show that the ranges of demand levels and fuel prices are comparable pre- and post-redesign, and there is no major change in market capacity during the sample period. However, demand levels and fuel prices fluctuate even within a very short window of time. Hence, the distribution may vary over time. In particular, during my sample period, the average demand post-redesign is lower than the average demand pre-redesign. Without taking these changes into account, I may misattribute a cost reduction due to demand shifts

as an indication of an effect of the market redesign.

I 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. I then use these estimates to construct counterfactual generation quantities which form the basis for the calculation of changes in overall generation costs and emissions. The idea is that if the centralized market results in an improvement in market efficiency, we should in general 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).



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

I treat wind power and nuclear power as non-dispatchable units unaffected by the market

redesign. For wind generators, generation quantity is largely determined by the availability of the wind, but 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, I do not find evidence supporting such a claim.[26] For nuclear power generators, given its low marginal costs and limited capacity to follow load, they almost always run at full capacity unless having an outage. Based on the above reasons, the rest of my analysis will focus on only thermal generators.

Let $ThermalDemand_{jt}$ be the residual demand for thermal generators after subtracting supply from wind, nuclear and other sources at weather zone j in time t.[27] I then separate $ThermalDemand$ at each zone into 12 mutually exclusive equal-frequency bins.[28] Let b_{jk} (j=1,...,8; k=1,...,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, I estimate a continuous piecewise linear model with respect to demand at each weather zone for the pre- and post-redesign periods respectively:

$$\text{Gen}_{it} = \beta_{0i} + \sum_{j=1}^{8}\sum_{k=1}^{12} \beta_{ijk} B_{jk}(ThermalDemand_{jt}) + \boldsymbol{\phi_{ih}} + \boldsymbol{\delta_{iw}} + \alpha_{1i} P_{Ng-Coal,t} + \alpha_{2i} P^2_{Ng-Coal,t} + \epsilon_{it} \tag{1}$$

I also include hour fixed effects $\boldsymbol{\phi_{ih}}$ and day-of-week fixed effects $\boldsymbol{\delta_{iw}}$, as well as a quadratic form of the price difference between coal and natural gas to control for the effect of fuel prices on the switch between coal and natural gas generation.[29] All of the coefficients are generator specific, and different before and after the market transition. Overall, there are 10,646 hourly observations in my sample. For each generator, I estimate 256 coefficients, resulting

[26] See Appendix A.5 for more details.

[27] Others include biomass, petroleum coke, distillate fuel oil, solar and electricity storage.

[28] The optimal number of bins is selected by using the leave-one-out cross validation technique. Specifically, given the number of bins, I estimate the corresponding model on (N-1) observations (hours) and predict the outcomes for the remaining one. I repeat the process for all N combinations and calculate the prediction errors. I experiment with different numbers of bins and choose the one that minimizes the mean squared error.

[29] Including higher-order polynomials of the fuel price difference yields similar results. I also perform ridge regressions as an alternative specification to address overfitting concern. The results are quantitatively similar.

in a total of 76,032 coefficients for the 297 generating units in the sample. To form my counterfactual, I use the estimates from the pre-redesign period and calculate the change in generation quantity for each generator i at each hour t in the post-redesign period. In the mathematical form,

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

The 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 up to 24 hours.

6 Results

6.1 Effect of the Market Redesign on Generation Quantity

In this section, I first present the estimated average hourly changes in generation quantity and then examine how the changes in generation vary with changes in demand and fuel prices. In light of the heterogeneity of costs across generators, I aggregate the results according to their fuel and technology types.

Table 3 reports the estimated changes in generation quantity averaged over all hours in the post-redesign period. The baseline column shows the results from the estimation of equation (1). On average, coal generation increases by 511.2 MWh per hour while natural gas generation decreases by a similar amount. This finding suggests that the centralized market makes use of lower-cost resources more than the bilateral trading market. To provide more perspective on the magnitude of this change, the overall coal generating capacity in ERCOT is 19,819 MW. Therefore, the increase in coal generation is roughly a 3% increase in the utilization of overall coal capacity. Within natural gas generators, the decrease in generation comes from both combined-cycle and steam-turbine generators. Interestingly, combustion turbine generators experience an increase in production after the redesign, although they do not have the lowest marginal costs. This increasing usage can be explained by their ability to adjust production quickly to serve peak loads. I will discuss a more nuanced picture of these changes later.

In addition, I run several alternative specifications to check the robustness of my results. First, since ambient temperature may affect thermal generators' efficiency, I re-run my

