Updating Allowance Allocations in Cap-and-Trade: Evidence from the NOx Budget Program

Ian Lange and Peter Maniloff*

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Abstract

The level and distribution of the costs of tradable allowance schemes are important determinants of whether the regulation is enacted. Theoretical and simulation models have shown that updating allowance allocations based on firm emissions or output can improve the efficiency of the scheme by acting as a production subsidy. Using the U.S. NOx Budget Program as a case study, this analysis tests whether electricity generators in states which chose an updating allocation increase their electricity production relative to plants in states that chose a fixed allocation. Econometric results provide evidence that updating allocations lead to an increase in generation for natural gas combined cycle generators, but not for coal generators. This effect is concentrated in low-demand overnight hours. These findings imply that an updating allocations confers a modest but meaningful subsidy to production relative to a fixed allocation and that firm responses are heterogeneous based on production technology and market conditions.

*Division of Economics and Business, Colorado School of Mines, 1500 Illinois St, Golden, CO, 80401. Maniloff's email: maniloff@mines.edu. Maniloff is corresponding author. The authors which to thank Josh Linn, Harrison Fell, ABB, and seminar and conference participants at Georgia Tech, the 2016 AERE Summer Conference, and the 2016 CU Environmental and Resource Economics Workshop.

1 Introduction

The distributional impacts of tradable permit schemes are an increasingly important part of any political debate over new environmental regulations. Past research has shown that the allocation method for permits is one way to improve the efficiency and alter the incidence of the regulation (Goulder et al. 1999; Fullerton and Metcalf 2001). Permits are often given away freely to regulated firms to meet distributional goals, including to offset costs to regulated firms in hopes of gaining their support for the policy. However, updating that allocation at regular time intervals to reflect each firm's relative share of emissions (or output) has been shown in theoretical and simulation models to be more efficient than a fixed allocation method in some second-best settings. Policymakers have started to widely consider alternatives to grandfathering, with the European Union's Emission Trading Scheme and California emissions trading system both utilizing an updating allocation for some emitters.

In this paper, we use the NOx Budget Program (NBP) to econometrically investigate the effect of updating allocations on electricity generators. The effectiveness of updating allocations is particularly interesting to explore given the current movement towards regional cap-and-trade systems which may be particularly vulnerable to leakage or market power.

By "updating allocations", we mean that a firm is granted free allowances under a cap-and-trade system, and that the firm's allocation depends on its economic activity during the policy period. For example, a firm may be allocated a share of allowances proportional to its share of production. This is in contrast to grandfathering, in which a firms' allocation is based on pre-period activity. Updating allocations acts as a production subsidy if allocations are based on production (or on other related activities) because increasing current production will result in a valuable increased future allocation.

Our results provide evidence that the production subsidy inherent in an updating allocation increase natural gas combined cycle (NGCC) generators' capacity factor (utilization rate) relative to the fixed allocation. The production subsidy inherent in an updating allocation is larger than the cost of the emissions cap for NGCC plants. Coal plants, with higher emissions rates, see a small decrease in capacity factor that is not always statistically significant. For coal plants, the production subsidy is not enough to completely offset the impact of the emissions cap.

A substantial theoretical literature has shown that updating allocation mechanisms can improve welfare when cap-and-trade programs are implemented in second best settings. Updating allocation has been proposed to mitigate concerns about emissions leakage (Fischer and Fox 2012), market power (Gersbach and Requate 2004), trade and tax interaction effects (Fischer and Fox 2007), or uncertainty (Meunier et al. 2018). Updating allocation acts as a production subsidy, which can ameliorate competition from uncapped regions (which leads to leakage) and encourage production (mitigating market power.) Fowlie, Reguant, and Ryan (2016) conduct a counterfactual simulation of an updating policy based on a structural econometric model, finding that updating allocations could address a cap-and-trade program's interactions with the market power concerns identified in Ryan (2012).

There are other effects of updating allocations. Allowance prices will be above marginal abatement costs under updating allocation, which may distort policy analysts' and investors' views about marginal abatement costs (Rosendahl 2008). Furthermore, updating allocations can reduce economic efficiency (Burtraw, Palmer, Bharvirkar, and Paul 2001; Rosendahl 2008), although this is not necessarily the case on the supply side (Böhringer and Lange

2005). Updating allocations will also in general reduce electricity prices relative to other allocation methods (Burtraw, Palmer, Bharvirkar, and Paul 2001; Neuhoff, Martinez, and Sato 2006), which reduces incentives for demand-side consumption reductions and increases the overall cost of emissions reductions.

While the theoretical literature is promising in some cases, the econometric literature on updating allocation mechanisms is quite sparse. Branger et al. (2015) find that cement plants respond to a step-wise allocation system by bunching just above production levels required to receive larger allocations. In a working paper, Fowlie (2010a) also uses the variation in allocation mechanism in the NBP as its testing ground. The outcome tested is whether a plant's decision to re-start after being shutdown is affected by the emissions regulation and the production subsidy. Fowlie (2010a) finds that the emissions restrictions lead to longer shutdown times, however the impact of the production subsidy is not consistently statistically different than zero.

