8-2015

Analysis of the U.S. Electric Power Industry

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I am submitting herewith a dissertation written by Yin Chu entitled "Analysis of the U.S. Electric Power Industry." I have examined the final electronic copy of this dissertation for form and content and recommend that it be accepted in partial fulfillment of the requirements for the degree of Doctor of Philosophy, with a major in Economics.

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Analysis of the U.S. Electric Power Industry

A Dissertation Presented for the

Doctor of Philosophy

Degree

The University of Tennessee, Knoxville

Yin Chu

August 2015

To my parents and thanks for their support for me.

Acknowledgements

I cannot express enough thanks to my committee co-chairs and my advisors, Dr. J. Scott Holladay and Dr. Jacob LaRiviere, for their continued support and guidance for my research and writing. I also want to show my sincere appreciation to my committee members, Dr. Christian Vossler and Dr. Fangxing Li, for their suggestions and guidance.

In addition, I also would like to thank Dr. Marianne Wannamaker, Dr. Donald Bruce, Dr. Scott Gilpatric and others who provided helpful feedbacks during seminars when I presented my dissertation researches. Thanks to Thomas MaManus and Matthew McMahon for their discussion with me about my research and proofreading and editing my writing.

Thanks to my parents as well, Mr. Shuguang Chu and Mrs. Hongquan Li. The countless times you kept encouraging me and all of your support will not be forgotten.

The larger the island of knowledge, the longer shoreline of wonder. - Ralph W. Sockman

Abstract

In the U.S., the power industry is a primary energy consumption sector. Accurate knowledge on production efficiency in the industry has vital welfare implication from both economic and environmental perspectives. The first two essays investigate the causal impact of the vertical separation of the electricity transmission sector from the generation sector on production efficiency. In the first essay, I ask whether the specific market restructuring is sufficient to enhance how efficiently production is allocated among producers. Based on a difference-in-difference comparison on cost-sensitivity of utilization between coal-fired generators in the treatment region (Southwest Power Pool) and that in a control region, I fail to find any significant private cost savings by reallocating production across firms. My second essay takes a further step and looks into one potential explanation of the results: enabled market power under restructuring. Following a common method to measure competition, I simulate the prices that would have occurred had the wholesale market been competitive. Then I compare the simulated prices with the best estimates available for actual wholesale prices to measure the market price-cost margins. Empirical results demonstrate that the vertical separation of the electricity transmission sector actually led to an increase in the markup in the wholesale market, indicating evidence of market power exercised. In the last essay, we propose to investigate whether there is stickiness in the pass-through from fossil fuel spot prices to the fossil-fuel procurement costs for the U.S. electric power producers, and if there is, to what extent the sluggishness is, and how it varies across different types of fossil fuels.

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Chapter 1

Market Restructuring, Vertical Separation and Regional Production Efficiency: Evidence from the U.S. Power Industry

1.1 Introduction

Economists generally believe that promoting competitive markets serves to enhance efficiency and welfare, evidence of which has been found by a series of empirical analyses across a wide spectrum of industries.[1] In this spirit, one of the most recent market restructuring transformations in the U.S. occurred in the electricity industry. Until the mid-1990s, the U.S. power industry was largely comprised of vertically integrated utilities in the chain of generation, transmission and distribution, operating as local natural monopolies. Regulated utilities were compensated under the "rate-of-return" principle to cover their costs plus a fair return. Agency models indicate that under the regulation structure, firms would deviate from cost-minimization behavior

[1] See Olley and Pakes (1996) on telecommunications, Ng and Seabright (2001) on airlines, Syverson (2004) on concrete industry, and Davis and Kilian (2011) on natural gas industry.

as regulators setting the prices are asymmetrically informed (Laffont and Tirole, 1993). Integrated utilities also have incentives to over-utilize their own facilities and provide discriminatory transmission service to non-integrated wholesale competitors to protect their sales for revenue compensation. Given these concerns, market restructuring activities have been enacted in several states since the mid-1990s, which provoked a considerable body of economic studies evaluating the impacts on the performance of the power industry.[2]

This study analyzes the welfare implications of one specific aspect of the market restructuring process in the U.S. power industry. Typically, restructuring may consist of the following aspects: (1) separating the transmission function from the vertically integrated natural monopolies, (2) allowing wholesale pricing, (3) divesting generation assets from retailers, and (4) imposing retailers under competition by allowing customers to switch their retailers. In order to evaluate the impacts of restructuring for policy recommendations, researchers must disentangle these channels, which is generally a difficult task.[3] The Southwest Power Pool (SPP) market, however, provides a venue to separate them because this market only experienced market restructuring in the transmission component. Taking advantage of the unique market, I investigate the potential efficiency gains brought about by the vertical separation of transmission network in the U.S. power industry.

In practice, the vertical separation is achieved by establishing organized competitive wholesale markets, defined as those intermediated by a Regional Transmission Operator (RTO), which takes over the transmission control from previously integrated utilities.[4] In this way, market participants can have fair access to the electricity

[2]See Borenstein et al. (2002), Fabrizio et al. (2007), Zhang (2007), Mansur (2007, 2008), Hortacsu and Puller (2008), Davis and Wolfram (2012), Craig and Savage (2013), Chan et al. (2013), etc.

[3]Previous literature that seeks to disentangle the channels include: Bushnell and Wolfram (2005), Davis and Wolfram (2012) and Hausman (2014), who all attempt to separate the impact of generation divestiture on operating efficiency from the introduced pressure of wholesale competition, and also Mansur (2007), who disentangles and assesses the consequence of vertical separation of retail function from generation on market power.

[4]Different from ownership separation, the firms still maintain the ownership of the transmission assets. This type of vertical separation is often referred as "legal unbundling".

network such that wholesale competition is fostered. Seven organized regional wholesale markets[5] have emerged in the Northeast, Midwest and Southwest of the U.S., the majority of which also underwent restructuring in components other than transmission, and implemented market-oriented tools designed to efficiently dispatch producers to further enhance wholesale competition.[6] SPP, however, has long been recognized as the organized electricity wholesale market with the least radical reform in term of market-oriented designs and protocols. Rather than through newly-designed market platforms, wholesale transactions in SPP largely depend on traditional bilateral trading.[7] Without advanced designs revealing and collecting market information, the main role of SPP is balancing demand and supply, and more relevant to this paper, maintaining non-discriminatory access to the transmission facilities.

The necessity of separating transmission function from other activities is largely grounded on the principle that an electricity market functions effectively only under the condition of non-discriminatory transmission access. Given the network nature of the power industry, transmission access is an essential input that competing power producers rely on to schedule and dispatch their generating units. Vertically integrated power producers who also operate the electricity network may have incentives to discriminate against non-integrated competing generators. Theoretical support of such discrimination is documented in previous literature on vertical integration (Vickers, 1995; Economides, 1998; Beard et al., 2001). On the one hand, due to potential asymmetric information from the regulator's perspective, price

[5]The locations of existing RTOs are shown in Figure 1.1.

[6]For instance, a typical example is the centralized dispatch mechanism that ranks the right to supply based on bidding offers in real-time and/or day-ahead markets. Market designs like this were employed in the northeastern U.S., such as the Pennsylvania, New Jersey, and Maryland (PJM) wholesale electricity market. See more details of market designs adopted in each organized wholesale market in Table 1.1.

[7]Although SPP launched a real-time energy market that employs centralized dispatch in Feb 2007, its function is restricted only to addressing imbalance between scheduled transactions and actual energy flow. Moreover, the market is voluntary, meaning the market participants can choose to either self-dispatch or participate fully by making its resources available. Thus, only a small amount of generation is traded through the market. In 2008, the transaction volume constituted roughly 8.5% of the total load in the region (2008 State of the Market Report, SPP, Inc.).

Figure 1.1: Regional Transmission Operators (RTOs) in North America

Table 1.1: Electricity Wholesale Market Designs in the U.S. in 2012

	Real-time Market		Day-ahead Market		Virtual Bidding	Ancillary Services	Financial Transmission Rights	Capacity Markets Markets	Associated Financial Markets
	RTO*	Bilateral	RTO*	Bilateral	RTO	RTO	RTO	RTO	
With RTO									
New England	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
New York	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
PJM	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
CAISO	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
ERCOT	Yes	Yes	Yes†	Yes	No	Yes	Yes	No	Yes
Midwest	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
SPP	Yes**	Yes	No	Yes	No	No	No	No	No
Without RTO									
Northwest	No	Yes	No	Yes	No	No	No	No	Yes
Southwest	No	Yes	No	Yes	No	No	No	No	Yes
Southeast (SERC)	No	Yes	No	Yes	No	No	No	No	Yes

Source: State of Market Reports, FERC
* means centralized dispatch market operated by the RTO.
** SPP launched the RTO-based centralized market as late as Feb 2007. Yet, only a trivial proportion of load is traded through the market (8.5% in 2008).

regulation constraint on upstream input might not be binding. This leaves room for a vertically integrated firm to engage in price discrimination on the upstream input and directly raise non-integrated rivals' input costs (Vickers, 1995).[8] On the other hand, even if upstream input price regulation is effective, it would in turn create a perverse incentive for the integrated firm to practice non-price discrimination through quality degradation of the upstream input (Beard et al., 2001). Such examples were documented in network industries (i.e., energy, telecommunications, etc.) in EU (Hoffler and Kranz, 2011).[9] Despite the extensive theoretical literature and great policy relevance, there have been relatively few empirical analyses on the efficiency impacts of the vertical separation. This study represents an intellectual endeavor to fill this gap.

In this paper, I look into the impact of the divestiture of transmission control from vertically integrated utility producers on regional production efficiency. The question of interest is: can such separation lead to better allocation of production resources and increase the probability of low-cost generating units being dispatched over high-cost ones? If it were the case that vertically integrated utility producers engage in transmission discrimination and over-utilize their own generating assets, outside lower-cost options would be potentially underutilized. This would lead to an inefficient allocation of the regional production resources. With transmission control handed over to an impartial RTO, the possibility of discriminatory transmission access is removed. Under enhanced wholesale competition, under-utilized cost-efficient plants would have incentives to bid more quantities and increase their sale for larger "rate-of-return" base. Intuitively, this would re-assign production resources and improve regional production efficiency.

[8]Under the context, "upstream" refers to transmission access. The "downstream" would be electricity generation.

[9]The examples include discriminatory information flow, overly complex contractual requirements, undue delays in delivery of the service, unreasonably high requirements of bank guarantees, and the like.

However, a series of previous studies have found evidence that restructuring the electricity market has enabled wholesalers to exercise market power by withholding generation to drive up higher prices.[10] Moreover, Joskow and Tirole (2000) also provide theoretical support of market power associated with the separation of transmission operation when a RTO has to allocate the scarce transmission capacity through a market for access rights. They find that if expensive generators in the importing regions have market power, their holding transmission rights can enhance that market power. If it were the case that market power is enhanced after the restructuring in electricity transmission network, the potential gains in regional cross-firm production efficiency would be undermined. Thus, whether the separation could improve regional production efficiency remains an empirical question to be answered.

Following Douglas (2006), I measure regional production efficiency through the sensitivity of unit utilization with respect to average costs. The implicit logic is that regions where production resources are allocated more efficiently should rely more on the low-cost generating units, rather than over-utilizing high-cost ones. Accordingly, the utilization of generators in such an environment should be more responsive to their own average costs. Under this logic, I employ the difference-in-difference strategy and compare the average cost sensitivity of unit utilization in SPP with that in a control region, where no market restructuring activities ever took place. Focusing on coal-fired capacities only, I utilize an 8-year monthly panel of detailed micro-data at the generating unit level and choose the establishment of the RTO-monitored wholesale market in SPP as the treatment event. I argue that conditional on all observables, the treatment is exogenous to the question of interest. I provide evidence that prior to the restructuring, cost sensitivity in SPP was not statistically higher than that in the control region such that SPP did not undergo the restructuring due to unobserved advantages related to regional production efficiency. Based on relatively noisy estimates of the coefficient of primary interest, I fail to find evidence that the

[10] See Borenstein and Bushnell (1999), Wolfram (1999), Borenstein et al. (2002), Mansur (2007, 2008), and Hortacsu and Puller (2008), etc.

restructuring activity in SPP results in increased utilization of low-cost generating units. The empirical results are also robust to alternative specifications, including treatment dates, sizes of the event window, and control groups. I conclude that divesting transmission control from integrated power producers alone is not sufficient to enhance regional production efficiency.

My study contributes to the literature in several aspects. First, by extending the analysis to a distinct organized wholesale market, this study adds to the literature by disentangling and assessing the effect of deregulation on one specific component of the sector: the electricity transmission network. Direct analysis on the vertical separation of electricity network and the consequent non-discriminatory transmission access is difficult since it is usually concurrent with other aspects of market restructuring. Earlier studies on market restructuring fail to disentangle it from other efficiency-enhancing channels, such as change of revenue rule, privatization of production assets, and establishment of centralized wholesale market platforms. Identifying the impact of each efficiency-enhancing channel separately is vital for policy recommendations on the optimal design of restructuring "packages". This is even emphasized considering the fact that the efforts of the Federal Energy Regulatory Commission (FERC) to promote the restructuring of electricity wholesale markets were vigorously challenged after the market crisis in California in 2000-2001. This study provides credence that in order to obtain regional production efficiency, restructuring needs to go beyond merely divesting transmission operation from the integrated utility power producers.

Second, this study also adds fuel to the current policy debates on the cost-and-benefit comparison between vertical integration and separation of network infrastructure in the EU energy sectors. Given inquiry on the role of vertically integrated incumbents in the energy sector, in September 2007, the EU commission adopted a package of energy proposals, one of which is the separation of transmission from production and supply in the electricity and gas sector. By evaluating the impact on the optimal allocation of regional production resources, this study also represents one of the few empirical studies in the literature of vertical separation.

This study relates to a considerable body of literature that test the effect of market restructuring on the performance of the power industry in the U.S. The majority of the literature investigates and confirms operating efficiency gains.[11] One of the few studies on regional production efficiency is Douglas (2006), which focuses on market restructuring in late 1990s in eastern region. My paper builds upon his study in that, with richer and more recent data, I am able to disentangle restructuring in the transmission component from other various channels of efficiency improvement. Another study on regional production efficiency is Mansur and White (2012). It compares two typical wholesale market mechanisms, decentralized bilateral trading and centralized auction, and finds empirical evidence that an organization change from the former to the latter substantially improved the overall market efficiency. In this paper, however, I investigate an independent change in vertical structure of the transmission component in the power industry.

The remainder of the paper proceeds as follows. Section 1.2 provides background information on deregulation in the U.S. power industry, the conditions of regional wholesale markets in the U.S., the related literature and the treatment and control regions under the study. Section 1.3 discusses the hypothesis tested and why separating transmission network operation from other activities affects regional production efficiency. Section 1.4 talks about the empirical model specifications and the identification issues. Section 1.5 describes the data, summary statistics and comparison between the treatment and control regions. Section 1.6 provides the estimation results and discussion. Section 1.7 concludes.

[11] See Fabrizio et al. (2007), Zhang (2007), Davis and Wolfram (2012), Craig and Savage (2013), Chan et al. (2013), etc.

1.2 Industry Background and Related Literature

1.2.1 The Regulation and Deregulation of the U.S. Power Industry

The U.S. Power industry in the traditional regulated setting is comprised of vertically integrated natural monopolies in the chain of production, transmission, distribution and retailing, with exclusive rights of provision within their geographic zones. The rationale underlying this arrangement is that this industry is characterized by extremely high fixed costs and low marginal costs. Accordingly, the U.S. government regulate all stages of the power industry. Within this structure, regulated electricity utilities are compensated under the cost-of-service principle to cover the costs plus a "fair" return on investment. In other words, they are guaranteed to have the operating expenses covered as long as transactions are approved by the state regulators. This principle exerts few incentives for firms to improve the operating performance, reduce cost, and search for and purchase lower-cost production sources other than self-generation. Adversely, the producers actually have incentives to welcome higher cost, which is their base of revenue under the rate-of-return principle, in order to cover their sunk costs. Thus, the ultimate goal of providing electricity of lowest costs possible to end consumers is compromised.

Aware of the flaw of traditional regulated structure, several states suffering from high electricity prices enacted restructuring legislation, beginning with California in 1996. Although the institutions and market designs vary dramatically across different deregulation processes, two common concepts shared among them are: (1) separating generation and retail function from the natural monopoly functions of transmission and distribution; (2) introducing competition by establishing wholesale (and retail) electricity markets. By the end of 2001, 23 states had passed deregulation legislature or implemented comprehensive regulatory orders on restructuring. Yet, the California electricity market crisis in 2000-2001 made policy makers re-evaluate the process, and consequently after 2001, no restructuring legislation was enacted.

Due to the heterogeneity in the level of restructuring in the industry across different jurisdictional regions, previous studies measure the event window of market restructuring in a variety of ways. They include: (a) access to a RTO-based wholesale electricity market; (b) the holding of a formal state hearing on restructuring; (c) the passing of state restructuring legislation; (d) the implementation of retail choice (allowing customers to switch their retailers); (e) the offering of complementary aspects of restructuring (such as capacity trading, mandatory divestiture of generation assets, etc.).[12] Following Craig and Savage (2013), I choose the establishment of a particular RTO-based wholesale electricity market as the criterion.

Under an electricity wholesale market, generators have to compete for the rights to supply. Due to the open access to the bulk enforced by FERC, non-discriminatory transmission services managed by respective RTOs, and increasingly diversified mix of participants in the market, traditional utilities have lost their franchised rights for providing electricity. Under the new competitive environment, lower-cost plants are more likely to supply the market and earn greater expected profits. In order to prevent short-term losses and potential market exit, plants have stronger incentive to reduce operating costs and enhance their production efficiency.

A large body of literature has aimed to test whether restructuring brought about efficiency gains in the industry, the majority of which pay attention to the effect on the operating performance of the generating power plants. Focusing on fossil-fueled plants between 1981 and 1998, Fabrizio et al. (2007) provide evidence that average labor and non-fuel operating expenses declined by 3-5% at investor-owned plants in states passing legislation of restructuring, compared to those under traditional regulation structure. Zhang (2007) studies operating efficiency gains in nuclear plants during the period of 1992 to 1998, and finds that market restructuring reduces operation

[12] See more details in Fabrizio et al. (2007), Zhang (2007), Kwoka (2008), Davis and Wolfram (2012), Chan et al. (2013) and Craig and Savage (2013).

costs by 11% and increases utilization rates by 7%. Later studies analyze longer-term benefits of deregulation and still confirm the cost-savings in operational perspectives. Davis and Wolfram (2012), using a large data set from 1970 to 2009, provide evidence that restructuring increases the operating efficiency by 10%, primarily via a reduction in the duration of reactor outages. They also consider the confounding effect of associated divestiture and consolidation but conclude that they explain only a relatively small proportion of the overall increases. Chan et al. (2013) document that deregulation made coal plants increase thermal efficiency and achieve lower negotiated fossil-fuel contracts with suppliers.

1.2.2 Establishment of Regional Wholesale Markets

The necessity of regional wholesale markets is largely grounded on the principle that an electricity market functions effectively only under the condition of non-discriminatory access to the transmission service. This can be guaranteed by impartial operators of adequate regional scope, called Regional Transmission Operators (RTOs) or Independent System Operators (ISOs).

The FERC regulates interstate transmission and wholesale of electricity. The establishment of regional wholesale markets was provoked by several pivotal FERC orders after the Congressional Energy Policy Act of 1992 granted FERC the authority to order utilities to provide transmission services to requesting wholesale generators. In 1996, FERC issued Orders 888 and 889, requiring non-discriminatory transmission access provided by the transmission grid owners. Order 2000 promoted the wholesale market design of ISOs, encouraging all FERC-jurisdictional utilities operating or owning the transmission grid to hand over the control to RTOs/ISOs in order to form regional wholesale market. FERC planned to advocate the model to all states. However, this became politically impossible after the California debacle mentioned earlier.

The first group of regional wholesale markets were founded in the states that passed restructuring legislation in late 1990s. This includes the California (CAISO) Electricity Market, Electric Reliability Council of Texas (ERCOT), and the three markets in the northeast, New York (NY-ISO) Electric Market, New England (ISO-NE) Electric Market and Pennsylvania, New Jersey and Maryland (PJM) Electric Market. Under the restructuring legislation, all of them consist of considerable number of divested utility generators (that are transferred to another utility) and non-utility Independent Power Producers (IPPs). Another two organized regional wholesale markets, Midwest (MISO) Electric Market and Southwest Power Pool (SPP) Electric Market emerged in 2002 and 2004 respectively. States incorporated by both regions granted utilities permission to access the organized wholesale markets, but only a few of the states passed restructuring legislation.[13] The majority of participating utilities are integrated utilities who voluntarily joined the markets.[14] This raises a potential self-selection problem which is discussed in later section.

The only three regions without organized wholesale electricity markets are the Southeastern, Northwestern and Southwestern parts of the U.S (shown in Figure 1.1). The vast majority of the states in the three regions did not pass market restructuring legislation and depend on integrated utilities to function as the central dispatchers for their own territories.[15] Wholesale trading exists between utilities through decentralized bilateral markets. Participants trade electricity bilaterally either directly or through brokers, with the majority of trading taking place in the Intercontinental Exchange (ICE). The main reason these regions stay in the traditional regulated structure is largely due to relatively low electricity rates, which made potential gains from restructuring questionable (Joskow, 1997; Bushnell and Wolfram, 2005; Fabrizio et al., 2007; Fowlie, 2010). Factors that led to relative low

[13] All of them are in MISO.

[14] This means that the market footprint could expand and also that members could choose to withdraw. Yet, SPP has long existed in the form of a power pool and barely experienced membership changes. MISO is not chosen under the analysis as its footprint changed several times.

[15] The only exception is Oregon. Nevada, Montana, Arizona, New Mexico, Arkansas and Virginia all suspended their restructuring activities.

prices in these regions include: access to cheap hydro, nuclear and coal generation or fewer long-term fixed-price contracts with costly independent power producers encouraged by the 1978 Public Utility Regulatory Act (Fowlie, 2010).

In addition to unstructured, decentralized bilateral trading markets like those in the regulated regions, all RTOs have established certain forms of centralized dispatching wholesale platforms. Market designs and tools adopted by the RTOs are different, which could potentially influence regional production efficiency in the respective regions. The three northeastern markets implemented the most complete set of market-oriented tools, including information-revelation designs which use a centralized bidding system for both real-time and day-ahead markets and other ancillary service markets. The main purpose of these designs is to collect and reveal information on the heterogeneous costs across producers in order to facilitate trading and thus dispatch production more efficiently. In contrast, wholesale trading in MISO and SPP occurred through decentralized bilateral systems with much less information disseminated until the mid-2000s. FERC's State of Market Report (2004) explicitly states that wholesale markets in both regions were much more opaque compared to others. The situation improved after new market designs were implemented. However, the new market established in SPP in Feb 2007, called "Energy Imbalance Service" (EIS) market, operates only as a spot market for correcting load imbalance between current demand and scheduled transactions under longer-term contracts (through decentralized bilateral trading). According to SPP's State of the Market Report (2008), transactions through the centralized market accounted for only 8.5% of the total load during that year. In contrast, this figure is roughly 60% in the three northeastern markets (2008 State of Market Report, FERC). Consequently, the effect of information-revelation mechanism in SPP largely diminishes. The market designs across the markets are shown in Table 1.1.

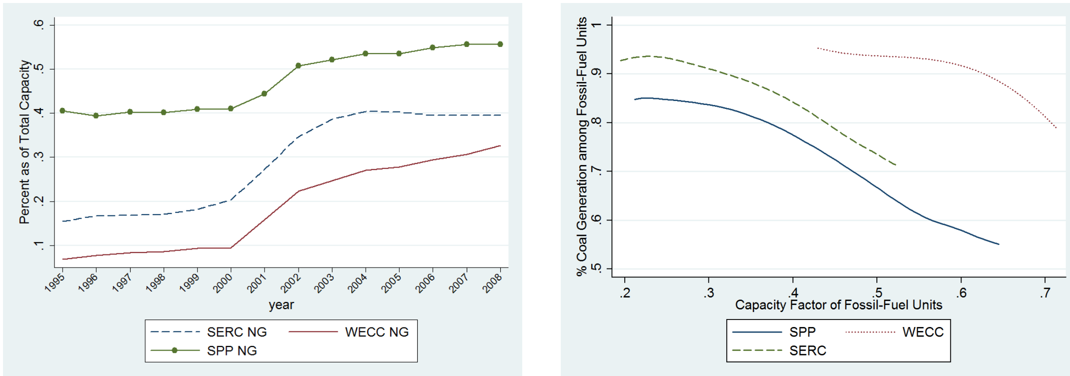
1.2.3 Control and Treatment Regions

In order to investigate whether divestiture of transmission control from integrated utilities improves regional cross-firm production efficiency, I need a control region for SPP. The natural choice are regions that did not go through any market restructuring activities and have significant fossil-fuel fired electricity generating capacity. There are two regions that meet the requirement: (1) Southeast Electric Reliability Council (SERC) and (2) mid-eastern part of Western Electricity Coordinating Council (WECC), including WY, CO, UT and NM. Both regions are a reliability council in North America Electricity Reliability Corporation (NERC), which serves as the balance and reliability authority in the North America.

There is evidence that SERC provides a better counterfactual for SPP. First, the intensity of competition from natural gas capacity faced by the coal-fired units[16] in SERC is closer to that in SPP. The comparison is shown in Figure 1.2. Figure 1.2(a) shows the share changes of natural gas capacity across time in the 3 regions. As demonstrated in the figure, the share of natural gas capacity in SERC is constantly higher than the level in WECC and closer to that in SPP. Moreover, the change of share in WECC (from almost zero to over 30%) was more dramatic relative to the change either in SPP or in SERC. Figure 1.2(b) illustrates how the share of coal-fired generation among all fossil-fuel units[17] varies with regional load, which is captured by the capacity factor of fossil-fuel units. From the figure, we can see that the pattern of the relationship in SERC relatively resemble that in SPP. In contrast, the relationship in WECC dramatically differs. WECC obviously relies more on coal-fired capacity such that coal-fired units face less competition from natural gas fired ones. Given these reasons, I choose SERC as the preferred candidate for the control region. However, for robustness check, I also exploit units in WECC as the counterfactuals and find that the results still hold.

[16] As discussed in later section, the paper focuses on coal-fired units only to limit unobserved heterogeneities.

[17] Other than coal units, the rest capacity is almost all natural gas fired.



(a) Changes in the Share of Natural-gas Capacity of the Regions

(b) Coal-fired Generation Share among Fossil Fuel Units across Load Levels in 2004

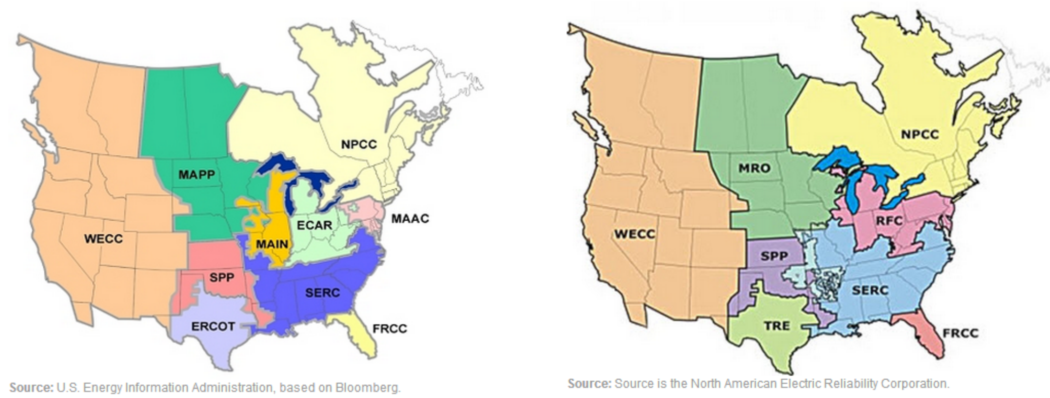
Figure 1.2: Competition from Natural-gas Capacity for Coal-fired Units in 3 Regions

Note: Graph (a) is based on EIA 860, which provides annual information on generator capacity. As well as EIA 860, graph (b) exploits hourly data of gross load from EPA Clean Air Market data. WECC here only includes CO, UT, NM and WY, where most of the fossil-fuel capacity is located.