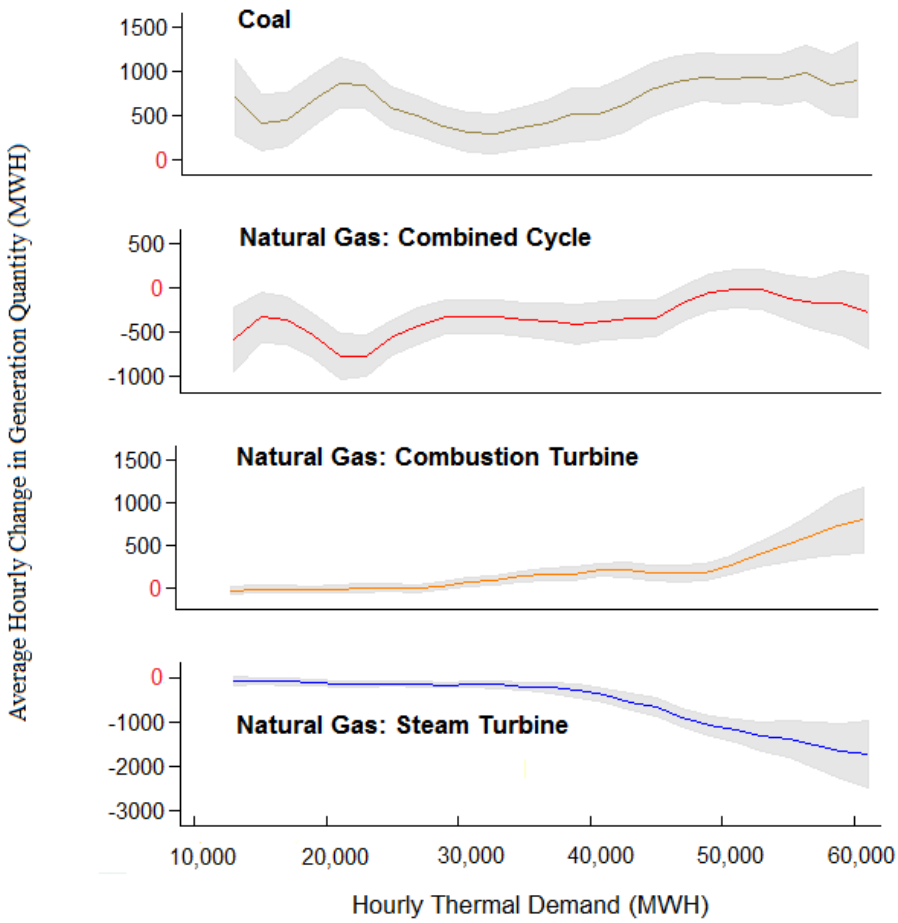
Fuel Type	Baseline Model	Alternative Models				
		(1)	(2)	(3)	(4)	(5)
Coal	511.2	524.2	508.2	509.1	554.9	480.4
	(71.2)	(68.6)	(75.6)	(73.5)	(70.8)	(71.5)
Natural Gas: CC	-353.4	-350.2	-352.7	-357.2	-362.4	-423.7
	(57.8)	(57.8)	(60.6)	(60.0)	(54.7)	(55.0)
Natural Gas: CT	106.8	86.5	106.2	113.6	115.6	95.7
	(15.4)	(13.6)	(15.2)	(16.0)	(16.5)	(15.3)
Natural Gas: ST	-306.3	-301.1	-303.3	-314.8	-281.9	-346.1
	(29.8)	(30.0)	(28.9)	(31.2)	(29.9)	(27.4)
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 the estimates of the 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

analysis including a quadratic form of temperature in model (1).[30] Second, generators differ in their ability to adjust output in response to load fluctuations. To capture this dynamic constraint, I include the daily variance of demand and one-hour lagged demand in models (2) and (3), respectively. Third, in model (4), I experiment with a higher order polynomial of the fuel price gap. Finally, in model (5), I truncate the predictions that are either below zero or beyond the generators' nameplate capacities. Note that while about 25% of the predictions are truncated, only 5% of these are more than 5 MWh away from the thresholds. The results from these alternative specifications are reported in Table 3. Although the magnitudes differ slightly, the overall pattern from each alternative specification is consistent with my baseline results. In addition, in Appendix A.4, I perform two placebo tests and find that these changes are not observed in other years when there is no market redesign.

[30]Temperature data are collected from National Centers for Environmental Information (NCEI)'s Integrated Surface Database. I use the average hourly temperature of the three largest cities in Texas, i.e., Houston, Dallas, and San Antonio.



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 per MMBtu for natural gas and \$2.17 per MMBtu for coal. The grey area indicates 95% confidence intervals.

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

Next, I examine how the average hourly change in generation quantity varies with demand levels, assuming average post-redesign fuel prices. Figure 7 plots the 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 MWh, the point at which coal and combined-cycle natural gas split on the marginal cost curve. The results 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, as this resource is relatively cheaper compared to steam turbines.

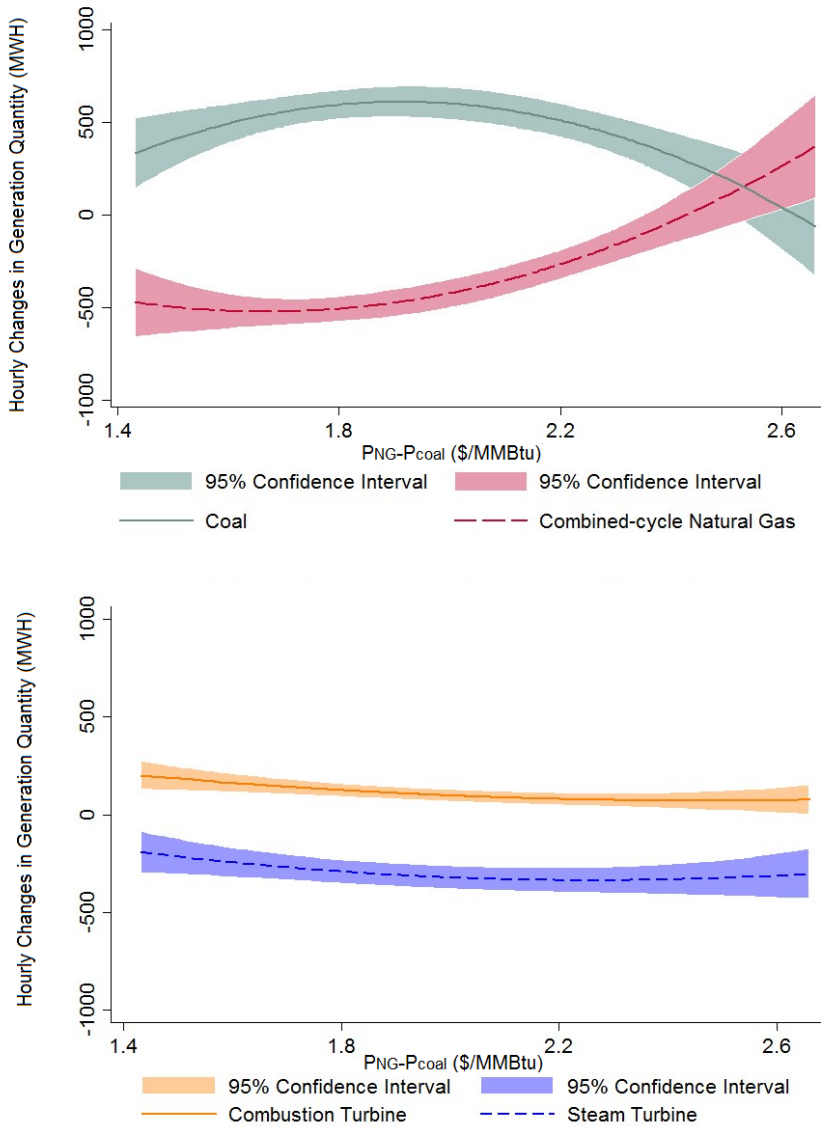
For combustion and steam turbines, their changes display interesting patterns. When demand is low, these two resources are less likely to be used. Consequently, the market redesign has little effect on their generation levels. However, when demand is high, combustion turbine generation increases and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