A much larger literature analyses production decisions in electricity generation. Coal and gas plants respond to variation in fuel prices, and an increase in the price of either fuel (coal or gas) causes substitution to the other (Linn and Muehlenbachs 2018; Cullen and Mansur 2017). When electricity generators are subject to an emissions price, they reduce their emissions level (Stavins 1998; Murray and Maniloff 2015). However, a number of papers find that regional emissions prices can result in leakage (Wing and Kolodziej 2009; Fowlie 2009; Burtraw, Palmer, Paul, and Pan 2015; Aichele and Felbermayr 2015; Višković, Chen, and Siddiqui 2017; Palmer, Burtraw, Paul, and Yin 2017; Fell and Maniloff 2018). Carley (2011) argues that cooperation between states to harmonize their cap-and-trade systems can help mitigate leakage. However, there is little econometric evidence on the effectiveness of policies to address leakage in the electricity sector.

We make two distinct contributions with this study. First, we provide econometric evidence that plants responded to the implicit price subsidy inherent in an updating allocation. Second, we provide evidence that low emissions intensity producers respond more to an updating allocation mechanism than high emissions intensity producers.

These results are instructive for policymakers planning the set-up of a tradable permit scheme. They reveal the magnitude of the production subsidy inherent in an updating allocation; small but substantial enough to see increases in production. Importantly, the results also provide information about the type of plant that changes production and when these changes occur. Plants with higher emissions intensity have their response to the production subsidy muted by the emissions restrictions. The biggest decline for high emissions intensity plants tend to occur in off-peak hours when there is spare generation capacity.

There are important caveats. First, our econometric approach follows a number of other papers by using a difference-in-difference identification approach (Fabrizio, Rose, and Wolfram 2007; Hausman 2014; Cicala 2015; Fell and Kaffine 2017; Fell and Maniloff 2018; Linn and Muehlenbachs 2018). A key assumption in this approach is that the treatment does not spillover to the control group. In this case, a spillover is likely because an increase in generation cost due to the a state cap-and-trade may lead to an increase in generation outside cap-and-trade states (Fell and Maniloff 2018). While the literature typically assumes that such spillovers are very small, if this assumption is mistaken then estimated treatment effects will be biased. In this case, treatment effects would be biased away from zero. Thus non-zero treatment effect estimates can be interpreted as evidence of a program effect (causing a change in generation in both the treatment and control regions), but cannot be interpreted as causal effects. Second, it is worth noting that these results were found during a period of a decreasing price of allowances. If instead an updating allocation mechanism were implemented in a setting with annually increasing emissions prices, firms might be even more responsive to updating allocation because the value of the subsidy would be larger relative to the emissions price.

The next section provides background on the NBP and how power plants can comply with the regulation. Section 3 outlines how we estimate the impact of updating allocations versus the NBP emissions cap using the data discussed in Section 4. Section 5 interprets the results of our estimation and Section 6 provide closing remarks on the analysis.

2 Background on the Regulatory Setting

The NBP was a cap-and-trade system for nitrogen oxide (NOx) emissions from fossil fuel electricity generation plants from 2003-2008. Nitrogen oxides, typically abbreviated NOx, are a chemical byproduct of burning fossil fuel. Under particular weather conditions (generally, summer days), NOx can combine with other atmospheric compounds to form ozone, which is a known hazard to human health.

The NBP capped emissions from plants in the NBP region from May 1 to September 30 of each year. The NBP started in 2003 for plants in northeastern states which were previously regulated under the Ozone Transport Commission[1]. Other states joined the NBP in 2004.[2]

[1] The NBP generally covered eastern and northeastern states. The states in the Ozone Transport Commission are: Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Maryland, and Delaware

[2] Alabama, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Maryland, Delaware, Ohio, Indiana, Illinois, Michigan, Missouri, Kentucky, Tennessee, Virginia, West Virginia, North Carolina, South Carolina and Georgia. Due to a lawsuit, some states did not join the NBP until May 24, 2004. Those states' compliance windows began on May 1 in subsequent years.