The basic information of three regions is contained in Table 1.2. One empirical difficulty is to determine the control and treatment sample since NERC changed its entity territories in 2005 (shown in Figure 1.3). Notably, SERC expanded its area to parts of KY, MO and IL after 2004. Since the newly added parts of MO and IL joined another RTO, MISO (see Figure 1.1), I do not include generating units in these two areas in the control group. Moreover, I also drop from the control region Dominion Company (part of VA and NC), which joined PJM in 2005.

1.3 Regional Production Efficiency Hypothesis

Unlike the majority of the literature which focuses on plant-level operating efficiency gains, I test the following hypothesis: can production resources be allocated more efficiently under the restructured environment associated the divestiture of transmission control from vertically integrated utilities? If so, the social cost of meeting the economy's electricity demand can be reduced.



(a) Up till 2004 **(b)** 2005 - 2010

Figure 1.3: Historical NERC Entities

Table 1.2: Regions in Data Sample

Region	Footprint	Time of Organized Wholesale Market	Market Organization	Changes in Footprint
SPP	KS, OK, NM*, TX*†, LA*, MO*, and AR*†	Oct 2004	RTO-monitored decentralized bilateral trading (Oct 2004 - Feb 2007), Centralized Spot Market available after Feb 2007	
SERC	TX*†, LA*, MO*, MS*, AR*†, TN, AL, GA, FL*, SC, NC†, VA*† and KY*	Never	Bilateral trading without RTO monitoring	Dominion Company (Part of VA and NC) joined PJM in 2005**
WECC	CO, UT, WY, NM*	Never	Bilateral trading without RTO monitoring	

* means only part of the state is in the footprint.
† means the states passed restructuring legislation. Note AR and VA suspended the deregulation process, and restructuring was never implemented.
** In regression analysis, I drop the associated plants of Dominion from SERC in the entire data span.

Market restructuring attempts to overcome the inefficient features of rate-of-return revenue principle and integrated structure of utilities. First, the agency model predicts that under the cost pass-through guaranteed by rate-of-return principle, regulated utility power producers would deviate from cost-minimizing behavior and seek to recover their costs to justify their own plant investment. Prior to the restructuring, in order to protect and increase the sale basis for revenue compensation, regulated power producers have incentives to favor their own generating units. Second, the vertical integration structure of the industry facilitates this motive of the regulated utility power producers by providing them the chance to gain economic rents of the transmission facility. Given the network nature of the power industry, transmission access is an essential input. Competing power producers must depend on transmission network to schedule and dispatch their generating units in order to accomplish the sale of electricity. A vertically integrated power producer, who has financial interest in the generation sector as mentioned above, and also operates the transmission facility, would have incentives to discriminate against its non-integrated competitors. The theoretical support of the incentives has been documented by earlier studies on vertical integration.[18]

Even though transmission discrimination is prohibited (FERC Order 888 and 889), vertical integrated utilities might still have chance to favor their own generating units through either price-discrimination or non-price-discrimination. On the one hand, due to potential asymmetric information from the regulator's perspective, price regulation constraint on transmission might not be binding. This leaves room for price-discrimination, which directly raises non-integrated competitor's input costs and thus the wholesale prices they are willing to accept. On the other hand side, Beard et al. (2001) documents theoretical support that effective regulation on price-discrimination can create a perverse incentive for the integrated firm to perform non-price discrimination through quality degradation of the upstream input. Such "sabotage" form of non-price discrimination was reported in network industries

[18] See Vickers (1995), Economides (1998), and Beard et al. (2001), etc.

(i.e., energy, telecommunications, etc.) in EU, the examples of which include discriminatory information flow, overly complex contractual requirements, undue delays in delivery of the service, unreasonably high requirements of bank guarantees, and so on (Hoffler and Kranz, 2011). Both means serve to lower production and sale of the non-integrated competitors.

Since vertically integrated utility power producers tend to over-utilize their own generating assets through discrimination, this can lead to underutilization of outside lower-cost options and thus an inefficient allocation of the regional production resources (i.e., inefficient dispatch algorithm). However, with the right of transmission control handed over to an impartial RTO, the possibility of discriminatory transmission access is removed. Consequently, under a more competitive RTO-monitored wholesale market with maintained non-discriminatory transmission, under-utilized efficient plants would have incentive to bid more quantities and increase sale through bilateral trading for larger base of rate-of-return profits. Thus, the fostered wholesale competition would potentially facilitate trading, re-assign production resources market-wise and enhance regional production efficiency.

Still, there are reasons why the efficiency gains mentioned above should be questioned. One important explanation is that market restructuring has enabled wholesalers to exercise market power. A large body of literature has documented evidence of Cournot behavior in restructured electricity wholesale markets (Borenstein and Bushnell, 1999; Wolfram, 1999; Borenstein et al., 2002; Mansur, 2007, 2008; Hortacsu and Puller, 2008). Market power could be exerted by universally reducing production or bidding above the marginal curves to force high-cost units to the margin for the purpose of higher clearing prices. Thus, the production efficiency would be distorted with potentially more efficient resources of the oligopolies under-utilized. Meanwhile, some high-cost units would be forced to the margin and over-utilized than otherwise. This pitfall becomes more salient when local congestion in demand occurs in the market. Also, with transmission control handed over to the RTO, a mechanism has to be proposed to allocate the scarcity of transmission capacity in an efficient manner. Joskow and Tirole (2000) proves that market power can arise under such mechanisms. Specifically, by withholding the transmission access rights off the market, high-cost generators with market power in the importing region can enhance their market power and inefficiently restrict import from cheap power producers. Moreover, the high market concentration in SPP accentuates the concern of inefficient allocation from this perspective. In 2003, the top ten owners[19] provided over 73% of capacity and 79% of generation in SPP (2004 State of Market Report, FERC). In sum, the potential issue of market power serves to counteract the gains in regional production efficiency brought about by the vertical separation of the electricity network, leaving the question of interest open to empirical analysis.

1.4 Empirical Model and Identification

The current analysis is restricted to coal-fired power generating units. Almost all coal-fired generating units employ the steam turbine technology[20] and have much smaller variation in the production efficiency (fuel heat input required per unit of output), compared to units using natural gas and oil, for which there are several technologies available. Thus, focusing on coal units has the advantage of limiting confounding factors across units due to heterogeneity in fuel, technology, operational standard, etc. However, there is still significant variation in average operating cost among coal-fired units. On the one hand, generating units have heterogeneous capital vintages, and thus different production efficiency; on the other hand, plants also procure coal at different prices.

[19]Nine of them were regional utilities, their affiliates or large municipals and cooperatives.

[20]See "The Changing Structure of the Electric Power Industry 2000: an Update", EIA.

1.4.1 Empirical Model

The empirical model in this paper analyzes how cost sensitivity of unit utilization changes associated with the vertical separation of electricity network. If units are dispatched more efficiently, the utilization should be more sensitive to the average operating cost, meaning *ceteris paribus*, costlier units are less likely to be dispatched, compared to the earlier scenario before the change. Although market production is dispatched based on marginal cost in real-time, this study focuses on a monthly interval such that average cost is a fairly logical measure for cost-efficiency. This is especially true since in both the control and treatment regions majority of the production is realized by intermediate- or long-term bilateral trading.

The treatment date is chosen to be Oct 2004, when SPP was granted by FERC the status of a RTO. I later vary the treatment date for robustness check. I select Jan 2001 as the start of the data sample to keep a relatively short event window, which can limit possibly differential pre-existing trends across the treatment and control region. The end of the data sample is Dec 2008, after which a new NO_x permit trading program start to operate under the Clean Air Interstate Rule (CAIR), complicating the calculation of emission costs.

I investigate the regional production efficiency hypothesis by applying empirical models with the following difference-in-difference specification:

$$\begin{aligned} Utilization\,Rate_{it} =& \beta_0 + \beta_1 \cdot log(AVC_{it}) + \beta_2 \cdot 1\{Treat\} \cdot log(AVC_{it}) + \beta_3 \cdot 1\{Post\} \cdot \\ & log(AVC_{it}) + \beta_4 \cdot 1\{Treat\} \cdot 1\{Post\} \cdot log(AVC_{it}) + \alpha \cdot X_{it} + \delta_i + \\ & \sum_{j=control,treatment} \eta_t \cdot 1[region = j] + \epsilon_{it} \end{aligned} \tag{1.1}$$

where subscript i indicates a generating unit (i.e., a boiler), t stands for a specific month out of the sample, $1\{Treat\}$ is a region dummy variable indicating whether a unit is located in SPP, and $1\{Post\}$ is a dummy variable indicating whether the observation occurs post the treatment date. X_{it} stands for a set of control variables. The dummy variables δ_i are unit fixed effect. The dummy variables η_t are month-of-sample time effects, which are interacted with the treatment region dummy so as to allow for the flexibility of possible differential trends across regions.[21] Following Davis and Wolfram (2012) and Hausman (2014), I cluster all standard errors at the plant level in order to make statistical inference robust to potential serial correlation.[22]

The coefficient of primary interest is β_4, associated with the interaction between the log average cost and the treatment-region and post-treatment indicators. It measures the change in cost sensitivity in the treatment region, relative to the change in the control region. I look into it to analyze the impact on regional production efficiency brought about by vertical separation of the electricity network and consequent fair transmission access. If the change in market condition leads to gains in regional production efficiency, the coefficient should be significantly negative such that the unit utilization becomes more responsive to average cost in SPP, compared to that in SERC. This means that costlier units are less likely to be dispatched and that the social production function moves toward the optimal one. Therefore, the empirical interest is to test the null hypothesis: $\beta_4 = 0$.

The dependent variable is the monthly utilization rate of a unit. In baseline models, I use capacity factor to capture this, which is defined as generation as a percent of the maximum possible output in a month. That is,

$$Utilization\ Rate_{it} = \frac{Monthly\ Generation_{it}}{Nameplate_{it} \times Total\ Hours\ in\ Month\ t} \tag{1.2}$$

where nameplate is the maximum possible load a unit can generate within an hour. Note that the capacity factor can be zero. It can also be larger than 1 as sometimes units are uprated to produce more generation than the designed capacity. I drop

[21] I also check specifications with only month-of-sample time effects, and get robust results.

[22] The importance of taking serial correlation into account is well discussed by Bertrand et al. (2004), who argue that positive serial correlation in error terms, if not addressed, can lead to over-rejection of the null hypothesis.

observations where the gross load is zero. The logic is that if the monthly generation of a unit is zero, it is most likely that the unit is shut down for necessary maintenance purposes, rather than not dispatched for economic reasons. This means regional production efficiency here only refers to the allocation of production for units that are available.

On the right-hand side, $log(AVC_{it})$ stands for the log of average operating cost of unit i in month t, which is captured by multiplying the plant-level monthly average of fuel procurement contract prices (dollars/MMBtu) with production efficiency (heat rate, i.e., fuel heat input per unit of output) of unit i (MMBtu/MWh). Except for emission compliance costs, other operation and maintenance costs are omitted. The implicit assumption is that these average non-fuel costs are the same across coal-fired units. If average non-fuel costs experienced a larger increase in SPP relative to SERC, attributing the operating costs only to fuel costs would lead to over-estimation of the treatment effect; or it would result in under-estimation otherwise. However, in the U.S., fuel cost accounts for the vast majority of the operating costs for fossil-fuel generators with steam technology,[23] which is predominantly used by coal-fired units.[24] Thus, I argue it is reasonable to use average fuel costs as a proxy for the cost efficiency of generating units.

Moreover, I do control for environmental compliance costs, taking advantage of emission permit price information for SO_2 and NO_x. The environmental compliance cost is the total actual cost burden due to covering emission (if a plant purchased permits), or the opportunity cost of using the permits (if the plant used free allocation of permits but could have sold them for earnings). The average environmental

[23]According to the FERC's Annual Report of Major Electric Utilities, during 2001-2011, fuel input costs consistently accounted for over 75% of the total operating and maintenance expenses for the U.S. power plants exploiting fossil steam turbine technology. The proportion increases to 85% if only production/operating cost is considered.

[24]See "The Changing Structure of the Electric Power Industry 2000: an Update", EIA.

compliance cost is calculated via the following formula:

$$\sum_j Price_{jt} * 1\{Emission\ Market_{jit}\} * Emission\ Rate_{ji} \qquad (1.3)$$

where subscript j stands for SO_2 or NO_x, t stands for a specific month, $Price_{jt}$ is the permit price for pollutant j, $1\{Emission\ Market_{jit}\}$ is a dummy variable indicating whether unit i participated in permit trading program for pollutant j in month t, and $Emission\ Rate_{ji}$ stands for average quantity of pollutant j emitted by unit i per unit of generation.

I obtain and update the heat and emission rates from year to year by averaging the hourly statistics for each coal-fired unit in the sample. This allows for the possibility of changes in operating efficiency in the long run during the sample span. In the short run, operating efficiency of a generating unit might also vary with utilization levels. For instance, at high utilization levels, unit might operate more efficiently with lower heat input required and pollutant emitted for each unit of output, i.e., lower heat and emission rates. In order to capture this possibility, I also allow the rates for each unit to differ in the high-demand season (Dec, Jan, Feb, Jun, July, and Aug) and in the low-demand season (Mar, Apr, May, Sept, Oct, and Nov).[25] Evidence of how heat and emission rates vary under the two seasons is shown in Table 1.3. Based on hourly operational data for coal-fired units in SPP, SERC and WECC between 2001 and 2008, I analyze how the hourly statistics differ between the high- and low-demand seasons. As shown in the table, heat and emission rates are significantly lower during high-demand seasons when the utilization is expected to be generally higher.

The coefficient on the average cost measures the cost sensitivity in the control region prior to the treatment event. The coefficient on the interaction between the average cost and the treatment-region dummy measures the deviation of cost sensitivity in the treatment region from that in the control region before the treatment

[25]Since in the electricity sector demand has to be balanced with supply on a minute-to-minute basis, utilization of generating units is expected to be high at high-demand seasons, and vice versa.

Table 1.3: Comparison of Heat and Emission Rates between High/Low-Demand Seasons

	Heat Rate	SO_2 Rate	NO_x Rate
1(High-demand Season)	-0.946***	-0.467*	-0.195***
	(0.237)	(0.273)	(0.0595)
Constant	11.93***	11.41***	4.334***
	(0.296)	(0.481)	(0.101)
Number of Obs	5101	5099	5101

Notes: Heat rate (MMBtu/MWh) is the amount of heat input used per unit of output. SO_2 and NO_x rate (lbs/MWh) is the amount of pollutant emitted per one unit of output. 1(High-demand Season) is a dummy variable indicating the high-demand season including December, January and February, June, July, and August. Observation is biannual averages of heat and emission rates calculated based on hourly operational data for units in SERC, SPP and WECC from 2001 to 2008. The standard errors are clustered at the generating unit level, and reported in the parentheses. ***p<0.01, ** p<0.05, and *p <0.1.

event. The coefficient on the interaction between the average cost and post-event indicator measures the common trend of changes in cost sensitivity for the control and treatment regions after the treatment event. I also include a set of control variables. It incorporates unit vintages up to the third polynomial, indicators for unit participation in the NO_x permit trading market[26], and indicators for whether a unit is equipped with abatement control technologies for SO_2 or NO_x. I also include monthly total generation (of all fuel sources) of the state where the unit is located to control for variation in demand level. This is important since even costly units would serve more load under high-demand scenarios. Regional load levels are also implicitly controlled for via the inclusion of the interaction between the month-of-sample indicators and the region dummy. This flexibility also allows for other trends to vary not only across time but also across the control and treatment regions. The later is crucial to control for since two regions could have experienced differential trends, the examples of which include natural-gas capacity add-ons during the data period (See Figure 1.2).[27]

[26] During the sample period, all coal-fired units had participated in the SO_2 permit trading market.

[27] Another way to control for possibly differential trends between the control and treatment region is further restricting the event window. For instance, most of the increase in natural-gas capacity occurred before 2003. I also apply this method, the results under which are shown in later section.

I also control for unit fixed effects in the empirical model. I check the plant and unit fixed effects for robustness in related subset of specifications, which control for unobserved time-invariant characteristics such as idiosyncratic operation condition at the unit and/or plant level, or more broadly, heterogeneities of state institutional policies or economic characteristics that did not change during the data span.

1.4.2 Identification

Several identification assumptions are required for valid estimation based on the empirical models outlined above. In this section, I discuss two assumptions that deserves caution under the current context. The first assumption is that the assignment of the treatment is exogenous, that is, SPP did not go through restructuring in transmission component in response to unobserved, endogenous factors that affect cost sensitivity. The second assumption relates to the potential simultaneity issue between unit average variable cost and utilization. In this section, I discuss why each of these assumptions is a concern and how I address potential violations in the empirical study.

First, the validity of the estimation of the average treatment effect lies on the assumption that conditional on all the observables, the treatment selection is exogenous. The assumption could potentially be violated under the context of the study. Previous literature on deregulation in the U.S. power industry argue that states decided not to restructure largely due to relatively low electricity rates,[28] so they seriously questioned the potential gains from deregulation (Joskow, 1997; Bushnell and Wolfram, 2005; Fabrizio et al., 2007; Fowlie, 2010). Earlier studies argue that this selection is exogenous to their investigated aspects, primarily operating performance. SPP has access to cheap coal from the Powder River Basin, while SERC has relatively

[28]Factors that led to relative low prices in these states include: access to cheap hydro and coal generation, limited sunk investments in nuclear power, or fewer long term contracts encouraged by the 1978 Public Utility Regulatory Act with independent power producers whose production costs were generally higher (Fowlie, 2010).

large share of hydro and nuclear-power production. Accordingly, both regions consist of member states without restructuring legislation.

A more relevant issue is whether SPP was established as a RTO-intermediated wholesale market based on members' belief that they were more likely to gain benefits compared to SERC. SPP was first founded when 11 regional power companies joined to keep an Arkansas aluminum factory powered to meet the demand for the Second World War. Then it retained as a power-pool organization that maintained electric reliability and coordination. I argue that the coordination experience and pre-set organization framework provided lower implementation cost for SPP compared to SERC to respond to FERC's request of the handover of transmission facilities to the control of a RTO. In this sense, the treatment is exogenous relative to the question of interest.

Yet, question still remains weather SPP went through the restructuring due to unobserved advantages related to regional production efficiency, such as long history of coordination as a power pool. If so, the validity of inference on the impact of regional production efficiency would be biased due to self-selection. To deal with the problem, I test whether units in SPP have higher cost-sensitivities compared to those in SERC before the treatment event. It turns out that the responsiveness was not statistically different between units in the two regions prior to the establishment of SPP as a RTO, moderating the concern of self-selection. This is also reflected in regression results in the empirical section.

The second assumption relates to the simultaneity concern between average variable costs and utilization rates of generating units. While units with low average cost may have higher utilization rates, altering utilization levels might also affect the heat and emission rates and thus the average fuel and emission costs. To address the simultaneity issue, Fabrizio et al. (2007) and Chan et al. (2013) use state-level demand-side factors to instrument for plant generation to calculate the average operating cost. Yet, because this paper gains extra data granularity at unit level, these factors would perform as a rather poor fit as instrument variables. To deal with the problem, I calculate the average heat and emission rates based on hourly observation biannually in high- and low-demand seasons such that the average heat and emission rates could not be temporarily determined by monthly utilization. Moreover, I also drop observations with abnormally high heat and emission rates. I argue it is highly likely that they are the results of low utilization levels.

Moreover, simultaneity is less of an issue in the paper since I focus on utilization of coal-fired units only. Compared to the natural-gas or petroleum counterparts, coal units have much higher start-up costs. If the coal-fired units are turned on, the average cost is relatively constant across utilization levels. The reverse impact of utilization on production efficiency, and thus on average cost is most likely to occur at low levels when coal-fired units are cycled on and off, which seldom occurs as they serve the base load. Thus, I investigate whether coal-fired units in the treatment and control regions become more likely to be turned on and off after the treatment event. Based on hourly unit-level load information from EPA Clean Air Market data, I calculate the standard deviation of hourly generation for all coal-fired units for a given month, and then average the statistics across both regions in SPP and SERC. The results are provided in Figure 1.5. As shown in the figure, except for the seasonal change, the standard deviation of hourly load maintains constant across time, and the trends of the 2 regions collapse. This provides evidence that coal-fired units in neither of the regions become more prone to being cycled on and off. Accordingly, the major simultaneity between utilization and average operating cost in the current analysis is largely moderated.

1.5 Data

1.5.1 Data Description

The rich data exploited in this study are mainly comprised of monthly information on the following aspects: operational activities of power generators, power plant

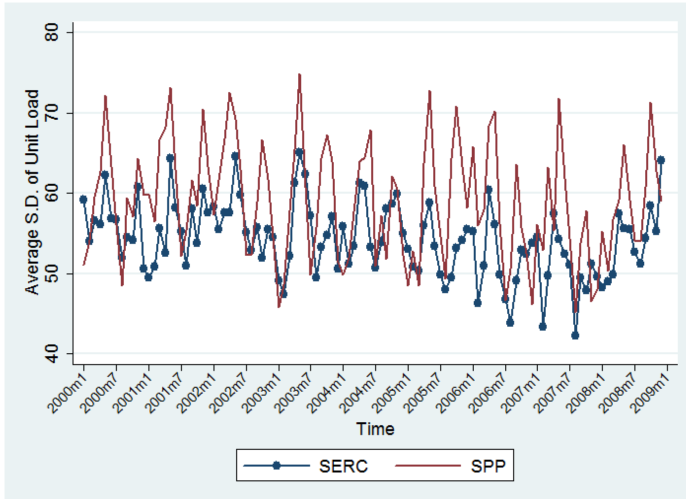


Figure 1.4: Average S.D. of Hourly Coal-fired Unit Load

Note: The graph is based on hourly operational data from EPA Clean Air Market Data. I calculate the standard deviations of generation for each unit in the sample and then average across units in SPP and SERC. The treatment event occurred at 2004.

fuel receipts and generating unit configuration. They are obtained from three major sources: EPA's Clean Air Markets data, FERC 423 (and EIA 923) and EIA 860. For the current study, I select all units with coal as the primary fuel type. I avoid choosing an event window that is too large. A large event window means other concurrent trends of related factors are more likely to bias the results. Further, in 2009, a new NO_x cap-and-trade market started to operate under the Clean Air Interstate Rule (CAIR), along with the previous NO_x Budget Trading program. This makes it complicated to calculate the emission costs. For the above two reasons, I choose a data sample between 2001 and 2008.

Data on boiler-level[29] electricity generation, fuel usage and emissions come from EPA's Clean Air Markets Division. Plants participating in the Acid Rain program, one of whose major target is power plants, must report unit-level data on the above variables. Moreover, the pollutant data is obtained through a continuous emission monitoring system with little measurement error. The data source also provides information on when a specific plant participated in the SO_2 and/or NO_x permit

[29] A boiler is a device that generates steam for power.

trading program. Based on the information, I calculate the amount of emission that burdens a plant with permit costs, by interacting the program-participation indicators with the corresponding SO_2/NO_x emission quantity.[30] This is vital as there are both time and spatial variations in unit participation in the two cap-and-trade programs.[31]

The fuel-cost data comes from FERC 423 and EIA 923.[32] The former contains the data prior to 2008. Both data sets include monthly fossil-fuel receipts for utility power plants with a total capacity over 50 megawatts. The transaction-level data contains purchased fossil fuel prices (including transportation costs and taxes), quantity of fuel delivered, average heat content of the fossil fuel, type of contract, quality of the fossil fuel (e.g., average sulfur and ash content), etc. Prices are adjusted to real terms based on the baseline value of Jan 1982 of the seasonally adjusted Producer Price Index: Intermediate Energy Goods (PPIIEG).[33] I calculate the monthly mean of fuel receipt prices, weighted by the transaction volumes within each plant. Matching them with boiler-level generation and fuel-consumption data, I compute the monthly average fuel costs per unit of load. Since the fuel receipt data is at the plant level, the implicit assumption is that the boilers/generators within the same plant employ fuel with negligible cost differences for a given month.

The SO_2 and NO_x permit prices are obtained from BGC Partners,[34] which is a leading global brokerage company with a variety of products under service. It calculates daily permit prices based on private transactions made through the

[30]Different from the SO_2 cap-and-trade market, which operates through the entire year, the market for NO_x only operates during the ozone season (May-Sep). Accordingly, I set participation dummy for NO_x permit trading program to be zero during non-ozone seasons even if a unit participated in the program.

[31]For instance, by 2001, the nationwide SO_2 permit trading program had brought in almost every new and existing fossil fuel generating unit in America. In contrast, participants of NO_x Budget Trading Program (NBP) are primarily located in northeastern and southeastern regions. Although a large proportion of units in SERC region were included in the NBP program since May, 2003, only 1 unit participated in SPP.

[32]Fuel cost data for non-utilities is publicly unavailable for privacy purposes, which leads to missing data if utility generating assets were sold to non-utility firms. However, no divestiture occurred in either of the regions during the data window (See Cicala, 2015). Also, vast majority of the electricity is produced by utility plants in both regions.

[33]It is available from Federal Reserve Economic Data (FRED II).

[34]I am grateful to Jacob LaRiviere and J. Scott Holladay for sharing the data.

company. I assume that the data reflects price variations of transactions in the entire market and the same cost burden of emission for all plants. If there were differential changes in actual permit prices across the treatment and control regions, the results would be biased. However, I argue that this assumption is relative reasonable since arbitrage should eliminate the price difference across regions.

The unit configuration data comes from EIA 860 form, which provides annual electric generator[35] data for all power-generating plants with total capacity over 1 megawatt. The data includes generator-level information on nameplate (maximum generation possible during for an hour), predominance order of the fuel sources, initial commercial operation date, retirement date, combustion system technology, etc. I explore the nameplate and capital vintage information and match them with the boiler-level monthly operational data. To accurately match across the data sets, I take advantage of a data set containing the generator-and-boiler association information, which is analyzed and collected by Shawhan et al. (2014). The data includes all units that are still operating in 2010. This means my analysis excludes units that retired before 2010.[36]

1.5.2 Comparison between the Control and Treatment Regions

Summary statistics for the data are provided in Table 1.4. As shown in the table, units in SERC on average have older vintage and higher fuel input costs.

I also check the trends across the control and treatment regions to confirm: (1) whether units in the two regions are comparable in each aspect; (2) if not, whether the differences are consistent throughout the data window. I first examine the trends of operational aspects of generating units across the regions: average operating cost (including fuel input cost only), fuel receipt price, heat rate and capacity factor. The

[35] An electric generator is a device that converts mechanical energy to electrical energy.

[36] This makes sense as including eventually retired units in the sample span means changes in the sample which would affect the average cost sensitivity.