Finally, in Figure 8, I examine the changes in generation quantity at different fuel prices, assuming average post-redesign demand levels. Regarding coal generation, the results indicate an interesting inverse-U shape. As the price gap between coal and natural gas increases, so does the switch from natural gas to coal generation. However, at a certain level, this increase in coal generation slows, as market participants can easily identify the cost advantages of coal at this gap level regardless of market design. As a result, there is less room for improvement under the centralized market. This pattern is also supported by the 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 the generation cost due to the market redesign, I use each generator's estimated quantity changes from the previous section and their average marginal costs in the post-redesign period.[31] The overall change in generation cost at hour t is the sum of changes from all the generators, i.e.,

[31]This approach assumes no start-up cost and constant marginal costs. An alternative approach is to run regressions similar to equation (1), but with a different dependent variable – the heat inputs. In this way, I can capture any nonlinearity in the fuel usage over the operational range of a generator. With the estimated changes in heat inputs, I can apply the fuel prices to derive the 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, I estimate the non-fuel cost changes using the 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 is \$8,332 per hour on average for the nine months post redesign. This is higher than the estimate without start-up costs, as it captures the additional cost saving from increasing generation by combustion turbines which have the lowest start-up cost. The limitation of this approach is that only generators covered in CEMS data have heat input information. Thus I must limit the sample to those generators, which comprise about two thirds of all thermal generators.



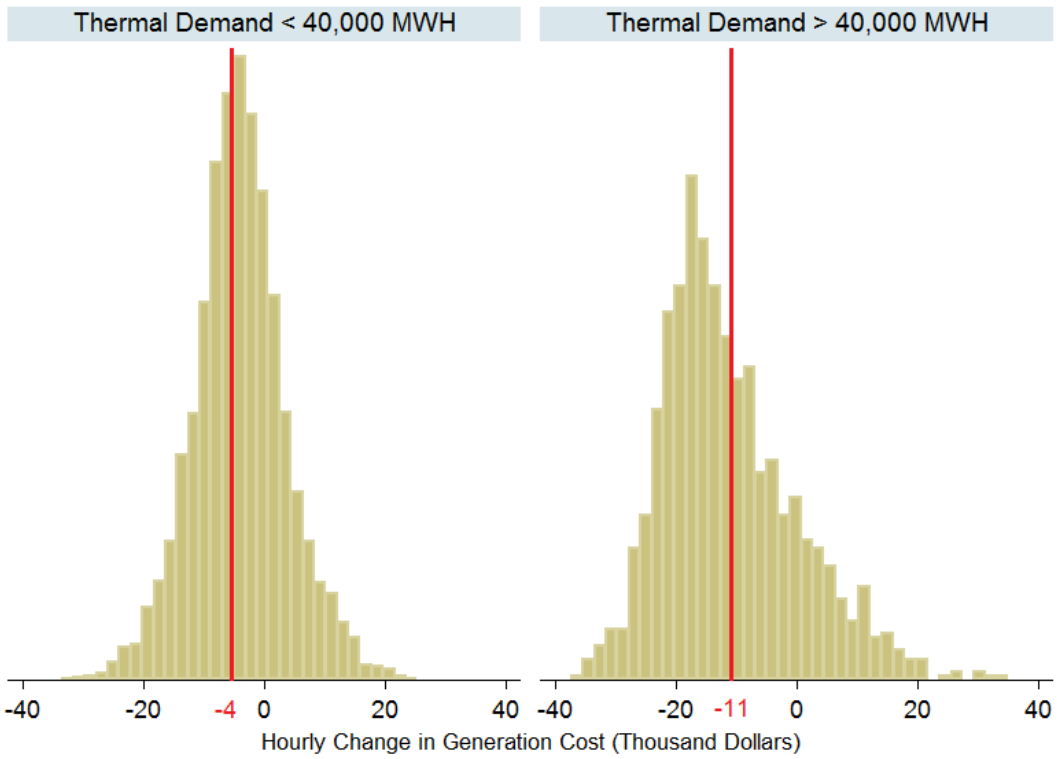
Notes: This figure shows the hourly changes in generation quantity over the price differences between natural gas and coal. Demand at each zone is assumed to be at its post-redesign average, which adds up to 31,196 MW for the overall thermal demand. The shaded area indicates 95% confidence intervals.

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

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

Averaging across all hours, the cost reduction is estimated to be \$5,062 per hour with a bootstrapped standard error of \$1,026 for the nine months in the post-redesign period. The reduction is roughly 0.5% 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 75% of the time. Figure 9 shows the distribution of hourly changes in generation cost for low and high demand hours separately. In general, we can see that the cost reduction is higher during high demand hours.



Notes: This figure shows the histograms of the estimated changes in generation cost for hours of low demand (thermal demand < 40,000 MWh) and hours of high demand (thermal demand > 40,000 MWh). The red lines indicate the average change in generation cost in each case.

Figure 9: Distribution of Estimated Changes in Generation Cost: Low v.s. High Demand

6.3 Effect of the Market Redesign 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 weighted against changes in external costs of emissions.

Given the available data, I focus on three pollutants: CO_2, SO_2 and NO_x. To estimate the change in emissions of each pollutant, I again use the estimated changes in electricity

generation quantity and each generator's emission rates. For pollutant j, I calculate the change in emission quantity at 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_2 emission increases by 350.5 tons per hour or 1.3 percent. This rise in CO_2 emission is not surprising given the increasing usage of coal generators in the centralized market. On average, coal power plants emit 1.16 tons of CO_2 per MWh, while natural gas plants emit only 0.65 tons of CO_2 per MWh. For SO_2 and NO_x, I find that emissions decrease by 0.268 and 0.239 tons per hour, respectively. Notably, SO_2 emissions decrease despite the fact that coal generators on average emit far more SO_2 than natural gas generators. This decrease is a result of generation changes within coal plants. The SO_2 emission rates of coal generators are dispersed, ranging from as low as 0.1 pound/MWh to as high as 14.8 pound/MWh. This variation is a reflection of heterogeneity in coal power plants' compliance strategies with environmental regulations. For example, coal plants can choose whether to install a scrubber or what kinds of coal to use. As a result, when high sulfur emitters are displaced by low sulfur emitters within coal generators, the overall SO_2 emission levels can decrease. However, this change is not significant, given the relatively large standard errors.

