Carbon Prices and Fuel Switching:

A Quasi-experiment in Electricity Markets

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Abstract

Within the Pennsylvania-New Jersey-Maryland (PJM) electricity market, Delaware and Maryland participate in the Regional Greenhouse Gas Initiative (RGGI) but other states do not, providing a quasi-experiment setting to study the effectiveness of the RGGI program. Using a difference-in-difference framework, we find that overall the RGGI program leads to 7.72 million short tons of CO_2 reduction per year in Delaware and Maryland, or about 34.36% of the average total annual emissions in these two states from 2009 to 2013. We find little evidence that utilities adjust their capacities within five years after program implementation except natural gas-only utilities. All utilities respond to the program by decreasing their heat input per capacity even including natural gas utilities. Counter-intuitively, the reduction is mainly achieved through reduction of coal and natural gas input and emission leakage instead of fuel switching from coal to natural gas or from fossil fuel (coal and natural gas) to non-fossil fuel. The results suggest that the power utilities do respond to the emission trading program with current carbon prices, but tremendous fuel switching did not occur before 2013 due to the program as it is less costly to leak the emissions under the regional regime.

Keywords: Carbon Emission Market, RGGI

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1 Introduction

The U.S. Electric power sector accounts for 2,122 million short tons of carbon dioxide (CO_2) emissions in 2015, or about 37% of the total U.S. energy-related CO_2 emissions. [1] To address the climate change issues, the power sector is critical. However, the power sector appears to have a limited option to reduce CO_2: phasing out coal power plants and replacing with cleaner plants, i.e. fuel switching in a general sense. It is far from easy, though, since emission reduction could force heavy economic burden on the existing fossil-duel power plants. Therefore, the Clean Power Plan, as the first-ever national standard to reduce CO_2 from power plants, has encountered very strong opposition since its announcement on August 3, 2015. [2] Understanding fuel switching for fossil-duel power plants is essential to the success of any future program targeting at reducing CO_2.

The Regional Greenhouse Gas Initiative (RGGI) is the first cooperative effort in the U.S. to reduce CO_2 emissions among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont, specifically in the electric power sector. [3] RGGI aims to stabilize and then reduce CO_2 emissions within the signatory states. Regulated sources of emissions are fossil fuel-fired power plants with a capacity of 25 MW or greater, located within the RGGI states. RGGI was formally initiated in 2003 and compliance started on January 1, 2009. [4] According to RGGI (2014), average

[1] EIA data: http://www.eia.gov/tools/faqs/faq.cfm?id=77&t=11.

[2] The U.S. Supreme Court granted a stay on the implementation of Clean Power Plan because of cases filed by more than two dozen states and numerous industry groups.

[3] Globally, the carbon emission trading market has been increasing in recent years. After the implementation of the European Union Emissions Trading Scheme (EU ETS), several domestic and regional initiatives emerged in developed and developing countries including the RGGI (Kossoy and Guigon, 2012). Currently, the United States has altogether three systems related to GHG emission trading: the RGGI, the California, Qubec and the Western Climate Initiative, and the Chicago Climate Exchange (CCX). The first two are mandatory schemes, while the CCX is operated on a voluntary base.Unlike traditional harmful pollutants explicitly regulated by the Clean Air Act (SO_2 and NO_x), CO_2 emissions are a new pollution source that raises many new questions. Reduction of CO_2 is regulated under section 111(d) of Clean Air Act which covers other unnamed potential pollutants. These pioneering programs can provide very helpful guidelines for the future carbon markets in the U.S.

[4] Every control period lasts three years, and, at the end of the third year of a control period, each regulated plant is required to hold one allowance for each ton of CO_2 emitted. Unused allowances do not expire and can be banked for future years. If a plant violates the rule, it needs to surrender a number of allowances equal to three times the number of its excess emissions.

CO_2 emissions from 2010-2012 in RGGI states decreased by 25.4%, compared with the average from 2006-2008. In addition, the CO_2 emission rate (pounds of CO_2 per megawatt hour) dropped by 16.7% during the same period. However, multiple factors could have triggered the emission decrease. Lower natural gas prices, decrease of demand or increase of renewable capacity could all lead to CO_2 emission reduction. This paper studies whether the RGGI program leads to the emission reduction.

There are five major ways for fossil-fuel power plants under the system of RGGI to reduce CO_2. The first one is switching to fuel with lower carbon content. [5] Changing from coal to natural gas, for instance, can reduces a power plant's carbon emissions by 40-60% per megawatt hour (Mwh) taking into consideration of efficiency loss (CCES, 2013). The second option is to switch from fossil fuel to non-fossil fuel. The third option is to improve energy efficiency during electricity generation. This would include using more efficient electrical appliances and improvement of technology (e.g. switching to a combined heat and power system). The fourth method is to sponsor CO_2 offset projects, including carbon capture and sequestration, emission reduction in the building and agriculture sector, etc. [6] The fifth method is to shift the production to non-RGGI areas. Consequently, it causes emission leakage. Among all these five methods, energy efficiency improvement and offset projects require much more technological advancement, therefore fuel switching and emission leakage are the main focus of this paper.

The RGGI program in the Pennsylvania-New Jersey-Maryland (PJM) electricity market provides a perfect quasi-experiment to study the fuel switching behavior. Within the PJM territory, Delaware and Maryland participate in the RGGI. Electric utilities from these two states form the treatment group in the quasi-experiment. [7] Ohio, Pennsylvania, Virginia and West Virginia, part of Illinois, Indiana, North Carolina and Kentucky are in the PJM

[5] Per million BTU of energy, coal emits around 215 pounds, oil emits 160 pounds and natural gas emits 117 pounds of CO_2.

[6] See http://www.rggi.org/market/offsets.

[7] An electric utility is the operating power generation unit, which can have multiple power plants and a power plant can have multiple generators.

market but do not participate in the RGGI. The electric utilities from these states are treated as the control group. Using a panel data from 2002-2013, we use a difference-in-difference (DID) framework to isolate the impact of the RGGI program.

Our empirical results show that the RGGI program leads to 7.72 million short tons of CO_2 reduction per year in Delaware and Maryland, or about 34.36% of the average total annual emissions in these two states from 2009 to 2013. Natural gas-only utilities increase 5.01% emissions of their own total emissions due to the program through long-term capacity investment, and decrease emissions by 42.26% through reducing short-term heat input per capacity (hereafter, called utilization rate). Coal-only utilities, natural gas capacities within the flexible utilities (with both natural gas and coal capacities) and coal capacities within the flexible utilities decrease CO_2 reduction by 20.34%, 27.14% and 38.69% of their own emissions due to the program respectively, all through reduction in utilization rate. The results suggest that the compliance strategies adopted by the flexible and non-flexible utilities are similar. We implement multiple robustness checks and confirm that our results hold under different specifications.

Another key concern we need to consider is emission leakage. Emission leakage refers to emissions shifting outside the jurisdictional area, driven by the enforced emission costs, which could be substantial and misleading when evaluating the effectiveness of carbon trading programs (Cullenward and Wara, 2014; Newell, Pizer, and Raimi, 2014). Interconnected grid network makes electricity transmission (import and/or export) possible between RGGI and adjacent areas. Potentially, it is possible that RGGI increases the import of electricity from non-RGGI areas. In this case, it would appear that emissions in the RGGI area are reduced, while national emissions stay the same or even increase. We consolidate the import data for Maryland and Delaware and find that the import did increase significantly after 2009. In addition, the power generation excluding natural gas and coal generation in Maryland and Delaware did not change after 2009. The results suggest that the reduction of coal input has not been replaced by non-fossil sources. Instead, it was covered by leaking the emissions to non-RGGI areas.

We compare our results to studies in the literature. Swinton (1998) estimates the shadow price of SO_2 emissions by modeling the joint production of electricity and sulfur dioxide. He finds that fuel-switching can also significantly reduce emissions in the short run. Linn, Mastrangelo, and Burtraw (2014) examine the operation of coal-fired generating units and find that a 10% increase in coal prices leads to a 0.2 to 0.5% decrease in heat rate. McKibbin, Morris, and Wilcoxen (2014) compare the effects of emission reduction programs imposed on the power sector only and economy-wide, and find that the power-sector-only approach requires a carbon price that is almost twice the economy-wide carbon price to achieve the same cumulative emission reduction. There is no clear evidence that pollution controls on the electric power sector will drive up CO_2 emissions outside this sector. Hitaj and Stocking (2014) find that the U.S. SO_2 allowance prices did not reflect marginal abatement costs in the early years after implementation. In terms of reduction reasons, Ellerman and Montero (1998) find that rail rates for shipping low-sulfur coal, rather than the 1990 Clean Air Act Amendments, are the principal reason why sulfur dioxide emissions by electric utilities declined from 1985 to 1993. Murray and Maniloff (2015) specifically examine the RGGI impact on CO_2 reduction and find that the emissions in the whole RGGI region would have been 24% higher without the program. Our study contributes to the literature by specifically estimating the fuel switching behavior to carbon price signals and examining how emissions are reduced at a micro-level. In addition, our studies trace the emission reduction back to individual utility level and take advantage of the quasi-experiment setting.

This paper also contributes to the literature on emission trading programs. A well-designed emission trading program has been learnt that it can effectively reduce air pollution (Joskow, Schmalensee, and Bailey, 1998; Stavins, 1998; Ellerman et al., 2000; Stavins, 2003; Sterner, 2003). Many studies examine these programs from different perspectives. For example, Bovenberg, Goulder, and Gurney (2005) examine the efficiency costs of choosing particular environmental permits and taxes. Rubin (1996) develops a framework for modeling emission trading, banking, and borrowing, and uses optimal control theory to derive optimal time paths for emissions by firms. Subramanian, Gupta, and Talbot (2007) characterize firms' compliance strategies under an emission cap and trade program with a three-stage model of structural decisions on abatement, permit auction, and production. Hart and Ahuja (1996) and Smale et al. (2006) examine the impact of emission regulations on firm performance. Joskow, Schmalensee, and Bailey (1998) evaluate the economic impacts of the RGGI on ten Northeast and Mid-Atlantic States and find that the program expenditures benefit the region's economy. Ruth et al. (2008) study the economic impact of participation in RGGI on the state of Maryland and find little net impact. Our paper examines the effectiveness of emission trading programs from the perspective of firm production decisions.

In addition to the literature on cap and trade program evaluation, our study also contributes to the literature investigating which factors can determine emissions. Vollebergh, Melenberg, and Dijkgraaf (2009) and Holtz-Eakin and Selden (1995) use country-level panel data to regress the amount of CO_2 or/and SO_2 emissions on variables such as income and per capita GDP. Auffhammer and Carson (2008) forecast China's CO_2 emissions using province-level data, and concluded that emissions in China are unlikely to decrease in the near future unless substantial changes in energy policies occur. Cole et al. (2013) explore the factors influencing firms' CO_2 emissions with firm-level data from Japan and found emissions among firms are spatially correlated. Our study takes the perspective of firm production and focuses on the input function and examines what factors determine CO_2 emissions.

The rest of the paper is organized as follows. Section 2 describes the methodology, followed by Section 3, which presents the data. Model results and robustness check are in Section 4 and 5. Section 6 presents the emission reduction quantification and Our conclusions are finally presented in Section 7.

2 Methodology

There are three fossil fuel types of utilities: coal, natural gas and Petroleum. Since petroleum is not frequently used and counts only a very small fraction of total heat generated from fossil fuel combustion, we hence focus on fuel switching between natural gas and coal among fossil fuel utilities. We define fuel switching between natural gas and coal as replacing coal heat input by natural gas. It can take multiple hypothetical forms. At the industry level, if natural gas utilities increase capacity and inputs, while coal utilities decrease capacity and inputs, the relative fuel inputs structure of the industry can change. It is also possible that more natural gas utilities enter the market and more coal utilities exit. At the utility level, a utility can directly increase their natural gas inputs relative to coal inputs in the short term. In the long term, they can invest more natural gas capacity. As different types of utilities have different forms of fuel switching, we divide the utilities into three excludable categories: 1) non-flexible always-staying utilities; 2) flexible always-staying utilities; and 3) entry and exit utilities. Entry and exit of utilities can alter the capacity structure in terms of fuel types. Those utilities who do not enter or exit the market are always-staying utilities. Among the always-staying utilities, we define flexible utilities as those having both coal and natural gas power plants. In fact, fuel switching can occur even at the generator level: some generators can use multiple types of fuel. [8] Non-flexible utilities are natural gas-only and coal-only utilities. [9] In the following, we analyze response to the RGGI program by each category separately.

For a non-flexible always-staying utility, its heat input can be written as:

$$I_{itx} = Z_{itx} * \frac{I_{itx}}{Z_{itx}} \quad for\ x = c, n \tag{1}$$

[8]See http://www.eia.gov/tools/faqs/faq.cfm?id=65&t=3. For a generator that can use both fuel types, we double count its capacity for natural gas capacity and coal capacity, but count only once for the total capacity.