Table 1.4: Summary Statistics for Coal-fired Units, 2001-2008

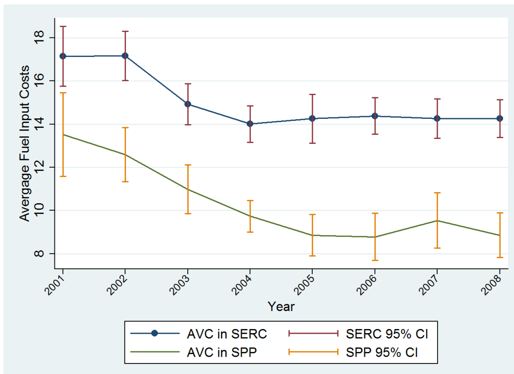
Region	SERC	SPP
Capacity (MW)	346.9	422.1
	(296.8)	(298.1)
Generation (1000 MWh)	181.0	215.0
	(173.7)	(160.3)
Capacity Factor	0.679	0.727
	(0.224)	(0.231)
Avg Fuel Input Costs	15.02	10.43
(Dollars/MWh)	(4.529)	(3.762)
NO_x Emission Rate	3.954	4.133
(Lbs/MWh)	(1.609)	(1.905)
SO_2 Emission Rate	12.88	7.202
(Lbs/MWh)	(6.442)	(4.614))
Heat Rate (MMBtu/MWh)	10.56	11.41
	(1.921)	(1.758)
Avg Fuel Receipt Price	1.45	0.91
(Dollars/MMBtu)	(0.34)	(0.29)
Avg Vintage (At Year 2004)	38.80	30.98
	(10.73)	(10.17)
Number of Observation	15981	4165
Number of Units	211	50

Notes: the data frequency is at the monthly level, except for heat rate and emission rate, which are recorded hourly. Abnormal observations with extreme heat rate (above 32), NO_X emission rate (above 12) or SO_2 emission rate (above 45) are dropped at the cutoff of the 99 percentiles. Standard deviations are reported in the parentheses.

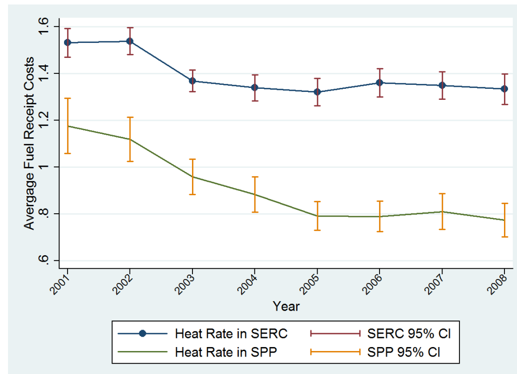
region-wide yearly averages, weighted by monthly unit load, are shown in Figure 1.4. The treatment and control regions differ in average fuel input costs and coal receipt prices. But both gaps remain relatively constant throughout the data window. Average fuel input cost ($/MWh) is the product of fuel receipt price ($/MMBtu) and heat rate (MMBtu/MWh). The decline in average fuel input costs is due to a decrease in the fuel price for both regions, as heat rates are time invariant. Moreover, the average capacity factor is not significantly different between the regions. These represent evidence that units in SERC present relatively good counterfactuals for those in SPP.

Second, I investigate trends in fossil-fuel capacity mix in the two regions during this period. I focus on coal and natural gas units as they account for the vast majority of the fossil-fuel capacity. The trends are shown in Figure 1.6. The most notable change is that both regions witnessed a dramatic increase in natural gas capacity, accompanied by a fall in the share of coal capacity. The change was greater in SERC. To control for common idiosyncratic shocks in a specific region for a given period in my empirical analysis, I include an interaction term between the month-of-sample dummy and the regional dummy.

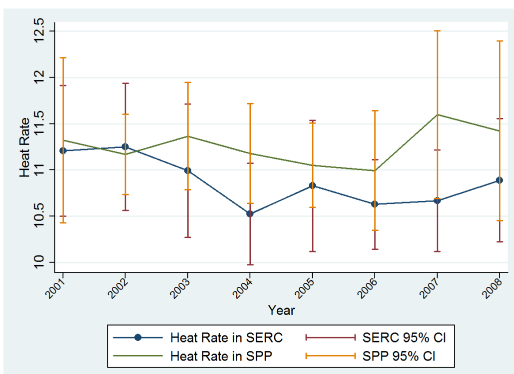
Third, I check for changes in the transmission system in each region. Better transmission infrastructure can mitigate regional congestion and theoretically lead to a more efficient allocation of production resources. Failing to account for different trends in transmission capacity across regions prior to the event might falsely attribute the effect of a better transmission system to the treatment effect under the current analysis. Exploiting NERC's Electricity Supply and Demand (ES&D) data set, I find that both SERC and SPP experienced minimum changes in transmission infrastructure prior to the event window of year 2004.



(a) Average Operating Costs



(b) Average Coal Receipt Prices



(c) Average Heat Rates

(d) Average Capacity Factors

Figure 1.5: Comparison of Unit Operational Characteristics between SPP and SERC

Note: The treatment event occurred at 2004. Graph (a) (c) and (d) are based on unit-level operational data, while (b) is based on plant-level transaction data. All statistics are weighted by monthly unit gross load. For each unit, average operating cost is a product of coal receipt price (dollars/MMBtu) and heat rate (MMBtu/MWh).

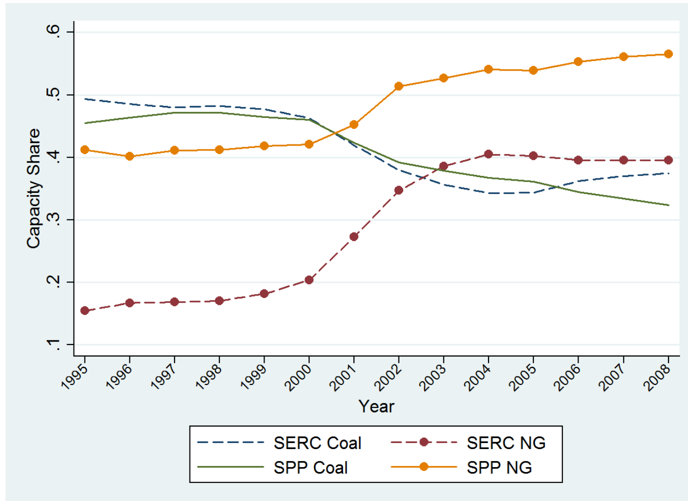


Figure 1.6: Existing Shares of Coal and NG capacity

Note: The treatment event occurred at 2004.

1.6 Empirical Evidence

1.6.1 Main Regression Results

The baseline estimation results are presented in Table 1.5. The outcome variable is capacity factor of a unit in a given month, that is, generation as a percent of the designed capacity. The event window is chosen to be Oct 2004, when SPP was granted by FERC the status of RTO and obtained the operational control of transmission facilities from vertically integrated utilities.

Model specifications listed in Table 1.5 vary in the way environmental compliance cost is controlled for. In model 1 - 3, I do not include in the regression the environmental compliance cost. In model 1, I control for plant fixed effects. In model 2, I add unit age to the third polynomial to capture the capital vintage. In model 3, I account for generating-unit fixed effects while controlling for unit age. In model 4, I implicitly account for the cost burden of emissions by including indicators for whether a unit actively participated in an emission market and suffered from costs for emitting SO_2 or NO_x emission,[37] and dummy variables for the installation of abatement devices. In model 5, I control for average emission cost based on equation (3) by adding it as a separate explanatory variable. The underlying assumption is that compared to the average fuel input costs, it might be associated with different cost sensitivity. I also include a set of its interactions with treatment-region and post-event dummies. In model 6, I model average operating costs jointly as the sum of average fuel and emission costs. Since the data of SO_2 permit price is only available after Oct 2001, I curtail the sample data thereafter for the last two specifications.

In each specification, the coefficients on the log of operating costs ($log(AVC_{it})$), are all significantly negative at the 1% level. This makes intuitive sense. Both in regions with organized wholesale markets (treatment group) and in those with separate integrated utilities as collective dispatchers (control group), production resources should generally be ranked based on the production cost of generating units, which is instrumented here by average fuel cost (and environmental compliance costs). The negative sign indicates costlier units are less likely to be dispatched in both regions.

The coefficient of primary interest is on the interaction of log average operating costs and the treatment-region and post-event dummies, shown on the fourth row. We can see that it is not significantly different from zero in any of the specification. With the magnitude being quite small compared to that of the coefficients on AVC, the coefficients are very much centered at zero, even though the standard errors are all relatively noisy (roughly 20% of the coefficient on AVC). This provides strong evidence that the separation of transmission control is not sufficient to bring about efficiency gains on the regional production efficiency. In other words, I do not find that production in SPP shifted from higher- to lower-cost generating units. This implies that in order to obtain adequate regional production efficiency, market restructuring needs to go beyond the minimum requirement of vertical separation of transmission

[37] SO_2 Market operated throughout the year, while NO_x Budget Trading Program only operated between May and September.

Table 1.5: Baseline Regressions

	(1)	(2)	(3)	(4)	(5)	(6)
AVC	-0.144***	-0.145***	-0.136***	-0.135***	-0.137***	-0.125***
	(0.0192)	(0.0186)	(0.0211)	(0.0205)	(0.0200)	(0.0202)
Treat × *AVC*	0.0824*	0.0849*	0.0513	0.0503	0.0489	0.0418
	(0.0434)	(0.0432)	(0.0410)	(0.0408)	(0.0389)	(0.0431)
Post × *AVC*	0.0251	0.0279	0.0259	0.0244	0.0279	0.00933
	(0.0210)	(0.0198)	(0.0218)	(0.0216)	(0.0211)	(0.0217)
Post × *Treat*	0.00335	0.00165	-0.00918	-0.0107	-0.0119	0.0212
×*AVC*	(0.0315)	(0.0315)	(0.0329)	(0.0324)	(0.0316)	(0.0315)
emission AVC					0.0136	
					(0.00881)	
Treat × *emission AVC*					-0.0142	
					(0.0201)	
Post × *emission AVC*					-0.0168*	
					(0.00900)	
Treat × *Post*					0.0328**	
×*emission AVC*					(0.0138)	
NO_x *market*				-0.0360***	-0.0396***	-0.0175
				(0.0119)	(0.0136)	(0.0125)
SO_2 *abatement*				-0.00792	-0.00854	-0.0109
				(0.0111)	(0.0123)	(0.0111)
NO_x *abatement*				-0.0172	-0.0193	-0.0209
				(0.0119)	(0.0158)	(0.0149)
Log state load	0.224***	0.218***	0.226***	0.190***	0.206***	0.216***
	(0.0337)	(0.0339)	(0.0338)	(0.0347)	(0.0348)	(0.0350)
Region-month-year dummies	Yes	Yes	Yes	Yes	Yes	Yes
Plant fixed effect	Yes	Yes	No	No	No	No
Unit fixed effect	No	No	Yes	Yes	Yes	Yes
Unit Vintage	No	Yes	Yes	Yes	Yes	Yes
Number of Obs	21543	21543	21543	21543	19641	19641
Adj. R^2	0.417	0.418	0.107	0.109	0.112	0.111

Notes: Observation is a coal-fired generating unit in a given month. The dependent variable is generation as a percent of designed capacity. *Treat* is a region dummy for SPP. *Post* is a dummy variable equal to 1 after Oct 2004, and 0 otherwise. In Model 1-4, average environmental compliance cost is omitted when I calculate the average operating cost. In Model 5, I add into the regression a set of variables associated with average environmental compliance cost. In the last model, when calculating average operating cost, I combine average environmental compliance cost and average fuel cost. The average environmental compliance cost is calculated by multiplying permit prices with emission rates and the operation dummy of the corresponding emission market, and then summing across the two pollutants. Since the SO_2 permit data is only available after Oct 2001 (when almost all fossil-fuel power plants had participated in the SO_2 emission market), I restrict the data sample in Model 5-6. Unit vintage is controlled for in in Model 2-6 by inclusion of the unit age to the third polynomial. Following Davis and Wolfram (2012), I cluster all standard errors at the plant level and report them in the parentheses. The explanation of the variable names are shown in Appendix 2. ***p<0.01, ** p<0.05, and *p <0.1.

and reach to aspects such as market-oriented designs for revealing generator supply curves, change of revenue rules, divestiture of production assets, etc.

The sign of the coefficient on the interaction between AVC and treatment-region dummy also deserves attention. In all specifications, the coefficients are all not significantly different from zero, meaning that prior to the treatment event, SPP did not have significant advantage in regional production efficiency relative to SERC. This moderates the self-selection concern that SPP set up as a RTO-based market based on unobserved advantages with regard to regional production efficiency.

I also explore how the treatment effect evolved across time. The concern is that after the treatment event, there could be a time lag before the production resources are re-assigned and regional production efficiency improves, or that the treatment effect might diminish over time. Under either scenario, the treatment effect can be netted out. I investigate the issue by estimating the following equation, based on Model 5 in Table 1.5:

$$Utilization\ Rate_{it} = \sum_{j=1}^{4} \beta_j \cdot 1[\tau_{i,t} = j] \cdot 1\{Treat\} \cdot log(AVC_{it}) + \alpha \cdot Z_{i,t} + \varepsilon_{i,t} \quad (1.4)$$

where $\tau_{i,t}$ denotes the year relative to the treatment event (e.g., $\tau_{i,4}$ denoting 4 years post the treatment event), $Z_{i,t}$ is the vector of variables shown in Equation (1.4) except the interactions between the log of average costs and treatment-region and post-treatment dummies. Thus, β_j captures the change in cost sensitivity of unit utilization for generators in SPP relative to that of the counterparts in SERC across the years following the treatment event. Figure 1.7 shows the estimated coefficients and corresponding 95% confidence intervals. We could see that the estimation is still relatively noisy for all years. Coefficients for the second and third year are trivial, while those for the first and fourth year are relatively large. There is no discernible pattern that the treatment impact increases or diminishes across time: the coefficients are all negative but insignificant such that no significant efficiency gain is found.

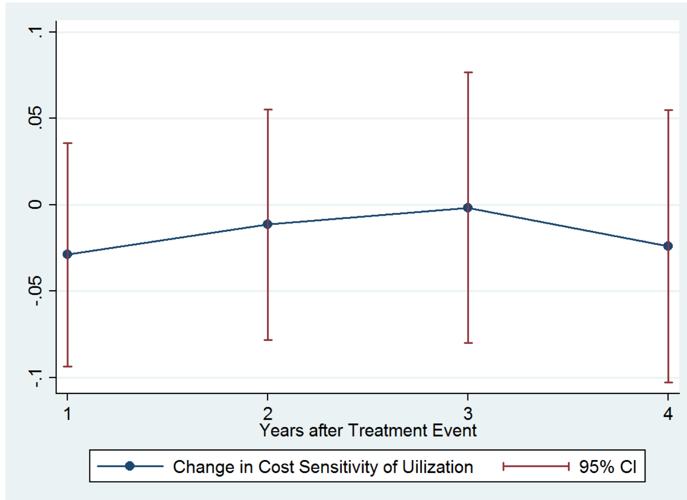
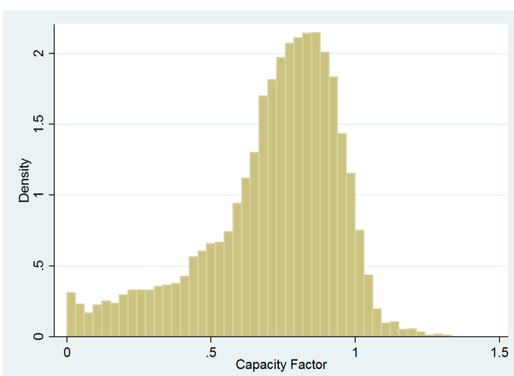
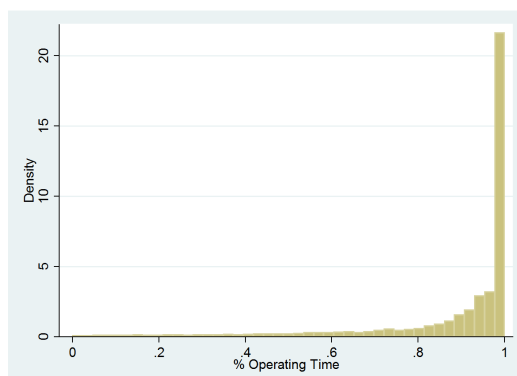


Figure 1.7: Relative Changes in Cost-sensitivity Across Time in SPP

Notes: the figure plots the coefficients of primary interest, which measure the estimated changes in cost-sensitivity of unit utilization in SPP relative to those in SERC after the treatment event. Time is normalized relative to the treatment event.



(a) Utilization Rates as Capacity Factor



(b) Utilization Rates as Percent Operating Time

Figure 1.8: Histograms of Utilization Rates

Note: in graph (a), utilization rate is capacity factor, which is the monthly generation as a percent of designed capacity. It could be larger than 1 since units could be up-rated. In graph (b), utilization rate is percent operating time, which is total operating hours over the total number of hours in the given month. Observations with zero generation or operating time are dropped.

1.6.2 Alternative Measure of Unit Utilization

I next explore whether the results are robust to the way how utilization rate is defined. Rather than basing it on generation and nameplate configuration of a unit, now I exploit monthly boiler operating time. This represents another measure of regional production efficiency. The calculation of utilization rate takes the following formula:

$$UtilizationRate_{it} = \frac{Monthly\,Operating\,Hours_{it}}{Total\,Hours\,in\,Month\,t} \tag{1.5}$$

For the new measure of utilization rate, a significant proportion of the value is 1. The histograms of unit utilization measured by percent of monthly operating time, and monthly capacity factor are shown in Figure 1.8. There is an obvious difference between the distributions of the variables. Most of the time, the coal-fired units are turned on as they serve the base load. However, this does not mean they are operated to the full capacity all the time. Monthly observations with zero operating time are dropped as they are mostly likely to be due to scheduled maintenance. The results are shown in Table 1.6. The coefficients of primary interest are still not significantly different from zero in any of the specifications. Yet, the results are still informative. It means that the results found in the paper should be cautiously interpreted. No regional production efficiency gain is found with regard to either whether a unit should be turned on or off line, or under what capacity factor a unit should be dispatched.

1.6.3 Alternative Measure of regional production Efficiency: Utilization Sensitivity to Relative Cost

So far, I look into the absolute average operating costs as the determinant of unit utilization. If units only compete with nearby counterparts in the region, another criterion of how generating units should be dispatched is relative cost efficiency. In the section, I exploit relative average operating costs as the criterion for the dispatch algorithm to analyze the impact of vertical separation of transmission in the U.S.

Table 1.6: Robustness Check: Percent of Operating time as Utilization Rate

	(1)	(2)	(3)	(4)	(5)	(6)
AVC	-0.114***	-0.114***	-0.102***	-0.101***	-0.0974***	-0.0997***
	(0.0154)	(0.0153)	(0.0181)	(0.0176)	(0.0192)	(0.0195)
$Treat \times AVC$	0.0478	0.0478	0.0180	0.0176	0.0144	0.0240
	(0.0298)	(0.0296)	(0.0309)	(0.0306)	(0.0337)	(0.0355)
$Post \times AVC$	0.00973	0.00842	0.00157	0.00241	0.00307	0.00582
	(0.0144)	(0.0144)	(0.0164)	(0.0162)	(0.0179)	(0.0186)
$Post \times Treat$	0.0128	0.0127	0.0162	0.0139	0.0134	0.0179
$\times AVC$	(0.0243)	(0.0241)	(0.0243)	(0.0241)	(0.0271)	(0.0258)
$emission\ AVC$					-0.000593	
					(0.00711)	
$Treat \times emission\ AVC$					0.00303	
					(0.0144)	
$Post \times emission\ AVC$					-0.00144	
					(0.00698)	
$Post \times Treat$					0.00943	
$\times emission\ AVC$					(0.0101)	
$NO_x\ mkt$				-0.0140	-0.0103	0.00172
				(0.00977)	(0.0117)	(0.0106)
$SO_2\ abatement$				-0.0193***	-0.0203**	-0.0234***
				(0.00722)	(0.00860)	(0.00819)
$NO_x\ abatement$				-0.0221**	-0.0257*	-0.0258*
				(0.0106)	(0.0141)	(0.0139)
$Log\ state\ load$	0.184***	0.187***	0.195***	0.180***	0.191***	0.195***
	(0.0325)	(0.0325)	(0.0325)	(0.0348)	(0.0360)	(0.0359)
Region-month-year dummies	Yes	Yes	Yes	Yes	Yes	Yes
Plant fixed effect	Yes	Yes	No	No	No	No
Unit fixed effect	No	No	Yes	Yes	Yes	Yes
Unit Vintage	No	Yes	Yes	Yes	Yes	Yes
Number of Obs	21546	21546	21546	21546	19644	19644
Adj. R^2	0.216	0.216	0.090	0.090	0.092	0.091

Notes: Observation is a coal-fired generating unit in a given month. The dependent variable is monthly operating hours as as percent of total number of hours in that month. $Treat$ is a region dummy for SPP. $Post$ is a dummy variable equal to 1 after Oct 2004, and 0 otherwise. In Model 1-4, average environmental compliance cost is omitted when I calculate the average operating cost. In Model 5, I add into the regression a set of variables associated with average environmental compliance cost. In the last model, when calculating average operating cost, I combine average environmental compliance cost and average fuel cost. The average environmental compliance cost is calculated by multiplying permit prices with emission rates and the operation dummy of the corresponding emission market, and then summing across the two pollutants. Since the SO_2 permit data is only available after Oct 2001 (when almost all fossil-fuel power plants had participated in the SO_2 emission market), I restrict the data sample in Model 5-6. Unit vintage is controlled for in in Model 2-6 by inclusion of the unit age to the third polynomial. Following Davis and Wolfram (2012), I cluster all standard errors at the plant level and report them in the parentheses. The explanation of the variable names are shown in Appendix 2. ***p<0.01, ** p<0.05, and *p <0.1.

Table 1.7: Robustness Check: Relative Cost-efficiency

Dependent Variable	Capacity Factor	Percent Operating Time
$Relative\ AVC$	-0.0202**	-0.0165**
	(0.00796)	(0.00772)
$Treat \times Relative\ AVC$	-0.00675	-0.00962
	(0.0199)	(0.0173)
$Post \times Relative\ AVC$	0.00926	0.00768
	(0.00734)	(0.00669)
$Post \times Treat$	0.000598	0.00110
$\times Relative\ AVC$	(0.0132)	(0.0116)
Region-month-year dummies	Yes	Yes
Unit fixed effect	Yes	Yes
Unit Vintage	Yes	Yes
Robust Heat and Emission Rate	Yes	Yes
Number of Obs	19787	19790
Adj. R^2	0.103	0.087

Notes: Observation is a coal-fired generating unit in a given month. $Treat$ is a region dummy for SPP. $Post$ is a dummy variable equal to 1 after Oct, 2004, and 0 otherwise. $Relative\ AVC$ is the monthly relative average operating cost (fuel and emission cost combined) which is normalized by the minimal average costs across units in each related region. Following Davis and Wolfram (2012), I cluster all standard errors at the plant level and report them in the parentheses. ***p<0.01, ** p<0.05, and *p <0.1.

power industry. The advantage in this fashion is normalizing not only the variation of average costs across time but also the gap in average costs between the treatment and control regions.

Empirically, I sum average fuel and emission costs for each generating unit and normalize the combined average operating costs by the varying monthly minimum in each region. This implies the variation in cost efficiency here measures changes in the extent of how much more costlier the operation of a unit is relative to the current most cost-efficient one within the region. The results are shown in Table 1.7. I vary the specifications by the definition of unit utilization. Yet, the empirical results still provide no significant evidence of improvement in regional production efficiency. The coefficients of primary interest are both small in magnitude and none of them is significantly different from zero.

1.6.4 Robustness Check on the Treatment Date

In the baseline models, I choose the treatment date as Oct 2004, when SPP was granted the status of a FERC-authorized RTO. The argument for the selection is that it means the proposal of transmission control by SPP was approved by FERC and SPP officially obtained the control right of the transmission network. Concerns exist whether this is truly the time when the treatment takes into effect. For instance, as a power pool, SPP might have already taken efforts to maintain a fair transmission access in order to obtain the status of a RTO; or there might be a time lag of the treatment effect on regional production efficiency due to the stickiness under long-term electricity contracts. If these circumstances are true, the current results of no identified regional production efficiency gains could be the consequence of a false selection of treatment date.

For these reasons, I perform a falsification test on the validity the choice of the treatment date. The magnitude of estimated treatment effect should reach the maximum at the true treatment date as either falsely assigning the treated

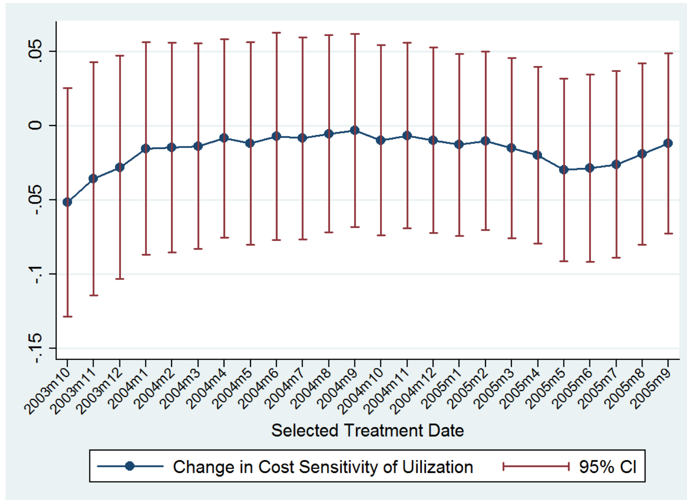


Figure 1.9: Change Differentials in Cost Sensitivity under Different Chosen Treatment Dates

Note: The employed empirical model is model 5 in baseline regressions. The control region is SERC.

observations into the untreated group, or assigning the untreated observations into the treated group would downward bias the estimation results. Accordingly, I randomly select months within a bandwidth of 1 year around Oct 2004 as the treatment dates and obtain the estimated coefficients of primary interest associated with each choice of the treatment date. If there indeed is significant treatment impact and the previous choice of treatment date is wrong, I should find at least one of the coefficients estimated to be significantly negative. And the coefficient should reach the lowest value (since the treatment effect is expected to be negative) at the right treatment date. The estimated coefficients are shown in Figure 1.9 along with the 95% confidence intervals. The data window is between Oct 2001 and Dec 2008. The empirical model applied is the same as Model 5 in Table 1.5. As shown in the figure, the estimated coefficients are quite invariant across time and none of them is significantly different from zero. This provides evidence that the result of no identified gains in regional production efficiency is robust to the selection of treatment date.

1.6.5 Variations in the Choice of Event Window

In this section, I investigate whether the empirical results found are robust to how the event window is chosen. First, I examine whether the results still hold if periods near the treatment event are excluded. Second, I vary the bandwidth of the event window. Third, I restrict the event window only to weekdays.

The logic of excluding periods shortly prior to the treatment event is that near the treatment event, market participants might have anticipated the upcoming changes in market condition and behaved differently. On the other hand, there might be a time lag before the market participants were able to respond to the market change. In order to investigate this concern, I drop 6 months before and after Oct 2004 and estimate the change in cost-sensitivity in SPP relative to that in SERC. The results are provided in the first and third columns of Table 1.8. The empirical model selected is still the the preferred one with average environmental cost controlled for separately. As shown in the table, there is still no evidence that utilization of units in SPP became more sensitive to average costs relative to that of units in SERC after the separation of transmission control.

Second, I vary the bandwidth of the event window out of the concern that under a long event window, the empirical results might be biased by other concurrent differential trends across the control and treatment regions. One example of differential trends is the add-ons of natural gas capacity in the SPP and SERC. Narrowing the event window could tease out the impacts of trends other than the separation of electricity network on cost sensitivities. In the second and third columns of Table 8, I trim down the length of the event window to be 4 years, centered around Oct 2004. Still, the coefficients of primary interest are not significantly different from zero. In the third column, I also drop 6 months before and after the treatment event. Yet, the result of no efficiency gains still holds. Taking advantage of daily data, I further narrow down the event window. The results are shown in Table 1.9. The length of event window varies from 2 years, 1 year, to 6 months. Again,

Table 1.8: Variation in the Event Window: Monthly Data

	(1)	(2)	(3)	(4)
AVC	-0.146***	-0.149***	-0.162***	-0.130***
	(0.0224)	(0.0242)	(0.0279)	(0.0213)
$Treat \times AVC$	0.0427	0.0408	0.0192	0.0498
	(0.0443)	(0.0399)	(0.0467)	(0.0450)
$Post \times AVC$	0.0439*	0.0214	0.0443	0.0291
	(0.0235)	(0.0240)	(0.0277)	(0.0214)
$Post \times Treat$	-0.0144	0.0231	0.0322	0.0111
$\times AVC$	(0.0362)	(0.0341)	(0.0364)	(0.0337)
Drop +/- 6 Months Around Treatment Event	Yes	No	Yes	No
Start of Sample	Oct, 2001	Oct, 2002	Oct, 2002	Oct, 2001
End of Sample	Dec, 2008	Oct, 2006	Oct, 2006	Dec, 2008
Drop High-NG-price Months	No	No	No	Yes
Number of Obs	16730	13698	10787	14679
Adj. R^2	0.116	0.101	0.101	0.108

Notes: Observation is a coal-fired generating unit on a given month in SPP and SERC. The treatment date chosen is Oct 2004. The empirical model chosen is the same as model 5 in the baseline regressions in Table 5, where environmental compliance cost is separately controlled for. In specification 1 and 3, I dropped 6 months before and after the treatment date. In model 4, I drop months with high natural gas spot prices (See Figure 11). ***p<0.01, ** p<0.05, and *p <0.1.

the coefficients measuring the relative change in cost-sensitivity in SPP are still not significantly different from zero.