In a similar way, I 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 value of emissions, I need to select appropriate measures of marginal damages. For CO_2, EPA (2016) compiles estimates on the social cost of carbon for use in regulatory analysis. For one metric ton of CO_2 emission in 2011, the social cost ranges from \$10 to \$51 in 2007 dollars depending on the assumed discount rates. I convert 2007 dollars to 2011 dollars to make the values comparable with generation cost estimates. For SO_2 and NO_x, I use Jaramillo and Muller (2016)'s marginal damage estimates. Unlike CO_2 which is a uniformly mixed pollutant, SO_2 and NO_x have relatively localized geographic impacts. Hence, these estimates are spatially differentiated at the county level. For SO_2, the marginal damage ranges from \$7,713.4 to \$41,959 per metric ton, while for NO_x, the marginal damage ranges from \$1,434.6 to \$7,785.2 per metric ton, both in 2011 dollars.

Pollutant	ΔEmission Quantity (Ton/Hour)	Marginal Damage (2011$/Ton)	ΔExternal Cost (2011$/Hour)
		11	3,855.5
			(688.6)
CO_2	350.5	35	12,267.5
	(62.6)		(2,191)
		56	19,628
			(3,505.6)
SO_2	-0.268	7,713.4 - 41,959	10,847
	(0.25)		(4,949)
NO_x	-0.239	1,434.6 - 7,785.2	-1,930.5
	(0.05)		(269.3)

Notes: This table reports the average hourly changes in emission quantities and the associated changes in external costs. Standard errors reported in the 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. The external costs of CO_2 emissions range from $3,855.5, to $19,628 per hour depending on the social cost of carbon, while the external costs of SO_2 and NO_x emissions are estimated to be $10,847 and $-1,930.5 per hour respectively. Taken together, these results show that the overall change in emission costs exceeds the private generation cost savings of $5,062 per hour. 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 CO_2 emissions are not regulated, SO_2 and NO_x are subject to cap and trade programs. However, this internalization should not significantly impact my results, since the average allowance prices for SO_2 and NO_x during my sample period are just $8.4 and $275.5 per ton respectively, a very small fraction of the actual damages. A second caveat is that I implicitly assume that any environmental damage incurred by changes in SO_2 and 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. However, if 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 SO_2 or NO_x, I find the increase in the external cost of CO_2 emissions itself completely offsets the private efficiency gain, as long as the marginal damage of CO_2 is greater than $15 per ton.

7 Discussion

The above results show that both the generation cost reduction and the external cost increase are statistically significant and economically large. In this section, I first compare my results with the predicted savings expected by ERCOT, and then discuss whether the redesign is 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, Inc. and Resero Consulting (CRA/Resero) in 2008, to conduct cost-benefit analyses of the new market design. These studies use the GE MAPS simulation model that includes a full transmission representation of ERCOT but assumes no market power. The annual production cost reduction is estimated to be $66.8 million and $48.0 million in 2008 dollars, respectively. Furthermore, a back-cast using bids submitted during a market trial suggests that the 2008 production cost 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, I find that the average hourly cost saving is $5,062, which amounts to $44.3 million on an annual base. This number is smaller than the aforementioned estimates, but of the same order of magnitude. The difference between my estimate and the engineering estimates suggests that changes in market power during the redesign is also important in determining generation cost savings.

Benefit	
Generation Cost Saving($m/year)	44.3 (Author's Calculation)
Ancillary Services Cost Saving($m/year)	17.0 (ERCOT, 2011a)
Savings from Improved Generation Siting($m/year)	34.9 (CRA/Resero, 2008)
Cost	
One-time Implementation Cost($m)	548.6 (ERCOT, 2011b)
Incremental Operational Costs($m/year)	14.6 (CRA/Resero, 2008)
Environmental Cost($m/year)	111.9-250.0 (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

A second question that arises is whether the market redesign is warranted when costs and benefits are considered. 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 $17 million per year.[32] Additionally,

[32] Ancillary services are those services necessary to maintain grid stability and support continuous balance

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 $34.9 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 $548.6 million as well as yearly recurring expenses of $14 million. Table 5 summarizes these benefit and cost components. Taken together, the picture that emerges is that the redesign will be cost effective for the first 10 years of operation if the discount rate is less than 8% without considering environmental costs. However, the market redesign will create a social welfare loss when the environmental impacts are taken into account.[33]

8 Conclusion

This paper examines the impact of the Texas electricity market redesign on both market efficiency and social welfare. To do so, I use a flexible semi-parametric approach to estimate the changes in generation allocation among different types of generators. I then use these estimates to quantify the associated changes in production costs and emissions. My results show that the market redesign improves market efficiency, suggesting that the informational benefits created by a centralized market outweighs 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 such a practice on the efficiency basis. Worldwide, there are still regions that either have not restructured their electricity markets or have adopted a bilateral trading model. The Texas' experience also provides a useful reference for those regions that may consider a move to a centralized market. Given that my estimates are based on the market conditions in Texas, in future research, it would be interesting to conduct a cross-market comparison to better understand any market-specific drivers that may impact the direction and magnitude of the efficiency changes.

While my results attest to the superiority of the centralized market design in terms of efficiency, I also find that the transition to a centralized market increases emission levels. The

between supply and demand.