In order to ensure a common market for emissions permits, the EPA drafted a model rule for each state to add to their state implementation plans for pollution control. This model rule included information such as NOx "budgets" for each state and emissions reporting guidelines. Several design issues were common across all states: the compliance period (May 1 to September 30), a prohibition on "borrowing" allowances against future vintages, and a restricted version of banking allowances (termed "progressive flow control"). The states split their choice of allocation method between a fixed allocation (grandfathering) and an updating allocation. The states that chose updating allocations are: Connecticut, Kentucky, Massachusetts, New Jersey, New York, Pennsylvania, Virginia, and West Virginia. The states which chose a fixed allocation are: Alabama, Delaware, Georgia, Illinois, Indiana, Maryland, Michigan, Missouri, North Carolina, Ohio, Rhode Island, South Carolina, and Tennessee.[3]

Grandfathering allocations were free allocations of emissions allowances to emitters based on pre-period activity (typically emissions). While these often covered a large portion of firms' compliance obligations, a key feature is that the allocation did not change based on firms' behavior during the policy period. As the NBP provided states with flexibility in deciding their allocation, there is some variability in the exact rules. States generally specified a NOx emissions rate and multiplied the plants heat input or electrical output for a time period previous to the NBP (typically 1995-1998) by this rate to determine the number of permits each plant receives initially. Every state had some discussion of how new units would be treated, with the majority of states explicitly setting aside a percent of their budget

[3]Ideally the choice of allocation mechanism would be random. It is difficult to perform statistical analyses with 21 observations (each state chose their allocation mechanism once). Generally both groups contain a mix of states in terms of geographic size, GDP, and population. The updating states contain the states with high levels of coal production (Kentucky, West Virginia, and Virginia) however the grandfathering states contain Illinois, Indiana, and Ohio, all of which have a moderate amount of coal production.

of permits for new units. Most states auctioned off the unused new unit set aside permits and had specific uses for those funds (for example, Kentucky had the revenues deposited in the states general fund while New York used the revenues for energy efficiency programs). The EPA had some requirements as to which emissions sources were involved (for example, most of the plants in the Acid Rain Program in regulated states were in the NBP) however states had the authority to add other emissions sources, such as cement kilns.

Updating allocations were free allocations of emissions allowances to electricity generators based on their economic activity during the policy period. In principle, all electricity generators could be eligible - coal, nuclear, natural gas, wind, hydropower, et cetera. For cap-and-trade systems covering other sectors, allocations could go to cement and chemical manufacturers, oil refiners, and other interested parties. In practice, they generally go to large emitters such as coal and natural gas-powered electricity generating units. We discuss details of updating allocation formulas in our study setting in Appendix A.

A firm with an electricity generating unit in a grandfathering state faces fairly standard choices. It faces an emissions price in the form of the price of an allowance. Even if the firm were freely granted an excess of allowances, it could sell those allowances and therefore faces an equivalent emissions price in the form of the opportunity cost of not selling allowances. In a competitive setting, the firm will therefore generate such that the marginal cost of reducing NOx emissions equals the emissions price (Baumol and Oates 1988).

A firm with an electricity generating unit in an updating state faces a more subtle choice - it faces the same emissions price, but also faces a subsidy to either emissions or generation. In a competitive equilibrium, the generating will thus emit (or generate) at a higher level than the unit in the grandfathering state. Put differently, it may reduce emissions by less than the unit in the grandfathering state.

A electricity firm wishing to reduce its NOx emissions has three choices: (1) it can reduce generation, (2) it can shift generation from more emissions-intensive sources to less emissions intensive sources, or (3) it can install end-of-pipe or production process technologies to reduce emissions. Linn (2008) has documented that many plants in the NBP have installed combustion control technologies that led to a 10-15% reduction in NOx emissions. Fowlie (2010b) shows that plants in regulated electricity markets are more likely to install post-combustion technologies given the capital recovery measures in place.

3 Empirical Strategy

Our empirical strategy relies on a multiple difference-in-differences approach. For the first difference, we compare capacity factors for plants which are under the NBP and plants which are not. As plants entered the NBP during our study period, we can compare NBP plants before and after the NBP was in effect for a difference-in-differences approach. As an additional difference-in-differences estimate, we can compare NBP plants which were eligible for updating allocations to NBP plants which received fixed allocations. This difference allows us to disentangle the effect of the emissions price and the updating allocation subsidy.

Finally, we can compare NBP generators' capacity factor before and during the NOx season each year, for an intra-plant comparison. This fourth difference is akin to a regression discontinuity design in that we will compare the (conditional) capacity factor of a given generator on May 1 to the capacity factor of the same plant on April 30. The identifying assumption is that, controlling for load and other observable factors, generation will be very similar but for the policy change. However, we will use a difference-in-difference approach again here because regression discontinuity estimates are only valid near the cutoff point, and we have no reason to believe that the policy effects will vary during the policy period.

$$CF_{ihdy} = \sum_{j \in J} \alpha_j^h TREAT_{idy}^j + \mathbf{X}'_{ihdy}\beta + \gamma_y + w_d + \phi_h + \theta_i + \mu_{ihdy} \quad (1)$$

We estimate Equation 1 with a dependent variable of capacity factor CF_{ihdy}, the ratio of actual electricity produced to the theoretical maximum amount that could be produced from generation unit i during hour of day h on day of year d in year y. $TREAT_{idy}^N$ and $TREAT_{idy}^U$ are treatment indicators for the NBP and updating allocation, respectively The estimated coefficient α_j^h then describes the effect of the emissions constraint or subsidy on generation, allowing this effect to vary by hour of day h. We let the effect vary because there is important diurnal variation in electricity demand, and responses may be different during the overnight hours when demand is low and there is substantial slack generation capacity relative to during daytime hours when demand is higher and there is little slack generation capacity.