Third, I restrict the data period to weekdays only. This can limit confounding factors as a result of potentially different market conditions during weekends, such as distinct market demand due to different residential consumption preference, institutional socio-economic situations, etc. It is more likely that during weekdays when demand is high, SPP and SERC face similar market conditions and thus also similar requirement of reliability control, level of transmission congestion, schedule of electricity transactions, etc. The results are shown in the second, fourth and sixth column in Table 1.9. The results still provide no evidence of gains in regional production efficiency in SPP.

1.6.6 WECC as the Control Region

I then check whether the results are robust to the selection of the control group. As discussed in Section 1.2.3, there are reasons why generating units in SERC might be

Table 1.9: Variation in the Event Window: Daily Data

	(1)	(2)	(3)	(4)	(5)	(6)
AVC	-0.0969***	-0.0937***	-0.149***	-0.143***	0.00286	0.0113
	(0.0328)	(0.0326)	(0.0493)	(0.0497)	(0.0608)	(0.0635)
$Treat \times AVC$	-0.00153	-0.00192	0.118	0.118	-0.0129	-0.0156
	(0.0561)	(0.0557)	(0.0761)	(0.0761)	(0.0677)	(0.0695)
$Post \times AVC$	-0.0190	-0.0212	-0.0934**	-0.0991**	-0.108**	-0.117**
	(0.0280)	(0.0283)	(0.0396)	(0.0395)	(0.0456)	(0.0465)
$Post \times Treat$	0.0375	0.0390	0.0500	0.0552	0.0408	0.0527
$\times AVC$	(0.0427)	(0.0418)	(0.0650)	(0.0634)	(0.0606)	(0.0602)
Start of Sample	Oct, 2003	Oct, 2003	April, 2004	April, 2004	July, 2004	July, 2004
End of Sample	Oct, 2005	Oct, 2005	April, 2005	April, 2005	Jan, 2005	Jan, 2005
Drop Weekends	No	Yes	No	Yes	No	Yes
Number of Obs	253910	217437	88443	75903	47952	41040
Adj. R^2	0.267	0.264	0.273	0.270	0.377	0.374

Notes: Observation is a coal-fired generating unit in a given day in SPP and SERC. With Oct 2004 being the treatment event, the length of the event window varies from 2 years, 1 year to 6 months. The empirical model chosen is the same as model 5 in the baseline regressions in Table 5, where environmental compliance cost is separately controlled for. Indicators for emission market participation and abatement device installment are omitted due to little variation as a result of the restricted event window. ***p<0.01, ** p<0.05, and *p <0.1.

better counterfactuals for those in SPP. Yet, extra caution is still needed to check the robustness of the current results by exploiting units in WECC as the counterfactuals instead. I select the following states in WECC where the vast majority of the coal plants are located: Utah, Colorado, New Mexico and Wyoming.[38] Units in Arizona is excluded as they are more prone to the import need of California.

The empirical model applied is still Model 5 in the baseline specifications, where average emission input costs are controlled for separately. I also vary the event window for robustness checks. The empirical results are provided in Table 1.10. As shown in the table, the signs of the coefficients of primary interest are mixed. But none of them is significantly different from zero (except for the one in the second specification with a weakly positive sign). Again, there is no evidence that the cost sensitivity of units in SPP increases relative to their counterparts in WECC.

[38]The states included are also where the vast majority of the natural gas plants are located.

Table 1.10: Robustness Checks: Coal Units in WECC as the Control Group

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
AVC	-0.136***	-0.123***	-0.146***	-0.148***	-0.310***	-0.303***	-0.103	-0.101
	(0.0391)	(0.0428)	(0.0353)	(0.0351)	(0.0772)	(0.0768)	(0.0773)	(0.0786)
$Treat \times AVC$	0.0249	-0.0174	0.0484	0.0534	0.276***	0.274***	0.0932	0.0967
	(0.0542)	(0.0602)	(0.0551)	(0.0549)	(0.0960)	(0.0955)	(0.0836)	(0.0843)
$Post \times AVC$	-0.0158	-0.0106	0.00130	0.00355	-0.00991	-0.0147	0.0117	0.00567
	(0.0301)	(0.0306)	(0.0311)	(0.0307)	(0.0296)	(0.0294)	(0.0355)	(0.0355)
$Post \times Treat$	0.0493	0.0704*	0.0193	0.0159	-0.0218	-0.0175	-0.0771	-0.0699
$\times AVC$	(0.0404)	(0.0407)	(0.0437)	(0.0424)	(0.0646)	(0.0631)	(0.0556)	(0.0541)
Data Frequency	Monthly	Monthly	Daily	Daily	Daily	Daily	Daily	Daily
Start of Sample	Oct, 2002	Oct, 2002	Oct, 2003	Oct, 2003	April, 2004	April, 2004	July, 2004	July, 2004
End of Sample	Oct, 2006	Oct, 2006	Oct, 2005	Oct, 2005	April, 2005	April, 2005	Jan, 2005	Jan, 2005
Drop Weekends	No	No	No	Yes	No	Yes	No	Yes
Number of Obs	4582	3365	105755	90557	36977	31730	20152	17243
Adj. R^2	0.088	0.097	0.294	0.296	0.300	0.302	0.376	0.378

Notes: Observation is a coal-fired generating unit in a given month/day in SPP and WECC. The dependent variable is generation as a percent of designed capacity. With Oct 2004 being the treatment event, the length of the event window varies among specifications. The empirical model chosen is the same as model 5 in the baseline regressions in Table 5, where environmental compliance cost is separately controlled for. In model 2, I dropped 6 months before and after the treatment event. ***p<0.01, ** p<0.05, and *p <0.1.

1.6.7 Changes in Natural Gas Prices

In this paper, natural gas generating units are excluded from the analysis. The intent is to limit unobserved heterogeneity across units. However, the potential challenge associated is failing to directly control for the possible competition between coal and natural gas capacity. For instance, if natural gas price increased dramatically, which is what occurred in 2005 and 2008 (shown in Figure 1.10), coal-fired units would replace the natural gas counterparts such that even the relative costly coal units would still be able to serve more load. Under the circumstance, failing to control this fuel displacement would lead to downward biased estimation of the cost sensitivity of utilization for coal-fired units. Since average coal prices and average fuel input costs in SPP are lower compared to those in SERC, relative costly coal units in their cohorts in SPP are more likely to replace natural gas units in the region. So the extent of downward biased estimation might be even higher in SPP than in SERC. This could be an alternative explanation of the results identified under previous analysis. Given this concern, I drop periods (June 2005 to Feb 2006 and the entire year of 2008) with abnormally high natural gas prices to tease out the impact of the fuel displacement pattern. I replicate Model 5 in the baseline specifications. The empirical results are provided in the fourth column in Table 1.8. The results are still robust: the

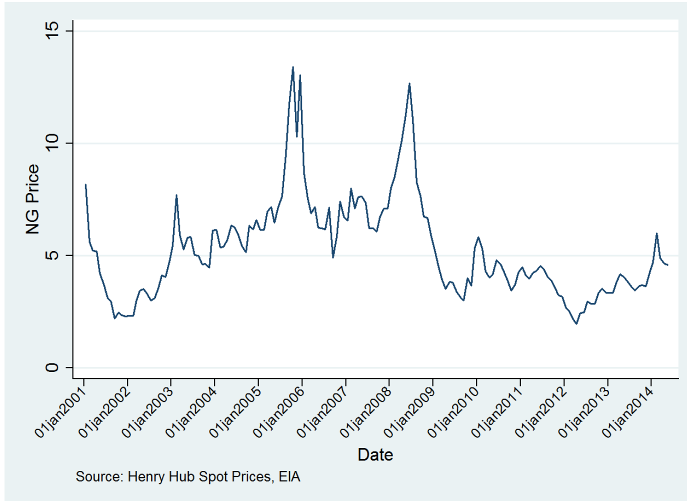


Figure 1.10: Henry Hub Natural Gas Spot Prices (Monthly Average)

coefficients implying regional production efficiency gains under the treatment effect are still not significantly different from zero.

1.7 Conclusion

Market restructuring in the U.S. power industry varies dramatically across regions. Unlike earlier studies, this paper takes advantage of a unique regional wholesale market in the U.S., the Southwest Power Pool. It experienced restructuring only in the transmission component of the sector, aimed to remove discriminatory transmission access. Comparing it with a control region where no restructuring activities ever took place, I fail to find any significant gains in regional production efficiency brought by the change. In other words, increased competition introduced by the vertical separation of transmission network and the consequent non-discriminatory access is not sufficient to make the region allocate the production resources more efficiently. An alternative explanation is that the efficiency gains could be offset by the potential loss as a result of arising market power associated with wholesale competition.

This paper renders useful evidence for policy implications. First of all, my findings shed light on future market restructuring activities in the power industry. Since the wholesale market models have been seriously challenged due to high implementation costs, this suggests caution in deciding which components are necessary and sufficient to be included in the restructuring "package". This paper provides arguments that in order to reach improvement in regional production efficiency, market restructuring in the power sector should go beyond the minimum requirement of divesting transmission control from vertically integrated utilities. Second, my study also adds knowledge to the recent debate in EU energy sector on the cost-and-benefit analysis in vertical integration and separation.

Certain caveats require attention. First, although I provide evidence that both region experienced only minimum increase in transmission infrastructure such that it does not represent another efficiency channel biasing the empirical results, it is still possible that the physical transmission constraint and reliability control could hinder the improvement of regional production efficiency. It could be the case that even though non-discriminatory transmission access under the RTO control facilitates the wholesale competition and provides a chance of cost-saving reallocation of production resources, the room of improvement is constrained by the physical capacity of transmission infrastructure. Second, the current study only focuses on coal-fired units to avoid systematic heterogeneities. A more complicated model should be proposed in future study to also incorporate natural-gas fired units in the study. After all, substitution between different fossil fuels is also an important aspect and channel of regional production efficiency in the industry.

Chapter 2

Vertical Separation of Transmission Control and Market Power in Electricity Markets

2.1 Introduction

Deregulation in the electricity industry has been one of the major market restructuring transformations in the U.S. over the past two decades. Before deregulation, the U.S. power industry was comprised of many local natural monopolies that are vertically integrated from generation, transmission to retail distribution. Deregulation of the industry was intended to introduce competition to improve production efficiency, reduce operation cost and eventually lower the price paid by the consumers. This goal was partially achieved. Efficiency gains identified by the literature include reduction in production costs (Fabrizio et al., 2007; Craig and Savage, 2013; Chan et al., 2013; Cicala, 2015), and increase in reliability (Zhang, 2007; Davis and Wolfram, 2012), etc. However, deregulation in the power industry also resulted in wholesalers exerting market power to reduce supply and increase prices.[1] On one hand, production cost

[1]See Borenstein and Bushnell (1999), Wolfram (1999), Borenstein et al. (2002), Mansur (2007, 2008), and Hortacsu and Puller (2008).

is reduced by increased production efficiency; on the other hand, the wholesale price was driven up by market power. A general concern of the literature is to determine which of the two forces dominates in term of the welfare implication.

This study pursues this question by looking into one specific aspect of the market restructuring process in the U.S. power industry. Typically, restructuring in the electricity industry may consist of a combination of: (1) allowing a third party to operate transmission lines rather than a vertically integrated natural monopoly, (2) allowing competitive bidding to drive wholesale pricing, (3) divesting generation capacity from retailers, and (4) imposing retail competition by allowing customers to switch between retailers. In order to evaluate the impacts of restructuring for policy recommendations, researchers must disentangle these channels, which is generally a difficult task.[2]

The transmission aspect of deregulation is overlooked by previous literature. The rationale of the divestiture of transmission control is to prevent the discriminatory use of the grid. Given the network nature of the power industry, transmission access is an essential input that competing power producers rely on to schedule and dispatch their generating units. A vertically integrated firm who operates both power plants and transmission facilities would have the incentive to discriminate against generators of their non-integrated competitors when providing the transmission services.[3] If this is true, divestiture of transmission control would enhance competition by removing the possibility of such discrimination, incentivize previously under-utilized low-cost generators to produce more and thus lead to more efficient allocation of regional production resources. Due to the specific deregulation process, the Southwest Power Pool (SPP) electricity market provides a venue to separately identify the effect

[2]Previous literature that seeks to disentangle the channels include: Bushnell and Wolfram (2005), Davis and Wolfram (2012) and Hausman (2014), who all attempt to separate the impact of generation divestiture on operating efficiency from the introduced pressure of wholesale competition, and also Mansur (2007), who disentangles and assesses the consequence of vertical separation of retail function from generation on market power.

[3]Theoretical support of such discrimination is documented in previous literature on vertical integration (Vickers, 1995; Economides, 1998; Beard et al., 2001).

of separating the transmission function from other activities. However, previous literature fails to find that the vertical separation of transmission network is sufficient to lead to better allocation of regional production resources (Chu, 2015).

This paper takes a further step to investigate one possible explanation of no identified gains in the cross-firm production efficiency. Associated with the divestiture of transmission control, an oligopolistic competition environment is introduced, where the production decision of one firm exerts more impacts on others. As indicated by a simple Cournot model, under such a scenario, firms have the incentive to drive up the wholesale prices by withholding capacity to force more expensive production to be on the margin; less expensive production owned by firms with market power is substituted such that production on a marketwide basis would be less efficient. The two forces could potentially offset each other, which may explain why no identified efficiency gain is found in Chu (2015). In the current study, I ask whether the specific restructuring in transmission can also lead to market failures by allowing wholesalers to set prices.

I also examine different incentives across firms to exercise market power through strategic withholding of generation capacity. In the SPP electricity market, firms remain vertically integrated such that they are not only power producers who sell in the wholesale market, but also retailers who are required to buy in the market to meet the demand in their service areas when necessary. Only net sellers have incentives to withhold generation in return for higher wholesale prices (Mansur, 2007). Due to reliability concerns, supply has always to be balanced with demand on a real-time basis in the power industry, and utility firms are mandated to provide power at any wholesale costs. Moreover, in contrast to wholesale prices that vary hour-to-hour, the retail prices paid by the consumers are frozen in the short run under the regulation in the power industry. Conversely, an integrated firm with a net buying position have no incentives to drive up wholesale prices since it faces a constant marginal revenue (i.e., the constant retail price). Withholding generation only serves to increase wholesale costs and thus decreases profits.

I follow a standard approach of measuring competition to market power in the SPP wholesale electricity market (Wolfram, 1999; Borenstein et al., 2002; Mansur, 2007). Specifically, I simulate the prices that would have occurred, had the wholesale market been perfectly competitive.[4] To do this, I take advantage of detailed information on operational and technological characteristics of generating units in the SPP market, and construct market marginal cost curves which indicate regional aggregate productions based on the least costly technology. By comparing the simulated competitive benchmark prices with the best estimates available for actual wholesale prices, I compute wholesale market price-cost margins, a standard measure of market power in the electricity industry.

I compare the price-cost margins in the wholesale market before and after restructuring occurred in the SPP market. In October 2004, SPP was granted by Federal Energy Regulatory Commission the status of a Regional Transmission Operator (RTO), which took over the transmission control from previously vertically integrated utility firms. I focus on high-demand summer months in 2003 and 2005 as the sample period.[5] This is out of the concern that during summer time units are typically not scheduled to be off-line for maintenance and firms are the mostly likely to exercise market power given the high demand (Borenstein et al., 2002; Mansur, 2007).[6] Based on the empirical results, I find that the price-cost margin increased by 6% to 10% after the divestiture of transmission control. I estimate the added costs of procuring electricity due to enhanced market power to be as large as $ 240,000 per hour or approximately 8% of the hourly average in the highest demand hours.

In the second part of the empirical analysis, I test whether firms' behaviors in strategic withholding of generation capacity were consistent with their incentives

[4]Note that in the simulation I follow a common method in the literature that ignores transmission congestion and production constraints (such as start-up costs). I am referring the prices as "competitive benchmark" without considering such practical realities.

[5]In 2004, significant proportion of data of key variables are missing, so I exploit summer 2003 to make the comparison.

[6]When generation and transmission capacity starts to bind during high-demand hours, residual demand of a single firm becomes inelastic such that they are more likely to exercise market power.

discussed above. Based on annual total sales/purchases data, I identify three firms with net selling positions in the SPP market and test whether they reduced generation relative to other firms after the restructuring. I compare the generation capacity utilization between the net sellers and net buyers in the data sample periods exploited earlier. The model specifications control for demand and supply shocks by including simulated unit production decisions under the competitive benchmark and a large number of fixed effects. I find evidence that firms with a net selling position reduced capacity utilization by approximately 3 percentage points relative to others.

My study contributes to the literature in several aspects. First, by extending the analysis to a distinct organized wholesale market, this study adds to the literature by disentangling and assessing the effect of the vertical separation of electricity network. Direct analysis is difficult since it is usually concurrent with other aspects of market restructuring. Earlier studies on market restructuring fail to disentangle it from other efficiency-enhancing channels.[7] Identifying the impact of each efficiency-enhancing channel separately is vital for policy recommendations on the optimal design of restructuring "packages". This is even highlighted considering the fact that the efforts of the Federal Energy Regulatory Commission (FERC) to promote the restructuring of electricity wholesale markets were vigorously challenged after the market crisis in California during 2000-2001. This study demonstrates that market power can arise even under the divestiture of transmission operation from the vertically integrated utility firms. This underscores the importance of the monitoring and mitigation of market power when policy makers think about market restructuring in the power industry.

Second, this study also informs the current policy debate on the cost-and-benefit comparison between vertical integration and separation of network infrastructure in the EU energy sectors. Given inquiry on the role of vertically integrated incumbents in the energy sectors, in September 2007, the EU commission adopted a package of

[7] For instance, the change of revenue rule, privatization of production assets, and establishment of centralized wholesale market platforms, etc.

energy proposals, one of which is the separation of transmission from production and supply in the electricity and gas sectors. By evaluating the impact on firms' incentives to exercise market power, this study represents one of the few empirical studies in the literature of vertical separation.

The remainder of the paper proceeds as follows. Section 2.2 provides background information on deregulation in the U.S. power industry and divestiture of transmission control, and discusses the incentives of firms in the SPP market to engage in generation-withholding behaviors. Section 2.3 talks about the method of simulating the competitive-benchmark prices and analyzes the change of the market price-cost margins before and after the restructuring in the SPP market. Section 2.4 empirically tests how firms with different net positions in the wholesale market behave differently in term of capacity-withholding. Section 2.5 concludes.

2.2 Industrial Background and Firms' Incentives

2.2.1 Deregulation of the U.S. Power Industry

The U.S. Power industry in the traditional regulated setting is comprised of vertically integrated natural monopolies in the chain of production, transmission, distribution and retailing, with exclusive rights of provision within their geographic zones. The rationale underlying this arrangement is that this industry is characterized by extremely high fixed costs and low marginal costs. Accordingly, the U.S. government regulates all stages of the power industry. Within this structure, regulated electricity utilities are compensated under the cost-of-service principle to cover the costs plus a "fair" return on investment. In other words, they are guaranteed to have the operating expenses covered as long as transactions are approved by the state regulators. This principle exerts few incentives for firms to improve the operating performance, reduce cost, and search for and purchase lower-cost production sources other than self-generation. Adversely, the producers have possible incentives to welcome higher cost, which is their base of revenue under the rate-of-return principle, in order to cover their sunk costs. Thus, the ultimate goal of providing electricity of lowest costs possible to end consumers is possibly compromised.

Aware of the flaws of traditional regulated structure, several states suffering from high electricity prices enacted restructuring legislation, beginning with California in 1996. The intent of deregulation is to bring down production costs and eventually electricity prices for consumers by breaking down previous market structure and introducing competition. Typically, restructuring can consist of the following aspects: (1) separating the transmission function from the vertically integrated natural monopolies, (2) allowing flexible wholesale pricing, (3) divesting generation assets from retailers, and (4) imposing retailers under competition by allowing customers to switch their retailers. In order to evaluate the impacts of restructuring for policy recommendations, researchers must disentangle these channels, which is generally a difficult task. By the end of 2001, 23 states had passed deregulation legislature or implemented comprehensive regulatory orders on restructuring. A series of previous studies have documented evidence of operating efficiency gains brought about by the deregulation, such as reduction in production costs, enhanced reliability, etc.[8]

Unfortunately, deregulation goals have not always been realized. A series of previous studies have found evidence that restructuring the electricity market has enabled wholesalers to exercise market power.[9] A well-known example is the California electricity market "crisis" during 2000-2001, which made policy makers re-evaluate the deregulation proposals in the power industry. Consequently after 2001, no restructuring legislation has been enacted. With enhanced wholesale competition, essentially a bidding structure is introduced under an oligopolistic competition setting such that power producers have incentives to withhold generation to drive up the wholesale prices. This is in line with a simple Cournot model. Notably, Mansur (2007)

[8]See Fabrizio et al. (2007), Zhang (2007), Davis and Wolfram (2012), Craig and Savage (2013), Chan et al. (2013), Cicala (2015), etc.

[9]See Borenstein and Bushnell (1999), Wolfram (1999), Borenstein et al. (2002), Joskow and Kahn (2002), Mansur (2007, 2008), and Hortacsu and Puller (2008), etc.

has provided both theoretical and empirical evidence that the vertical integration of generation and retail serves to mitigate the problem of market power. If generation and retail are still integrated, only the wholesalers who are net sellers have incentives to withhold generation to seek abnormal markup. In the SPP, no generating assets were divested such that the logic of firms' incentives applies under the current study.

2.2.2 Vertical Separation of Transmission Control and Market Conditions in the SPP

In practice, the vertical separation of transmission control is achieved by establishing a Regional Transmission Operator (RTO) or Independent System Operator (ISO), which takes over the transmission control from previously vertically integrated utilities. Different from ownership separation, the firms still maintain the ownership of the transmission assets. This type of vertical separation is often referred to as "legal unbundling". In this way, market participants can have fair access to the electricity network, potentially fostering wholesale competition.

Seven RTOs/ISOs have emerged in the Northeast, Midwest and Southwest of the U.S.. The majority of these regions implemented policies that required divesting generation and supply function from retailing and established market-oriented tools designed to efficiently dispatch producers to further enhance wholesale competition. For instance, a typical example is the centralized dispatch mechanism that ranks the right to supply based on bidding offers in real-time and/or day-ahead markets.[10] Some of them even introduced retail competition and allowed consumers a choice between retailers. The SPP market, however, is distinct and only experienced restructuring in the form of divestiture of transmission control during the data period under analysis. A notable step of the restructuring of the SPP market occurred in October 2004, when SPP was granted the status of a RTO by the Federal Energy Regulatory Commission.

[10] Market designs like this were employed in the northeastern U.S., such as the Pennsylvania, New Jersey, and Maryland (PJM) wholesale electricity market.

Even though transmission control rights were divested, all utilities in the SPP are still vertically integrated, functioning not only as power producers but also retailers. This means they may not only sell but also buy electricity in the wholesale market. Due to reliability concerns, power industry regulation requires the supply to be always balanced with the demand on a minute-to-minute basis. Utility firms are mandated to provide power to their customers at any wholesale costs. Sometimes, firms might need to purchase electricity in the wholesale market to meet the demand in their service areas. In other cases, firms may be able to sell additional power to others after meeting obligations to their customers.

Table 2.1 shows the generation capacity of eight major utilities in the SPP market, categorized by primary fuel types, in 2003 and 2005, which is the sample period under analysis.[11] The SPP consisted of eight major utilities and had a generation capacity of approximately 56,000 megawatts (MW) in 2003. From the table, we can see that coal and natural-gas capacities account for the vast majority (93%) of the total in the SPP. Due to low marginal costs of operation and the production constraints of not being quickly ramped up and down, coal generating units provide the baseload generation during most of the hours in the SPP market. In contrast, natural-gas units, which are more flexible yet more expensive, represent the peak capacities that only operate during a few hours a day, mostly when the demand is high. Another thing deserving notice is that the total generation capacity and the shares of each primary fuel category stayed relatively stable during the sample period.

2.2.3 Incentives of the Net Wholesale Sellers

In this section, I explain the incentives of firms who are net sellers in the wholesale electricity market to engage in strategic withholding of generation capacity. This has already been discussed in detail by Mansur (2007).

[11] The reason why year 2004 is not included is discussed in later section.

Table 2.1: Generation Capacity by Firm and Fuel Type in 2003 and 2005

Year 2003						
Firm	Coal	NG	Nuclear	Hydro	Wind	Total
American Electric Power West	3899	4782	-	-	-	8681
Aquila, Inc	614	880	-	-	-	1494
Cleco Power	1279	3066	-	-	-	4345
Empire District Electricity	319	1108	-	16	-	1443
Kansas City Power and Light	3462	932	-	-	-	4394
Oklahoma Gas and Electricity	2854	4050	-	-	-	6904
Southwestern Public Service Co.	2253	2229	-	-	-	4482
Westar Energy	2958	1931	-	-	1	4890
Others	3676	11592	1236	2273	372	19149
Total	21314	30570	1236	2289	373	55788
Market Share	38%	55%	3%	5%	1%	100%

Year 2005						
Firm	Coal	NG	Nuclear	Hydro	Wind	Total
American Electric Power West	3899	4782	-	-	-	8681
Aquila, Inc	614	880	-	-	-	1494
Cleco Power	1279	3227	-	-	-	4506
Empire District Electricity	319	1114	-	16	-	1449
Kansas City Power and Light	3462	932	-	-	-	4394
Oklahoma Gas and Electricity	2854	4050	-	-	-	6904
Southwestern Public Service Co.	2216	2229	-	-	-	4445
Westar Energy	2958	1920	-	-	1	4878
Others	3662	12990	1236	2273	372	20533
Total	21263	32124	1236	2289	373	57285
Market Share	37%	56%	2%	4%	1%	100%

Note: capacity (in megawatts, MW) is the designed maximum of generation a unit can produce during an hour. The capacity data is available at the generator level in the EIA 860 form. The data form also provides information on the primary fuel type used in each generator. The generators are aggregated into the firm level based on ownership information in eGrid data (2004).

To understand the issue, one must begin by recognizing that the retail prices paid by consumers are fixed for utilities in the short run such that short-run price elasticity of demand is virtually zero. Also, utilities are mandated to provide power at any wholesale costs to meet demand in their service areas. If a firm is a net buyer, intuitively, it have no incentive to drive up high wholesale prices since it faces a fixed marginal revenue, which is the constant retail price. Withholding generation to drive up wholesale prices would only serve to increase wholesale costs and thus decrease profits.