[33]One caveat that should be noted is that the extrapolation is based on the market conditions between June 1, 2010 to August 31, 2011. During the subsequent years, natural gas prices have dropped from about $4/ MMBtu to less than $2/ MMBtu. This decrease in natural gas prices has led to widespread substitution of natural gas for coal (Cullen and Mansur, 2014). 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.

conflict between efficiency improvement and pollution mitigation is a result of the disparity between private and social costs, rather than flaws in the design per se. Setting up carbon pricing schemes or appropriate emission caps provides one solution to resolve this conflict. In recent years, the idea of an ISO-administered "carbon adder" – a price on carbon added to generators' bids – has been proposed as an alternative way to reduce carbon emissions. Though still in the discussion phase, this approach provides another solution to resolve the conflict. The environmental cost associated with increasing emissions is not trivial. In fact, when those costs are taken into account, I find the redesign no longer passes a cost-benefit test. This finding highlights the need to take environmental impact into account when we make decisions in the energy market.

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Appendix

A.1 ERCOT Market Operation

This section provides details on the 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. The operation of the market consists of two major phases.[34]

1. Day-ahead scheduling process
   Load serving entities and generation resources negotiate privately with each other to buy and sell energy. The resulting bilateral contracts specify the transfer of electricity at negotiated terms such as duration, price, and time of delivery. In the day-ahead period, market participants are required to submit their "balanced schedules" to the ERCOT ISO through Qualified Scheduling Entities (QSEs) which are qualified by ERCOT to submit schedules for a portfolio of generators and power purchasers. These schedules specify the origins and destinations of power flows by congestion zone for each 15-minute settlement interval.[35] The scheduled resource production should not deviate from the forecasted demand beyond an established range. ERCOT analyzes the day-ahead schedules and notifies the QSEs of anticipated inter-zonal congestion. Market participants are allowed to adjust their schedules to relieve the forecasted congestion. Once the schedules are accepted by ERCOT, the generators are "physically" committed to produce the scheduled quantity unless being instructed to increase or decrease their production in the balancing market. Any uninstructed deviation exceeding 1.5% or 5 MWh of the QSE's schedule results in a penalty payment (Sioshansi and Hurlbut, 2010). 95% of the overall generation is scheduled through this process.

2. Real-time balancing market
   During the day-ahead scheduling process, generation resources also submit balancing energy bids for adjusting their generation relative to their scheduled quantities. In real-time, ERCOT manages energy imbalance and transmission congestion between zones by intersecting the bidding functions separately for each zone. For intra-zonal

[34] There is also an adjustment period between the day-ahead period and the operating period.

[35] ERCOT divides its territory into 4 congestion zones. A congestion zone is a group of buses that have similar shift factors on commercially significant constraints. Dividing the entire grid into several congestion zones simplifies the modeling of the network.

congestion, ERCOT deploys resources based on the 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. These 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. The supply offer may contain three parts: the startup offer, the minimum-energy offer and the energy offer curve. These offers are used in the day-ahead energy market. 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 account for approximately 40 percent of the real-time load (Potomac Economics, 2012). After the completion of the day-ahead energy market, ERCOT executes a reliability unit commitment process to ensure that it has enough capacity committed to serve the forecasted load for the operating day.

2. Real-time operation
   While bilateral trades and the day-ahead energy market transfer *financial* responsibility among QSEs, the Security Constrained Economic Dispatch (SCED) program actually dispatches the resources in the real time. ERCOT utilizes a network operation model which represents the system with 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 their submitted energy offer curves. The execution of SCED results in locational marginal prices at approximately 4,000 nodes.[36]

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 $\mathrm{P_B}$, note that if we increase production at both A and B by 1 MW each, production at C can be reduced by 2 MW to meet the same level of

[36]Hence, the centralized market is also known as the "nodal market."

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

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

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

$$\frac{\partial}{\partial Q_B} = 0$$
$$\frac{\partial}{\partial Q_C} < 0$$

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

A.3 Data Appendix

A.3.1 Coal Price

The majority of a power plant's coal is purchased through long-term contracts. Therefore, I use monthly plant-level coal receipt cost data from EIA-923 forms as the relevant coal prices. Some previous studies have used spot market coal prices to approximate the opportunity costs for coal plants (Mansur (2008), Mansur and White (2012)). However, spot market prices are not appropriate proxies for opportunity costs 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, which 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.

The fuel receipt cost data are publicly available for regulated plants.[37] There are 16

[37] Unfortunately, access to the proprietary data on deregulated plants from EIA requires US citizenship.

coal plants in ERCOT, 6 of which are regulated. For deregulated plants, I 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 2 regulated plants purchase lignite. Since lignite is produced within Texas, I assume that the transportation costs are relatively small while the content of the coal matters more for the price. Hence, I use the coal prices paid by plant Pirkey to approximate the prices for deregulated plants, since the characteristics of coal purchased by Pirkey are close to the average lignite being purchased. However, for sub-bituminous coal, the transportation cost is likely to be important. Therefore, I match every deregulated plant to its closest regulated neighbor and use the matched plant's coal price as its price. I am 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, I use the average price of the months preceding and following that month instead. Table A1 summarizes the 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
	Coleto Creek	SUB	J T Deely
	Limestone	SUB	Gibbons Creek
		LIG	Pirkey
	Martin Lake	SUB	Welsh
		LIG	Pirkey
	Monticello	SUB	Welsh
		LIG	Pirkey
	Oak Grove	LIG	Pirkey
	Sandow No 4	LIG	Pirkey
	Sandow No 5	LIG	Pirkey
	Twin Oaks Power One	LIG	Pirkey
	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 Price

Daily natural gas spot prices are collected from SNL Financial. I 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. I use the 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 Price

Power plants in ERCOT are subject to three programs: the Acid Rain Program (ARP), The Clean Air Interstate Rule (CAIR) annual SO_2 program and The Clean Air Interstate Rule (CAIR) annual NO_x program. The ARP, established under Title IV of the 1990 Clean Air Act (CAA) Amendments, requires major emission reductions of SO_2 and NO_x, 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_x and 2010 for SO_2. The CAIR SO_2 and NO_x annual programs require further reductions for large electricity generating units in 28 eastern states including Texas. Not all generating units are affected by these three programs. To determine each generating units' coverage status, I use information provided by the EPA's Air Markets Program Data (AMPD) and cross check my data with The Code Of Federal Regulations Parts 72 and 96 (40 CFR Part 72 and Part 96).