[9]In our data, some utilities are non-flexible always-staying utilities in some years and flexible always-staying utilities in other years. We categorize them into flexible always-staying utilities.

in which I_{itx} is utility i's heat input at time t and Z is its capacity. The notation x indicates its fuel type. While $x = n$ indicates a natural gas utility, $x = c$ indicates a coal utility. Therefore, the change of heat input can be written as:

$$\begin{aligned} \triangle I_{itx} &= \triangle Z_{itx} * \frac{I_{itx}}{Z_{itx}} + Z_{itx} * \triangle \frac{I_{itx}}{Z_{itx}} \\ &= \triangle Z_{itx} * U_{itx} + Z_{itx} * \triangle U_{itx} \end{aligned} \tag{2}$$

Equation 2 states that the change of heat input can be decomposed into a long-term capacity adjustment $\triangle Z_{itx}$ and a change in the utilization rate U_{itx}. Later, we need to examine whether the RGGI program has led to changes in these two terms.

For a flexible always-staying utility, since it has both natural gas and coal power plants, a direct way is to treat its natural gas and coal capacities as two separate units and examine their capacity adjustment and heat input decisions separately. However, within one single utility, the decisions of capacity adjustment and input decisions of natural gas and coal are inter-correlated and not independent. Therefore, we write its inputs of natural gas and coal as the following:

$$\begin{cases} I_{itc} = (Z_{itn} + Z_{itc}) * \frac{Z_{itc}}{Z_{itn}+Z_{itc}} * \frac{I_{itc}}{Z_{itc}} \\ I_{itn} = (Z_{itn} + Z_{itc}) * \frac{Z_{itn}}{Z_{itn}+Z_{itc}} * \frac{I_{itn}}{Z_{itn}} \end{cases} \tag{3}$$

in which

$$Z_{itx}\% = \frac{Z_{itx}}{Z_{itc} + Z_{itn}} \qquad for \;\; x = c, n$$

Again, we call $\frac{I_{itc}}{Z_{itc}}$ as U_{itc}. Then we can write down the change of heat inputs as:

$$\begin{cases} \triangle I_{itc} = \triangle(Z_{itn} + Z_{itc}) * Z_{itc}\%U_{itc} + (Z_{itn} + Z_{itc}) * \triangle Z_{itc}\%U_{itc} + (Z_{itn} + Z_{itc}) * Z_{itc}\% \triangle U_{itc} \\ \triangle I_{itn} = \triangle(Z_{itn} + Z_{itc}) * Z_{itn}\%U_{itn} + (Z_{itn} + Z_{itc}) * \triangle Z_{itn}\%U_{itn} + (Z_{itn} + Z_{itc}) * Z_{itn}\% \triangle U_{itn} \end{cases} \tag{4}$$

Differently from coal-only and natural gas-only utilities, change of inputs can be decomposed to change of total capacity, percentange change of each fuel type of capacity and utilization rate. Using this method, we examine four key changes: $\triangle(Z_{itc} + Z_{itc})$, $\triangle Z_{itn}\%$, $\triangle U_{itc}$ and $\triangle U_{itn}$.

For entry and exit utilities, we also start with examining their capacity change. We find that their capacity change is a very small amount. We therefore ignore the impact of the RGGI program on this category of utilities.

As noted in the Introduction, we take the advantage of a quasi-experimental setting. Figure 1 describes the quasi-experiment. Currently, Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont participate in the RGGI. Within the PJM territory, Delaware and Maryland are regulated by the program. Utilities from these two states serve as the treatment group. Other states in the PJM market but not regulated by the RGGI that we include in our analysis are Ohio, Pennsylvania, Virginia and West Virginia, part of Illinois, Indiana, North Carolina and Kentucky. Utilities from these states serve as the control group. In other words, within the Pennsylvania-New Jersey-Maryland (PJM) market, power utilities in Maryland and Delaware have to purchase CO2 allowances after 2009 under RGGI, while utilities in other states are free to emit CO2. New Jersey is also in PJM, but they withdrew from the program at the end of year 2011. So we exclude New Jersey from our analysis.

With the quasi-experimental setting and panel data, we apply a simple DID method to isolate the impact of RGGI program on each category of utilites. For the non-flexible always-staying utilities, the corresponding reduced DID regression can be written as:

$$\begin{aligned} Y_{itx} =& \beta_0 + \beta_1 P_{itx} + \beta_2 P_{et} + \beta_3 trend_{year} + \beta_4 Demand_t + \beta_5 S_{it} \\ &+ \beta_6 After_{year} + \beta_7 After_{year} * RGGI_i + \alpha_i + \varepsilon_{it} \quad for \;\; x = c, n \end{aligned} \tag{5}$$

in which

$$Y_{itx} = Z_{itx} \;\; or \;\; U_{itx}$$

where Y_{itx} is the dependent variable and it could be Z_{itx} or U_{itx}. Z_{itx} is the capacity of natural gas or coal of i^{th} utility in time t and U_{itx} is the utilization rate. When estimating the capacity model, the data is yearly, and when estimating the utilization rate model, the data is monthly. So the time t is different for these two models. For the utilization rate model, monthly dummies from January to December are added to control for seasonal patterns. The term P_{itx} is fuel price across individual utility and time and P_{et} is electricity price at time t. The term $trend$ is the yearly time trend. We also include PJM area's total demand and regard it exogenous. With higher electricity demand, more natural gas plants need to be brought up online, to serve the peak demand along with the base load coal plants, thus increasing natural gas usage. The term α_i is the time-invariant individual utility fixed effect and S_{it} is time-variant characteristics of utilities including capacity, combined heat and power (CHP) availability and age. $After$ is a dummy variable, which equals to 1 for the years after 2009 and 0 otherwise. It captures any change before and after 2009 for the whole PJM area. Dummy of $RGGI$ captures regional differences of natural gas usage percentage. If the utility is located in the RGGI area, $RGGI$ is equal to 1, 0 otherwise. The term $After_{it} * RGGI_i$ is the treatment. After controlling for year 2009 and individual fixed effects, the coefficient, β_7, is expected to reflect the impact of the RGGI program on Y_{itx}.

For the flexible always-staying utilities, a few things need to be altered:

$$\begin{aligned} Y_{itx} =& \beta_0 + \beta_1 P_{itn} + \beta_2 P_{itc} + \beta_3 P_{et} + \beta_4 trend_{year} + \beta_5 Demand_t + \beta_6 S_{it} \\ &+ \beta_7 After_{year} + \beta_8 After_{year} * RGGI_i + \alpha_i + \varepsilon_{it} \quad for \;\; x = c, n \end{aligned} \tag{6}$$

in which

$$Y_{itx} = Z_{itc} + Z_{itc}, \;\; logit(Z_{itc}\%), \;\; U_{itc} \;\; or \;\; U_{itn}$$

The dependent variables are $Z_{itc} + Z_{itc}$, $logit(Z_{itc}\%)$, U_{itc} and U_{itn}. $Z_{itc} + Z_{itc}$ is the total capacity including natural gas and coal. $Z_{itc}\%$ is the percentage of capacity from natural gas. Since it is a percentage value ranging from 0 to 1, we use its logit transformation. U_{itc} and U_{itn} are the utilization rate of natural gas and coal, respectively. In Equation 6, we use both fuel prices p_{itn} and p_{itc} as the explanatory variables, which can be considered by a flexible utility simultaneously.

3 Data

Three major datasets are used. The first one is EIA 860, which collects generator-level information, including whether the generator has a co-fire function, its capacity, operation age, fuel type, whether it has a combined heat and power system, region, etc. The second dataset is EIA 923, which contains detailed electricity generation data, including heat content of fuels, quantity of fuels, prime mover, net generation, heat content/fuel cost by contract, contract type, contract expiration date, fuel cost, abatement expense and abatement investment for all pollution, etc. The third dataset is the Emissions & Generation Resource Integrated Database (eGRID), provided by the U.S. Environmental Protection Agency (EPA), which is the main data source on CO_2 emissions. Plant identification information from PJM's website is used to match PJM plants with the above three datasets.[10] We also acquire state-level fuel costs, demand and generation from EIA's Electric Power Monthly issues.[11] The data consist of 196 fossil fuel electric facilities from 124 utilities operating in the PJM area over the 144-month period from 2002-2013, for a total of 14940 observations.[12] Because of entry and exit, not every utility appears in all the 144 months. The average number of observations per utility is 120.5.

Table 1 reports summary statistics of variables used in regressions and data sources. Fuel prices are averaged over monthly transactions, thus vary across utilities and time. If a utility's fuel prices are missing, we replace them with the monthly average state fuel prices reported in EIA's Electric Power Monthly issues. Figure 2 plots the average monthly natural gas price and coal price. Comparing to coal, natural gas has a much higher price per unit

[10] See http://www.pjm.com/documents/reports/eia-reports.aspx.

[11] See http://www.eia.gov/electricity/monthly/.

[12] If an utility has plants in multiple states, we treat them as separate utilities, as they face distinct state-level regulation policies.

of heat input, about three times as expensive as coal on average. Our data also show that coal is the dominant fossil fuel in this industry: heat input by coal is about 9 times as high as heat input by natural gas. This is due to the reason that coal plants are often used to serve base load and operate almost constantly. The average coal capacity is only 240 MW more than the natural gas capacity, indicating a significant potential for fuel switching even without new investment. We weight the age of generators from the same utility by capacity to get a utility's weighted age, and the average is 20 years. For the utilities we include in our sample, the RGGI regulated areas are Delaware and Maryland, which encompasses 11.49% of the total electricity generation by natural gas and coal.

The CO_2 auction related information is shown in Figure 3. The top panel plots the quarterly auction prices for CO_2 from the end of 2008 to 2015 (two years later than our analysis). The bottom panel compares the offered and actually sold auction volumes. The flat price from 2010 to 2013 is the reserve price as the supply of volumes is greater than the demand.

Figure 4 plots the total annual heat input for RGGI and non-RGGI areas. Each column contain natural gas-only, coal-only, natural gas of flexible and coal of flexible utilities. The figure shows that RGGI and non-RGGI regions have similar patterns. Natural gas inputs increase for all types and areas over time, while coal inputs decrease except that coal from RGGI coal-only utilities increase before 2008 and then decrease after 2008. Figure 5 shows the corresponding capacity. Coal-only utilities show stable capacity before 2012, but have a relatively huge decrease in 2013 for both RGGI and non-RGGI area. Coal capacity from flexible utilities decreases significantly after 2012. Natural gas capacity show a increase over years for both RGGI and non-RGGI areas. We furthermore show the pattern of utilization rate in Figure 6. We present the average monthly utilization rate over individual utilities. The coal utilization rate is much higher than the natural gas utilization rate for all areas. For the non-RGGI areas, the utilization rate of natural gas has an increasing pattern and coal has a decreasing pattern. The RGGI area has more noise as it has fewer number of utilities, so the pattern is less clear. We will rely on the DID setting to compare RGGI and non-RGGI regions and estimate if the RGGI region has extra fuel switching due to the RGGI program.

4 Estimation Results: the Baseline Model

As we state above, the non-flexible and flexible always-staying utilities can adjust their own capacity and utilization rate, which changes the the fuel structure of the industry. Entry of new natural gas utilities and exit of old coal utilities can also change the structure. For each category, adjusting utilization rate is regarded as a short-term change, while capacity adjustment by investing in natural gas plants and divesting in coal plants is a long-term change. In the following, we divide electricity utilities into three exclusive categories and evaluate their fuel switching behavior separately.

Non-flexible Always-staying Utilities

We first examine the factors that can influence the long-term fuel-switching behavior of non-flexible always utilities. As seen from our data, natural gas power plants are newly built and coal plants are retired. According to American Electric Power (AEP), "Simple cycle natural gas plants are typically constructed in 18 to 30 months and combined cycle natural gas plants are constructed in about 36 months. These lead times are significantly less than the average for solid fuel plants (i.e. coal plants), about 72 months."[13] As natural gas power plants require multiple years to construct, the capacity adjustment cannot occur instantaneously. Therefore, we estimate lag models by forwarding capacity two years or three years. Two years might be the minimum year that the capacity can respond to the emission market. Coal plants require even longer time to construct. Retiring a coal plant also takes a very long time as it has to be planned ahead for electricity reliability concerns and approved by regulatory commissions (NACAA, 2015). Our data time frame is not long

[13] See https://www.aep.com/about/IssuesAndPositions/Generation/Technologies/NaturalGas.aspx.

enough, so we assume that the coal capacity is not able to be adjusted due to the RGGI program for simplicity.

Table 2 reports the results for the natural gas capacity adjustment model using yearly data. The dependent variable for the first two columns is two-year lead capacity. In Column (1), many variables are insignificant, but the coefficient for the treatment effect $After*RGGI$ is positive and significant at 1% level. Column (2) and Column (1) are identical except that it replaces the DID variable $After * RGGI$ with the weighted yearly CO_2 allowance price from transactions recorded by RGGI. For observations of utilities located in non-RGGI area and year before 2009, we set the CO_2 allowance price to be 0. Compared with Column (1), all other variables are quite similar and the coefficient of CO_2 price also positive and significant. The third and fourth columns report the same two models but with three-year lead capacity as the dependent variable. Column (3) also shows that the RGGI program can increase the natural gas capacity for the natural gas-only always-staying utilities three years later. The CO_2 price in Column (4), again, shows a positive and significant effect. Therefore, the natural gas-only always-staying utilities respond to the program by increasing their capacity more than non-RGGI corresponding utilities. We use the three-year lag model as the baseline result. Note that for all the models, we add time-invariant fixed effect to control for unobserved heterogeneity.