Electricity generators vary widely on efficiency and emissions intensity even among a given type (Linn, Mastrangelo, and Burtraw 2014, Figure 2). Therefore we calculate generator-specific variable costs of both compliance with the NOx Budget Plan and the value of the updating subsidy. In some specifications, we will use these continuous measures instead of discrete treatment indicators. In Equation 2, π_{idy}^1 and π_{idy}^2 represent the per-kWh cost of compliance with the NBP and per-kWh expected marginal revenue from additional updating allocations, respectively. We describe the calculation of marginal compliance costs and subsidy values in detail in Section 4 and Appendix A.

There are several sources of variation in π^j_{idy}. First, of course, $\pi^j_{idy} = 0$ for observations which are under the NOx cap and in NOx season, but not in updating states. This comparison between updating and non-updating units under the NOx cap is the same variation that identifies the treatment indicator. Beyond that, there is state variation in allocation methods, time variation in the allowance price, and variation between units in the heat intensity (or emissions intensity) of generation. This efficiency variation yields variation in the price per unit of generation between units in the same state (and time), as well as between units in different states (and times).

$$CF_{ihdy} = \sum_{j \in J} \alpha^h_j \pi^j_{idy} + \mathbf{X}'_{ihdy}\beta + \gamma_y + w_d + \phi_h + \theta_i + \mu_{ihdy} \tag{2}$$

We estimate Equations 1 and 2 separately for coal and NGCC plants because they respond differently to control variables and may respond differently to treatment effects (for example, lower gas prices lead to more generation from NGCC generators and less generation from coal generators). NGCC plants tend to be larger and run more often than other types of natural gas plants.[4]

The vector of control variables X includes natural log of load (a measure of the quantity of electricity demanded), the level of the Renewable Portfolio Standard[5] in the state the plant is located in, an indicator for whether a plant was previously under the OTC program[6], and

[4]We do not estimate the impact of our treatment variables on other types of plants such as single cycle natural gas plants or oil plants as they are often smaller and used only for short periods of time during the day to meet peak demand.

[5]Renewable Portfolio Standards (RPS) require specified percentages of electricity supply to be renewable. A higher RPS thus means less demand for fossil generation, conditional on load.

[6]The OTC program, as described above, was a tradable permit scheme for northeast and mid-Atlantic states which was replaced by the NBP. Generators which were under OTC before the NBP undergo a smaller

the ratio of local coal to natural gas prices. Finally, we allow for unobserved factors by including fixed effects for year γ_y, week of year w_d, hour of day ϕ_h, and generation unit θ_i. Errors are clustered at the plant level.[7]

There are important limitations to this approach. First, we study only short-run generation decisions. That is, we take the capital stock as fixed. However, simulation work finds that allocation mechanisms can have important effects on capital investment (Burtraw, Palmer, Paul, and Pan 2015; Palmer, Burtraw, Paul, and Yin 2017). Second, our coefficients of interest may be biased away from zero. We discuss this point in detail in Section 3.1.

3.1 Interpreting Coefficient Estimates

To interpret the α_N^h estimated in Equation 1, let us first assume that treatment does not spill over to the control group. In that case, α_N^h will represent the difference between generation units under the NBP and control units for hour of day h, relative to their difference when the NBP is not in effect. If treatment is exogenous, unobservables are uncorrelated, and the model is correctly specified, we can interpret α_N^h as the causal effect of the NBP. This is a typical approach for econometric studies of electricity policy (Fabrizio, Rose, and Wolfram 2007; Hausman 2014; Cicala 2015; Fell and Kaffine 2017; Linn and Muehlenbachs 2018; Fell and Maniloff 2018), but there is evidence that even relatively weak policies can spill over in this setting (Fell and Maniloff 2018).

Now, assume that there may be generation spillovers to the control group. That is,

change in their treatment stringency than non-OTC generators.

[7] Other error specifications, such as AR(1), yield smaller standard errors. We cluster at the plant level for conservatism.

the NBP may cause NBP generators to reduce generation. However, if quantity demanded remains constant (or decreases by less than the generation decrease), then control units will increase generation to meet the quantity demanded. In this case, the difference in generation between treatment and control groups will reflect both the true effect of the policy and the spillover - that is, the coefficient α_N^h will be biased away from zero as an estimate of the causal effect. We must keep this in mind when interpreting regression results in Section 5.