All three programs are cap-and-trade programs designed to allow power plants to arrange for the cheapest possible reductions among covered sources to meet the overarching cap. For each ton of SO_2 emitted, ARP compliance requires the surrender of 1 ARP allowance, while CAIR compliance requires an additional ARP allowances of prompt vintage. For each ton of NO_x emitted, 1 NO_x annual allowance has to be deducted. Generally, these allowances are traded among companies and individuals through brokers. I acquire daily SO_2 and NO_x allowance price indexes from a leading over-the-counter energy brokerage firm based in Texas. I use the last trading price each day as the relevant price. For non-trading days, I approxi-

mate the price by taking the average of the prices from the two trading days preceding and following that day.

Compared to the fuel cost, the emission cost makes up a very small portion of the variable cost. For coal power plants, the emission cost on average counts for only 0.96% of the marginal cost. For natural gas generators, the percentage is less than 0.3%.

A.3.5 Wholesale Electricity Price Data

From ERCOT, I also collect the 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.[38] When there is no congestion, the hub prices are the same throughout the system. However, if congestion does exist, LMPs differ from node to node, as do the hub prices. Therefore, I define an hour to be congested if the electricity prices at the four hubs are not the same. Congestion is quite common in my sample. Of all the hours in the post-redesign sample period, about 60% are congested.

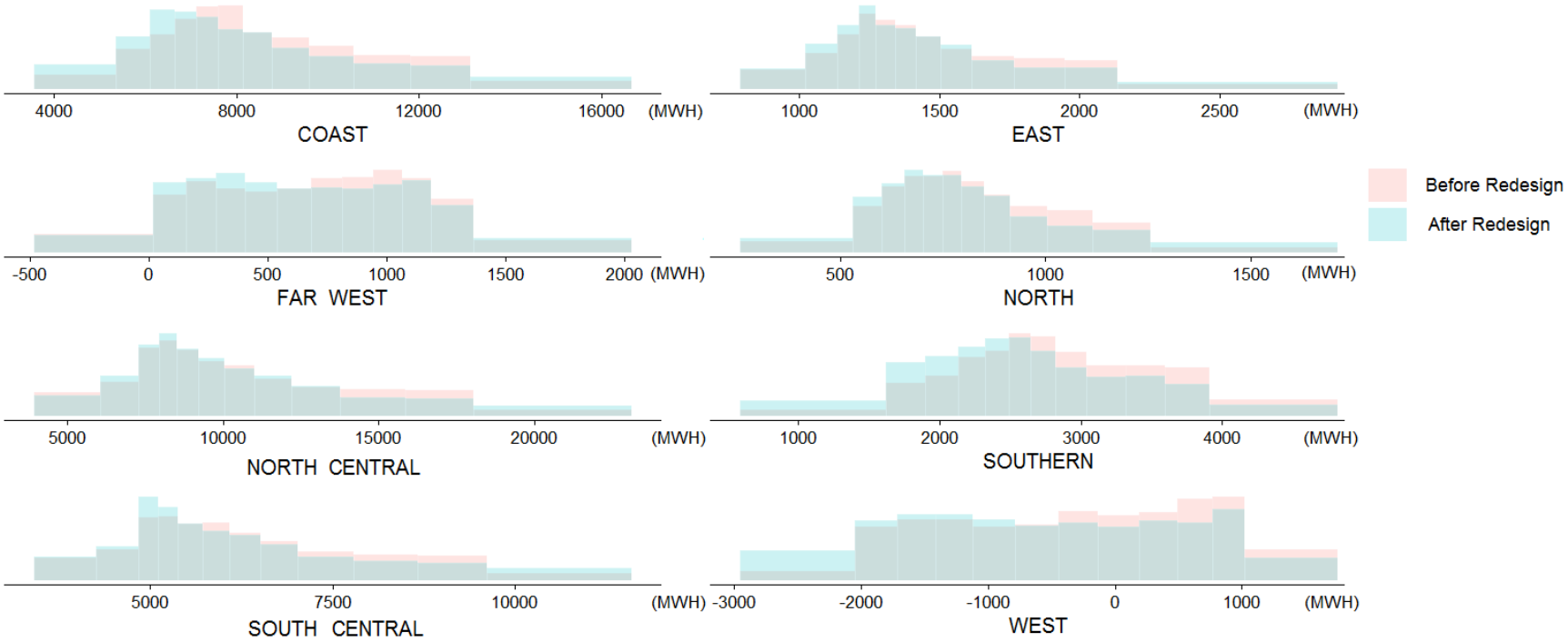
A.4 Additional Results and Robustness Checks

This section contains additional evidence that supports the validity of the empirical approach and the robustness of the findings. First, I show that although the market conditions pre- and post-redesign are not exactly the same, they are quite comparable: the span of demand at each zone overlaps; the changes in fuel prices are moderate; and the entry or exit of generators does not exert a significant impact on the market. Second, I provide further evidence showing that the observed changes pre- and post-redesign are not seen in any other year.

A.4.1 Comparison of Demand

Figure A1 compares the distributions of demands 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 can 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.

[38] 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 would be determined by the cost of delivering the 11th MW.