In the short-term, utilities can adjust their heat inputs per capacity (utilization rate). Table 3 reports the results for both natural gas-only and coal-only utilities using monthly data. For natural gas-only utilities, the fuel price variable is natural gas price, while for coal-only utilities, it is coal price. Again, Column (2) and (4) are identical to Column (1) and (3), respectively, except replacing dummy variables $After * RGGI$ with CO_2 price.

For natural gas-only models, the coefficient for fuel price is negative and significant as expected, suggesting that a higher fuel price decreases inputs. A higher electricity price also increases heat input. Larger utilities (those with higher capacity) have a higher utilization rate than smaller utilities. From year to year, the utilization rate has an increasing trend.

We also include monthly dummies and find a significant seasonal pattern: the utilization rate is higher from May to September and December when temperature is high or low.

We are particularly interested in the variables that are policy relevant. The variable $After$ captures any change before and after 2009 for all areas. Column (1) shows that there is a statistically insignificant decrease from pre-2009 to post-2009 controlling other factors. The coefficients of $After * RGGI$ and CO_2 price are the DID estimates of RGGI's impact on regulated utilities located in Delaware and Maryland. They are negative and statistically significant for both models, suggesting that the RGGI program does decrease the natural gas-only utilities' utilization rate, surprisingly. There are two possible explanations. One is that there is an emission leakage problem that RGGI utilities shift the production to non-RGGI utilities. The other is that more non-fossil fuel replaces the fossil fuel in the RGGI area.

For coal-only models, the signs for many coefficients are similar to the results of the natural gas-only models. The seasonal pattern of coal use is similar that there are a much higher utilization rate in summer and winter. The coefficients of $After * RGGI$ and CO_2 prices are both significant, suggesting that coal-only utilities also decrease their utilization rate responding to the RGGI program.

Flexible Always-staying Utilities

From the above analysis, we find that the RGGI program increases natural gas capacity investment among natural gas-only always-staying utilities, which is a relatively longer-term adjustment. We also find short-term adjustment that both types of non-flexible utilities decrease their utilization rate. In this subsection, we investigate whether there is evidence of short-term or long-term fuel switching for flexible always-staying utilities. We first examine the total capacity and the percentage of natural gas capacity.

Table 4 reports the regression results using yearly data. We also estimate two-year and three-year lagged models. Columns (1) to (4) are for the total capacity and Column (5) to (8) are for the percentage of natural gas capacity. For the capacity percentage of natural gas, we take logit transformation of the dependent variable. In the table, again, Columns with even numbers replace the DID estimator $After * RGGI$ with weighted yearly CO_2 price. As shown in the table, the coefficients for $After * RGGI$ and CO_2 price are all insignificant, suggesting that the RGGI program does not induce flexible always-staying utilities to invest more on natural gas plants than before and other areas.

Although we find no significant change in total capacity and natural gas capacity percentage caused by RGGI, with the existence of the program, regulated utilities may use natural gas plants more often even with the same natural gas capacity. We hence examine the factors that influence the utilization of capacity. The regression results are shown in Table 5 using monthly data. The dependent variable is U_{itn} for Column (1) and (2), U_{itc} for Column (3) and (4). The results show that a lower natural gas price leads to more natural gas heat input per capacity. Coal heat input is not sensitive either coal or natural gas prices. Utilities with higher total capacity have a lower utilization rate in coal than those with lower total capacity. Higher monthly total demand in the PJM market leads to an insignificant change in usage of natural gas but increase in coal use. Again, there is a clear seasonal pattern. From June to September, natural gas plants are used more often than other months during a year. Coal plants are used more often in both winter and summer time. The coefficients for the treatment effects in four models are all significant, indicating that the RGGI program leads to a lower utilization rate of natural gas and coal, which is consistent to the response from natural gas-only and coal-only utilities. More specifically, one unit increase in the CO_2 allowance price causes the natural gas utilization rate to decrease by about 120 MMtbu/thousand MW, and causes the coal utilization rate to decrease by 423 MMtbu/thousand MW. Overall, we find that flexible utilities and non-flexible utilities have similar emission reduction strategies. They all tend to use the short-term method by reducing heat input. Only the natural gas-only utilities have been found also adjusting their capacity, which is a long-term method.

Entry and Exit of Utilities

The last fuel switching behavior between natural gas and fuel we intend to examine is through entry and exit of fossil fuel utilities. Coal utilities usually exit and natural gas utilities enter. In our data, there are altogether 124 utilities, 13 of them are located in Delaware and Maryland. During the sample period the exit at utility level is minimal: Only one utility located in Pennsylvania exited the market before 2009.[14] Among the 124 utilities, 9 entered after 2009, and only one of them is within the RGGI region. From 2009 to 2013, the entering capacity counts for 4.43% of the total capacity in the whole PJM area. Therefore, the RGGI policy impact on utilities' entry & exit decisions is minimal.

5 Robustness Check and Causality

The previous baseline models test whether the RGGI program is effective in inducing fuel switching and how utilities respond. In this section we apply multiple tests to check the robustness of previous results.

5.1 Specification Check

We first repeat all the previous analyses with logged dependent variables. Since the utilization rate could be equal to zero, we add 1 to the rate and then take the logarithm format. All the regression results are reported in Appendix A. We find that with logged format of dependent variables, all the results are robust to the specification except that the treatment effect becomes weakly significant for the natural gas utilization rate in the flexible utilities. We will discuss this more later.

5.2 Falsification Tests

Next we use falsification tests to check if our model specification produces spurious results. In the tests, we include only utilities in unregulated states (the control group in previous

[14]Moreover, it exited after year 2004, which was well before the proposition of RGGI.

analysis) in the PJM area, and then create "fake" treatment groups by randomly assign treatment to half of the sample. Under this scenario, the treatment effects are supposed to be zero. If the treatment effects for the "fake" treatment groups are different from 0, then our previous results are likely to be biased. Table 6 reports the results of falsification tests for the previous regression models with significant results. As shown in the table, the coefficients of $After * RGGI$ are all not statistically significant. The results show that since no significant impact of RGGI is found, it is a good sign that our significant results are not spurious.

5.3 Event Study-Style Model

In the previous DID framework, we have a single coefficient for treatment effect. It does not allow for heterogeneous effects varying before and after the policy year. In the following, we re-estimate event study-style models allowing for heterogeneous effects, following Greenstone and Hanna (2014). The new model can be written as:

$$\begin{aligned} Y_{itx} =& \beta_0 + \beta_1 P_{itx} + \beta_2 P_{et} + \beta_3 trend_{year} + \beta_4 Demand_t + \beta_5 S_{it} \\ &+ \sum_{year=1}^{T} d_{year} D_{year} + \sum_{year=1}^{T} \gamma_{year} D_{year} * RGGI_i + \alpha_i + \varepsilon_{it} \quad for\ \ x = c, n \end{aligned} \tag{7}$$

The difference between this framework and the previous one is that instead of using $After_{year}$, we use dummy variables for each year (D_{year}), and instead of using $After_{year} * RGGI_i$, we use $D_{year} * RGGI_i$. Therefore, there is a different coefficient each year for the effect. After obtaining the yearly effect, we test whether there is a break in the yearly effect due to the policy using the following model:

$$\gamma_{year} = r_0 + r_1 After_{year} + r_2 trend_{year} + r_3 After_{year} * trend_{year} + \zeta_{year} \tag{8}$$

Figure 7 presents the event study graphs of the yearly effect, γ_{year}, from estimating

Equation 7. Panel (a) to (d) show yearly effects on the utilization rate of natural gas-only utilities, coal-only utilities, flexible utilities-natural gas and flexible utilities-coal respectively. The year of policy year, 2009, is denoted by zero and marked with a vertical line in all panels. The Zero effect is noted by a horizontal line.

These figures visually reveal the possible pattern of the policy impact. Except the flexible utilities-natural gas, other utilities have a close to zero impact before policy year, suggesting that the impact on utilization rate in the RGGI area are similar to non-RGGI utilities. For the flexible utilities-natural gas, the impact does not start with zero, but with some negative value meaning that such RGGI utilities have a lower value before 2009 compared to non-RGGI utilities.

Among all utilities, flexible utilities-coal are more likely to have a clear break in the policy year just by visually examining the graph. More formal tests are reported in Table 7. Column (3) is the full model for Equation 8, while Column (1) only contains a dummy for $After$ and Column (2) allows for a dummy for $After$ and a time trend. The full model is more flexible and additionally allows for different trend after 2009. We list the results, again, by the order of natural gas-only utilities, coal-only utilities, flexible utilities-natural gas and flexible utilities-coal. The results show that if allowing for the maximum flexibility (Column (3)), natural gas utilities for both flexible and non-flexible utilities do not have a break in the policy year because both coefficients for $After$ and $After * t$ are not significant, suggesting that the RGGI policy impact is not significant. However, the tests for coal utilities show that there is a clear significant policy impact. Concerning that there are only 11 observations, the evidence is strong that coal utilities respond to the RGGI policy by reducing their utilization rate.

5.4 Pre-policy Effects

Although the RGGI program is effective on January 1, 2009, the history of the initiative goes back to 2003 when nine states start the discussion. Early in December of 2005, a

Memorandum of Understanding (MOU) is signed to implement the Regional Greenhouse Gas Initiative. Delaware signed it in December, 2005, joined by Maryland in 2007. Therefore, utilities in Delaware and Maryland were aware of their obligation before 2009. So it is possible for them to respond to the program before 2009. In order to understand the pre-policy effects, we restrict the year of observations to 2002-2008 only, and set 2006 to be the first year of agreement (the middle year for Delaware and Maryland) and rerun the basic analyses for policy impact on utilization rate.

Table 8 reports the results. Column (1) to (4) are models of utilization rate for natural gas-only utilities, coal-only utilities, flexible utilities-natural gas and flexible utilities-coal respectively. The results show that the policy announcement does not affect the natural gas-only utilities while affect others. Specifically, the announcement decreases the utilization rate for flexible utilities-natural gas by 203.73 MMtbu/thousand MW, which is lower than the policy implementation effect (323.90 MMtbu/thousand MW) but with the same direction. Opposite to the policy impact of implementation, the announcement increases the utilization rate for coal in both flexible and non-flexible utilities. This suggests that coal utilities are aware that they need to pay for CO_2 emission after 2009 and will reduce coal use after 2009, so they in fact increase coal use before 2009 and after announcement.

Such evidence of pre-policy effect raises an issue that the impact of policy implementation identified in the baseline model might be over-estimated for the coal utilities as they deliberately increased the coal use right before 2009. In the other hand, the estimation for flexible utilities-natural gas might be under-stated. Unfortunately, we are not able to isolate the bias, but just document the caveat here.

6 Emission Reduction

6.1 Emission Reduction and Fuel Switching

In the previous sections, we have examined how the RGGI could potentially induce the fuel switching behavior and conducted multiple robustness tests. However, only with regression results, we are not clear about the magnitude of emission reduction. In this section, we will calculate counterfactuals to quantify the emission reduction.

The counterfactual change can be calculated according to the regression results in Column (3) of Table 2, and Columns (1) and (3) of Table 3 and 5. In fact for the natural gas-only utilities, the RGGI program effectively increases the capacity by 38.88 MW on average three years later. The utilization rate decreases by 256.23 MMbtu/thousand MW for natural-gas only utilities, and 578.42 MMbtu/thousand MW for coal-only utilities. We can calculate the counterfactuals with and without policy according to Equation 2. For the flexible utilities, the program induces an average utility to decrease the natural gas utilization rate by 323.90 MMbtu/thousand MW, and decrease the coal utilization rate by 1291.24 MMbtu/thousand MW. Given the total fossil capacity ($Z_{itn} + Z_{itc}$) for a regulated flexible utility, we can calculate its change of fuel use using Equation 4. In the counterfactual scenario when there is no RGGI program, the treatment coefficient is set to zero.

The changes due to the RGGI program can be read from Table 9. It reports the annual heat input with and without the RGGI program in Delaware and Maryland. For the natural gas-only utilities, we consider the capacity adjustment after 2012 (three years after 2009) and consider the adjustment of utilization rate after 2009. The total natural gas heat input is 48.15 million MMBtu with policy for the period of 2009 to 2013, while if without policy the input increases by 17.94 million MMBtu. The capacity increase accounts for 2.41 million MMBtu increase in natural gas heat input, while the utilization rate adjustment accounts for 20.35 million MMBtu decrease in natural gas heat input. So overall the the RGGI program leads to 17.94 million MMBtu reduction in natural gas input, which is 37.26% of their total heat input. In contrast, the natural gas heat input of flexible always-staying utilities decreases by 49.30 million MMBtu over the period 2009 to 2013, which is 27.14% of their own total input. The coal heat input of coal-only utilities decreases by 37.05 million MMBtu from 2009 to 2013 in total, or about 20.34% of their total coal input, while the coal heat input of flexible utilities decreases by 285.40 million MMBtu which is 38.69% of their total coal input.