The same basic idea applies to estimates from Equation 2. However, identification of these coefficients relies both on the comparison between treatment units and control units, as well as comparing variation in the effective emissions price between treated units. Therefore estimates of α_N^h from Equation 2 may be less biased than those from Equation 1, although will still have bias if there are spillovers.

Analagous logic applies to estimates of α_U^h. In particular, if the updating allocation mechanism leads to generation shifting from grandfathering states to updating states (which we expect), then there will be both an increase in generation in the updating states and a decrease in the grandfathering states. This will bias α_U^h away from zero.

4 Data

Our primary data set consists of detailed electricity generation data from the United States Energy Information Administration Forms 923 and 860 along with the EPA's Continuous Emissions Monitoring System[8]. This data provides hourly generation unit[9] observations of

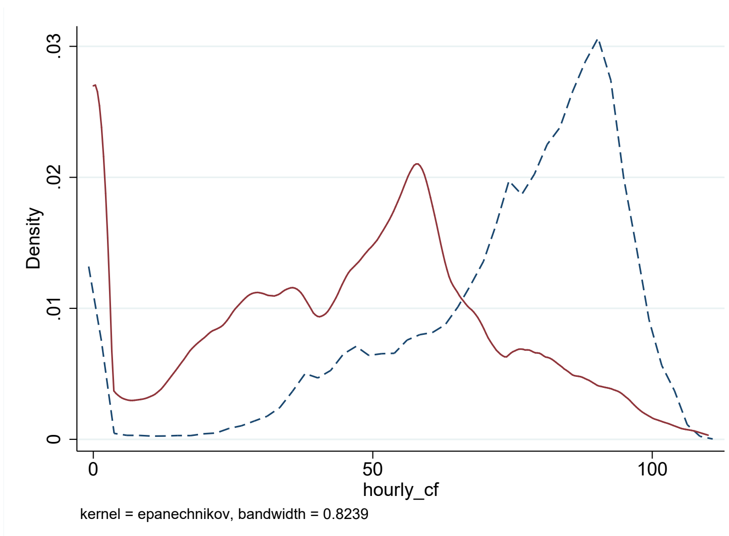
[8]All data sources we employ were made available by ABB Ventyx via their Velocity Suite data management product, which organizes all publicly available datasets on electricity generating facilities.

[9]An electricity generation unit is a single boiler (or other technology) which produces electricity. A power plant can have multiple generation units. A generation unit typically burns a single primary fuel, while a power plant can have multiple generation units using different fuel types or different technologies.

electricity generation as well as a rich set of generator, plant, and regional characteristics. This data covers the years 2003-2008 for plants in the eastern United States.[10] Table 1 lists summary statistics for major variables.

Figure 1 provides kernel densities of daily capacity factors for coal and gas plants. We see the typical pre-fracking pattern of electricity generation. Coal units, which were generally inframarginal, run more on both the intensive and extensive margins. They also generally have very high capacity factors, which is their most efficient operating range. NGCC units are more likely to be off entirely, and have a wider range of capacity factors. They are more often marginal generators, and adjust their generation over the diurnal demand (load) cycle.

Figure 1: Capacity Factor Distribution



Kernel densities of coal (dashed lined) and NGCC (solid line) units.
Rule-of-thumb bandwidth with Epanechnikov kernel.

The key determinants of capacity factor are the quantity of electricity demanded (here-

[10]We include AL, AR, CT, DE, FL, GA, IA, IL, IN, KS, KY, LA, MA, MD, MI, MD, MO, MS, NC, ND, NE, NH, NJ, NY, OH, PA, SC, SD, TN, VA, WI, and WV. We include these states because they (approximately) comprise the Eastern Interconnection, a region of the country where the electricity grid is relatively well integrated.

after referred to as load), the marginal cost of generation, and the marginal cost of generation from other plants. We follow Fell and Maniloff (2018) in observing and controlling for load at a regional level.[11]

Table 1: Summary Statistics

	NGCC	Coal
Capacity Factor	44.3	73.0
	(26.5)	(23.4)
Log Load	8.03	8.16
	(1.07)	(1.13)
NOx Cost ($/MWh)	0.339	3.14
(if > 0)	(0.466)	(2.26)
Updating Subsidy ($/MWh)	3.67	2.50
(if > 0)	(2.19)	(1.94)
Residual Variation	19.2	19.9
Number of Observations	664,089	3,280,464

Standard deviations listed in parentheses.

We control for marginal cost of both the generation unit's fuel type (coal or gas) and the substitute fuel price (coal for gas plants, gas for coal plants). Fuel is plants' major variable cost, and fuel prices provide the major variance in variable costs.

Approximately 33 percent of coal plant observations and 23 percent of NGCC observations are under the NBP. Approximately 42 percent and 69 percent of these are eligible for updating allowances. For each group, we calculate the per-kWh cost of purchasing emissions allowances to comply with the NBP as well as the per kWh subsidy value of updating allocation.[12]

The per kWh cost of the NBP is the NOx allowance price (per ton) multiplied by the

[11] We assign plants to ABB Ventyx's "transmission zones" and use load in each zone. A "transmission zone" is a pocket of the electricity grid over which load typically rises and falls together.