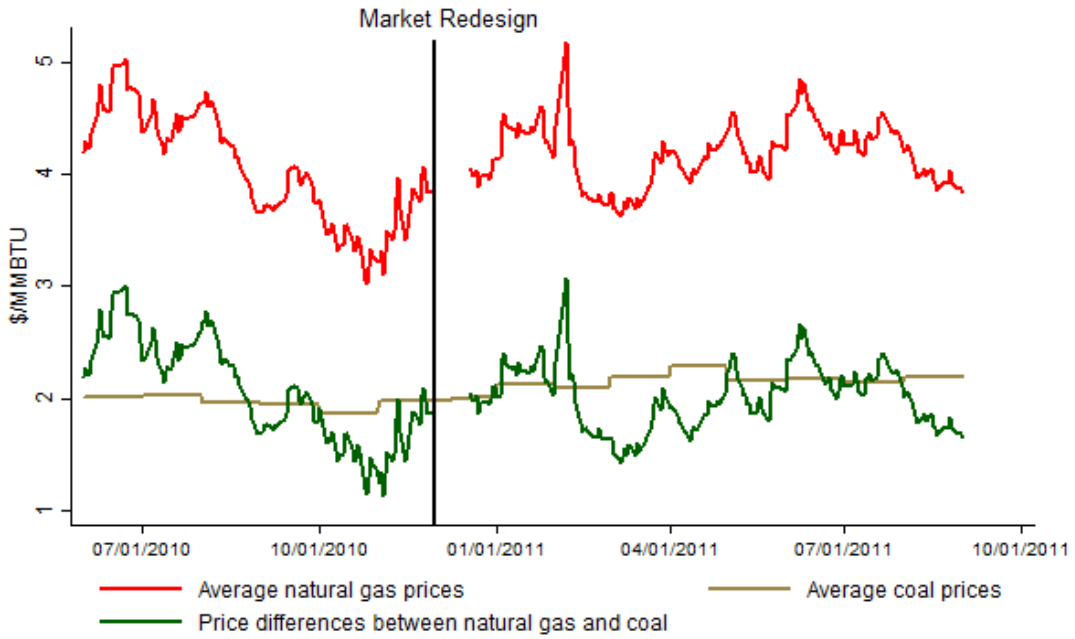
Notes: These figures show the histograms of hourly thermal demands at eight weather zones separately for pre-redesign and post-redesign periods. The pre-redesign period runs from June 1, 2010 to November 30, 2010. The post-redesign period runs from December 1, 2010 to August 31, 2011. Demand at each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

Figure A1: Histogram of Hourly Thermal Demand By Weather Zone

A.4.2 Comparison of Fuel Prices

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

Figure A2 plots the movement of coal prices and natural gas prices during the sample period.[39] 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 19.8 cents (10%) and 12.9 cents (3%) respectively, compared to the pre-redesign period. The ranges of the price differences are also similar pre- and post-redesign.



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

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

The comparability of fuel prices pre- and post-redesign provides reassuring evidence that my results are not driven by any price trend. Furthermore, I directly include a quadratic

[39] To be consist with the sample I use for estimation, I exclude dates between December 1, 2010 to December 17, 2010, for the lack of ERCOT data, and also dates between February 2, 2011 and February 5, 2011, for the unusual winter storm.

form of the price differences between natural gas and coal in the baseline model to capture any effect caused by relative changes in fuel prices. I find it is unlikely that the relative changes in fuel prices are the cause of the switch between coal and natural gas generation, because on average, the price for coal increases more than the price of natural gas during the post-redesign period. This would make coal generators less appealing, but instead I find coal displaces natural gas generation by significant amounts in the post-redesign period. Finally, as a robustness check, I 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. Since within natural gas generators, the marginal cost order is basically determined by their heat rates and unaffected by the change of natural gas prices, any relative change in generation within them is not confounded by movements in fuel prices. The results from these regressions support the main findings: generation from cheaper resources, such as combined-cycle generators and combustion turbines, increases while generation from more costly resources, i.e. steam turbines, decreases.

A.4.3 Entry and Exit of Thermal Generators

In the estimation, I restrict the sample to all thermal generating units that were continually operating during the entire sample period. There are three thermal units that have either entered or exited the market in this time period. Two steam turbines, each with a capacity 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, I contend that this is not likely to be the case. The average hourly generation quantities from these three units while they were operating were only 69.9, 4.71 and 127.9 MWh, respectively. Their generation accounts for less than 0.1% of the total thermal generation. Given the magnitude of their average generation, I conclude that my results cannot be explained by their entry and exit.

A.4.4 Placebo Tests

Finally, I perform placebo tests to show that the magnitudes of the changes I find are indeed unusual and not seen in other years. For this exercise, I consider two hypothetical scenarios where a redesign occurred on December 1, 2009 as well as December 1, 2011 and repeat the analyses. I focus on a very short time period – two months centered around the

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	4.71
Jack County	Entry	Mar 16, 2011	Natural gas: combined cycle	640	32.5	127.9

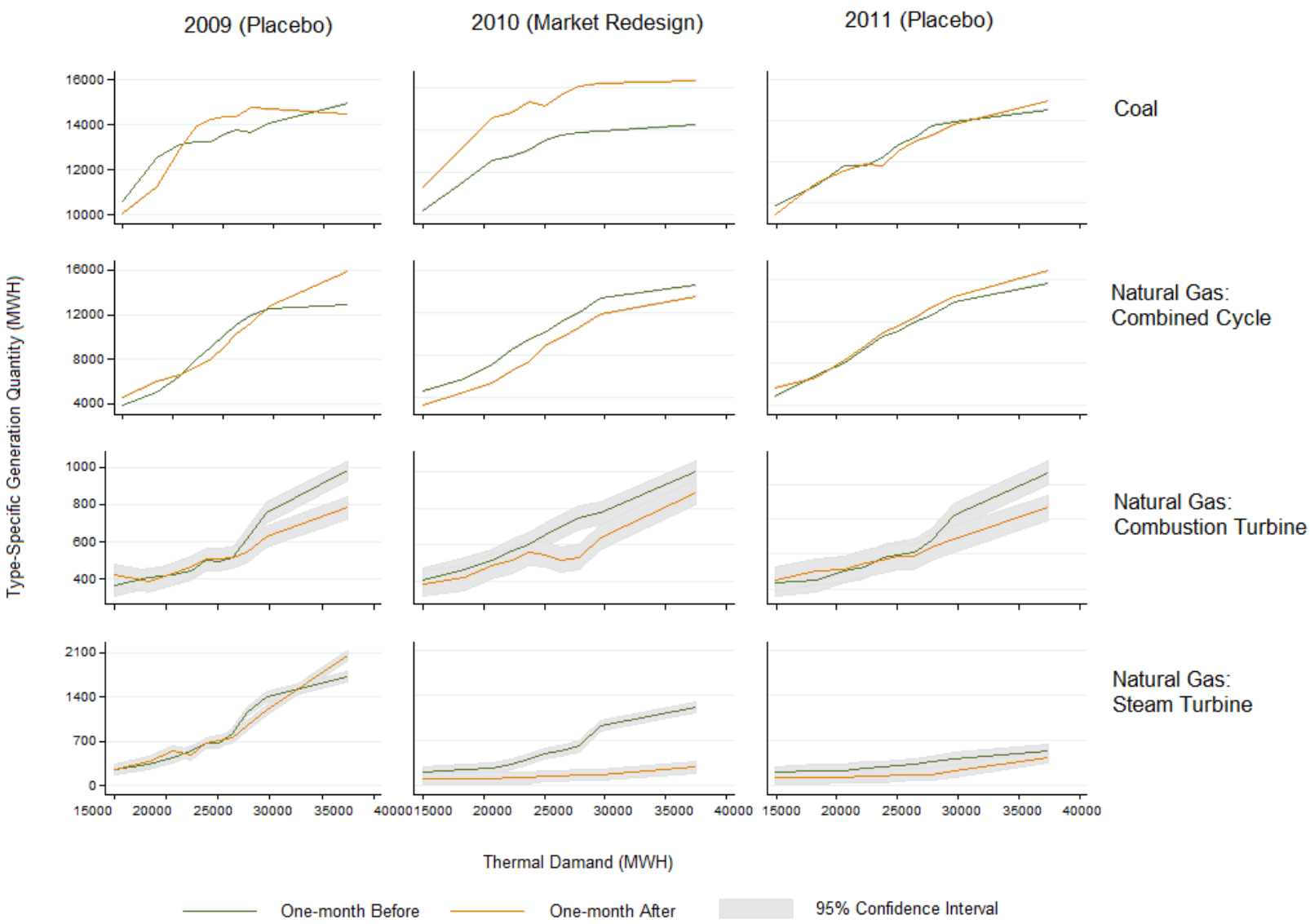
Notes: This table lists the thermal generators that have entered or exited the market during the sample period. The data come from EIA-860 forms. The entry/exit dates are also cross-checked with CEMS data and web sources.