Given the information of heat input change, we can directly calculate the emission change. [15] Overall, the RGGI program leads to 7.72 million short tons of CO_2 reduction per year in Delaware and Maryland, which is about 34.36% of the average total annual emissions in these two states from 2009 to 2013. However, as discussed in the sections of "Specification Check" and "Event Study-style Model", models for natural gas are not as robust as coal models. To be conservative, if we only calculate the emission reduction through coal utilities only, the fuel switching under the RGGI program causes 6.93 million short tons of CO_2 reduction per year, or about 35.06% of the average total annual emissions.

Table 9 also reports the natural gas input rate change due to the program implementation. With the baseline model, the program implementation changes the rate from 21.68% to 22.98% on average between 2009 and 2013. If using the results from the event study-style model, the implementation increases the percentage from 17.96% to 22.98%. For both cases, natural gas heat input rate increases due to the program.

6.2 Replacement for Reduced Coal in RGGI

In Delaware and Maryland, we observe that coal heat input has decreased and natural gas input has increased, but the decreased coal input cannot be covered by the increased coal input. We then need to examine what replaced the gap left by coal reduction. One potential way is to increase the non-fossil fuel input within the RGGI area. The other way is simply to shift the production to non-RGGI areas. We use two tests to test these two hypotheses,

[15] In our data, the correlation between CO2 and heat input is 0.99.

which are reported in Table 10. In the first column, we regress the total power generation in each state of Delaware and Maryland excluding generation from natural gas and coal[16] on the $After$ dummy and other monthly dummies, and find that non-fossil fuel generation did not increase as the coefficient for $After$ is insignificant. In the second column, we first define the import of electricity of one state as total consumption minus total power generation by the utilities located in the state, and then regress the monthly import on the $After$ dummy and other monthly dummies. We find that the import increased significantly after 2009. This is, in fact, an evidence for the emission leakage problem. Two tests combined show that emission reduction in Delaware and Maryland due to the RGGI program is not achieved by replacing fossil fuel (natural gas and coal) by non-fossil, but by leaking emissions to non-RGGI areas. It reveals an important fact that leaking emissions to other non-RGGI areas is less costly than fuel switching.

7 Discussion and Conclusion

In this paper, we empirically test the role of fuel switching in a carbon emission market under the context of the RGGI program. Fuel switching between natural gas and coal includes long-term capacity adjustment and short-term input adjustment. We find statistical evidence that the RGGI program is effective in reducing emissions, but mainly through reduction of coal and natural gas inputs. We find that the program is responsible for 7.72 million short tons of CO_2 reduction under the program, which is 34.36% of the average total annual emissions in Delaware and Maryland from 2009 to 2013. We also find that flexible and non-flexible utilities have adopted similar reduction strategies. All utilities tend to decrease utilization rate, except natural gas-only utilities adopt longer-term method through increasing capacity additionally.

Our major findings are based on comparing treatment and control groups. We have applied separate DID analyses to different utility categories: natural-gas only and coal-only

[16] The power generation from petroleum is very small.

utilities and flexible utilities. The separate analyses help prevent the endogeneity issue of the RGGI program, i.e. states who are easier to fuel switch are more likely to join the RGGI program. For example, a state with a higher capacity rate of natural gas may be easier to reduce CO_2 emissions. As the treatment and control groups are in the same category in terms of fuel type, we face a less severe problem.

Although our results show that utilities do respond to the not very high CO_2 price in the emission trading program, we find that the RGGI program leads to neither fuel switching from coal to natural gas nor from fossil fuel to non-fossil fuel. Instead, emission leakage occurred. It reveals an important fact that under the CO_2 emission trading program, it is less costly to reduce CO_2 by leaking emissions to non-RGGI areas than using more non-fossil fuel or more natural gas. In the other words, the CO_2 emission trading program can provide incentives for emission reduction. However, under the current regional program, shifting emissions to other areas is, unfortunately, the first option. Therefore, we need to be conservative about the CO_2 emission reduction due to the emission trading program if the program becomes national in the future.

There are a few caveats to our analyses that should be noted. First, our model does not control for vertical arrangement. To hedge risk, power plants often sign long-term contracts with electricity retailers to supply electricity. Such a fixed commitment can affect industry structure (Wolak, 2000) and change producers' behavior (Fabra and Toro, 2005). Bushnell, Mansur, and Saravia (2008) emphasize the importance of accounting for the vertical arrangement in the electricity price equilibrium model. In addition, power plants also tend to sign long-term contracts with fuel suppliers (Jha, 2015). All these long-term contracts are constraints on power firms that are not taken into account in our model. Firm fixed effects may help alleviate the problem, however. Second, although we account for other types of pollutants in our profit maximization problem, we do not have sufficient information to isolate the empirical influence of regulations on other pollutants. Last but not least, the impact of the RGGI program may take a long time to fully emerge, and the equilibrium could change over time. Our results should be viewed as measuring the program's impact in the short run.

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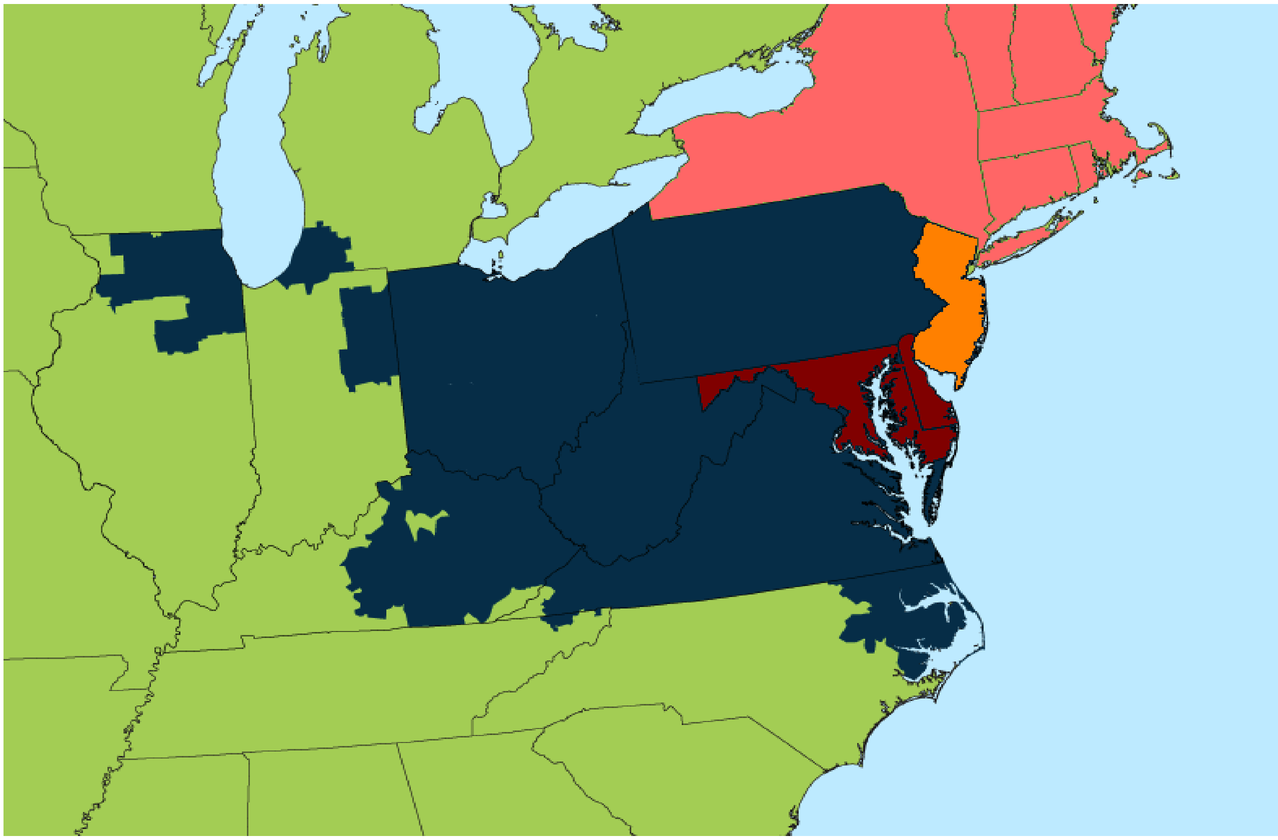
Figure 1: PJM territory served and RGGI



Note: Currently, Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont are in RGGI, in which Delaware and Maryland are in the PJM territory. Other states in PJM but not regulated by PJM that we include in our analysis are Ohio, Pennsylvania, Virginia and West Virginia, part of Illinois, Indiana, North Carolina and Kentucky.