[12] We drop several dozen outlying calculated costs or subsidy values more than 10 times the value of the 99th percentile for each fuel. These seem to have mistaken data entries.

emissions rate (tons per btu) and the heat rate (btu per kWh). Figure 2 shows the price of NOx allowances over time.[13] We use the daily price as a measure of the cost for firms. On days with no trades, we linearly interpolate prices. For each year, we use the price of that year's vintage allowances.

We calculate the value of the subsidy based on states' allocation rules, observed plant level generation or heat inputs, and spot allowance prices. By using spot prices, we implicitly assume that firms are forward looking in the allowance market. Appendix A describes each state's allocation formula.

As a back-of-the-envelope calculation, the emissions price is economically important for coal units, and the subsidy is substantial for both coal and NGCC units. Typical fuel costs for these generators average about 25 dollars per MWh (EIA 2017, Table 8.4). The average value of the subsidy is on the order of 10-15% of fuel costs. While this appears to be a small change in costs, prior studies of regional electricity policies find that a fairly modest allowance price can have economically substantial effects (Burtraw, Palmer, Paul, and Pan 2015; Fell and Maniloff 2018).

We control for fossil fuel prices with a fifth order polynomial of the coal-gas price ratio.[14] For both coal and gas, we take the average of the price (in energy equivalent units) over each transmissions zone - month.[15]

Finally, because of the pseudo-regression discontinuity approach we are taking with the start of the compliance period each year, we focus on the start of the NOx season by trimming

[13]Provided by ABB Ventyx.

[14]Cullen and Mansur (2017) suggest that a nonparametric approach is more appropriate due a "kink point" when gas becomes cheap relative to coal. Our study period ends before fracking had lead to such low gas prices that a kink point existed.

[15]As in Footnote 11, transmission zones are local grid areas in which load typically is consistent over the zone.

Figure 2: NOx Allowance Prices

our sample to a small time window before and after the start of NOx season each year. Our primary specification will use a 3 week window before and after the start of each NOx season; we will present results for other windows as robustness checks.

$$CF_{ihdy} = \gamma_y + w_d + \phi_h + \theta_i + \varepsilon_{ihdy} \tag{3}$$

Our empirical strategy outlined in Section 3 relies on a rich set of fixed effects for identification. One natural question is how much variation is remaining after controlling for fixed effects. Table 1 reports "residual variation", that is, the standard deviation of ε_{ihdy} from estimating Equation 3. For both coal and NGCC, we see that the standard deviation of ε_{ihdy} is between 19 and 20, while the (unconditional) standard deviation of CF_{iydh} is 26.5 and 23.4, respectively. This suggests that there is substantial residual variation even after controlling for fixed effects.

5 Results

Our primary finding is that NGCC units increase their generation under a NBP updating allocation relative to grandfathered allocations. Coal units reduce generation in response to the NOx compliance costs. The impacts vary with per-kWh cost for each plant type. Finally, both compliance costs and subsidies primarily affect overnight generation, when demand is low and there is slack generation capacity. We find no evidence that the NOx Budget Plan affected daytime emissions.

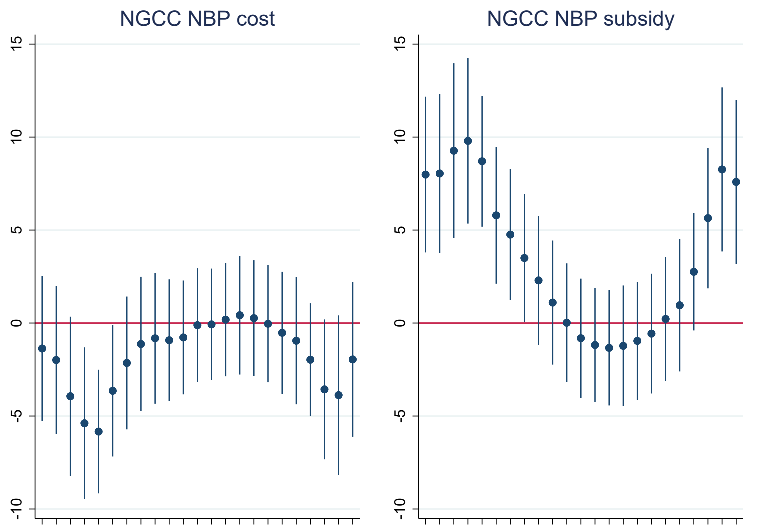
In interpreting the coefficient estimates α_j^h, it is important to keep in mind the potential SUTVA violations in difference-in-differences identification. All coefficients represent a comparison betwenn the control and treatment groups. If there are treatment spillovers, these cannot be interpreted as causal effects. Instead, non-zero estimates can be interpreted as evidence of effects.