Table A2: List of Entering and Exiting Generators

(real or pseudo) implementation date of the market redesign. Given the short time frame, I am confident that there are no significant changes in capacity, cost, or other aspects of the market. I run regressions similar to equation (1). However, given fewer observations, I simplify the analysis by using the entire thermal demand instead of the demand at each zone, and fitting a constant line within each bin. I 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:

$$\text{Gen}_{it} = \sum_{k=1}^{12} \beta_{ik} Bin_k(ThermalDemand_t) + \epsilon_{it}$$

where 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. From Figure A3, 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 occurs only 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.

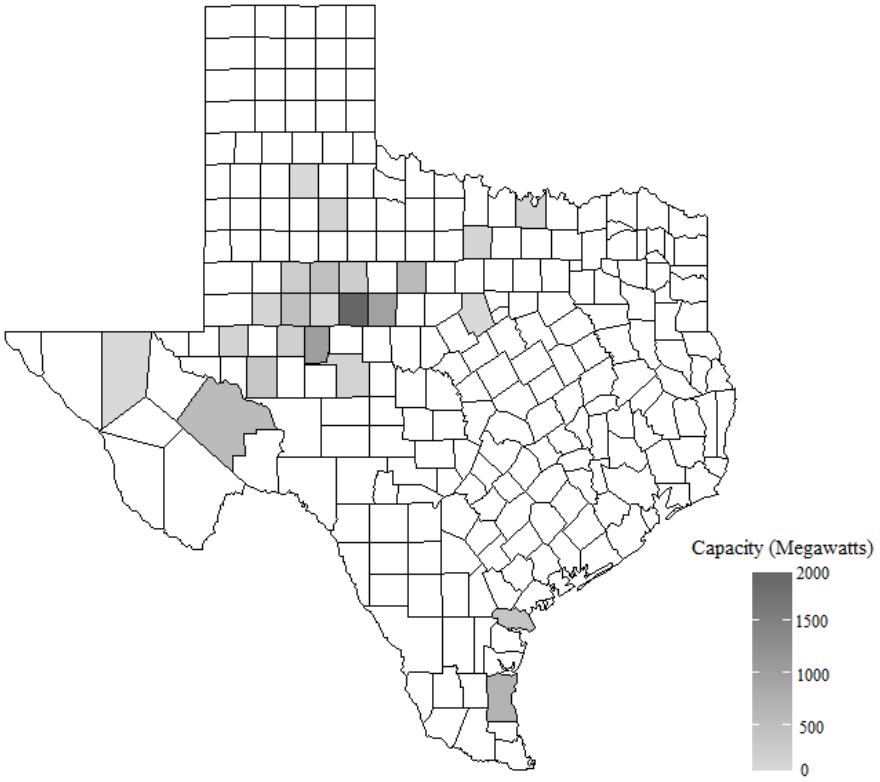


Notes: These figures report the results from the placebo tests as explained in the text.

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 amounts to 9,363 MW, representing 9.45% of the overall generating capacity. As shown in Figure A3, the majority of the wind farms are located in the west of Texas, with the rest in the southern portion of the state.



Notes: This figure is constructed by the author 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, the level of electrical output a wind turbine can generate is proportional to its cross-sectional area as well as the cube of the wind speed. Wind is non-dispatchable in the sense that wind speed cannot be changed by will. However, cases do occur in which potential wind generation is not fully used. This happens largely because of the limited transmission capacity between western Texas where the most abundant wind resources are, and eastern Texas where most of the demand is. In some cases, wind generation has to be curtailed to avoid overloading the

congested transmission lines.[40] Therefore, it is natural to ask if the market redesign results in fewer incidences of curtailment and better integration of wind resources.

Without data on the frequency of wind curtailments, I 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 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 rule out this effect, I restrict my sample to a subset of wind farms that were already in operation as of June 1, 2010. I conduct the analysis at the weather zone level. For zone i at hour t, I 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.[41] I also include demands 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 some 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 of the regions post-redesign.

[40] See Sioshansi and Hurlbut (2010) for an extensive discussion of the ERCOT market protocols with respect to wind generation.

[41] 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**	31.30	-19.98
	(24.03)	(23.35)	(26.15)
North	21.54***	18.34***	2.94
	(5.17)	(4.76)	(5.57)
North Central	26.72***	12.42	-26.19**
	(9.95)	(9.18)	(12.10)
Southern	7.68	8.42	-13.56
	(8.98)	(9.05)	(12.03)
West	23.97	-44.42	-129.56***
	(36.28)	(30.45)	(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