Figure 2: Monthly Fuel Prices

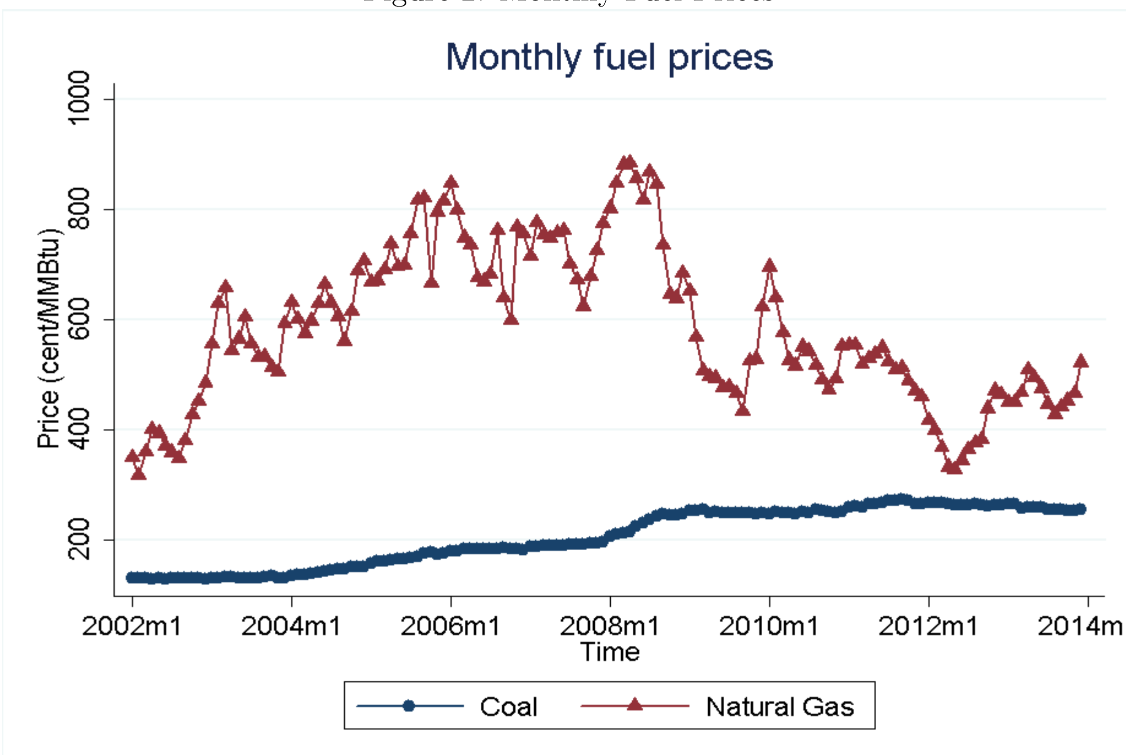


Figure 3: Carbon Prices

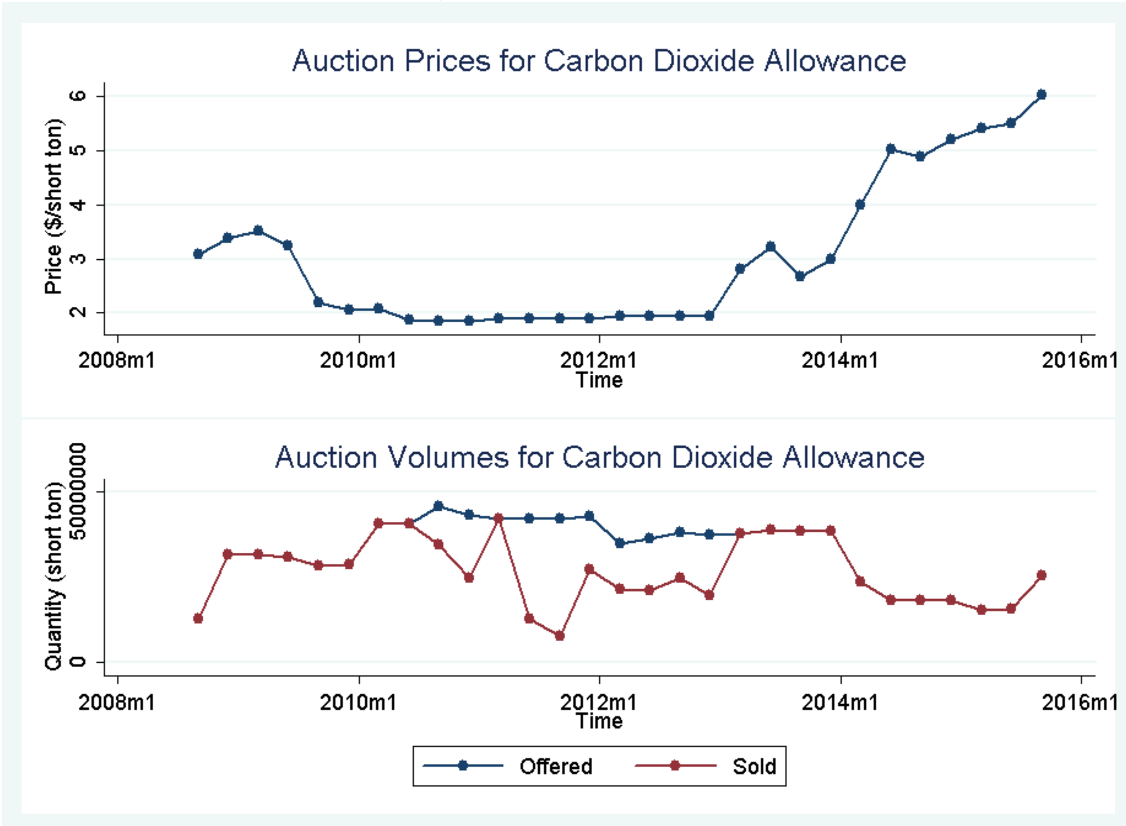
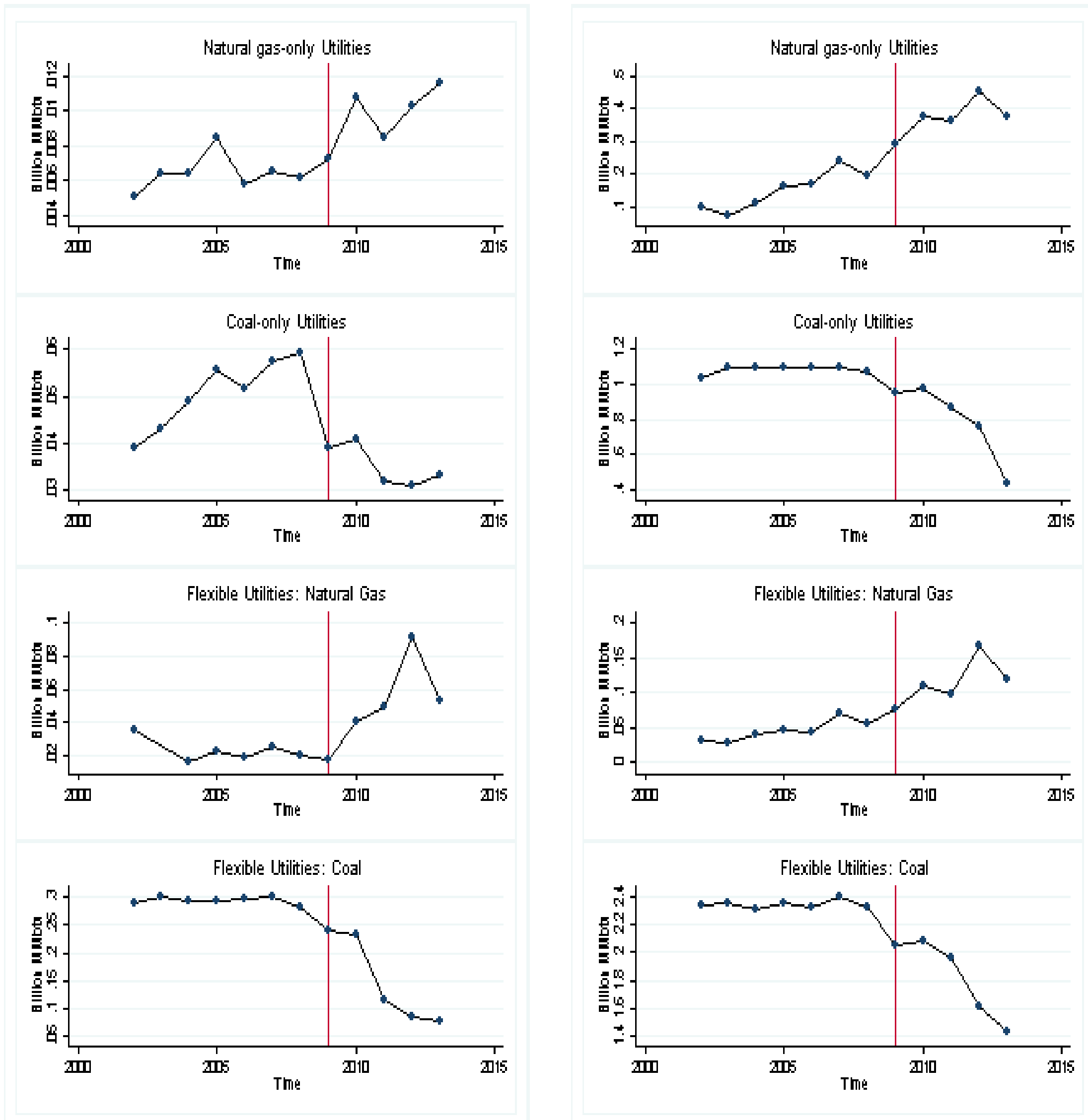


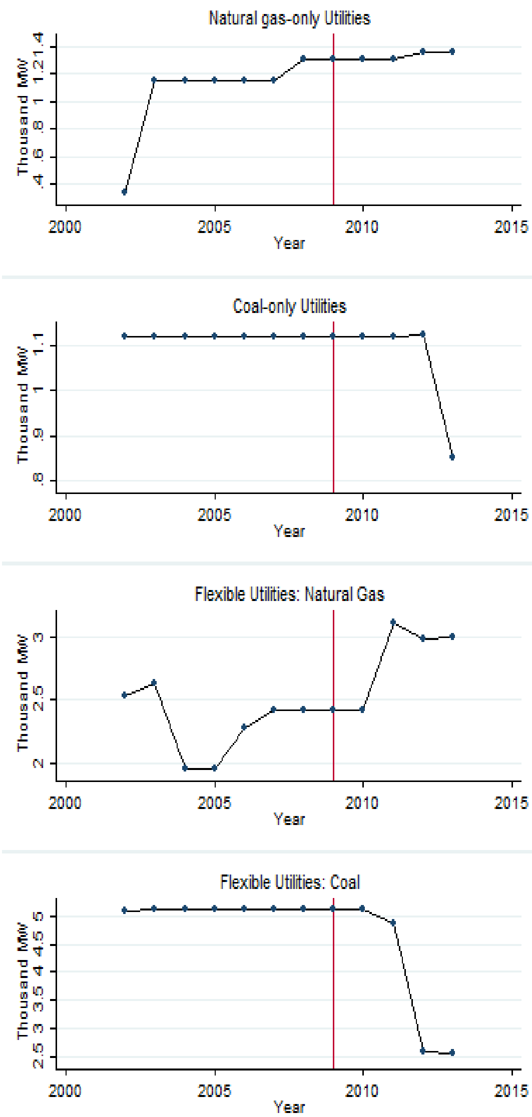
Figure 4: Total Annual Heat



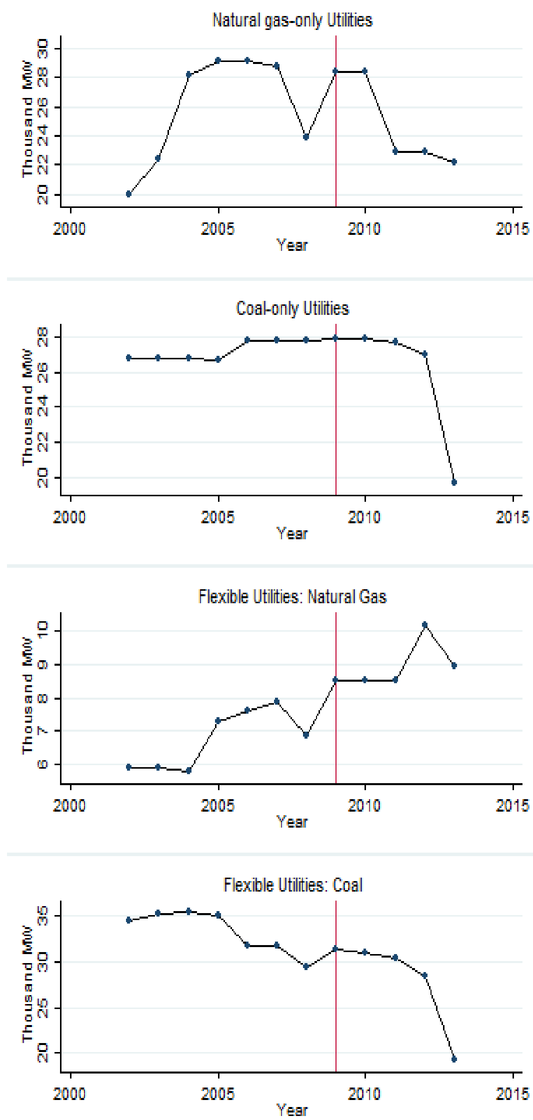
(a) RGGI

(b) Non-RGGI

Figure 5: Capacity

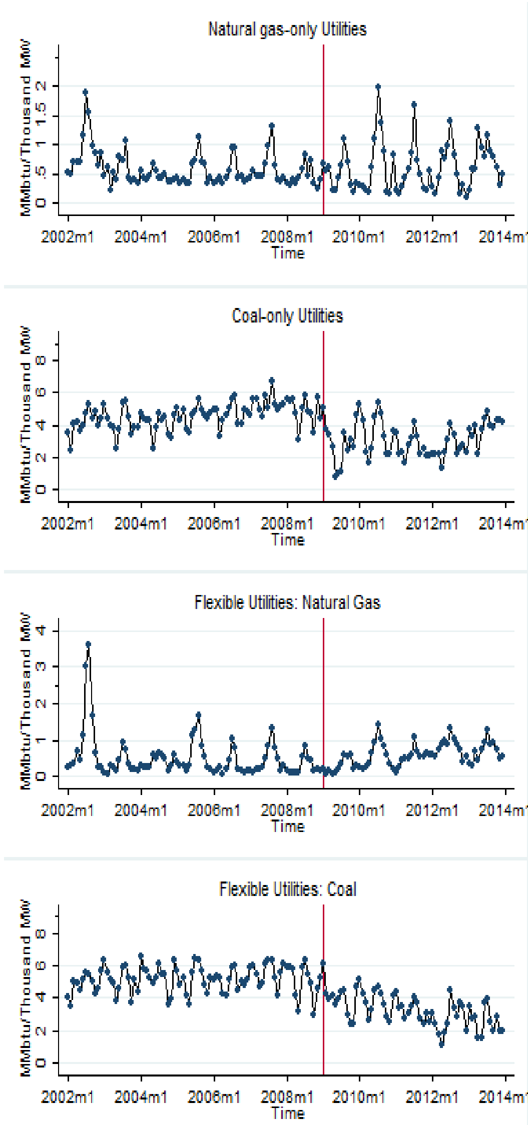


(a) RGGI

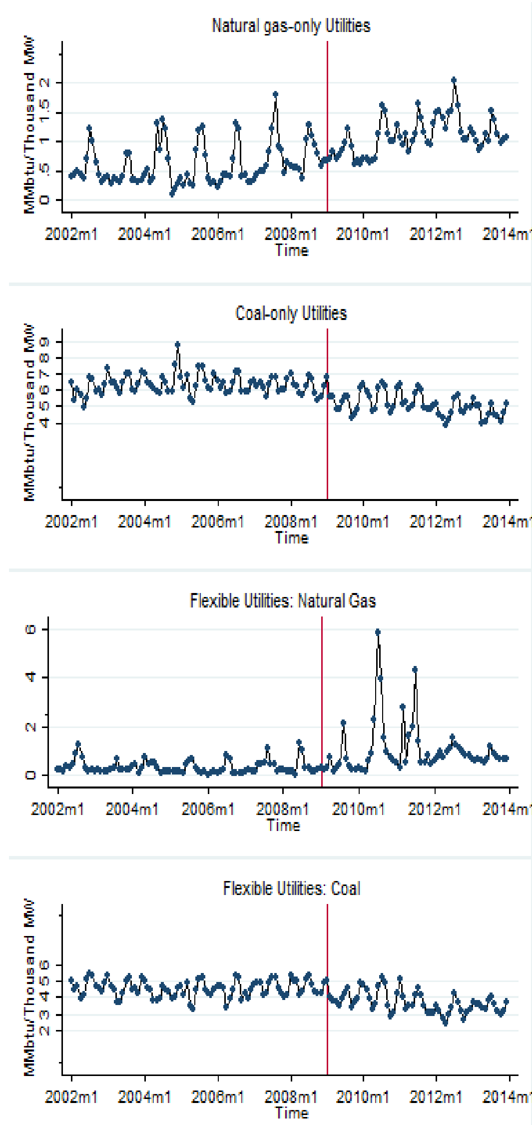


(b) Non-RGGI

Figure 6: Average Utilization Rate

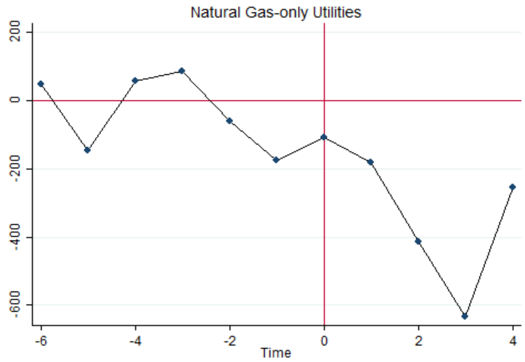


(a) RGGI

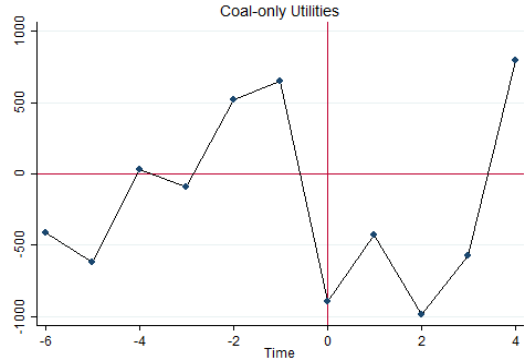


(b) Non-RGGI

Figure 7:



(a)



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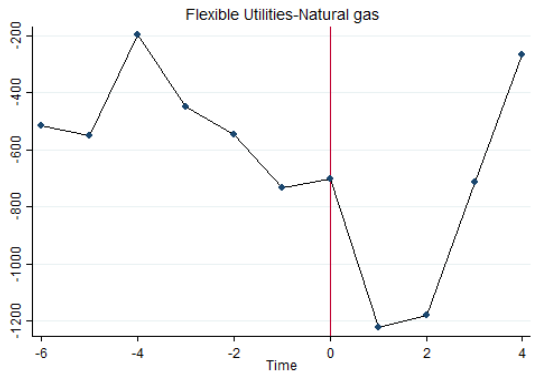
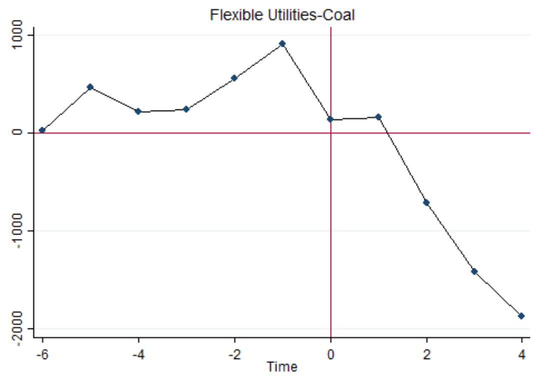


(c)



(d)

Table 1: Summary Statistics

Variables	Mean	Std. Dev.	Source
Natural gas price (¢/MMBtu)	630.23	247.61	EIA 923
Coal price (¢/MMBtu)	208.12	70.99	EIA 923
Heat input by coal (Million MMBtu)	2.76	5.70	EIA 923
Heat input by natural gas (Million MMBtu)	0.32	0.90	EIA 923
Dummy of CHP availability (%)	25.62		EIA 923
Dummy of after policy year 2009 (%)	42.17		EIA 923
Age (year)	20.44	14.49	EIA 860
Coal Capacity (MW)	628.70	1256.03	EIA 860
Natural gas Capacity (MW)	390.28	619.68	EIA 860
Ownership-Joint (%)	7.95		EIA 860
Ownership-Single (%)	74.78		EIA 860
Ownership-Other (%)	17.27		EIA 860
Dummy of within RGGI area (%)	11.48		EIA 860
PJM monthly load (Million MWh)	53.20	14.80	PJM
Delaware (%)	4.66		PJM
Illinois (%)	15.68		PJM
Indiana (%)	4.58		PJM
Kentucky (%)	1.93		PJM
Maryland (%)	6.83		PJM
North Carolina (%)	1.93		PJM
Ohio (%)	8.84		PJM
Pennsylvania (%)	37.17		PJM
Virginia (%)	10.60		PJM
West Virginia (%)	7.79		PJM

Table 2: Natural Gas-Only Utilities: Total Capacity

Variable	**Two-year lead Z_{itn}**		**Three-year lead Z_{itn}**	
	(1)	(2)	(3)	(4)
Natural gas price	0.087	0.086	0.042	0.041
	(0.061)	(0.061)	(0.047)	(0.047)
Electricity price	-1.487	-1.472	-0.831	-0.799
	(1.294)	(1.300)	(0.865)	(0.869)
After	2.478	2.672	-3.610	-3.160
	(21.191)	(21.221)	(15.124)	(15.098)
After*RGGI	43.137***		38.876***	
	(15.086)		(13.876)	
CO_2 price		15.780**		14.659**
		(6.977)		(5.756)
Trend	0.284	0.381	0.746	0.746
	(4.363)	(4.361)	(3.005)	(2.998)
CHP	20.710***	14.728**	16.755**	13.256**
	(7.992)	(7.403)	(6.985)	(6.051)
Age	-1.219*	-1.170*	-0.931	-0.909
	(0.700)	(0.694)	(0.631)	(0.627)
Ownership-Single	-17.793**	-17.204**	-12.619*	-12.296*
	(7.865)	(7.769)	(7.354)	(7.276)
Ownership-Other	-12.670	-11.913	-11.768	-11.405
	(9.369)	(9.270)	(8.005)	(7.889)
PJM annual load [a]	-0.246	-0.258	-0.294	-0.304
	(0.492)	(0.492)	(0.444)	(0.444)
Constant	1292.754***	1292.565***	1286.386***	1285.513***
	(60.926)	(60.879)	(46.375)	(46.233)
Utility fixed effects	Yes	Yes	Yes	Yes
R^2	0.9853	0.9853	0.9873	0.9873
Observations	421	421	379	379

[a] Coefficients are multiplied by 10^7.
Robust standard errors in parentheses. ***: $p < 1\%$, **: $p < 5\%$, *: $p < 10\%$.

Table 3: Natural Gas-Only and Coal-Only Utilities: Utilization Rate

Variable	**Natural gas-only** U_{itn}		**Coal-only** U_{itc}	
	(1)	(2)	(3)	(4)
Natural gas price	-1.014***	-1.014***		
	(0.087)	(0.087)		
Coal price			-3.412***	-3.545***
			(0.751)	(0.752)
Electricity price	12.647***	12.651***	20.858***	20.897***
	(1.429)	(1.431)	(2.105)	(2.105)
After	-16.068	-20.841	209.104**	210.613**
	(45.307)	(45.279)	(102.860)	(103.004)
After*RGGI	-256.228***		-578.418***	
	(52.137)		(135.512)	
CO_2 price		-83.997***		-213.408***
		(20.383)		(56.514)
Capacity	0.260***	0.250***	-5.781***	-5.795***
	(0.059)	(0.058)	(0.369)	(0.370)
Trend	44.710***	44.760***	-418.170***	-415.124***
	(10.198)	(10.197)	(44.848)	(44.942)
CHP	185.483	218.853	1900.774***	1894.540***
	(163.732)	(159.440)	(171.776)	(171.540)
Age	17.851***	17.957***	274.036***	271.664***
	(3.676)	(3.671)	(38.285)	(38.369)
Ownership-Single	69.618	74.183	-811.729***	-813.074***
	(56.206)	(55.401)	(152.208)	(152.210)
Ownership-Other	-67.944	-63.901	-1297.950***	-1293.342***
	(81.643)	(81.060)	(178.775)	(178.729)
PJM monthly load [a]	-4.810***	-4.840***	20.100***	20.200***
	(1.860)	(1.860)	(3.750)	(3.750)
Feb.	-39.740	-39.101	-507.743***	-505.268***
	(45.712)	(45.771)	(84.844)	(84.924)
Mar.	-11.749	-11.492	-379.041***	-377.299***
	(44.627)	(44.678)	(93.006)	(93.088)
Apr.	-78.585	-77.968	-839.121***	-835.974***
	(49.224)	(49.259)	(99.679)	(99.755)
May.	78.553	79.175	-1009.563***	-1006.760***
	(60.389)	(60.392)	(102.342)	(102.327)
Jun.	220.159***	220.476***	-694.894***	-694.223***
	(46.049)	(46.075)	(94.085)	(94.080)
Jul.	560.257***	560.750***	-286.148***	-286.315***
	(71.386)	(71.403)	(85.263)	(85.247)
Aug.	529.754***	530.028***	-272.006***	-272.086***
	(62.006)	(62.020)	(90.735)	(90.806)
Sept.	162.528***	161.738***	-747.984***	-747.940***
	(43.380)	(43.411)	(94.161)	(94.231)
Oct.	8.283	7.680	-838.813***	-838.116***
	(45.409)	(45.451)	(99.598)	(99.660)
Nov.	-18.073	-16.863	-512.871***	-508.321***
	(45.809)	(45.847)	(101.640)	(101.708)
Dec.	120.940***	120.544***	-121.495	-121.976
	(44.781)	(44.824)	(103.355)	(103.447)
Constant	539.705***	549.781***	2018.082***	2054.572***
	(195.720)	(195.307)	(600.673)	(602.289)
Utility fixed effects	Yes	Yes	Yes	Yes
R^2	0.6036	0.6034	0.6605	0.6604
Observations	6240	6240	5364	5364

[a] Coefficients are multiplied by 10^6.
Robust standard errors in parentheses. ***: $p < 1\%$, **: $p < 5\%$, *: $p < 10\%$.

Table 4: Flexible Utilities: Total Capacity and Natural Gas Capacity Percentage

Variable	$Z_{itn} + Z_{itc}$				**logit**$(Z_{itn}\%)$			
	Two-year lead		Three-year lead		Two-year lead		Three-year lead	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Natural gas price [a]	-8.340	-8.530	7.780	-7.364	-0.002	-0.000	-0.003	-0.004
	(6.010)	(6.080)	(6.100)	(6.132)	(0.041)	(0.041)	(0.036)	(0.036)
Coal price	2.567	2.014	5.507*	5.295*	0.004	0.006	0.003	0.004
	(2.749)	(2.784)	(2.782)	(2.744)	(0.011)	(0.011)	(0.009)	(0.010)
Electricity price	17.241	18.089	4.542	3.438	-0.040	-0.045	0.057	0.061
	(15.239)	(15.464)	(13.536)	(13.649)	(0.067)	(0.067)	(0.065)	(0.065)
After	347.934	324.417	-372.760	-393.224	-1.069	-0.954	1.820	1.907
	(379.153)	(383.439)	(342.877)	(342.424)	(1.766)	(1.772)	(1.564)	(1.567)
After*RGGI	-362.780		-459.759		0.673		1.821	
	(298.353)		(376.320)		(1.280)		(1.558)	
CO_2 price		-94.387		-166.902		0.070		0.653
		(117.520)		(152.865)		(0.502)		(0.635)
Capacity [b]					0.007	0.008	-0.461	-0.465
					(0.585)	(0.584)	(0.577)	(0.577)
t	-60.784	-55.535	-30.941	-27.545	0.739	0.716	0.255	0.241
	(101.830)	(102.573)	(83.710)	(83.851)	(0.525)	(0.525)	(0.440)	(0.442)
CHP	223.594	188.782	234.752	222.422	1.622*	1.739*	1.820*	1.871*
	(161.188)	(150.647)	(179.168)	(175.633)	(0.971)	(0.981)	(0.981)	(0.970)
Age	-61.818**	-59.855**	-49.584**	-49.010**	-0.235	-0.241	-0.182	-0.185
	(28.145)	(27.820)	(22.839)	(22.608)	(0.147)	(0.147)	(0.118)	(0.118)
Ownership-Single	-478.658	-465.856	290.180	294.601	-2.942*	-2.987*	-2.985*	-3.007*
	(626.057)	(626.548)	(322.451)	(322.564)	(1.695)	(1.703)	(1.598)	(1.594)
Ownership-Other	-827.349	-801.592	69.451	77.312	-3.130	-3.213	-3.682*	-3.720*
	(725.976)	(723.795)	(300.860)	(296.499)	(2.143)	(2.156)	(1.931)	(1.935)
PJM annual load [c]	186.000	169.000	145.000	173.000	1.300	1.450	-0.092	-0.197
	(866.000)	(875.000)	(811.000)	(817.000)	(4.340)	(4.340)	(4.010)	(4.000)
Constant	7829.006***	7860.583***	6870.464***	6913.343***	11.094	10.943	7.390	7.250
	(2022.899)	(2024.064)	(1198.228)	(1195.583)	(11.697)	(11.685)	(9.837)	(9.880)
Utility fixed effects	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
R^2	0.9370	0.9366	0.9443	0.9441	0.7360	0.7355	0.7786	0.7779
Observations	163	163	147	147	163	163	147	147

[a] Coefficients are multiplied by 10.
[b] Coefficients are multiplied by 10^3.
[c] Coefficients are multiplied by 10^9.
Robust standard errors in parentheses. ***: $p < 1\%$, **: $p < 5\%$, *: $p < 10\%$.