I follow Mansur (2007) and set up the simple theoretical model to explain the question. Based on the assumption that firms are quantity-setting, the objective function for a firm i, vertically integrated in retail and generation, would be

$$\underset{q_i}{Max} \quad P_i(q_i) \cdot (q_i - q_i^d) + r_i^d \cdot q_i^d - C_i(q_i) \tag{2.1}$$

where $P_i(q_i)$ is the inverse residual demand function firm i faces in the wholesale market; q_i is the production of firm i; r_i^d and q_i^d are the retail price and quantity of demand faced by firm i in its service area; $C_i(q_i)$ is total production costs. Solving for the first order condition and assuming an interior solution, we have:

$$P_i - C_i' = -P_i' \cdot (q_i - q_i^d) \tag{2.2}$$

Given the condition, firms have incentives to drive up wholesale prices only if they are net sellers, that is, $q_i > q_i^d$.

Based on State of Market Reports of the SPP market, I identify net sellers in the SPP wholesale electricity market through annual total sale/purchase data for the major utility firms. The statistics for year 2004 is shown in Table 2.2. There are three firms with a net selling position in the SPP electricity market: Southwestern Public Service corporation, Westar Energy and Kansas City Power and Light, whose geographic locations are shown in Figure 2.1. The three major utility firms account

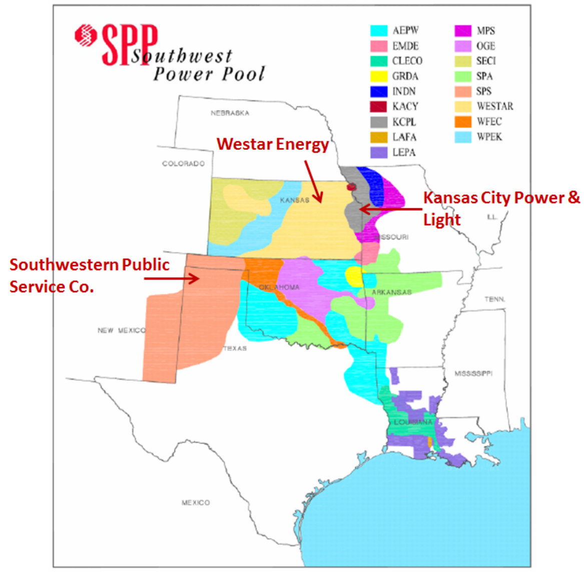


Figure 2.1: Location of the Firms in the SPP Market

Source: 2004 SPP State of Market Report. The map shows the power control areas in the SPP. The areas of the 3 firms with a net position of selling are marked.

for approximately 24.7% of the total generating capacity in the market (shown in Table 2.1). Moreover, the net positions of all the utility firms in the SPP market maintained the same through my data sample period (2003-2005). The only exception is American Electric Power West Corporation, which had approximately balanced sale and purchase (a net sale of 3% of the total sale) in 2003 before it became a significant net purchaser in 2004 and 2005. Given the negligible share, I argue that it did not have incentives to excise market power throughout the data span.

Based on net sellers' incentives to withhold generation to drive up wholesale prices, I argue they have the potential to exercise market power under a more competitive environment due to the specific restructuring under current analysis. In section 2.3, I test the hypothesis that the market power is enhanced after the divestiture of transmission control, using price-cost markups. In section 2.4, I characterize two groups of firms (net sellers and net buyers) with distinct incentives to engage in anti-competitive behaviors and compare the generation-withholding behaviors between the

Table 2.2: Sales and Purchases by Major Utilities: Year 2004

Utility	Sales (GWh)	Purchases (GWh)	Net Sales (GWh)	Percent Net Sale
American Electric Power West	6452	8531	-1989	-34%
Cleco Power	1258	5801	-4543	-78%
Southwestern Public Service Co.	10306	5701	4665	45%
Aquila, Inc.	1245	5268	-4023	-76%
Oklahoma Gas and Electricity	1400	4231	-2830	-67%
Empire District Electricity	533	1719	-1186	-69%
Westar Energy	8658	1454	7204	83%
Kansas City Power and Light	6602	850	5752	87%
Total	36612	34951	1661	4.5%

Notes: the statistics are available from the SPP 2005 State of Market Report, based on FERC Form 1 data. Percent net sale is net sale as a percent of total sales if a firm is a net seller, or net sale as a percent of total purchase if a firm is a net buyer.

two groups before and after the restructuring. This provides a venue to analyze the underlying mechanism of how market power was exercised, implied by the theoretical intuition under the current market condition in the SPP market.

2.3 Measuring Market Power

2.3.1 General Approach

In this section, I discuss how I measure and detect market power in the SPP electricity market, associated with the divestiture of transmission control. I follow the general literature of evaluating market power in electricity industry and use the criteria of the market-level price-cost margin. Another criterion commonly used in the industrial organization literature is an indicator of horizontal concentration, for instance, the Herfindahl-Hirschman Index. However, such measures actually present poor indicators of the existence of market power in the power industry. A utility firm with a small market share could still exercise market power as a result of the following characteristics of the industry: highly variable price-inelastic demand, significant short-run capacity constraint and extremely costly storage (Borenstein et al., 2002).

The perfectly inelastic demand implied by the regulation of fixed retail electricity prices in the short run simplifies the calculation of price-cost margins in power industry. Distinguished from estimating price-cost margins in other sectors in recent industrial organization literature, no assumptions and estimates are needed on the demand side under the analysis of the power industry. Instead, estimating the price-cost margins centers on analysis on the supply side and specifically on the calculation of the marginal costs in order to compute the competitive-benchmark prices.

I measure the market-level price-cost margins in the SPP market based on a method commonly used in the literature to measure competition.[12] The method was developed by Wolfram (1999) and Borenstein et al. (2002), who analyze the market power issues associated with deregulation in England-Wales market and California market separately. Generally, the method requires constructing a competitive counterfactual under which each firm behaves as a price-taker such that they would produce and sell power from a given generator so long as the wholesale price is larger than the marginal production cost. Specifically, they calculate the marginal costs of each generating unit in the market to construct the market marginal cost curves, namely, the competitive supply curves, which indicate market aggregate production exploiting the least costly technology. Then based on the counterfactual supply curves and information on electricity demand, they calculate the prices that would have occurred had the wholesale market been competitive. That is, the competitive price equals the marginal cost of additional unit of electricity generated, given that the least costly technologies have already been exploited to meet the demand. Finally, they compare the simulated prices with the actual prices to compute the market price-cost margins and investigate the issue of market power. I apply this empirical approach in the SPP market in this paper.

Figure 2.2 provides an illustration of how the competitive-benchmark price is determined based on the common technique. It depends on the actual supply curve, the competitive supply curve, and the demand curve. It is assumed that the actual supply curve is above the competitive supply curve. Given that demand is perfectly inelastic in the power industry, if we assume away inter-market electricity exchanges, the competitive-benchmark price would simply be the marginal cost

[12] See Wolfram (1999), Borenstein et al. (2002), Joskow and Kahn (2002), Mansur (2007), etc.

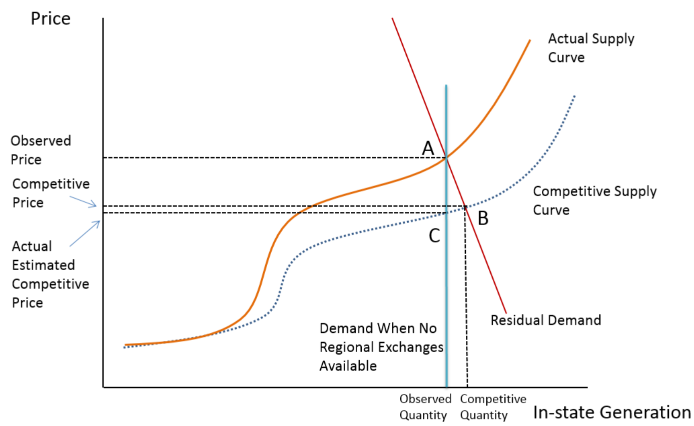


Figure 2.2: Determining the Competitive-benchmark Price

indicated by the constructed competitive supply curve at the observed demand. Under the circumstance, the difference between actual wholesale price and simulated counterfactual price is demonstrated by the difference between point A and C at the observed quantity demanded.

In contrast, if exchanges between the SPP market and outside regions are taken into account, then we have a negatively-sloped residual demand curve, which means the market demand in the SPP market minus the supply function of imports. The logic of the negative slope of the residual demand curve is that the higher the market price is in the SPP market, the more electricity is imported, and thus less of the demand is met by firms within the SPP market. Accordingly, instead of finding the competitive price at point C, we should move along the residual demand curve and find its intersection with the competitive supply curve at B. As the price falls to competitive equilibrium, net import decreases (or net export increases) and more of the quantity demanded must be met by firms in the SPP market. This means more expensive units would be dispatched at the margin in a competitive market, leading to an increase in the competitive-benchmark price (indicated by point B) compared to the counterfactual under the calculation of which exchanges with outside market are assumed away. Thus, failure to account for electricity exchanges would understate the competitive prices and thus overstate the price-cost margins.

To address this issue, assuming that firms in outside markets behave as price takers, previous analyses either directly aggregate confidential import bid curves (Borenstein et al., 2002) or indirectly estimate the net import/export supply functions (Mansur, 2007) given information on exchange data. Unfortunately, I do not observe electricity exchange data between the SPP market and outside markets. But different from the electricity markets analyzed by earlier studies, the SPP market has rich low-cost coal and nuclear capacities, and engages in relatively limited power exchange with other markets. This is demonstrated in Figure 2.3, which shows the annual net power flows across regions in North America in 2010, representing the general power exchange pattern between regions. In Figure 2.3, the SPP electricity market corresponds to the Central region. From the figure, we can see that the net import in the northern part of the SPP market roughly offset the net export in the southern part. Plus, each of them merely account for approximately 2.5% of the net in-state generation (257 million megawatthours). In contrast, two markets under previous analysis, the California market and the PJM market (corresponding to Mid-Atlantic region excluding the far western part in northern Illinois, which had not been incorporated in PJM under previous analysis) engage in significant inter-region electricity exchanges with outside markets.[13]

Given these reasons, I argue that the residual demand curve in Figure 2.2 for SPP is very close to being vertical such that the miscalculation due to differences between competitive-benchmark prices indicated by point B and C is negligible. Based on this argument, I find the competitive price by returning the marginal cost based on the constructed competitive supply curve and the observed demand.

Moreover, different from previous literature, I cannot observe the actual wholesale electricity prices in the SPP market during the data period. Previous literature

[13]According to the EIA report, the import in California represented about 25% of the in-state electricity supply, and the substantial flow from low-cost nuclear and coal capacities from the Midwest to eastern coast (indicated by the red arrow) represented about 16.7% of the in-state generation. See more details in EIA reports available at http://www.eia.gov/todayinenergy/detail.cfm?id=4270.

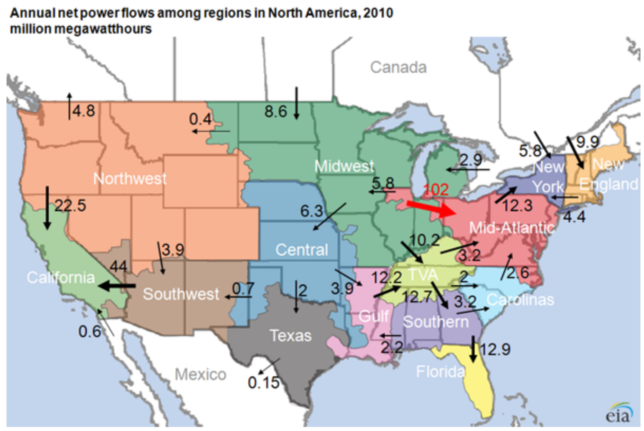


Figure 2.3: Annual Net Power Flows across Regions in North America

Source: EIA figure based on FERC form 714 data, http://www.eia.gov/todayinenergy/detail.cfm?id=4270. The figure shows the annual net power flows across regions in North America in 2010. SPP here is indicated by region "Central" excluding Nebraska. The figure shows that the net exchange of electricity between SPP and outside regions is very limited.

analyze the price-cost markup in centralized spot or day-ahead market market where price information is easily accessible from the RTO/ISO.[14] In contrast, during the sample period, all electricity wholesale transactions in the SPP market are realized through decentralized bilateral trading directly between firms or indirectly via brokers, making the price information more opaque. Instead, I employ the best data available to approximate the wholesale prices, that is, the hourly System Lambda data, which is an estimate of the marginal cost of electricity generation in a given hour in a power control area. It is employed in earlier literature (Graff Zivin et al., 2014) for markets under similar scenarios as the SPP market. In a restructured market where centralized wholesale market design is established such as that in California, the system lambda would simply be the market prices. I take the system lambda in each power control area and calculate the market-level average weighted by the hourly generation in the respective power control area.[15] If the lambda data is missing for a

[14] A centralized market assigns the rights to supply based on bids made by firms, aggregates the offers to sell and buy and determines market-clearing prices.

[15] As discussed in later subsection, I focus on fossil-fuel capacities when construct the market competitive supply curve. Accordingly, I weight the system lambda by fossil-fuel generation in each power control area.

power control area, I take the most costly unit that is turned on and use the marginal cost of that unit as the marginal cost of the generation of the power control area.

2.3.2 Sample Period

The establishment of the SPP as a RTO and the divestiture of transmission control occurred in October 2004. I focus on the the following summer from April through September 2005 to detect the potential problem of market power associated with the restructuring. It is likely that the regulators might not have understood and taken correspondent actions toward all possible manners in which market power could be exercised by the firms right after the market restructuring. I focus on the summer period for two reasons. First, demand during summer is generally high such that generation and transmission capacity constraints are likely to bind. This means that a single firm's residual demand is inelastic, making it more prone to exercising market power. Second, when demand is high, planned outage of generating units due to scheduled maintenance is irrelevant. This facilitates the simulation of competitive supply curves indicating aggregate productions using the least costly capacities available, as is further discussed in the following subsection. I compare the sample period of summer 2005 with that of 2003 as the system lambda data in 2004 is missing for the vast majority of the firms.

In order to attribute the changes in price-cost markups to market power and investigate its extent, researchers have to take into account the variations in supply and demand factors that could also drive up the electricity prices in a perfectly competitive market. Table 2.3 provides information on the changes in the monthly demand in the SPP electricity market, available from SPP's State of Market Report (2008). The last three columns show the percentage change for a month-to-month comparison between years during 2003 to 2005. From the table statistics, we can see that there existed minor growth in demand between summer 2003 and 2005, except for June and September.

Table 2.3: Change in Monthly Demand: Year 2003 - 2005

Month	2003	2004	2005	% Change 2003-2004	% Change 2004-2005	% Change 2003-2005
1	15476	16004	16210	0.034	0.013	0.047
2	13715	15131	13801	0.103	-0.088	0.006
3	13840	14222	14770	0.028	0.039	0.067
4	13505	13684	13842	0.013	0.012	0.025
5	15041	16399	16137	0.09	-0.016	0.073
6	16407	17252	19207	0.052	0.113	0.171
7	20660	19553	21137	-0.054	0.081	0.023
8	20619	18953	21130	-0.081	0.115	0.025
9	15205	17245	18491	0.134	0.072	0.216
10	13866	14905	15504	0.075	0.04	0.118
11	13494	14298	14775	0.06	0.033	0.095
12	14792	16277	17074	0.1	0.049	0.154

Notes: the data is monthly total electric energy usage (GWh) within SPP by month and year. The last three column shows the percent change between 2003-2004, 2004-2005, and 2003-2005 for each month. The data is obtained from SPP State of Market Report 2008.

Table 2.4: SPP Market Summary Statistics for Production Costs: Summers of 2003 and 2005

Variable	Units	Mean	SD	% Min	Max
Summer of 2003					
Coal Input Costs	\$/MMBtu	1.09	0.21	0.35	1.62
NG Input Costs	\$/MMBtu	5.36	0.47	3.85	10.33
SO_2 Permit Price	\$/Ton	172.11	8.15	161	185
MC Coal Units	\$/MWh	13.79	4.71	7.08	35.53
MC NG Units	\$/MWh	62.84	13.13	29.98	152.21
Summer of 2005					
Coal Input Costs	\$/MMBtu	1.21	0.26	0.69	2.33
NG Input Costs	\$/MMBtu	7.57	1.32	5.43	12.86
SO_2 Permit Price	\$/Ton	828.91	46.72	725	895
MC Coal Units	\$/MWh	17.89	8.07	8.17	57.60
MC NG Units	\$/MWh	85.06	26.08	38.98	188.82

Notes: coal and natural gas input costs are receipt prices by power plants in SPP, obtained from FERC 423 Form. SO2 permit prices are based on data provided by BGC Partners, which is a leading brokerage firm. Marginal costs of coal and natural-gas units incorporate both fuel costs and environmental costs of operation.

On the supply side, Table 2.4 describes the summary statistics of production costs for firms in the SPP electricity market. First, fuel input prices increased from 2003 to 2005. The mean coal and natural gas prices rose by 11 percent and 41 percent respectively. Moreover, during the study period, power producers in the SPP market also suffered from environmental costs under compliance of SO_2 cap-and-trade program.[16] Notably, the mean SO_2 permit price increased dramatically from 172.11 dollars/ton to 828.91 dollars/ton from summer 2003 to summer 2005. Even though the coal units did not encounter an increase in fuel prices as significant as the natural-gas units, they are heavier polluters in SO_2 such that the dramatic increase in the permit price also resulted in significant increase in production costs of coal units. With both fuel costs and environmental costs combined, the production costs of coal and natural-gas units increased from 13.79 dollars/MWh to 17.89 dollars/MWh, and 62.84 dollars/MWh to 85.06 dollars/MWh respectively.

2.3.3 Marginal Costs of Fossil-fuel Generating Units

In this subsection, I discuss how I construct the market competitive supply curves and compute competitive-benchmark prices in details. I focus on the fossil-fuel generating units only. The reasons are: (1) shown in Table 1, non-fossil-fuel generating capacities represent only small proportion in the total generating capacity in the SPP market; (2) they are always infra-marginal in term of setting the market price since their marginal costs are generally thought be zero.

As mentioned above, estimating the competitive supply curves in SPP first requires estimating the marginal costs for all generating units. Following the previously literature, I assume constant marginal costs for all units. Based on hourly observations on unit operation information, i.e., generation, emission, and fuel usage, I calculate the average input (fuel and emission) required per unit output for a given year. The logic to update the statistics on a yearly basis is to allow for

[16] The NO_x cap-and-trade program did not cover firms in the SPP market.

the possibility that the unit production efficiency might change associated with the market restructuring, the evidence of which is found in other restructured electricity markets in the previous literature. Moreover, I also observe fossil fuel receipt prices and emission (SO_2) permit prices on a monthly basis. Combine the two sets of data, I estimate the monthly marginal costs for all units. In sum, unit i's marginal cost of production (c_{iym}) in year y month m would be:

$$c_{iym} = Price_{iym}^{Fuel} \times Heat\ Rate_{iy} + Price_{iym}^{SO_2} \times Emission\ Rate_{iy}^{SO2} \tag{2.3}$$

where $Price_{ijm}^{Fuel}$ is fuel prices procured by the power plant of unit i, $HeatRate_{iy}$ is fuel heat input required per unit of electricity generation, $Price_{ijm}^{SO_2}$ is the permit prices for SO_2 emission, $Emission\ Rate_{ijym}^{SO_2}$ stands for average quantity of SO_2 emitted by unit i per unit of output. This means I am able to construct competitive supply curves on a monthly basis in the empirical analysis. Data sources I take advantage of for the calculation is discussed in Appendix B.

In addition to the marginal costs of the units, information of their production capacities is also needed for constructing the market competitive supply curve. Under the common technique, an on-off strategy is assumed for all generating units. That is, unit i would run at full capacity if and only if the competitive price equals or exceeds the marginal costs. Combining information on marginal costs and generation capacity at the unit level, for each given month in the data sample period, I assign a dispatch order of the units starting from the least costly to the most. The competitive supply curve would simply be a step-wise function based on each unit's marginal cost, capacity and the dispatch order. Figure 2.3 shows the constructed competitive supply curves in SPP market in August 2003 and 2005. From the graph we can see there are supply shocks that shift up the curves from 2003 to 2005. This is consistent with the input price increases shown in the summary statistics of Table 2.4. There is a significant kink around 20,000 megawatt, representing a switch from coal to natural capacities. Notably, since there is extensive natural-gas capacity in SPP market, there

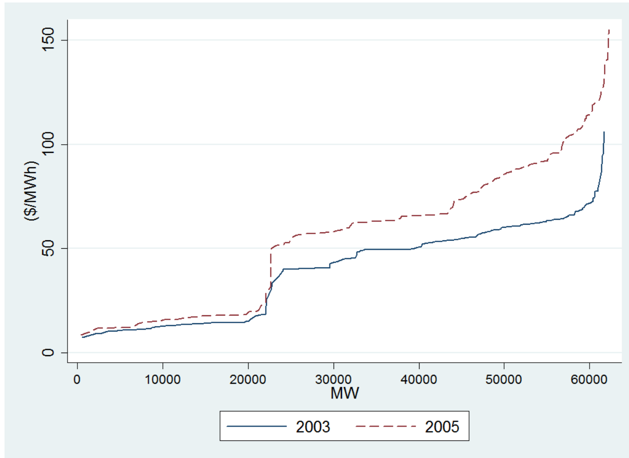


Figure 2.4: SPP Fossil-Fuel Units Marginal Cost Curves, August

exist potential opportunities for firms to withhold generations of coal-fired units to drive natural-gas units on the margin for higher prices.

The supply curves in Figure 2.4 have not adjusted for possible scenarios of unit outages. Generating units cannot be operated constantly and have to be shut down from time to time, limiting the available capacity. There are two main types of unit outages. The first one is "planned outage" for routine maintenance. As discussed previously, unit maintenance is typically scheduled in low-demand spring and fall seasons for profit concerns. For this reason, such outages are not a concern since this paper looks into summer months for analysis.

The other type of outage is due to unplanned reasons. Such "forced outages" have been treated as random, independent events in previous literature (Wolfram, 1999; Borenstein et al., 2002; Mansur, 2007). It is assumed that for a given unit i, "forced outage" can happen at any moment with a probability, which is often referred as the forced outage factor, fof_i. Forced outages affect unit availability and should be accounted for when the competitive supply curve is simulated. One of the possible manner to handle the concern is to derate the capacity of a unit to the expected value, i.e., $cap_i \cdot (1 - fof_i)$. However, this method is problematic in the sense that based on such unit expected capacity, the construct of market marginal cost curve, which is convex, would understate the actual expected cost at any given output level, and consequently overstate the price-cost margin applied to detect market power.[17]

Instead, following the previous literature (Wolfram, 1999; Borenstein et al., 2002; Mansur, 2007), I take advantage of the historical forced outage factors and perform Monte Carlo simulations to simulate the market marginal cost curves. In each hour in the sample, I make a random draw from a [0,1] uniform distribution for each unit. As long as the random draw is less than a unit's forced outage factor, the unit is simulated to undergo an unplanned outage. With units $i = 1, \ldots$,N ordered according to incremental marginal costs, the market marginal cost $C(Q)$ would be the marginal cost of the kth cheapest generating unit that is necessary to meet the demand of Q, given the unavailability of certain units that have randomly assigned to suffer forced outages in the iteration of the simulation. In other words, k is determined by

$$k = arg\, min\{x| \sum_{i=1}^{x} I(i) \cdot cap_i \geqslant Q\}, \tag{2.4}$$

and

$$I(i) = \begin{cases} 1, & if\ \epsilon_{it} > fof_i \\ 0, & otherwise \end{cases} \tag{2.5}$$

where ϵ_{it} is a random draw for unit i in hour t, cap_i is the generation capacity of unit i, $I(i)$ is an indicator variable that takes value of 1 if unit i is simulated to be available (with a probability of (1 - fof_i)) and 0 otherwise.

For each hour, the Monte Carlo simulation of each unit's forced outage is repeated 100 times. I then calculate the mean of these simulations of the competitive-benchmark price $\bar{P}_t^*$ for each hour. This is an unbiased estimate of the expected prices that would have occurred had the market been perfectly competitive. The price-cost markups $(P_t - \bar{P}_t^*)/P_t$ are computed to measure the market power, which I use to detect the variation before and after the divestiture of transmission control.

[17]Under Jensen's inequality, for a random variable q and any convex function $C(\cdot)$, we have $E(C(q)) > C(E(q))$.

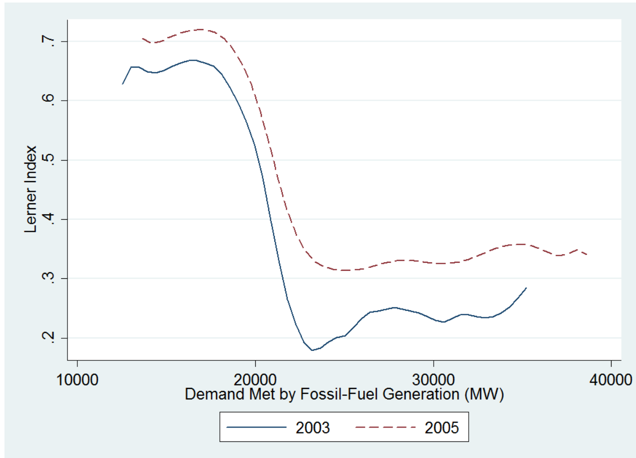


Figure 2.5: Kernel Regressions of Lerner Index: Summer 2003 and 2005

2.3.4 Detecting the Change of Market Price-cost Margin

In this section, I investigate how the market price-cost margin derived based on above methodology changes after the market restructuring activities occurred in the SPP electricity market. If the margin increases, it would provide evidence that certain firms were enabled to exercise market power by setting wholesale prices. As mentioned above, I compare the market conditions between summer 2005 and summer 2003 to perform the empirical analysis.

Figure 2.5 provides a graphic illustration of the relationship between the estimated market price-cost margin and the demand met by the fossil-fuel generators in the SPP market. Specifically, I apply kernel regressions of the hourly price-cost markups, (i.e., the Lerner Indexes) against the demand realized by fossil-fuel generation in the SPP in the summer months of 2003 and 2005. Given an upward shift of the curve, it seems like that the markup increases significantly from summer 2003 to summer 2005 at all levels of demand. Notably, the increase is dramatic at high demand level by approximately 10 percent, while there is only minor increase in the markup at low demand level. Although no conclusive statements can be drawn from the graphical illustration, it still provides preliminary evidence that divestiture of transmission control enabled at least some wholesalers to exercise market power.

Another pattern of the relationship deserving discussion is that for each summer, the markup is high at low level of demand below 20,000 MW and starts to tumble beyond that level. Notice that the cutoff point corresponds exactly to the significant kink of the constructed supply curve shown in Figure 2.3, where the regional capacities switch from coal units to natural-gas units. There are several potential explanations for this correspondence. For one thing, when cheap coal units began to reach capacity limits, it is likely that the extensive resources of natural-gas capacity provide firms the opportunity to withhold coal units to force more expensive natural-gas units to the margin to obtain abnormal markup.

For another, this pattern might also be attributed to overestimation under current calculation. First, the computation of the competitive supply curve does not account for possible generation and transmission capacity constraints. This might lead to scenarios where even though low-cost coal units are assigned to be dispatched, certain natural-gas units still have to run and determine the wholesale prices as the units on the margin. Second, the underestimation of market marginal cost due to failure to account for net import/export is the high at the kink.[18] Yet, overestimation of the markup due to both reasons would shrink significantly when the demand level increases to the level where natural-gas units are supposed to serve under a competitive market.