We present our core results in Figures 3-6.[16] Each of these graphs the coefficient α_j^h along with its 95% confidence interval versus the hour of the day. In Figures 3 and 4, we use treatment indicators for whether a plant is facing a NOx price or an updating allocation (Equation 1). On the left panel of Figure 3, we see that the NOx cap is generally not associated with a change in NGCC generation relative to control groups. Tested individually, there are two hours with coefficients different than zero ($p < 0.05$), so this constitutes weak evidence of NGCC generators responding to the NOx price. On the right panel, we see that updating allocations are associated with a 8-9 percentage point relative increase in NGCC capacity factors overnight relative to controls. This effect appears to be largest during

[16] Additional coefficient estimates are presented in Appendix B.

the hours of lowest demand (1-5 am) and is economically substantial - the average NGCC capacity factor in our sample is 44 percent, and the average from 9PM to 6 AM is 36 percent.

Figure 3: NGCC Results with Discrete Treatment

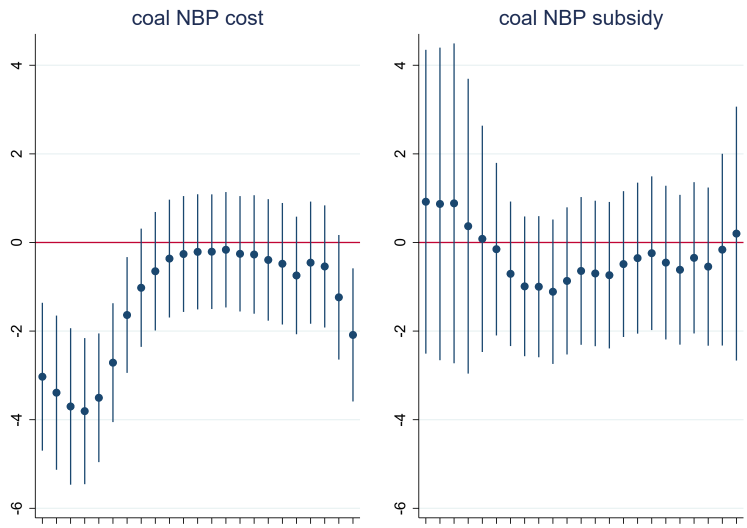


Graphs show the point estimates and 95% confidence intervals for α_j^h for each hour of the day. Each day starts at midnight. A value of 10 represents a 10 percentage point increase in capacity factor.

Moving to the left panel of Figure 4, we see that coal units reduce overnight generation by 3-4 percentage points under a NOx price relative to controls, but (in the right panel) coal units do not seem to respond to the subsidy. However, estimates of the subsidy's overnight effect are quite noisy, and the confidence intervals are consistent with an α_2^h of up to approximately 4 percentage points.

Figures 5 and 6 report results from estimation Equation 2. Here, the estimated coefficients describe the change in capacity factor per change in emissions cost or subsidy. Costs and subsidies are measured in dollars per MWh, so a coefficient of 10 would imply that a 1 dollar per MWh increase in subsidies is associated with a 10 percentage point relative increase in capacity factor. We again see evidence of a relative increase in overnight generation from

Figure 4: Coal Results with Discrete Treatment



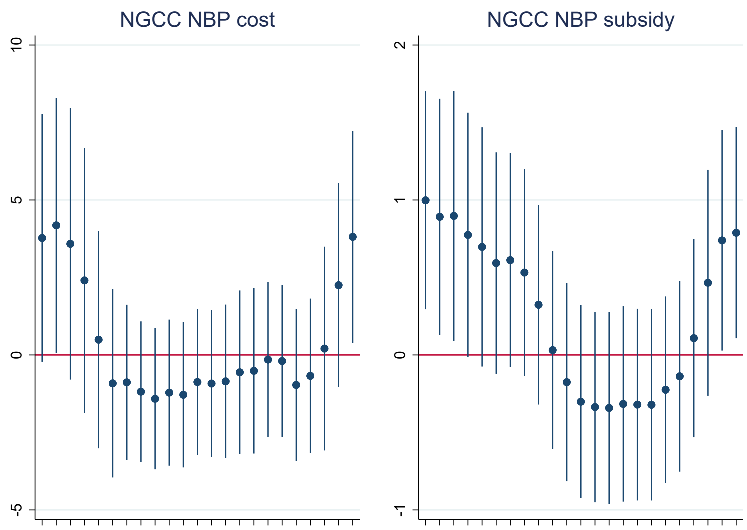
Graphs show the point estimates and 95% confidence intervals for α_j^h for each hour of the day. Each day starts at midnight. A value of 10 represents a 10 percentage point increase in capacity factor.

NGCC units eligible for updating allocations and a relative decrease in overnight generation from coal units.