Table 5: Flexible Utilities: Natural Gas and Coal Utilization Rate

Variable	U_{itn}		U_{itc}	
	(1)	(2)	(3)	(4)
Natural gas price	-0.783***	-0.770***	-0.148	-0.135
	(0.145)	(0.144)	(0.197)	(0.200)
Coal price	0.184	-0.041	0.250	-0.887
	(0.449)	(0.423)	(0.874)	(0.870)
Electricity price	14.628***	14.616***	22.983***	23.545***
	(4.274)	(4.294)	(3.367)	(3.417)
After	569.424***	568.477***	649.493***	610.896***
	(211.988)	(209.851)	(147.779)	(149.534)
After*RGGI	-323.897***		-1291.242***	
	(94.290)		(136.905)	
CO_2 price		-119.942***		-422.861***
		(31.510)		(60.233)
Capacity	-0.056	-0.055	-0.339***	-0.335***
	(0.041)	(0.041)	(0.050)	(0.051)
t	37.330	40.325*	-348.802***	-333.831***
	(25.036)	(24.401)	(36.559)	(36.490)
CHP	80.346	71.126	-902.782***	-971.068***
	(71.658)	(70.802)	(135.293)	(140.889)
Age	-76.025***	-76.054***	27.677	26.887
	(6.777)	(6.809)	(18.445)	(18.359)
Ownership-Single	256.398***	257.702***	239.336*	249.856*
	(85.801)	(86.179)	(131.959)	(132.637)
Ownership-Other	166.013*	172.303*	480.604***	531.963***
	(92.374)	(91.364)	(171.700)	(172.318)
PJM monthly load [a]	-0.001	-0.001	0.017***	0.017***
	(0.003)	(0.003)	(0.005)	(0.005)
Feb.	-15.172	-10.838	-297.028**	-280.721**
	(51.745)	(51.811)	(135.168)	(136.856)
Mar.	112.258	115.546	-342.326**	-328.719**
	(96.748)	(97.070)	(143.835)	(145.242)
Apr.	63.978	69.473	-859.920***	-837.603***
	(60.202)	(60.533)	(146.024)	(148.394)
May.	153.410**	159.125**	-896.442***	-872.332***
	(70.883)	(71.344)	(137.427)	(138.854)
Jun.	272.021***	275.713***	-444.492***	-432.488***
	(93.874)	(93.927)	(131.756)	(133.480)
Jul.	590.324***	595.351***	-217.770	-205.818
	(188.126)	(188.544)	(138.535)	(140.661)
Aug.	484.206***	488.432***	-295.183**	-284.113**
	(144.380)	(144.598)	(135.747)	(137.424)
Sept.	214.095***	214.136***	-603.077***	-600.031***
	(64.974)	(64.974)	(128.189)	(129.553)
Oct.	126.073**	126.516**	-853.334***	-847.067***
	(58.641)	(58.657)	(137.790)	(138.561)
Nov.	109.359*	117.663*	-708.855***	-673.701***
	(61.051)	(61.981)	(135.867)	(137.275)
Dec.	72.715	72.627	-418.524***	-414.514***
	(49.773)	(49.756)	(144.282)	(145.375)
Constant	2482.944***	2526.304***	2932.554***	3166.971***
	(279.526)	(284.185)	(1036.922)	(1031.896)
Utility fixed effects	Yes	Yes	Yes	Yes
R^2	0.1801	0.1801	0.6172	0.6134
Observations	2376	2376	2376	2376

[a] Coefficients are multiplied by 10^3.
Robust standard errors in parentheses. ***: $p < 1\%$, **: $p < 5\%$, *: $p < 10\%$.

Table 6: Falsification Tests: Random Treatment

	Natural gas-only		Coal-only	Flexible-natural gas	Flexible-coal
Variable	**Three-year lead** Z_{itn}	U_{itn}	U_{itc}	U_{itn}	U_{itc}
	(1)	(2)	(3)	(4)	(5)
Natural gas price	0.049	-1.046***		-0.719**	-0.533**
	(0.062)	(0.094)		(0.298)	(0.242)
Coal price			-4.193***	3.089*	-2.914*
			(0.865)	(1.859)	(1.509)
Electricity price	-0.850	12.917***	20.048***	16.341***	20.171***
	(1.149)	(1.558)	(2.211)	(5.151)	(4.180)
After	1.152	-60.184	324.005***	548.609**	133.950
	(21.275)	(50.676)	(113.693)	(216.882)	(175.981)
After*RGGI	9.613	-2.703	-38.471	48.212	74.844
	(10.558)	(34.379)	(70.186)	(118.135)	(95.856)
Capacity		0.339***	-5.634***	-0.103**	-0.410***
		(0.060)	(0.387)	(0.052)	(0.042)
t	-0.781	56.199***	-438.178***	1.017	-238.176***
	(4.136)	(11.044)	(48.845)	(43.881)	(35.606)
CHP	26.656	588.679**	1878.771***	-377.040	-442.126**
	(16.346)	(272.946)	(171.852)	(247.242)	(200.615)
Age	-1.195	16.139***	285.549***	-73.213***	29.788***
	(0.809)	(3.759)	(41.319)	(13.186)	(10.699)
Ownership-Single	-15.020	104.406*	-818.577***	199.523	227.245
	(10.369)	(60.552)	(152.462)	(185.081)	(150.177)
Ownership-Other	-15.696	-32.750	-1267.488***	53.565	385.614*
	(11.907)	(84.825)	(179.270)	(262.088)	(212.662)
PJM load [a]	-6.590	-614.000***	2180.000***	-329.000	1370.000**
	(6.640)	(204.000)	(401.000)	(676.000)	(549.000)
Feb.		-49.693	-513.533***	-20.393	-295.746**
		(49.641)	(88.748)	(185.151)	(150.234)
Mar.		-18.597	-368.761***	130.409	-359.042**
		(48.611)	(96.440)	(185.548)	(150.556)
Apr.		-107.690**	-830.267***	49.621	-899.192***
		(53.020)	(105.398)	(193.923)	(157.351)
May.		66.038	-991.679***	147.974	-826.576***
		(65.789)	(107.905)	(187.278)	(151.960)
Jun.		213.757***	-712.164***	263.373	-422.208***
		(49.883)	(99.256)	(183.561)	(148.943)
Jul.		569.332***	-304.771***	601.445***	-198.154
		(77.573)	(88.275)	(195.993)	(159.031)
Aug.		541.684***	-306.789***	449.173**	-257.456*
		(67.495)	(95.939)	(192.029)	(155.815)
Sept.		153.920***	-773.711***	154.954	-626.552***
		(47.154)	(99.418)	(184.959)	(150.078)
Oct.		3.519	-856.026***	94.245	-727.887***
		(49.280)	(104.604)	(186.441)	(151.280)
Nov.		-20.250	-518.579***	113.988	-686.264***
		(49.898)	(107.515)	(186.942)	(151.687)
Dec.		129.565***	-102.618	53.893	-337.826**
		(48.592)	(109.412)	(183.398)	(148.811)
Constant	1313.903***	533.555***	-1082.363	2009.734**	4930.363***
	(49.269)	(204.117)	(1071.766)	(830.980)	(674.267)
Utility fixed effects	Yes	Yes	Yes	Yes	Yes
R^2	0.9841	0.6028	0.6503	0.1616	0.6211
Observations	267	5688	4944	1668	1668

[a] Coefficients are multiplied by 10^8.
Robust standard errors in parentheses. ***: $p < 1\%$, **: $p < 5\%$, *: $p < 10\%$.

Table 7: Break Tests For Yearly Effects

Generating Utilities	(1)	(2)	(3)
Natural Gas Only Utilities			
After	-280.336**	-53.471	-45.579
	(102.679)	(118.890)	(113.697)
Trend		-42.539*	-25.236
		(22.742)	(22.622)
After*Trend			-53.154
			(66.487)
Constant	-28.935	-175.633*	-115.961
	(46.423)	(79.453)	(86.673)
Coal Only Utilities			
After	-409.771	-1933.216***	-1942.225***
	(378.913)	(286.958)	(330.957)
Trend		273.466***	245.821***
		(67.377)	(47.247)
After*Trend			80.522
			(173.017)
Constant	2.446	972.268***	874.229***
	(205.322)	(228.994)	(140.207)
Flexible Utilities- Natural Gas			
After	-250.348	-354.653	-383.146
	(179.598)	(301.934)	(338.584)
Trend		18.601	-37.170
		(50.188)	(35.093)
After*Trend			162.720
			(114.475)
Constant	-498.233***	-432.935*	-628.715***
	(70.612)	(216.270)	(129.856)
Flexible Utilities- Coal			
After	-1054.226**	-462.933	-485.917
	(419.054)	(891.236)	(306.703)
Trend		-110.300	132.006**
		(148.970)	(46.446)
After*Trend			-688.427***
			(88.998)
Constant	397.250***	10.394	860.236***
	(121.438)	(589.792)	(180.232)
Observations	11	11	11

Table 8: Pre-policy: 2002-2008 with 2006 as Policy Year

	Natural gas-only	**Coal-only**	**Flexible-natural gas**	**Flexible-coal**
Variable	U_{itn}	U_{itc}	U_{itn}	U_{itc}
	(1)	(2)	(3)	(4)
Natural gas price	-0.728***		-0.317***	-0.956***
	(0.088)		(0.087)	(0.217)
Coal price		-2.955***	0.170	-1.023
		(1.020)	(0.465)	(1.156)
Electricity price	11.923***	9.755***	8.784***	22.351***
	(2.008)	(2.625)	(1.552)	(3.860)
After	-11.319	128.883	199.752***	170.273
	(55.512)	(111.303)	(54.814)	(136.307)
After*RGGI	-46.536	507.539***	-203.725***	334.954**
	(46.234)	(153.034)	(53.105)	(132.056)
Capacity	-0.002	-2.884**	0.029	-0.912***
	(0.065)	(1.464)	(0.023)	(0.057)
t	29.138	-687.693***	-73.706***	-25.237
	(22.094)	(192.946)	(23.376)	(58.129)
CHP	1376.381***	97.690	-325.109***	-118.300
	(472.727)	(241.311)	(65.967)	(164.040)
Age	-1.630	661.547***	-8.590	-122.630***
	(4.562)	(184.019)	(6.860)	(17.060)
Ownership-Single	-81.282	-976.745***	12.414	113.992
	(88.849)	(175.839)	(64.211)	(159.674)
Ownership-Other	-154.372	-530.122**	114.018	484.940*
	(125.880)	(216.744)	(103.953)	(258.502)
PJM monthly load [a]	-3.160*	11.900***	0.135	0.267
	(1.830)	(4.150)	(1.900)	(4.740)
Feb.	-29.910	-569.010***	-14.309	-389.564***
	(39.264)	(99.460)	(56.439)	(140.346)
Mar.	21.963	-340.512***	-15.753	-294.383**
	(37.888)	(107.848)	(56.366)	(140.165)
Apr.	-3.639	-777.326***	18.189	-1127.569***
	(44.056)	(113.960)	(57.772)	(143.661)
May.	167.015**	-1102.642***	75.060	-1124.148***
	(75.503)	(123.461)	(56.482)	(140.454)
June.	308.231***	-691.955***	180.808***	-498.417***
	(50.643)	(116.605)	(56.783)	(141.203)
Jul.	639.443***	-16.945	316.349***	-77.462
	(97.129)	(97.148)	(60.999)	(151.687)
Aug.	639.326***	-71.307	354.647***	-213.593
	(88.306)	(112.337)	(61.677)	(153.372)
Sept.	255.102***	-682.962***	162.387***	-599.323***
	(40.206)	(110.041)	(56.184)	(139.715)
Oct.	105.529***	-824.244***	49.573	-905.544***
	(40.655)	(115.013)	(56.180)	(139.702)
Nov.	4.347	-504.556***	18.439	-786.092***
	(39.121)	(125.790)	(56.313)	(140.034)
Dec.	96.232**	69.726	12.167	-238.162*
	(38.008)	(137.273)	(57.091)	(141.969)
Constant	288.692	-420.756	-568.945	14635.215***
	(257.025)	(2454.871)	(425.820)	(1058.892)
Utility fixed effects	Yes	Yes	Yes	Yes
R^2	0.5871	0.6522	0.3666	0.6193
Observations	3660	3192	1404	1404

[a] Coefficients are multiplied by 10^6.
Robust standard errors in parentheses. ***: $p < 1\%$, **: $p < 5\%$, *: $p < 10\%$.