I then turn to regression analysis to investigate the problem. Specifically, I compare the price-cost markup $(P_t - \bar{P}_t^*)/P_t$ by applying empirical models with the

[18]At the switching point between coal and natural capacity, as price fall from the actual to competitive price, net import would decrease (or net export would increase), much more expensive natural-gas units have to be utilized, which is on the margin to set the wholesale price. Thus failure to account for inter-market exchanges would cause significant underestimation of the true competitive prices and thus significant overestimation of the markup.

following specification:

$$\begin{aligned} Markup_t =& \alpha + \beta_1 \cdot Restructuring_t + \beta_2 \cdot Load_t + \sum_{j=1}^{24} \eta_j \cdot 1[hour = j] \\ &+ \sum_{k=1}^{7} \sum_{m=4}^{9} \eta_j \cdot 1[day = k] \cdot 1[month = m] + \epsilon_t \end{aligned} \tag{2.6}$$

where t is a given hour, *Restructuring* is an indicator for the time period after the market restructuring (i.e, summer 2005), *load* is hourly regional demand realized by fossil-fuel capacity, $1[hour = j]$ is an indicator variable for hour j, $1[day = k]$ is a day-of-week indicator for the kth day of week, and $1[month = m]$ is dummy variable for the month m. All specifications are based on the OLS estimation with robust standard errors.[19]

The coefficient of primary interest is β_1, which presents an estimate of the change in the markup after the divestiture of transmission control from vertically integrated utility firms. The estimation results are provided in Table 2.5. Model specifications vary in the data sample selected. In the first column, I include all hourly observations during summer months (April-September) of 2003 and 2005, while in columns 2-5 I restrict the sample to hours associated with the first to the fourth quartiles of the total market demand realized by the fossil fuel capacity. Despite the model specification variations, the coefficient of primary interest are robust and are all statistically larger than zero at the 1 percent level. This implies that market markup in the SPP electricity market increases at all level of demand after the specific market restructuring, as indicated in Figure 2.5.

As for the magnitude of the increase of the market markup, it varies from approximately 6 percent to 10 percent across the quartiles of demand realized by the fossil fuel capacity. Comparing between the quartiles, we can find that the increase in the markup becomes gradually larger as the demand rises and reaches the peak at the

[19]Prais-Winsten estimation is also applied for robustness checks, which provides similar results. However, the Durbin-Watson statistics of all specifications are higher than the upper bound of the 5% confidence interval for positive AR(1) autocorrelation.

Table 2.5: Comparison of the Lerner Index

	All	1st Quartile Regional Load	2nd Quartile Regional Load	3rd Quartile Regional Load	4th Quartile Regional Load
Restructuring	0.0935***	0.0613***	0.0946***	0.105***	0.0846***
	(0.00242)	(0.00201)	(0.00263)	(0.00329)	(0.00297)
N	8784	2197	2195	2196	2196
Adj. R^2	0.680	0.367	0.794	0.517	0.589
Avg. Hourly TC (in Million $)	1.98	1.15	1.50	2.00	2.89
Estimated Increase in TC (in Million $)	0.19	0.07	0.14	0.21	0.24
	(0.00479)	(0.00231)	(0.00394)	(0.00659)	(0.00858)

Notes: All specifications are based on OLS regressions with robust standard errors. Prais-Winsten estimation is also applied for robustness checks, which provides similar results. However, the Durbin-Watson statistics of all specifications are higher than the upper bound of the 5% confidence interval for positive AR(1) autocorrelation. Robust standard errors are in parenthesis. ***p<0.01, ** p<0.05, and *p <0.1.

third quartile. One possible explanation is that the exercise of market power through generation withholding is easier to be detected when the demand is low, while it is less feasible when the pool of additional supply sources dwindle when the demand is high.

Based on the estimates of the increase in the price-cost markup, I compute the increases in procurement costs through the electricity wholesale market at different demand levels. Since retail rates are fixed by regulation, these represent wealth transfers from some utility firms to those who are net sellers in the wholesale market. To derive the estimates, I first calculate the average hourly total procurement costs overall and in each of the load quartiles. I then evaluate at the mean of the average hourly costs to estimate the added costs of procuring electricity due to the enhanced market power. As shown in the table, the increases vary from 70,000 dollars in an hour of the first demand quartile to 240,000 dollars in an hour of the fourth demand quartile.

2.4 Generation-Withholding Behaviors of the Net Wholesalers

Under the theoretical prediction discussed in Section 2.3, I investigate in this section the market power issue in the SPP market through analysis on the differential incentives between two groups of firms (the net sellers and buyers in the wholesale market) to engage in capacity-withholding behaviors after the market restructuring. This also provides an explanation for the underlying mechanism for the results of increased price-cost margins found in Section 2.3.4. Specifically, I test whether unit capacity factors (i.e., generation as a percent of unit designed capacity) of the firms with net selling position dropped relative to the other firms. Despite the large shares of some of the fringe suppliers, they are modeled as price takers based on the argument that it is likely that they don't have the incentives to manipulate prices.

Empirically, I identify net sellers (i.e., Southwestern Public Service corporation, Westar Energy and Kansas City Power and Light) through yearly power sale/purchase data available from SPP's State of Market Reports. Based on ownership information from the eGrid data from EPA, I match the generating units to each firm in the wholesale market. To test the hypothesis, I apply the difference-in-difference methodology with model specifications of the following general form:

$$CF_{it} = \alpha + \beta \cdot Restructuring_t + \gamma \cdot Restructuring_t \cdot Seller_i + Z'_{it} \cdot X_{it} + \eta_i + \varepsilon_{it} \quad (2.7)$$

where CF_{it} is capacity factor of unit i in hour t, $Restructuring$ is an indicator for summer 2005 after the market restructuring, $seller_i$ is a dummy variable that takes the value of 1 if unit i is owned by a firm that is a net seller, X_{it} is a set of other control variables, and η_i is the unit fixed effect. All standard error is clustered at the unit level to control for potential serial correlation in the error term.

In line with Mansur (2007), in X_{it} I also control for estimates of unit competitive production decisions simulated under methodology discussed in Section 2.3. This is out of the concern that restructuring might affect competitive firms asymmetrically. Moreover, recall that the estimates also control for the demand and supply factor changes during the data span. Thus, inclusion of the variable serves to control for unobserved supply or demand shocks that are endogenous to production decisions. X_{it} also include indicators that controls for demand fluctuations, such as the indicator for the hour of the day, the interaction between the indicators for the day of the week and those for the month of the year, and dummy variables for the deciles of the demand realized by the fossil-fuel units. I also include unit marginal cost (fuel cost plus environmental cost) to check whether the simulated competitive production decision can fully account for supply shocks. The coefficient of the indicator variable *Restructuring* measures the common change in capacity factors to all firms in the summer of 2005 after the divestiture of transmission control in the SPP market. $\beta + \eta$ measures the average change of capacity factors of units of the net sellers after the restructuring. The difference-in-different coefficient, γ, is the estimate of the behavior changes in unit capacity utilization of the net sellers following the market restructuring relative to other firms.

Table 2.6 reports the results of empirical model shown in equation (2.7) with 5 specifications. The specifications vary by the included control regressors. Except for model 3, all specifications provide robust estimates of the coefficient of primary interest, γ. It is estimated to be approximately 0.03, implying that on average, firms with a net selling position reduced capacity factor by 3% relative to others to induce higher wholesale prices. In model 1 and 3, I do not include the indicators that control for demand variations, while in the rest of the models they are controlled for in the regression. In model 1 and 2, I do not control for the unit capacity factors under estimated competitive production decisions, which I add into the specifications for robustness checks in model 3-5. In model 5, I add the unit marginal costs to control for unit supply shocks. However, the correspondent coefficient on unit marginal cost is not statistically different from zero, indicating adequate predictive power on

Table 2.6: Capacity Withholding for Net Wholesale Sellers

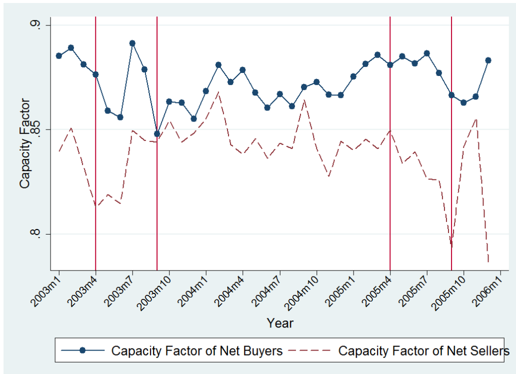
	(1)	(2)	(3)	(4)	(5)
Restructuring	0.0448***	0.0158**	0.0375***	0.0147*	0.0206**
	(0.00777)	(0.00774)	(0.00734)	(0.00754)	(0.00937)
Restructuring	-0.0294**	-0.0303**	-0.0222	-0.0279**	-0.0288**
× Net Seller	(0.0142)	(0.0142)	(0.0136)	(0.0138)	(0.0140)
Constructed			0.205***	0.0648***	0.0588***
Capacity Factor			(0.0196)	(0.0193)	(0.0191)
MC					-0.000334
					(0.000224)
Other Controls	No	Yes	No	Yes	Yes
Unit FE	Yes	Yes	Yes	Yes	Yes
N	1804342	1804342	1804342	1804342	1765109
Adj. R^2	0.572	0.641	0.585	0.642	0.638

Notes: Dependent variable is actual capacity factor, which is hourly load as a percent of designed nameplate capacity, by generating unit and hour. Unit fixed effects are included in all specifications. "Restructuring" is an indicator for the time period after the market restructuring (which here is summer 2005) and "Net Seller" is an indicator for generating units owned by firms with a net position of sale in the wholesale market. "Other Controls" is a set of variables that control for the hourly demand fluctuations, including indicators for the hour of the day, the interaction between the indicators of the day of the week and those of the month of the year, and dummy variables for the deciles of the regional total fossil-fuel generation. "MC" is the unit marginal cost (fuel cost plus SO_2 emission cost). Standard errors are clustered at the unit level to take care of potential autocorrelation problem. ***p<0.01, ** p<0.05, and *p <0.1.

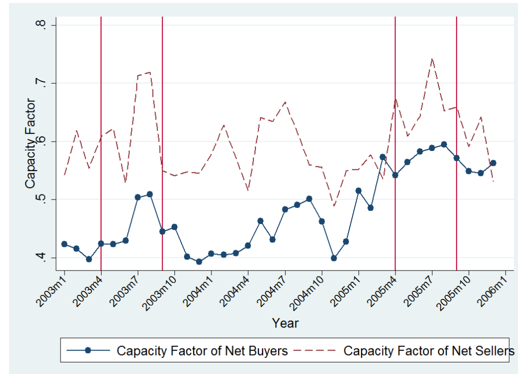
the supply shocks of the simulated capacity factors under competitive production decisions.

I then look into firms' anti-competitive behaviors on the operation of coal and natural-gas units separately. Figure 2.6(a) shows the differential trends of the monthly averages of unit capacity factors between the two groups of firms for coal capacities. The monthly averages are based on hourly observations and weighted by the unit load. The vertical lines represent the bounds of the time windows of summer 2003 and summer 2005. From the figure, one can tell that the gap between weighted averages of the two groups increases after the restructuring (October 2004). Even though the mean of unit capacity factor of the net buyers who are on the competitive fringe stays relatively stable, there is a significant drop in the mean of the net sellers, especially during July to September in 2005 when the demand is expected to be the highest during the year. The similar comparison for natural-gas units between the net sellers and buyers is demonstrated in Figure 2.6(b). From the figure, we can see that the gap between average unit capacity factors of the two groups of firms shrinks for natural-gas units. Specifically, under a steadily growth of demand across the summers of the years in the data sample (shown in Table 2.3), unlike the firms on the competitive fringe, firms with a net selling position did not increase capacity factor of natural gas units to adjust to the market condition. In this sense, they withheld the capacity to set the up the prices.

Evidence demonstrated in Figure 2.6(a) and 2.6(b) is confirmed in regression analysis. I perform the difference-in-difference model outlined in equation (7) for coal and natural-gas units separately. As well as focusing on the entire summer months (April to September) , I also vary the specifications by looking specifically into June to August when the demand is the highest. In the first and third column, I include all hours during summers of 2003 and 2005. For coal units, the estimate of the relative change in unit capacity factor of firms with a net selling position is not significantly different from zero. In contrast, the estimate for natural-gas capacities is statistically lower than zero. The result shows that the net sellers withheld capacity of their



(a) Coal Units



(b) NG Units

Figure 2.6: Capacity Factors of the Net Wholesale Sellers and Buyers

Note: capacity factor is generation as a percent of the nameplate capacity. The statistics are based on data of hourly unit load available from EPA Clean Air Market data. The statistics are calculated as averages weighted by load. The vertical lines indicate the sample period of summer (April to September) of 2003 and 2005.

natural gas units by approximately 2.6 percent relative to other firms. In column 2 and 4, I restrict the data sample to June to August. In line with the regression results (shown in Table 2.5) that the extent of enhanced power tends to be generally higher as demand level rises, the magnitude of estimates of γ increases for both coal and natural-gas units when the comparison is restricted within June to August. On the one hand side, there is significant evidence that during June to August, coal units of net sellers experienced a drop in capacity factor by approximately 5 percent relative to those of the firms on the competitive fringe. On the other hand side, the estimated relative decrease in capacity factor of natural-gas units of the net sellers is approximately 5 percent, larger than that when all months between April to September are included in the data sample.

2.5 Conclusion

Economists generally believe that promoting competitive markets can enhance efficiency and welfare. Under this spirit, deregulation activities in the power industry

Table 2.7: Test of Capacity Withholding Behavior for Net Wholesale Sellers: Coal Units and NG Units

	Coal Units All Summer	Coal Units June-August	NG Units All Summer	NG Units June-August
Restructuring	-0.00939	-0.00814	0.0213**	0.0173
	(0.0159)	(0.0128)	(0.00830)	(0.0106)
Restructuring × Net Seller	-0.0165	-0.0481**	-0.0260**	-0.0454***
	(0.0305)	(0.0196)	(0.0129)	(0.0149)
Constructed Capacity Factor	0.0363	-0.0102	0.0738***	0.0901***
	(0.0283)	(0.0186)	(0.0273)	(0.0253)
Other Controls	Yes	Yes	Yes	Yes
Unit FE	Yes	Yes	Yes	Yes
N	474336	238464	1330006	672864
adj. R^2	0.258	0.360	0.479	0.528

Notes: Dependent variable is the actual capacity factor, which is hourly load as a percent of designed nameplate capacity, by generating unit and hour. Unit fixed effects are included in all specifications. "Restructuring" is an indicator for the time period after the market restructuring (which here is summer 2005) and "Net Seller" is an indicator for generating units owned by firms with a net position of sale in the wholesale market. "Other Controls" include indicators for the hour of the day, the interaction between the indicators of the day of the week and those of the month of the year, and dummy variables for the deciles of the regional total fossil-fuel generation. Models 1-2 and model 3-4 are based on observations on coal-fired units and NG-fired units. In model 3 and 4, I focus on high-demand summer months (June-August). Standard errors are clustered at the unit level to take care of potential within-unit serial correlation problem. Standard errors are included in the parenthesis. ***p<0.01, ** p<0.05, and *p <0.1.

became a general momentum after the mid-1990s and were enacted in many states in the U.S.. Facing concerns on the huge up-front implementation costs held by the opponents, economists and policy makers devoted significant attention to the evaluation of the welfare implications of the dramatic market restructuring. This can be a difficult task as researchers must disentangle various aspects associated with the deregulation in order to make clear policy recommendations. By taking advantage of a unique electricity market, Southwest Power Pool, this paper evaluates one specific aspect of market restructuring activities, that is, the divestiture of transmission control, and investigate whether market power arises under the specific restructuring.

Previous literature have shown that despite potential operating efficiency gains within plants or at regional aggregate level, substantial market failures to allow wholesalers to set prices also come along with the restructuring of the power industry. This study demonstrates that even in an electricity market where restructuring activities only required the divestiture of transmission control, certain firms have incentives to engage in anti-competitive behaviors to drive up wholesale costs. After the divestiture of transmission control, the price-cost margin in the SPP wholesale market increased by six to ten percent depending on the level of the demand, indicating an added costs of procuring electricity as large as 0.24 million dollars within an hour.

I also investigate the underlying mechanism of the results. Specifically, I identify two groups of firms with distinct incentives to engage in anti-competitive behaviors: the net sellers and buyers in the wholesale market. I find that after the restructuring, three firms with a net selling position in the wholesale market reduced capacity utilization by approximate 3 percent to drive up the price, as indicated by a simple Cournot model. Although the reduction is relatively small in scale compared to earlier analysis by Mansur (2007) under the Pennsylvania, New Jersey, and Maryland (PJM) market, the paper's results still caution regulators that they should pay attention to firms' anti-competitive behaviors even only the transmission control is divested, and they should especially target on firms with a net selling position in the wholesale market.

Chapter 3

Pass-through from Fossil Fuel Market Prices to Procurement Costs of the U.S. Power Producers

3.1 Introduction

The change in prices in response to a cost shock, i.e., cost pass-through, is a key question that receives broad attention in economics. In international economics, there are a series of studies that investigate the transmission of exchange rate fluctuations to prices of imported goods (among others, see Goldberg and Knetter, 1997). The analysis of cost pass-through also provides important implications on the issue of tax incidence in public economics (Marion and Muehlegger, 2011) and price discrimination (Aguirre et al., 2010), merger assessment (Weyl and Fabinger, 2013) and cartel damage quantifications (Verboven and van Dijk, 2009) in industrial organization. Cost pass-through is also a major topic in the energy economics. Earlier cost pass-through analyses in the electric power industry mainly focused on the transmission of emission costs to electricity prices, especially in the context of the European Union's Emissions Trading System (ETS).[1]

In the current study, we look at a specific pass-through in the energy market: the changes in fossil fuel procurement costs for the U.S. electricity producers resulting from fluctuations in corresponding spot market prices. We investigate whether there is stickiness in the pass-through from fossil fuel spot prices to the U.S. power producers' procurement costs, and if there is, to what extent the sluggishness of the pass-through process is. We measure the specific pass-through for three types of fossil fuels: coal, natural gas and petroleum. Understanding on the question has intellectual value for analyzing the impact of changes in fossil fuel spot prices on the U.S. electricity sector and the overall economy. Examples of recent significant changes in the U.S. fossil fuel spot markets include increases in coal prices due to demand changes in the world market, and the dramatic drop in natural gas prices as a result of the technological breakthrough of hydraulic fracturing. However, we are aware of no previous studies devoted to this question.

In line with the pass-through literature, we find incomplete pass-through from fossil fuel spot market prices to receipt costs of power plants, specifically for coal. The major channels of pass-through incompleteness identified in the literature include: (1) the strategic adjustment of markups associated with cost shocks; (2) the presence of a large proportion of costs which remain unaffected by the observed cost shocks (e.g., non-traded costs in the exchange rate pass-through literature in international economics); (3) the price rigidity and other dynamic factors; (4) the mismatch between observed cost shocks and a firm's actual opportunity costs (Nakamura and Zerom, 2010; Fabra and Reguant, 2014).

In this paper, we explore a channel within the realm of price rigidity: duration of contracts made between power plants and fossil fuel suppliers. Generally, power plants purchase coal on a contracted long-term basis, while natural gas mostly in the

[1] See Zachmann and Von Hirschhausen (2008), Fezzi and Bunn (2009), Fell (2010), Kirat and Ahamada (2011), Sijm et al. (2012), Fell et al. (2013), Lo Prete and Norman (2013), Fabra and Reguant (2014), etc.

spot market. We find that the pass-through from spot price changes to delivered contract costs for power plants are faster and more complete for natural gas (and oil) than coal. A 1% change in natural gas spot price can lead to an approximately 0.85% change in the contract prices received by the power plants within 1 month. However, a 1% change in coal spot price can only lead to an approximately 0.11% change in the contract prices received by power plants even after 12 months.

We also examine how the pass-through pattern varies under different scenarios. First, we compare the pattern between traditional regulated power plants and divested Independent Power Producers (IPPs). Previous literature on deregulation in the electric power industry documents evidence that divested power plants operated more efficiently under competition pressure. Specifically, deregulated coal-fired plants were able to substantially reduce prices paid for coal relatively to those without any regulatory change (Chan et al., 2013; Cicala, 2015; Jha, 2015). Given these empirical results, people might wonder whether transmission of fossil fuel market prices to contract prices also differs between plants of different regulatory status. For natural gas purchases, we document evidence that the transmission of spot prices to power producers' procurement costs is faster within deregulated power plants. In contrast, we don't find any significant differences in the pass-through pattern across regulatory status for coal purchases.

Second, we analyze whether the pass-through varies given a positive market price change versus a negative one. Asymmetric price adjustment has been empirically documented in a number of commodity markets (Peltzman, 2000), especially for the fuel market (Borenstein et al., 1997; Brown and Yücel, 2000). Zachmann and Von Hirschhausen (2008) first raised the puzzle of an asymmetric pass-through from European Union's CO_2 emission prices to wholesale electricity prices. Mokinski and Wölfing (2014) document empirical evidence of asymmetric adjustment of wholesale electricity prices in response to CO_2 emission prices. We find that market prices of natural gas have faster pass-through under negative shocks. In contrast, we don't find evidence of asymmetric pass-through for coal or oil purchases.

Third, we are able to measure the pass-through patterns of coal extracted from three major deposits in the U.S. with distinct characteristics: the Powder River Basin (thereafter, "PRB"), the Illinois Basin and Central Appalachia (thereafter, "CAPP"). Coal varies widely on many aspects (e.g., sulfur and heat content) among the three origins.[2] Given the different characteristics, spot prices for them are significantly different from each other.

The paper has intellectual value in several aspects. First, the study confirms the fast and complete pass-through from natural gas spot prices to procurement costs of power producers. Given volatile natural gas market prices and an increasing share of natural gas in the fuel mix for electricity generation due to the hydraulic fracturing mining technology breakthrough, our results indicate that it become increasingly harder for the power producers to plan their business and hedge against the market risk of input procurement costs. Since the changes in natural gas prices eventually fall on the consumers, it means that the increasing share of natural gas generation might hurt low income households.

Second, it also has implications on the welfare distribution effects of cheap natural gas prices due to technology breakthrough of hydraulic fracturing. The relative complete and fast pass-through of natural gas spot prices indicates a large part of welfare gains of cheap natural gas is also able to fall on power producers and end consumers.[3]

Third, we document evidence that there are distinct pass-through patterns from fossil fuel spot prices to procurement costs across different regulatory status. The transmission is faster for deregulated power plants for natural gas purchases. This

[2] According to Busse and Keohane (2007), the median sulfur content of PRB coal is around 0.33% by weight, compared to much higher medians for Central Appalachia coal (0.90%) and Illinois Basin coal (2.7%); PRB coal also has much lower heat content than Central Appalachian and Illinois Basin Coal. The median heat content for PRB coal is 8674 British thermal units per pound, while the statistics are 12490 and 11309 for Central Appalachian and the Illinois Basin coal.

[3] The distribution of welfare gains between power producers and end consumers would depend on whether the electricity market is restructured or not. In a traditional regulated market, the consumers are the residual claimants of any fossil fuel price changes. In contrast, power producers become directly the residual claimant in a restructured market and it will be difficult to determine how much welfare gains consumers would obtain.

is consistent with previous findings that deregulation affects the fossil fuel purchase behaviors of power plants (Chan et al., 2013; Cicala, 2015; Jha, 2015).[4] This implies an extra cost of deregulation: increasing market risk due to volatility of fuel procurement costs for power producers.

Fourth, the adjustment lag between fossil fuel spot prices and procurement receipt prices for power plants also has methodological value by raising the caution for future empirical works in the U.S. electric power industry: spot prices do not always reflect the true opportunity costs of using the fuel (Fabra and Reguant, 2014). For instance, it has implications on constructing counterfactual competitive supply curves commonly used in the static approach of measuring market power in the electricity market.[5] Most of the literature use respective fossil fuel spot prices to calculate the marginal costs of generating units and build counterfactual competitive supply curves. Our results imply that while this might be appropriate for natural-gas-fired units, it might not be the case for coal-fired units.

The paper proceeds as follows. Section 3.2 describes the context of the analysis. Section 3.3 describes the data and summary statistics. In Section 3.4, we present the baseline empirical model. In section 3.5, we provide the empirical results and the discussion. Section 3.6 concludes.

3.2 Context

3.2.1 Contract Duration of Different Fossil Fuels

In this paper, we look into one price rigidity that potentially leads to incomplete pass-through: duration of fossil fuel contracts between the power producers and suppliers, which previous studies has realized as a key factor affecting fuel substitution given spot price shocks (OECD/IEA, 2013). There is significant difference in contract

[4]However, our findings are not sufficient to make causal inference since we do not observe cross-sectional variation in regulatory status.

[5]See Borenstein and Bushnell (1999), Wolfram (1999), Borenstein et al. (2002), Mansur (2007), etc.

duration between the coal and natural gas markets in the U.S. Coal market is characterized by long contracts: the median contract averages around 2 years in 2014 (Matisoff et al., 2014); 93% of coal consumed for electricity generation in the U.S. was purchased via long-term contracts of more than a year (rather than spot contracts) in 2011 (EIA, 2012). In contrast, the standard contract in the natural gas market is much shorter. In 2011, 66% of natural gas consumed for electricity generation in the U.S. was purchased via spot contract (EIA, 2012). The result of short contract terms for natural gas in the U.S. is thought be contributed by the creation of competitive markets in natural gas and somewhat competitive markets in transportation (Petrash, 2006). As for contract terms between power producers and oil suppliers, since oil purchases is generally used for peak or specialized purpose, spot contracts are also common.

3.2.2 Difficulty of Measuring the Pass-through to Wholesale Electricity Prices

Most previous literature of cost pass-through in the electricity market focuses on the transmission of input price shocks (e.g., emission allowance price variations) to wholesale electricity prices. Although we have detailed plant-level data, we lack some key variables to measure how shocks in fossil fuel receipt prices lead to changes in wholesale electricity prices.

For traditional regulated electricity markets, transactions are realized via bilateral trading where market price determination mechanism is opaque. Also it is unclear what regulators use as marginal cost estimates for wholesale transactions between regulated utilities. For restructured markets, the wholesale price is determined by bidding in multi-unit auctions. Caution should be taken when researchers measure the responses of the bidding behaviors of the marginal generating unit who sets the market price to changes in its marginal costs (e.g., fluctuations of fossil fuel procurement costs). This is because how a firm's optimal bidding behavior changes depends on not only fossil fuel price shocks, but also the strategic adjustment of markups (Wolfram, 1998; Borenstein et al., 2002; Hortacsu and Puller, 2008; Fabra and Reguant, 2014, etc). To cleanly identify the pass-through from fossil fuel price changes to wholesale electricity prices, researchers have to tease out the the contribution of strategic adjustment of markups. The previous literature derives the markup from the first-order condition of the profit maximization, which depends on the net quantity sold by the utility firm (i.e., its production minus its vertical commitment), and the slope of the residual demand faced by the firm. The general approach of the previous literature is calculating the former by subtracting the firm's output by purchases from its subsidiaries, and approximating the latter based on the bid data. Unfortunately, we don't access to the above data sets. So we focus on the pass-through between fossil fuel market prices and procurement costs by power plants.

3.3 Data

3.3.1 Data Description

The study mainly exploits three separate data sets: (1) market spot prices of fossil fuels; (2) plant-level fossil fuel receipt cost data for electricity producers; (3) cost estimates of railway transportation.

The first data set is mainly obtained from Bloomberg. From the Bloomberg data, we obtain spot and future prices for natural gas at several hubs and coal extracted in the three major deposits in the U.S.: Powder River Basin, Illinois Basin and Central Appalachian. We also extract West Texas Intermediate spot prices from EIA, which is widely considered to be the benchmark in the U.S. oil markets. We aggregate the daily (or weekly) market prices to monthly averages to be consistent with frequency of the rest of the data.

The main source of the second data set is the records of FERC-423 and EIA-423 data form, the "Monthly Report of Cost and Quality of Fuels of Electric Power

Plants". FERC-423 form must be filed by all utility electricity-generating plants with a capacity of at least 50 megawatts, while EIA-423 is designated for the non-utility counterparts with capacity above the same cutoff. After 2008, both forms were incorporated in survey Form EIA-923.[6] The transaction-level data contains purchased fossil fuel types with details to sub-fuel categories (e.g., bituminous coal), contract prices (including transportation costs and taxes), quantity of fuel delivered, average heat content of the fossil fuel, contract terms (e.g., contract type and expiration date),[7] "dirtiness" of the fossil fuel (e.g., average sulfur and ash content), location of the purchasing plant and the origin of fuel (mine name and location for coal only). Based on the information, we can categorize the transactions by fuel mining sources and match with the market prices from Bloomberg.[8]

Fuel receipt cost data also includes transportation delivery costs. Ideally, having accurate transportation rate data is desired to understand the pass-through question under the current analysis, especially for coal transactions. According to EIA report, railroad is the main transportation mode for coal delivered to electric power plants (over 70% in 2010). Moreover, rail transportation costs account for a sizable share of total delivered costs of coals for electric power producers and vary across shipments of coal originating from different coal basins.[9] For these reasons, unobserved changes in rail transportation rates would bias the estimated results on the pass-through from

[6]The non-utility part of the data is not publicly available for privacy protection purpose. We requested the proprietary data from EIA by signing a non-disclosure agreement.

[7]The contract types are divided into "spot market" deliveries (for contracts that expire in less than one year), and "contract" delivery (for longer-duration contracts). Expiration dates are available for those that would expire in the next 24 months.

[8]We match natural gas purchases to the nearest trading hubs based on major transportation flow pattern of the U.S. Natural Gas market. See the map available from EIA: http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/MarketCenterHubsMap.html. We match spot prices at Waha Hub (TX) for plants in NE and KS, prices at Opal Hub (WY) for plants at UT, WY and CO, prices at Blanco Hub (NM) for plants at AZ and NM, prices at Chicago Hub for plants at WI and IL, and prices at AECO Hub (Canada) for plants at IA, MN, ND, MT, WA, OR and NV, and prices at Henry Hub (LA) for the rest of plants.

[9]EIA reports that during 2001-2008, the national average share of rail transportation cost as percent of total coal delivered costs is 20%. The number could reach as high as 59% for shipments of coal originating in Powder River Basin. See more details on EIA reports available at http://www.eia.gov/coal/transportationrates/archive/2010/trend-coal.cfm.

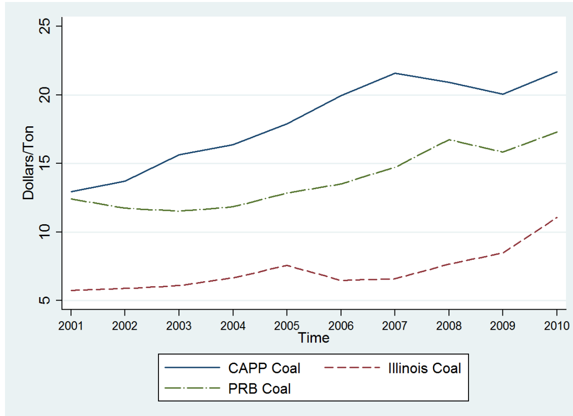


Figure 3.1: Rail Transportation Costs for Coal, by Mining Basins

Note: 2001-2007 data is based on the Surface Transportation Board (STB)'s 900-Byte Carload Waybill Sample. 2008-2010 data is calculated by EIA, which augmented STB's Waybill sample by EIA-923 Power Plant Operations Report data.

coal market prices to input receipt cost of power plants. EIA estimates that the rail transportation costs of coal from mines to power plants rose by 46% nationally from $ 11.83 to $17.25 per ton from 2001-2010. Figure 3.1 shows the estimated rail transportation costs for coal originating from three major coal deposit basins analyzed in the current study. There are substantial increases in the rail delivery costs for coals from all 3 basins. Unfortunately, we lack detailed data on coal transportation rate for power plants.

In order to handle the issue, we combine two data sets to approximate the changes in railroad transportation costs. The first data set is the EIA-estimated rail transportation cost data ($/ton), which is available on yearly basis, and provides detailed information about deliveries from each coal basin to each state destination. For some deliveries, the data is proprietary to protect firms' competitive advantages. We use the average cost of deliveries from the same basin for proxies. The second data set is the Rail Cost Adjustment Factor exploited in Busse and Keohane (2007), which is a national cost index computed quarterly by the Association of American Railroads to measure the rate of inflation in railroad input such as labor and fuel. It is also adjusted for productivity gains. The cost index is used by Surface Transportation

Board to assess railroad rates. We transform the yearly data from EIA to quarterly data based on the quarterly deviation of Rail Cost Adjustment Factor as the share of the yearly average. The transformation is done by using the following formula:

$$Rail\ Cost_{y,q=i} = Rail\ Cost_y + \frac{RCAF_{y,q=i} - \frac{1}{4}\sum_{q=i}^{4} RCAF_{y,q=i}}{\frac{1}{4}\sum_{q=i}^{4} RCAF_{y,q=i}} * Rail\ Cost_y, \quad (3.1)$$

where y is a specific year, q is a quarter of year, $RCAF$ is the Rail Cost Adjustment Factor. We then assume within the same quarter, the rail transportation costs for coal deliveries to power plants grow at a constant rate. Then we are able to calculate the monthly time series for rail delivery costs for coal.

We also exploit the North American Industry Classification System Code information available from the records of the EIA-906 data form (also incorporated in EIA-923 after 2008), "Annual Electric Utility Data", to restrict the sample to electricity-generating plants in the electric power industry only. We further take advantage of the EIA Sector Code to identify plants that are divested non-utility Independent Power Producers (IPPs) and those that are regulated electric utility producers.

Table 3.1: Summary Statistics

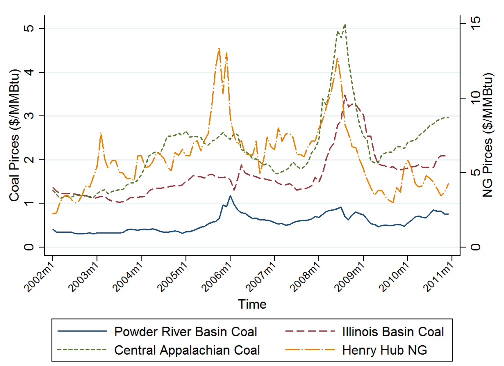
	Unit	**Mean**	**Std. Dev.**	**Min.**	**Max.**	**N**
Receipt Prices for Power Plants						
PRB Coal	Cents/MMBtu	141.9	52.3	12	957.5	46041
IL Coal	Cents/MMBtu	235.6	97.0	5.9	1022.9	74178
CAPP Coal	Cents/MMBtu	179.9	74.3	31.8	640.0	16161
NG	Cents/MMBtu	643.6	254.3	1.6	1785.8	138269
Oil	Cents/MMBtu	1287.9	554.2	1	2978.2	27968
Spot Market Prices						
PRB Coal	Cents/MMBtu	55.4	19.5	30.6	117.9	108
IL Coal	Cents/MMBtu	165.7	53.4	103.2	348.2	108
CAPP Coal	Cents/MMBtu	222.7	80.9	111.6	511.3	108
NG (Henry Hub)	Cents/MMBtu	605.4	227.465	225.7	1342.3	108
Oil (WTI)	Cents/MMBtu	1023.2	436.2	339.9	2308.3	108
Rail Transportation Cost	Dollars/Ton	14.0	5.0	2.4	37.4	8328

Note: The summary table is based on data from 2002 to 2010. For some natural gas and oil and purchases with trivial volumes, the receipt prices is overly high. We drop receipt prices of natural and gas above the 99th percentile.

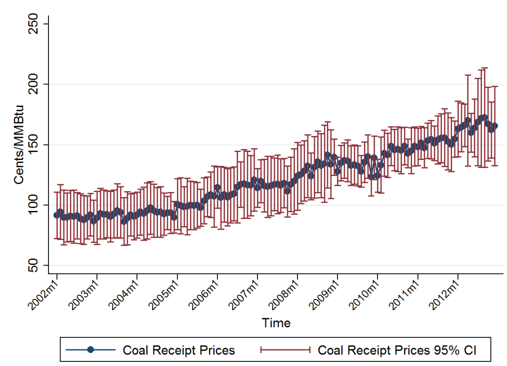
3.3.2 Summary Statistics and Variable Trends

The summary statistics of data are shown in Table 3.1. One can see that there are significant differences between the averages of spot market prices and the receipt procurement costs of power producers. The differences might result from two factors: 1) different levels of pass-through and 2) transportation delivery costs incorporated in the receipt price data. Moreover, the mean spot market prices represent much smaller shares of the receipt costs for coal compared with natural gas and oil. This is in line with the fact that transportation cost accounts for a more sizable proportion of the receipt prices for coal. And among the three types of coal from different origins, the mean spot market price of the PRB coal account for the least share as a percentage of total delivered receipt price. This corresponds to the fact that the rail transportation cost accounts for a very large share of delivered receipt price for the PRB coal.

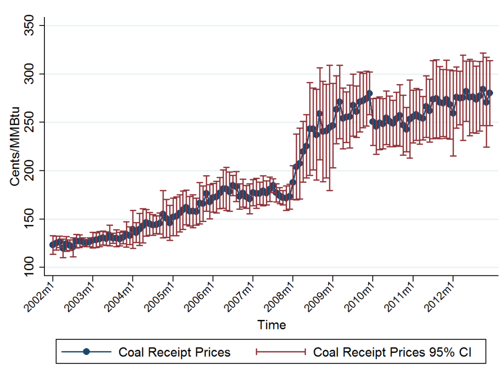
To get a sense of the pass-through from fossil fuel market prices to procurement costs by power plants, it is illustrative to show their evolution over the sample period. The trends of changes in fossil fuel prices are shown in Figure 3.2. Figure 3.2(a) displays the fluctuations in fossil fuel spot market prices across time. Note that contrary to natural gas and other types of coal, the spot market prices of the Powder River Basin coal only experienced minor fluctuations. Transactions made by power plants near the relevant coal mining basins are selected to be compared with the spot market prices. Coal transactions delivered for plants in Colorado are selected to show how the receipt prices of the PRB coal evolved over the sample period. Coal transactions delivered for plants in West Virginia are selected to show how the receipt prices of the Illinois Basin and CAPP coal evolved over the sample period. Compared with the coal spot market prices show in Figure 3.2(a), the receipt prices present obvious pattern of incomplete pass-through. This is in contrast to the pass-through pattern for natural gas. The receipt prices of natural gas for power plants of New York State displays a paralleled trend to that of the spot market prices, indicating faster and more complete pass-through.



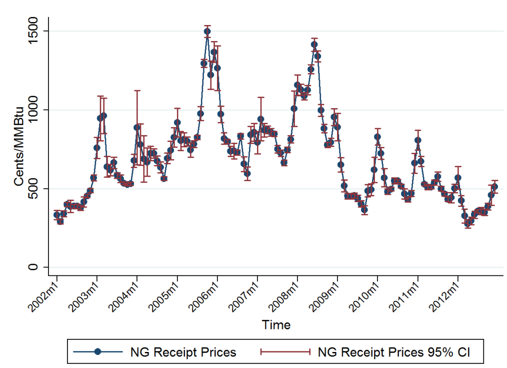
(a) Fossil Fuel Spot Market Prices



(b) Average Coal Delivered Receipt Costs in Colorado



(c) Average Coal Delivered Receipt Costs in West Virginia



(d) Average NG Delivered Receipt Costs in New York State

Figure 3.2: Fossil Fuel Spot Market Prices and Delivered Receipt Costs for Power Plants

Note: the average fossil fuel delivered costs for power plants is weighted by transaction volume. Coal purchases for plants in Colorado are selected to represent those for the PRB coal. Coal purchases for plants in West Virginia are selected to represent those for the CAPP and Illinois Basin coal. Fossil fuel receipt prices for power plants also include delivery costs.

3.4 Empirical Strategy

In order to understand how changes in fossil fuel spot prices are transmitted to power producers' procurement prices, we apply a common empirical model in the pass-through literature (especially on the pass-through of exchange rate in international economics),[10] which takes the following form:

$$\Delta log(FuelPrice)^f_{it} = \alpha + \sum_{k=1}^{12} \beta^f_k \cdot \Delta log(SpotPrice)^f_{t-k} + Z \cdot X + \epsilon^f_{it}, \tag{3.2}$$

where t represents a specific month of the sample, i indexes a power plant, f is a specific type of fossil fuel (coal, natural gas or oil). Δ represents first difference transformations. $log(FuelPrice)^f_{it}$ is the log of mean delivered cost of transactions for plant i in month t, $log(SpotPrice)^f_{t-k}$ is the log spot market price for fuel f. X is a vector of control variables. k is the number of lags, which varies from 0 to 12. We add lagged fossil fuel spot prices to allow for the possibility of gradual adjustment of power plants' procurement costs to spot prices, especially given the contract duration terms discussed in Section 3.2.1. β^f_k is the coefficient of interest, which measures the percentage change in receipt prices of fuel f associated with a one percentage change in the corresponding spot market price k months ago. The cumulative sum of the coefficients, $\sum_{k=0}^{12} \beta_k$, is then defined to be the aggregate long-run pass-through. The coefficients are identified off variation in changes of spot prices within a fuel type, month of year, and a power plant owning firm.

The empirical model is motivated by the fact, as in Campa and Goldberg (2005), Nakamura and Zerom (2010) and Goldberg and Campa (2010), the regressor is highly persistent: Dickey-Fuller tests for the hypothesis of a unit root in fossil fuel spot prices cannot be rejected at a 5% significance level.[11] Since the current study focuses only on measuring the pass-through responses rather than disentangling the underlying

[10] See Campa and Goldberg (2005), Nakamura and Zerom (2010), Goldberg and Campa (2010), etc.

[11] We were unable to reject the hypothesis that the series of coal prices at the 3 mining basins, natural gas prices at various hubs, and WTI oil prices were nonstationary. The Dickey-Fuller unit

channels of pass-through, we apply a reduced form approach without building upon a detailed theoretical model. In line with previous studies in the exchange rate pass-through literature where firms take the exchange rates as given when pricing the imported goods, the necessary assumption required in the current specification is that power plants are price takers in the fossil fuel spot markets. We argue that this is a valid assumption given the fact that the fossil fuel spot markets are all large with many participates from diverse sectors such that no single power plant (or a power plant owning firm) has the market power to manipulate the spot prices.[12] This form of empirical model has also been applied in previous studies with data structure very similar to ours.[13]

In addition to fossil fuel spot prices, we also control for other variables in X, including month-of-year fixed effects, change in log rail transportation costs,[14] owner firm fixed effects, etc. We estimate the model using the data described in Section 3, for monthly changes in procurement costs and spot market prices over the 2002 - 2010 period.[15] The standard errors are clustered at the plant level to allow for arbitrary serial correlation.[16]

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root test on the spot prices in an econometric specification with a time trend rejects the unit root hypothesis only in natural gas prices at Chicago Hub.

[12]Although individual plants or firms can engage in bilateral contracting with the fuel miners beside purchasing via spot prices, we argue this would not grant them power to manipulate the spot market prices.

[13]The model has been applied in different data structures, such as time series (Campa and Goldberg, 2005) and panel data sets for both aggregate country- or industry-level studies and detailed producer- or product-level studies (Goldberg and Campa, 2010; Nakamura and Zerom, 2010). In this study, we exploit detailed plant-level data to overcome to the shortcomings of aggregate data.

[14]Log rail transportation costs are set to zero for natural gas and oil, and for coal plants that are not matched with the estimated rail cost data from EIA (meaning the delivery is via transportation mode other than railroads, such as barge, truck, etc.).

[15]The data sample ends at 2010 because the EIA estimates of coal rail transportation costs are only available till 2010.

[16]We were not able to reject the null hypothesis of no first order autocorrelation under the Wooldridge test for autocorrelation in panel data (Wooldridge, 2010).

3.5 Empirical Results

3.5.1 Main Results

We first apply empirical model indicated by equation (2) to estimate the pass-through elasticities for coal, natural gas and oil. Since the pass-through patterns of natural gas and oil are very similar, we only show the coefficients of pass-through elasticities for coal and natural gas.

As shown in Figure 3.3, the pass-through pattern of coal is distinct from that of natural gas (oil). Changes in the spot market prices in natural gas (oil) quickly pass through to delivered contract costs for power plants. The pass-through responses occur almost entirely over the current period and the first lag month, and the sum is approximately 0.85 (with a standard error of 0.01) based on the delta method calculation. This means a 1% change in natural gas spot market price should lead to an approximately 0.85% change in the contract prices paid by the power plants within 1 month. In contrast, the pass-through is much more sluggish and far less complete for coal transactions. The pass-through from coal spot market prices to delivered receipt costs of power plants could take as long as 12 months, given the statistically significant coefficient at the 12th lag. Also, the pass-through is much smaller in magnitude for coal transactions. The long-run pass-through after 12 months is only 0.11 (with a standard error of 0.01.) This means a 1% change in coal spot market price can only lead to an approximately 0.11% change in the contract prices received by power plants even after 12 months. Based on the fact that on average coal contracts in the U.S. last for approximately 2 years, we also check the empirical model in equation (2) with 24 lags specifically for coal. However, the long-run the pass-through after 24 months only increases to 0.27 (with a standard error of 0.03).[17]

[17] Given the fact that there is a substantial wedge between the spot prices and the power plants' receipt prices for coal (shown in Table 3.1), we also check level specifications for empirical model (2). Under the level specifications, the long-run pass-through after 12 and 24 lags is 0.19 (s.e.=0.03) and 0.48 (s.e.=0.05) respectively, meaning 1 cent increase in coal spot prices leads to 0.19 cent and 0.48 cent increase in power plants' procurement receipt prices after 12 and 24 months.

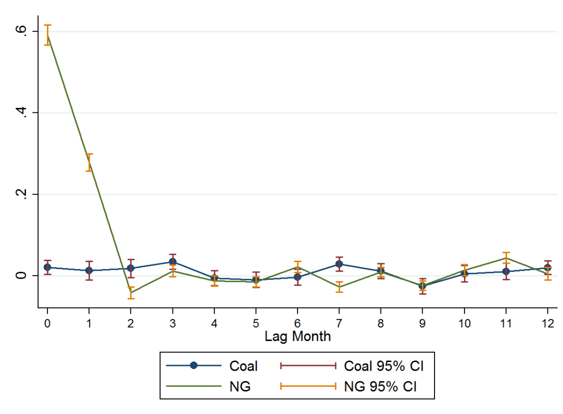


Figure 3.3: Pass-through Elasticity

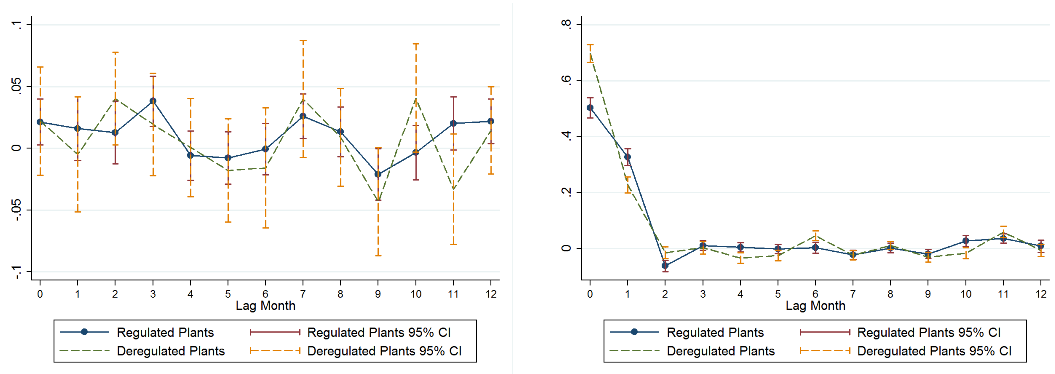
3.5.2 Variations by Regulatory Status

We further investigate the pass-through pattern between traditional regulated power plants and divested deregulated plants. The empirical model applied takes the following form:

$$\begin{aligned} \Delta log(FuelPrice)_{it}^{f} =& \alpha + \sum_{k=1}^{12} \gamma_k^f \cdot \Delta log(SpotPrice)_{t-k}^{f} \cdot 1[Deregulation]_i \\ &+ \sum_{k=1}^{12} \beta_k^f \cdot \Delta log(SpotPrice)_{t-k}^{f} + Z \cdot X + \epsilon_{it}^{f}, \end{aligned} \tag{3.3}$$

where $1[Deregulation]$ is an indicator variable taking value of 1 if a plant is a divested independent power producer. β^f now measures the pass-through elasticity of the regulated plants for fossil fuel f, γ_f instead measures the deviation of pass-through elasticity of the deregulated plants relative to the regulated counterparts for fuel f. Since oil power plants are clustered in the northeastern U.S. and the vast majority were divested Independent Power Producers, we lack adequate sample for regulated counterparts for oil purchases. Accordingly, we focus on coal and natural gas. Table C.1 in the Appendix shows β_{kf} and γ_{kf} for k up to 6. The coefficients are identified off variation in changes of spot prices within a fuel type, month of year, and a deregulated (or regulated) power plant owning firm. Specification (1) report the pass-through coefficients for coal and natural gas without adding the dummy of deregulation status. Specification (2) and (3) report the coefficients of the interaction terms with the regulatory dummy, which indicate the deviation of pass-through for divested plants relative to the regulated counterparts. In specification (3), we add the owner fixed effects to allow for distinct trends of changes in fossil fuel procurement costs at each owner firm, which potentially could be the decision maker of fuel negotiation and contracting. Complementary to Table C.1 in the Appendix, Figure 3.4(a) and 3.4(b) plot the the mean pass-through coefficients based on specification (3) for the regulated and deregulated power plants, associated with the correspondent 95% confident intervals, against the lag month period (up to 12) for coal and natural gas purchases.

Based on Figure 3.4 and Table C.1, we can see that for coal transactions, there are no distinguishable pattern of pass-through between regulated and deregulated power plants. For deregulated plants, the receipt price of coal only responds to market price changes after 2 months. For regulated plants, the pass-through from the spot market price of coal to the receipt price could take up to 12 months, and the current receipt price responds to market price changes in current, lag 3, 7 and 12 month. As for natural gas purchases, in line with previous results in Section 3.5.1, vast majority of market price changes pass on to procurement costs within 1 month for both regulated and deregulated plants. Moreover, comparing between deregulated and regulated plants, one can find that the pass-through from natural gas spot market prices to power plant receipt costs are faster within deregulated power plants. For the current period of a given spot market price change, the pass-through coefficient of deregulated power plants is significantly higher than that of the regulated plants by 0.21. This indicates that given a 1% increase in the spot prices, on average the increase of natural gas procurement prices in deregulated plants is larger by 0.21% than that of regulated plants at the current period. This makes intuitive sense as under deregulation, power plants are more prone to market changes such that they suffer more from the volatility of natural gas spot prices.



(a) Coal Transactions **(b)** NG Transactions

Figure 3.4: Pass-through Elasticity: Regulated vs. Deregulated

Note: deregulated plants are defined as divested ones of the independent power producers.

3.5.3 Variations by Negative and Positive Market Price Shocks

We then ask whether the pass-through differs given a positive market price change versus a negative one. The empirical model applied takes the following form:

$$\begin{aligned}\Delta log(FuelPrice)_{it}^{f} =& \alpha + \sum_{k=1}^{12} \delta_k^f \cdot \Delta log(SpotPrice)_{t-k}^{f} \cdot 1[Negative]_{t-k}^{f} \\ &+ \sum_{k=1}^{12} \beta_k^f \cdot \Delta log(SpotPrice)_{t-k}^{f} + Z \cdot X + \epsilon_{it}^{f},\end{aligned} \tag{3.4}$$

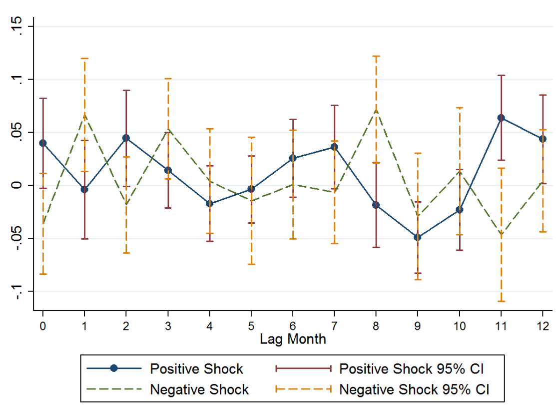
where $1[Negative]$ is an indicator variable for a decrease in the spot market price of fuel f k month ago. β^f now measures the pass-through elasticity given a market price increase for fossil fuel f. δ_f instead measures the deviation of pass-through elasticity given a market price decrease relative to an increase for fuel f. Table C.2 in the Appendix shows β_{kf} and δ_{kf} for k up to 6. The coefficients are identified off variation in increases (or desecrates) of spot prices within a fuel type, month of year, and a power plant owning firm. Specification (1) report the pass-through coefficients for coal, natural gas and oil without adding the dummy for a negative market shock.

Specification (2) and (3) report the coefficients of the interaction with the dummy. In specification (3), we add the owner fixed effects to allow for distinct trends of changes in fossil fuel procurement costs at each owner firm. Complementary to Table C.2, Figure 3.5(a)-3.5(c) plot the the mean pass-through elasticities given a positive and a negative market price shock, associated with correspondent 95% confident intervals, against the lag month period (up to 12) for coal, natural gas and oil.

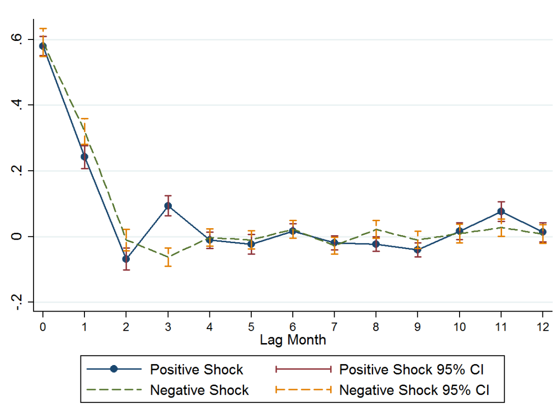
As shown in Figure 3.5 and Table C.2, for coal purchases, there is no obvious asymmetric pass-through pattern in response to positive or negative spot market shocks. The responses under spot price increases and decreases at different lags are not statistically different from each other at least within the first 10 months. For natural gas purchases, receipt prices respond quickly (within 1 month) to both negative and positive spot market shocks. Yet, a 1-month lag negative shock passes on to receipt prices more than a 1-month lag positive shock (by 0.08% given a 1% change in spot price in absolute value). For oil purchases, we focus on the current and lag 1-month periods when majority of the pass-through responses occur. A Wald test cannot reject (at 5% significance level) the null hypothesis that the sum of the pass-through responses under a positive shock is statistically different from the sum under a negative shock. Thus, we do not find asymmetric pass-through between power plants' procurement costs and spot prices for oil purchases.

3.5.4 Subcategories of Coal Purchases

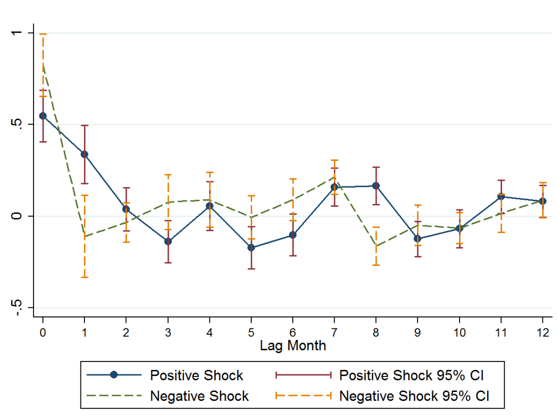
We then focus on coal only and categorize coal purchases from three major coal mining basins with coal production of significantly distinguishable characteristics. We first investigate pass-through patterns of the 3 types of coal between traditional regulated power plants and divested deregulated Independent Power Producers. Table C.3 in the Appendix shows the deviation of pass-through elasticities for deregulated plants relative to the regulated counterparts. Specification (1) report the pass-through coefficients for the three types of coal without adding the dummy of deregulation



(a) Coal Transactions



(b) NG Transactions



(c) Oil Transactions

Figure 3.5: Pass-through Elasticity: Positive vs. Negative Shocks

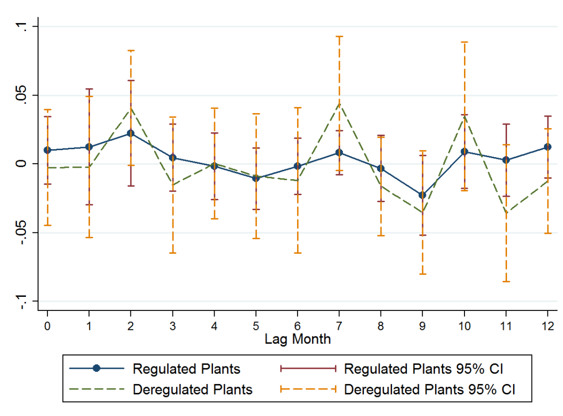
Note: a positive shock means an increase in the relevant spot market price.

status. Specification (2) and (3) report the the coefficients of interaction terms with the deregulation dummy, which indicate the deviation of pass-through for divested deregulated plants relative to the regulated counterparts. In specification (3), we add the owner fixed effects to allow for distinct trends of changes in fossil fuel procurement costs at each owner firm. Figure 3.6(a)-(c) plot the mean pass-through elasticity coefficients and corresponding 95% confidence intervals against the lag month term (up to 12).