Table 9: Emission Reduction in RGGI Area : 2009-2013

Generating Utilities	2009	2010	2011	2012	2013	Total
Natural Gas Only Utilities						
With policy	7.18	10.74	8.41	10.22	11.60	48.15
Without policy change-capacity				-1.06	-1.35	-2.41
Without policy change-utilization	+4.01	+4.01	+4.01	+4.16	+4.16	+20.35
Without policy change-overall	+4.01	+4.01	+4.01	+3.10	+2.81	+17.94
Emission Change (Thousand Short Tons)	-234.59	-234.59	-234.59	-181.35	-164.39	-1049.49
Coal Only Utilities						
With policy	40.61	43.84	32.78	31.94	33.00	182.17
Without policy change	+7.78	+7.78	+7.78	+7.81	+5.90	+37.05
Emission Change (Thousand Short Tons)	-836.35	-836.35	-836.35	-839.58	-634.25	-3982.88
Flexible Utilities- Natural Gas						
With policy	12.73	26.55	40.69	57.17	44.49	181.63
Without policy change	+9.39	+9.39	+12.10	+11.59	+11.66	+54.13
Emission Change (Thousand Short Tons)	-549.32	-549.32	-707.85	-678.02	-682.11	-3166.61
Flexible Utilities- Coal						
With policy	236.76	229.35	112.83	82.37	76.34	737.65
Without policy change	+79.06	+79.06	+75.16	+40.07	+39.79	+313.04
Emission Change (Thousand Short Tons)	-8498.95	-8498.95	-8079.70	-4307.53	-4277.43	-33651.80
Natural gas heat input percentage	2009	2010	2011	2012	2013	Average
With policy	6.70%	12.01%	25.22%	37.09%	33.91%	22.98%
The Baseline Model						
Change due to policy	-1.64%	-0.36%	+2.80%	+3.27%	+2.45%	+1.30%
The Event Study-style Model						
Change due to policy	+1.42%	+2.46%	+7.10%	+7.27%	+6.89%	+5.03%

Table 10: Replacement for Reduced Coal in RGGI

	Power generation excluding natural gas and coal generation	Import
After	-123.149	271.944***
	(90.760)	(86.874)
Feb.	-253.000	145.417
	(221.579)	(222.333)
Mar.	-281.125	40.667
	(220.430)	(216.970)
Apr.	-177.042	-175.292
	(231.389)	(187.569)
May.	-138.458	-163.333
	(238.934)	(191.830)
Jun.	-134.500	-107.542
	(237.374)	(205.081)
Jul.	-101.167	-26.458
	(236.800)	(217.922)
Aug.	-99.042	63.208
	(239.598)	(224.491)
Sept.	-175.875	1.833
	(233.212)	(196.509)
Oct.	-116.542	-223.958
	(236.427)	(185.742)
Nov.	-172.500	-187.417
	(236.093)	(183.007)
Dec.	-41.708	-63.333
	(250.801)	(205.305)
Constant	1008.687***	917.648***
	(181.951)	(149.208)
R_2	0.0165	0.0637
Observations	288	288

Appendix A

Table A1: Natural Gas-Only Utilities: Total Capacity

Variable	Two-year lead $\log(Z_{itn})$		Three-year lead $\log(Z_{itn})$	
	(1)	(2)	(3)	(4)
Natural gas price [a]	0.131	0.123	0.098	0.086
	(0.115)	(0.114)	(0.098)	(0.097)
Electricity price	-0.003	-0.003	-0.002	-0.001
	(0.003)	(0.003)	(0.002)	(0.002)
After	-0.048	-0.048	-0.007	-0.004
	(0.054)	(0.055)	(0.045)	(0.045)
After*RGGI	0.381***		0.371***	
	(0.130)		(0.129)	
CO_2 price		0.143**		0.145***
		(0.060)		(0.054)
Trend [b]	0.104	0.113	-0.001	-0.003
	(0.113)	(0.115)	(0.098)	(0.096)
CHP	0.157*	0.107	0.107	0.076
	(0.093)	(0.072)	(0.089)	(0.068)
Age	-0.003	-0.002	-0.001	-0.001
	(0.002)	(0.002)	(0.001)	(0.001)
Ownership-Single	-0.038**	-0.033*	-0.022	-0.019
	(0.019)	(0.018)	(0.016)	(0.016)
Ownership-Other	-0.031	-0.025	-0.023	-0.020
	(0.021)	(0.021)	(0.017)	(0.017)
PJM annual load [c]	-0.029	-0.041	0.041	0.030
	(0.128)	(0.127)	(0.116)	(0.116)
Constant	7.198***	7.190***	7.139***	7.131***
	(0.071)	(0.071)	(0.067)	(0.067)
Utility fixed effects	Yes	Yes	Yes	Yes
R^2	0.9848	0.9844	0.9856	0.9855
Observations	421	421	379	379

[a] Coefficients are multiplied by 10^3.
[b] Coefficients are multiplied by 10.
[c] Coefficients are multiplied by 10^9.
Robust standard errors in parentheses. ***: $p < 1\%$, **: $p < 5\%$, *: $p < 10\%$.

Table A2: Natural Gas-Only and Coal-Only Utilities: Utilization Rate

Variable	**Natural gas-only log(U_{itn})**		**Coal-only log(U_{itc})**	
	(1)	(2)	(3)	(4)
Natural gas price	-0.002***	-0.002***		
	(0.000)	(0.000)		
Coal price			-0.000	-0.001
			(0.001)	(0.001)
Electricity price	0.029***	0.029***	0.011***	0.011***
	(0.003)	(0.003)	(0.001)	(0.001)
After	0.026	0.022	0.255***	0.257***
	(0.113)	(0.112)	(0.068)	(0.068)
After*RGGI	-0.574***		-0.813***	
	(0.133)		(0.166)	
CO_2 price		-0.217***		-0.298***
		(0.051)		(0.067)
Capacity	-0.001***	-0.001***	-0.001***	-0.001***
	(0.000)	(0.000)	(0.000)	(0.000)
Trend	0.000	0.000	-0.075***	-0.070**
	(0.026)	(0.026)	(0.029)	(0.029)
CHP	0.655**	0.705***	0.678***	0.669***
	(0.263)	(0.255)	(0.139)	(0.138)
Age	0.040***	0.040***	-0.050*	-0.053**
	(0.014)	(0.014)	(0.026)	(0.027)
Ownership-Single	0.041	0.047	-0.466***	-0.468***
	(0.236)	(0.235)	(0.120)	(0.120)
Ownership-Other	-0.474*	-0.468*	-0.259**	-0.253**
	(0.275)	(0.275)	(0.116)	(0.116)
PJM monthly load [a]	13.200***	13.100***	9.760***	9.930***
	(4.240)	(4.240)	(2.180)	(2.180)
Feb.	-0.030	-0.028	-0.076	-0.072
	(0.125)	(0.125)	(0.046)	(0.047)
Mar.	0.157	0.158	-0.128**	-0.126**
	(0.124)	(0.124)	(0.055)	(0.056)
Apr.	0.409***	0.411***	-0.226***	-0.222***
	(0.130)	(0.130)	(0.064)	(0.064)
May.	0.949***	0.950***	-0.310***	-0.306***
	(0.122)	(0.122)	(0.069)	(0.069)
Jun.	1.513***	1.514***	-0.248***	-0.247***
	(0.115)	(0.115)	(0.062)	(0.062)
Jul.	1.716***	1.719***	-0.158***	-0.158***
	(0.124)	(0.124)	(0.045)	(0.045)
Aug.	1.847***	1.849***	-0.154***	-0.154***
	(0.117)	(0.117)	(0.050)	(0.050)
Sept.	1.218***	1.216***	-0.226***	-0.226***
	(0.117)	(0.117)	(0.059)	(0.059)
Oct.	0.442***	0.440***	-0.351***	-0.350***
	(0.122)	(0.122)	(0.074)	(0.074)
Nov.	0.133	0.136	-0.228***	-0.221***
	(0.122)	(0.122)	(0.066)	(0.066)
Dec.	0.213*	0.211*	-0.186***	-0.187***
	(0.122)	(0.122)	(0.065)	(0.065)
Constant	4.034***	4.044***	8.481***	8.532***
	(0.623)	(0.623)	(0.442)	(0.447)
Utility fixed effects	Yes	Yes	Yes	Yes
R^2	0.5781	0.5781	0.2649	0.2640
Observations	6240	6240	5364	5364

[a] Coefficients are multiplied by 10^9.
Robust standard errors in parentheses. ***: $p < 1\%$, **: $p < 5\%$, *: $p < 10\%$.

Table A3: Flexible Utilities: Total Capacity

Variable	$\log(Z_{itn} + Z_{itc})$			
	Two-year lead		Three-year lead	
	(1)	(2)	(3)	(4)
Natural gas price [a]	-0.219	-0.239	-0.465	-0.420
	(0.503)	(0.506)	(0.530)	(0.530)
Coal price	-0.000	-0.001	0.001	0.001
	(0.001)	(0.001)	(0.001)	(0.001)
Electricity price	0.008	0.009	0.003	0.002
	(0.010)	(0.010)	(0.009)	(0.009)
After	0.169	0.153	-0.070	-0.082
	(0.227)	(0.228)	(0.245)	(0.243)
After*RGGI	-0.134		-0.360	
	(0.179)		(0.236)	
CO_2 price		-0.024		-0.136
		(0.068)		(0.096)
t	0.031	0.034	0.043	0.045
	(0.066)	(0.066)	(0.062)	(0.062)
CHP	0.112	0.094	0.180	0.173
	(0.094)	(0.085)	(0.109)	(0.106)
Age	-0.046**	-0.045**	-0.057**	-0.057**
	(0.022)	(0.022)	(0.023)	(0.023)
Ownership-Single	0.036	0.043	0.304	0.306
	(0.331)	(0.331)	(0.266)	(0.266)
Ownership-Other	-0.107	-0.093	0.221	0.226
	(0.339)	(0.339)	(0.250)	(0.248)
PJM annual load [b]	-0.317	-0.335	-0.181	-0.155
	(0.532)	(0.530)	(0.534)	(0.531)
Constant	10.470***	10.491***	10.639***	10.671***
	(1.225)	(1.224)	(1.077)	(1.082)
Utility fixed effects	Yes	Yes	Yes	Yes
R^2	0.9217	0.9214	0.9267	0.9264
Observations	163	163	147	147

[a] Coefficients are multiplied by 10^3.
[b] Coefficients are multiplied by 10^9.
Robust standard errors in parentheses. ***: $p < 1\%$, **: $p < 5\%$, *: $p < 10\%$.

Table A4: Flexible Utilities: Natural Gas and Coal Utilization Rate

Variable	$\log(U_{itn})$		$\log(U_{itc})$	
	(1)	(2)	(3)	(4)
Natural gas price [a]	-0.060***	-0.060***	0.002**	0.002**
	(0.010)	(0.010)	(0.001)	(0.001)
Coal price	0.020***	0.018***	0.001*	0.000
	(0.004)	(0.003)	(0.000)	(0.000)
Electricity price	0.052***	0.054***	0.004**	0.004**
	(0.014)	(0.014)	(0.002)	(0.002)
After	-0.391	-0.520	0.395***	0.377***
	(0.468)	(0.467)	(0.075)	(0.076)
After*RGGI	-2.486***		-0.625***	
	(0.437)		(0.076)	
CO_2 price		-0.727***		-0.206***
		(0.159)		(0.032)
Capacity [b]	0.243***	0.244***	-0.002	-0.001
	(0.016)	(0.016)	(0.028)	(0.003)
t	0.387***	0.420***	-0.230***	-0.222***
	(0.105)	(0.105)	(0.019)	(0.019)
CHP	-2.832***	-3.014***	-0.753***	-0.786***
	(0.704)	(0.686)	(0.077)	(0.080)
Age	-0.424***	-0.426***	0.036***	0.036***
	(0.038)	(0.038)	(0.009)	(0.009)
Ownership-Single	2.980***	3.009***	0.120	0.125
	(0.608)	(0.612)	(0.105)	(0.106)
Ownership-Other	5.880***	6.020***	0.429***	0.453***
	(0.825)	(0.828)	(0.115)	(0.116)
PJM monthly load [c]	-3.150*	-3.140*	1.420***	1.420***
	(1.750)	(1.750)	(0.225)	(0.225)
Feb.	-0.661	-0.631	0.006	0.014
	(0.475)	(0.477)	(0.068)	(0.068)
Mar.	-0.631	-0.604	-0.025	-0.018
	(0.471)	(0.473)	(0.068)	(0.069)
Apr.	-0.782	-0.738	-0.115	-0.104
	(0.506)	(0.509)	(0.070)	(0.071)
May.	-0.283	-0.235	-0.164**	-0.153**
	(0.489)	(0.491)	(0.068)	(0.068)
Jun.	0.459	0.478	-0.082	-0.076
	(0.459)	(0.461)	(0.065)	(0.066)
Jul.	0.343	0.353	-0.091	-0.085
	(0.500)	(0.502)	(0.070)	(0.071)
Aug.	0.449	0.461	-0.098	-0.093
	(0.475)	(0.477)	(0.069)	(0.070)
Sept.	-0.017	-0.007	-0.110*	-0.109*
	(0.464)	(0.465)	(0.065)	(0.065)
Oct.	-0.689	-0.670	-0.222***	-0.219***
	(0.480)	(0.481)	(0.071)	(0.071)
Nov.	-0.213	-0.142	-0.200***	-0.183***
	(0.461)	(0.464)	(0.070)	(0.070)
Dec.	0.157	0.172	-0.204***	-0.203***
	(0.451)	(0.453)	(0.074)	(0.075)
Constant	-4.987**	-4.438*	5.195***	5.307***
	(2.336)	(2.322)	(0.511)	(0.509)
Utility fixed effects	Yes	Yes	Yes	Yes
R^2	0.6935	0.6919	0.5581	0.5545
Observations	2376	2376	2376	2376

[a] Coefficients are multiplied by 10.
[b] Coefficients are multiplied by 100.
[c] Coefficients are multiplied by 10^8.
Robust standard errors in parentheses. ***: $p < 1\%$, **: $p < 5\%$, *: $p < 10\%$.