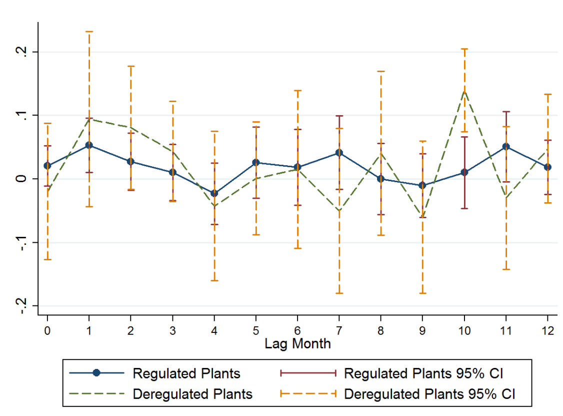
As for general pass-through patterns for purchases of the three types of coal, one notable finding is that the pass-through between spot price changes and the receipt prices of power plants for PRB coal is almost zero. The empirical results of essentially no pass-through could be due to the fact that the vast majority of delivered receipt price is the railway transportation cost, which is not tracked 100% accurately from month to month in study (see Section 3.3). In contrast, for the CAPP and IL Basin Coal purchases, the sum of pass-through responses within as short as 3 months are approximately 0.10%, given a 1% change in market spot price.

We then move forward to the differences in pass-through for the 3 types of coal between regulatory status. For PRB coal, there are no significant differences. For CAPP coal, spot market prices have relative faster pass-through for regulated plants. A spot market price change of CAPP coal takes only 1 month to affect the receipt prices for regulated plants. This is in contrast to 10 months for deregulated plants. For IL Basin coal, spot market prices also have relative faster pass-through for regulated plants. A spot market price change of IL Basin coal takes only 1 month to affect the procurement costs of regulated plants with a relatively large magnitude. This is in contrast to 5 months for deregulated plants.

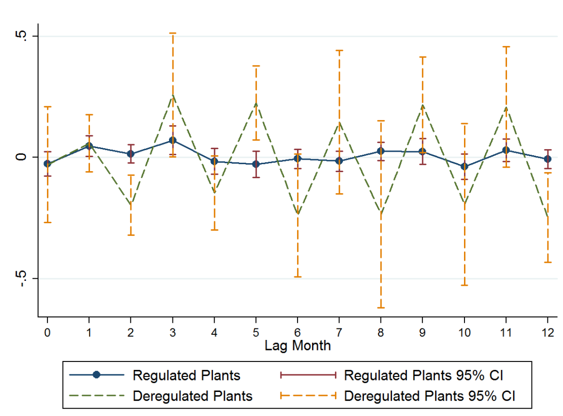
We then examine pass-through patterns of the 3 types of coal given different directions of market price shocks. Table C.4 in the Appendix shows the deviations of pass-through elasticities for negative shocks relative to positive ones. Figure 3.7 plots the mean pass-through elasticity coefficients and correspondent 95% confidence intervals against the lag month terms. For CAPP transactions, the pass-through



(a) PRB Coal Transactions



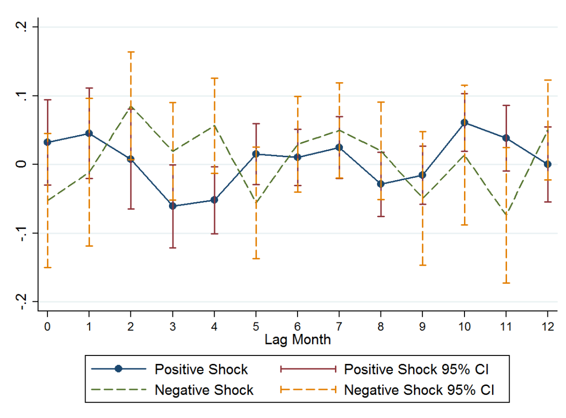
(b) CAPP Coal Transactions



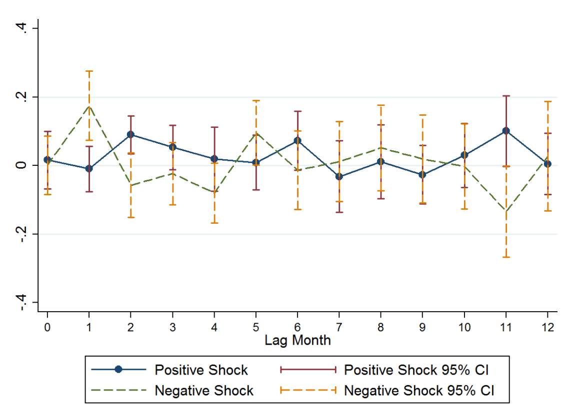
(c) IL Basin Coal Transactions

Figure 3.6: Pass-through Elasticity: Regulated vs. Deregulated

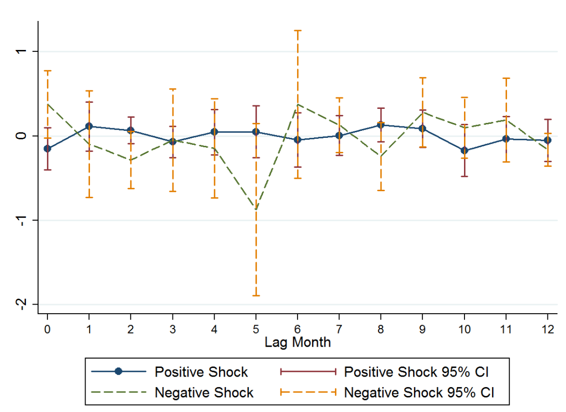
Note: deregulated plants are defined as divested ones of the independent power producers.



(a) PRB Coal Transactions



(b) CAPP Coal Transactions



(c) IL Basin Coal Transactions

Figure 3.7: Pass-through Elasticity: Positive vs. Negative Shocks

Note: a positive shock means an increase in the relevant spot market price.

under a spot price decrease is faster given the significantly larger response coefficient at the 1-month lag. In contrast, for PRB and Illinois Basin coal transactions, the pass-through patterns of an increase or a decrease in spot market price do not differ significantly from each other.

3.6 Conclusion

In this study, we seek to investigate a specific pass-through previous literature overlooks in energy markets: the changes in fossil fuel procurement prices for the U.S. power producers resulting from fluctuations in spot market prices. By quantitatively measuring the pass-through between different fossil fuels, we provide evidence that spot price changes of natural gas and oil quickly pass on to the procurement costs of power producers, while the procurement costs of coal only respond sluggishly.

Our findings have implications for the increasingly important role of natural gas generation in the U.S. electric power industry. First, given that the volatility of natural gas market prices can be quickly transmitted to procurement costs of power producers, they face increasing risks from upstream input markets and higher difficulty to plan business and hedge against market uncertainty. Second, it also sheds light on welfare distribution effects of dramatic fall of natural gas prices due to technology breakthrough of hydraulic fracturing. The relative fast and complete pass-through indicates a large part of welfare gains of cheap natural gas are able to quickly fall on power producers and the end consumers. Third, the market trend of more volatile electricity prices might also hurt low income households.

The results of our study also inform future studies in the electric power industry. The adjustment lag between fossil fuel spot prices and procurement receipt prices for power plants implies that spot prices do not always reflect the true opportunity costs of using the fuel. It has implications on how to apply the static model of measuring market power commonly used in the electricity market: when researchers construct regional supply curves, it might be appropriate to use relevant spot market prices to calculate the marginal costs of natural-gas-fired generators. For the marginal cost calculation of coal-fired generators, we should instead use observed coal receipt data from the E.I.A or other sources.

We also document evidence that under deregulation, the transmission from fossil fuel spot prices to procurement costs of power plants are faster. However, our findings are not causal since we observe no variation in regulatory status across time in our data. Our results are consistent with existing literature which finds that deregulated electric utility firms bargain to pay lower costs for fuel prices in that we find differences in pass-through between regulated and deregulated natural gas power plants.[18]

Our paper also indicates possible opportunities of future studies. One limitation of our study is not being able to identify the causal impact of various potential channels underlying the differences in pass-through under various scenarios. For the comparison between fossil fuels, although we indicate an anecdotal story of distinct contract terms in different fossil fuel markets, we do not specifically model how a specific market factor contribute to the disparities. For instance, an inventory model might be built and incorporated into empirical results. Also, for the comparison between regulatory status, our studies suggest opportunities for future studies to investigate specific channels behind deregulation that lead to the differences in the pass-through pattern.

[18] One possible conjecture is that faster natural gas pass-through was more profit maximizing over our study period.

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Appendix

Appendix A

Appendix A discusses one potential empirical concern associated with the exogeneity of treatment assignment in Chapter 1.

One trend that might bias the estimation is the changes in the transmission system in each region. A better transmission system helps to mitigate regional congestion, which theoretically leads to a more efficient allocation of production resources. If prior to the event window, two regions witnessed different trends in construction of transmission capacity, the empirical results of the study would be confounded. I exploit transmission infrastructure data from NERC's Electricity Supply and Demand (ES&D) dataset, which provides annual total mileage information on existing transmission lines with operating voltage of 151 kV or more since 1990 at the NERC-region level.[19] Specifically, the data records the total mileage of transmission lines for several ranges of operating voltage (KV) rating in each NERC region (and the subregions). Based on this, I calculate the total length for SPP and SERC, weighted by the mean operating voltage (KV) rating for the corresponding ranges.[20] The trends of total weighted existing transmission line mileage in SPP and SERC are shown in Figure A.1. The figure shows that both regions experienced minimum changes in transmission infrastructure prior to the treatment event window of year 2004.[21] I also check NERC's annual Long-term Reliability Assessment Reports (1995-2003), which provide future forecast of generation and reliability for the following 10 years based on plans submitted by power plants. According to the reports, prior to 2004 in SPP, "minimal additions of transmission facilities of regional significance were planned". Only one of them was scheduled to be in service before 2004,

[19] Each region in the study is also a NERC region. SERC changed its territory after NERC reassigned its member territories in 2005. In order to handle this problem, I exclude the newly added area of subregion "Gateway" and part of Kentucky in the "Central" subregion (which had transmission lines predominantly at an operating voltage rating of 345 kV) in SERC.

[20] For instance, a mile of transmission line in the operating voltage range of 600+ kV is normalized as a mile, while a mile in the operating voltage range of 200-299 kV is normalized to be 250/600=0.42 mile.

[21] The equivalent, yet opposite changes in the two regions in 1998 shown in Figure 12 are due to the fact that a certain part of SPP was re-assigned to SERC when the data was collected. Thus, the change does not imply an economically meaningful shift.

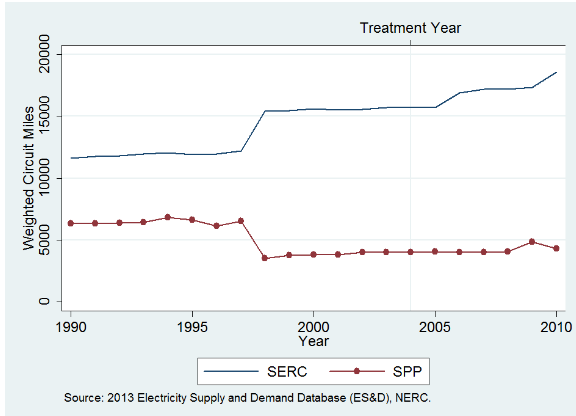

Figure A.1: Total Weighted Mileage of Existing Transmission Lines

Note: The graph is based on NERC's Electricity Supply and Demand (ES&D) database, which provides annual information on existing transmission line mileage since 1990 at the NERC-region level for different operating voltage ranges (151-199 kV, 200-299 kV, 300-399 kV, 400-599 kV and 600+ kV). I weight the mileage by the mean operating voltage (KV) rating for each range. For instance, a mile of transmission line in the operating voltage range of 600+ kV is normalized as a mile, while a mile in the operating voltage range of 200-299 kV is normalized to be 250/600=0.42 mile. Note that there are equivalent, yet opposite changes in the two regions in 1998. This is due to the fact that a certain part of SPP was re-assigned to SERC when the data was collected. Thus, the change does not imply an economically meaningful shift.

and other additions planned "primarily benefit local areas and have no significant impact on subregional or regional transfer capacity". All these moderate the concern that the potential efficiency gains might be brought about by pre-existing trends of transmission infrastructure in the control and treatment regions.

Appendix B

Appendix B contains descriptions on data sources exploited in Chapter 2.

Calculation of unit marginal costs requires information on unit production efficiency and generation capacity, and unit input cost. For the former two, I exploit hourly operational data at the boiler-level[22] on the following aspects: electricity generation, fuel usage and emissions[23] from EPA's Continuous Emission Monitoring System (CEMS) data. I use the hourly information to calculate the average "heat rate" (i.e., fuel input required per unit of output) and emission rate (i.e., emission emitted per unit of output) in year 2003 and 2005. As for the unit capacity, I treat the maximum generation of each unit during 2002-2008 as the correspondent unit capacity.

I take advantage of fuel receipt price data from FERC 423.[24] The data set includes monthly fossil-fuel receipts for utility power plants with a total capacity over 50 megawatts. Note that there might be multiple transactions of fuel purchase for a power plant. I calculate the weighted averages of fuel cost based on the volume of transactions for each month at a given plant. Then matching them with the unit "heat rate" data, I compute the unit marginal fuel costs on a monthly basis. Since the fuel receipt data is at the plant level, the implicit assumption is that units within the same plant employ fuel with negligible cost differences for a given month. I obtain the SO_2 permit prices from the BGC Partners,[25] which is a leading global brokerage company with a variety of products under service. It calculates daily permit prices based on private transactions made through the company. I assume that the data reflects price variations of transactions in the entire market and the same cost burden

[22] A boiler is a device that generates steam for power.

[23] I focus on SO_2 only as it is the only emission that burdens power producers in the SPP market with environmental costs.

[24] Fuel cost data for non-utilities is publicly unavailable for privacy purposes, which leads to missing data if utility generating assets were sold to non-utility firms. However, no divestiture occurred in the SPP market during the data window (See Cicala, 2015).

[25] I am grateful to Jacob LaRiviere and J. Scott Holladay for sharing the data.

of emission for all plants. I argue that this assumption is relative reasonable since arbitrage should eliminate the price differences across regions.

I also take advantage of the hourly unit information to apply the test on firms' generation-withholding behaviors.

In the SPP market, wholesale electricity transactions are realized through decentralized bilateral contracts, which makes the market prices publicly unavailable. Instead, I exploit system lambda data from FERC 714 form, which indicates the marginal cost of hourly production within a power control area, to proximate the actual wholesale prices in the the SPP. In a restructured market where centralized wholesale market design is established such as that in California, the System Lambda would simply be the market prices.[26]

Due to transmission constraints, electricity prices varies from location to location. To deal with the problem, typically restructured markets use a nodal pricing system, where each node is a point where energy is supplied, demanded, or transmitted. Following the previously literature, I obtain a single price for the market by calculating the load-based average of all power control areas for a given hour. I match generating units into correspondent power control areas based on information from EPA eGrid data. Then I aggregate hourly total fossil fuel generation in each power control area and calculate hourly averages of system lambdas weighted by fossil-fuel generation in each power control area, which are used as the proxies for the actual bilateral contract electricity prices. For power control areas where system lambda is missing from the data, I substitute it by the cost of the marginal unit (that is the most costly online) within that area in that hour.

[26]A centralized market assigns the rights to supply based on bids made by firms, aggregates the offers to sell and buy and determines market-clearing prices.

Appendix C

Appendix C includes tables of regression results in Chapter 3.

Table C.1 shows β_{kf} and γ_{kf} for k up to 6 in Equation 3.3. Specification (1) report the pass-through coefficients for coal and natural gas without adding the dummy of deregulation status. Specification (2) and (3) report the coefficients of the interaction terms with the regulatory dummy, which indicate the deviation of pass-through for divested plants relative to the regulated counterparts. In specification (3), we add the owner fixed effects to allow for distinct trends of changes in fossil fuel procurement costs at each owner firm.

Table C.2 shows β_{kf} and δ_{kf} for k up to 6 in Equation 3.4. Specification (1) report the pass-through coefficients for coal, natural gas and oil without adding the dummy for a negative market shock. Specification (2) and (3) report the coefficients of the interaction with the dummy. In specification (3), we add the owner fixed effects to allow for distinct trends of changes in fossil fuel procurement costs at each owner firm.

Table C.3 shows the deviation of pass-through elasticities for deregulated plants relative to the regulated counterparts for transactions of 3 types of coal.

Table C.4 shows the deviations of pass-through elasticities for negative shocks relative to positive ones for transactions of 3 types of coal.

Table C.1: Regression Results: Regulated versus Deregulated

	(1)	(2)	(3)
Coal × L0	0.0235***	0.0243***	0.0221**
Coal × Dereg × L0		-0.000961	0.000502
NG × L0	0.589***	0.501***	0.501***
NG × Dereg × L0		0.195***	0.195***
Coal × L1	0.0132	0.0170	0.0152
Coal × Dereg × L1		-0.0233	-0.0218
NG × L1	0.277***	0.326***	0.325***
NG × Dereg × L1		-0.100***	-0.0995***
Coal × L2	0.0174	0.0121	0.0109
Coal × Dereg × L2		0.0257	0.0268
NG × L2	-0.0424***	-0.0630***	-0.0637***
NG × Dereg × L2		0.0465***	0.0473***
Coal × L3	0.0375***	0.0411***	0.0401***
Coal × Dereg × L3		-0.0193	-0.0185
NG × L3	0.0122*	0.0114	0.0110
NG × Dereg × L3		-0.00861	-0.00794
Coal × L4	-0.00642	-0.00705	-0.00788
Coal × Dereg × L4		0.00607	0.00688
NG × L4	-0.00820	0.00925	0.00893
NG × Dereg × L4		-0.0399***	-0.0395***
Coal × L5	-0.00693	-0.00477	-0.00564
Coal × Dereg × L5		-0.0106	-0.00967
NG × L5	-0.0143**	-0.00121	-0.00148
NG × Dereg × L5		-0.0241*	-0.0238*
Coal × L6	-0.00463	-0.00201	-0.00265
Coal × Dereg × L6		-0.0162	-0.0156
NG × L6	0.0236***	0.00475	0.00434
NG × Dereg × L6		0.0420***	0.0423***
Observations	55756	55756	55756
Month FE	Yes	Yes	Yes
Owner FE	No	No	Yes
Adjusted R^2	0.218	0.225	0.221

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$

Table C.2: Regression Results: (+) versus (-) Shocks

	(1)	(2)	(3)
Coal × L0	0.0222**	0.0407*	0.0399*
Coal × Negative × L0		-0.0788**	-0.0760**
NG × L0	0.591***	0.580***	0.580***
NG × Negative × L0		0.0113	0.0108
Oil × L0	0.627***	0.551***	0.547***
Oil × Negative × L0		0.266*	0.277*
Coal × L1	0.0138	-0.00164	-0.00388
Coal × Negative × L1		0.0672	0.0706*
NG × L1	0.279***	0.242***	0.242***
NG × Negative × L1		0.0786***	0.0780**
Oil × L1	0.120***	0.342***	0.337***
Oil × Negative × L1		-0.459**	-0.448**
Coal × L2	0.0189*	0.0456**	0.0446*
Coal × Negative × L2		-0.0630*	-0.0627*
NG × L2	-0.0411***	-0.0687***	-0.0685***
NG × Negative × L2		0.0589**	0.0584*
Oil × L2	-0.0157	0.0422	0.0380
Oil × Negative × L2		-0.0785	-0.0718
Coal × L3	0.0353***	0.0144	0.0144
Coal × Negative × L3		0.0394	0.0391
NG × L3	0.0119	0.0930***	0.0935***
NG × Negative × L3		-0.155***	-0.156***
Oil × L3	0.0144	-0.135**	-0.139**
Oil × Negative × L3		0.212*	0.216*
Coal × L4	-0.00453	-0.0170	-0.0171
Coal × Negative × L4		0.0210	0.0212
NG × L4	-0.0122*	-0.0115	-0.0112
NG × Negative × L4		0.00872	0.00819
Oil × L4	0.0851**	0.0618	0.0557
Oil × Negative × L4		0.0277	0.0343
Coal × L5	-0.00915	-0.00274	-0.00368
Coal × Negative × L5		-0.0132	-0.0107
NG × L5	-0.0143**	-0.0240	-0.0235
NG × Negative × L5		0.0146	0.0134
Oil × L5	-0.0428	-0.167***	-0.171***
Oil × Negative × L5		0.162*	0.165*
Coal × L6	-0.00277	0.0271	0.0258
Coal × Negative × L6		-0.0261	-0.0249
NG × L6	0.0225***	0.0167	0.0171
NG × Negative × L6		0.00657	0.00527
Oil × L6	0.0170	-0.0972*	-0.102*
Oil × Negative × L6		0.188*	0.192*
Observations	61598	53091	53091
Month FE	Yes	Yes	Yes
Owner FE	No	No	Yes
Adjusted R^2	0.208	0.216	0.212

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$

Table C.3: Regression Results: Regulated versus Deregulated for Coal Purchases

	(1)	(2)	(3)
PRB × L0	0.00692	0.00992	0.0101
PRB × Dereg × L0		-0.0140	-0.0127
CAPP × L0	0.0138	0.0209	0.0208
CAPP × Dereg × L0		-0.0404	-0.0406
IL × L0	-0.0274	-0.0251	-0.0261
IL × Dereg × L0		-0.00194	-0.00375
PRB × L1	0.00869	0.0124	0.0124
PRB × Dereg × L1		-0.0159	-0.0147
CAPP × L1	0.0612***	0.0536**	0.0532**
CAPP × Dereg × L1		0.0413	0.0411
IL × L1	0.0493**	0.0475**	0.0469**
IL × Dereg × L1		0.0146	0.0120
PRB × L2	0.0262	0.0224	0.0223
PRB × Dereg × L2		0.0174	0.0185
CAPP × L2	0.0364*	0.0275	0.0274
CAPP × Dereg × L2		0.0550	0.0536
IL × L2	0.00440	0.0146	0.0143
IL × Dereg × L2		-0.207***	-0.211***
PRB × L3	0.000360	0.00461	0.00450
PRB × Dereg × L3		-0.0209	-0.0198
CAPP × L3	0.0164	0.0106	0.0104
CAPP × Dereg × L3		0.0327	0.0330
IL × L3	0.0793***	0.0716**	0.0711**
IL × Dereg × L3		0.190	0.187
PRB × L4	-0.00160	-0.00156	-0.00163
PRB × Dereg × L4		0.000661	0.00199
CAPP × L4	-0.0256	-0.0229	-0.0232
CAPP × Dereg × L4		-0.0198	-0.0195
IL × L4	-0.0168	-0.0155	-0.0164
IL × Dereg × L4		-0.129	-0.130
PRB × L5	-0.0103	-0.0104	-0.0107
PRB × Dereg × L5		0.000531	0.00185
CAPP × L5	0.0203	0.0256	0.0257
CAPP × Dereg × L5		-0.0245	-0.0248
IL × L5	-0.0211	-0.0283	-0.0291
IL × Dereg × L5		0.255***	0.254***
PRB × L6	-0.00355	-0.00140	-0.00169
PRB × Dereg × L6		-0.0113	-0.0102
CAPP × L6	0.0176	0.0184	0.0186
CAPP × Dereg × L6		-0.00350	-0.00330
IL × L6	-0.0117	-0.00550	-0.00615
IL × Dereg × L6		-0.233*	-0.233*
Observations	22288	22288	22288
Month FE	Yes	Yes	Yes
Owner FE	No	No	Yes
Adjusted R^2	0.014	0.014	0.008

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$

Table C.4: Regression Results: (+) versus (-) Shocks for Coal Purchases

	(1)	(2)	(3)
PRB × L0	0.00692	0.0332	0.0321
PRB × Negative × L0		-0.0842	-0.0846
CAPP × L0	0.0138	0.00700	0.0160
CAPP × Negative × L0		-0.00664	-0.0146
IL × L0	-0.0274	-0.147	-0.151
IL × Negative × L0		0.544*	0.527*
PRB × L1	0.00869	0.0472	0.0453
PRB × Negative × L1		-0.0587	-0.0564
CAPP × L1	0.0612***	-0.0122	-0.00960
CAPP × Negative × L1		0.184***	0.185***
IL × L1	0.0493**	0.138	0.113
IL × Negative × L1		-0.246	-0.208
PRB × L2	0.0262	0.0102	0.00782
PRB × Negative × L2		0.0739	0.0777
CAPP × L2	0.0364*	0.0873***	0.0897***
CAPP × Negative × L2		-0.149**	-0.147**
IL × L2	0.00440	0.0640	0.0673
IL × Negative × L2		-0.314	-0.353
PRB × L3	0.000360	-0.0588*	-0.0608**
PRB × Negative × L3		0.0784	0.0800
CAPP × L3	0.0164	0.0506	0.0527
CAPP × Negative × L3		-0.0779	-0.0763
IL × L3	0.0793***	-0.0764	-0.0708
IL × Negative × L3		0.0825	0.0235
PRB × L4	-0.00160	-0.0499**	-0.0520**
PRB × Negative × L4		0.104**	0.109**
CAPP × L4	-0.0256	0.0197	0.0186
CAPP × Negative × L4		-0.101	-0.0985
IL × L4	-0.0168	0.0511	0.0457
IL × Negative × L4		-0.178	-0.192
PRB × L5	-0.0103	0.0164	0.0151
PRB × Negative × L5		-0.0720	-0.0708
CAPP × L5	0.0203	0.0103	0.00902
CAPP × Negative × L5		0.0828	0.0869
IL × L5	-0.0211	0.0495	0.0483
IL × Negative × L5		-0.946	-0.923
PRB × L6	-0.00355	0.0121	0.0102
PRB × Negative × L6		0.0152	0.0192
CAPP × L6	0.0176	0.0735*	0.0723*
CAPP × Negative × L6		-0.0834	-0.0857
IL × L6	-0.0117	-0.0640	-0.0478
IL × Negative × L6		0.482	0.424
Observations	22288	13781	13781
Month FE	Yes	Yes	Yes
Owner FE	No	No	Yes
Adjusted R^2	0.014	0.014	0.005

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$

Vita

Yin Chu was born in Zaozhuang, Shandong province in China on May 9th, 1987. He attended Shandong University for undergraduate study in 2005. In 2009, he graduated from Shandong University with a degree of Bachelor of Arts in Philosophy and second degree in Finance. After that, he was admitted by the Economics Department in the University of California, Santa Barbara for graduate study. In 2010, he graduated and earned a degree of Master of Arts in Economics. Then he started the doctoral study in Economics in the University of Tennessee, Knoxville. His projects is concentrated on the U.S. power industry and investigate topics such as causal impact of market reforms on market outcomes. He expects to graduate with a Doctor of Philosophy in Economics in July 2015.