Average subsidy values are about 3 dollars per MWh, so at average subsidies, an NGCC unit increases generation by about 3 percentage points overnight, which is somewhat smaller than but generally comparable to the estimates of Figure 3. The average NOx cost for coal units is about 3 dollars per MWh, so a coefficient of 1 would imply an average 3 percentage point reduction in capacity factor, comparable to the estimates in Figure 4.

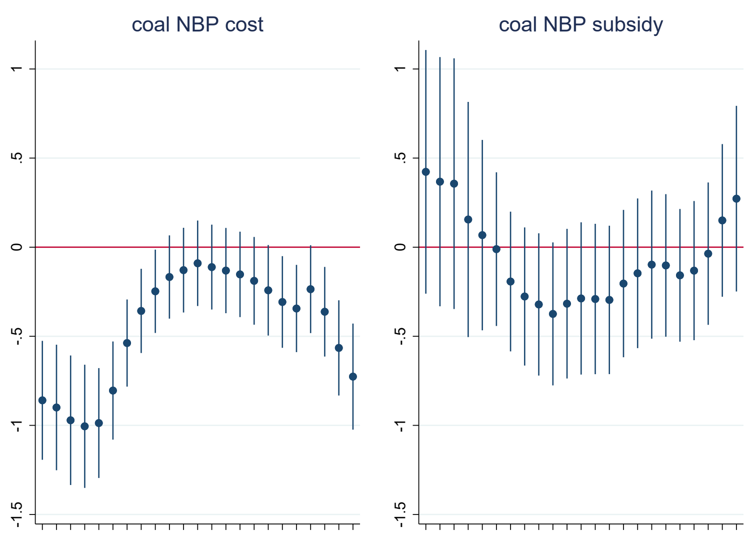
On the right panel of Figure 6, all confidence intervals include zero. However, overnight confidence intervals also include values of 0.5-1, close to the effect of emissions costs. Thus while we do not find evidence that coal plants respond to the updating allocation subsidy, we are also unable to reject a null that they respond with at a magnitude similar to their response to emissions costs.

Figure 5: NGCC Results with Cost Measure



Graphs show the point estimates and 95% confidence intervals for α_j^h for each hour of the day. Each day starts at midnight. A value of 10 represents a 10 percentage point increase in capacity factor per dollar per MWh.

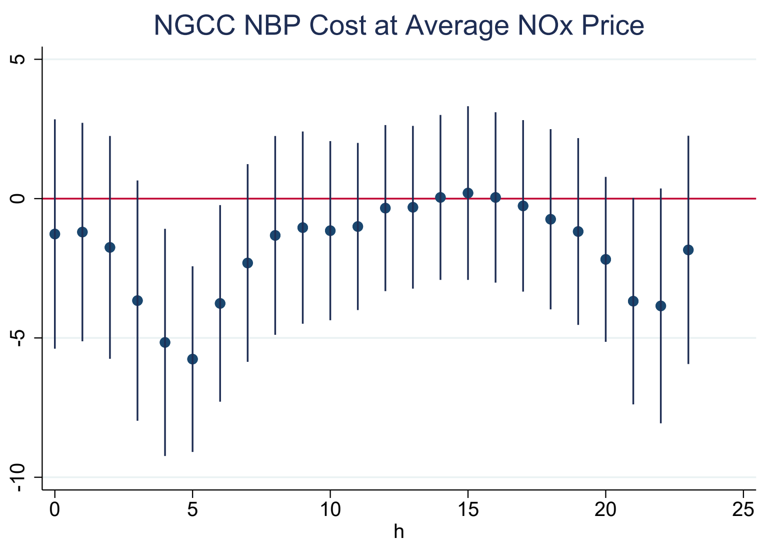
Figure 6: Coal Results with Cost Measure



Graphs show the point estimates and 95% confidence intervals for α_j^h for each hour of the day. Each day starts at midnight. A value of 10 represents a 10 percentage point increase in capacity factor per dollar per MWh.

Finally, on the left panel of Figure 5, the impact of NOx costs on NGCC generation is noisy and generally positive. One possibility is that this reflects errors in our calculation of the NOx cost to NGCC generators. As a simple check, we include both the discrete and continuous treatments and calculate their combined effect at the average NOx price level. The results, presented in Figure 7, are comparable to Figure 3.

Figure 7: NGCC Results with Joint Estimates



Graphs show the point estimates and 95% confidence intervals for α_j^h for each hour of the day. Each day starts at midnight. A value of 10 represents a 10 percentage point increase in capacity factor at the average NOx price.

The idea that firms might respond to a relatively small emissions price or subsidy is striking. It is, however, consistent with prior work finding that a relatively modest cap-and-trade system (for greenhouse gases) can lead to economically substantial leakage in electricity generation (Wing and Kolodziej 2009; Burtraw, Palmer, Paul, and Pan 2015; Fell and Maniloff 2018; Višković, Chen, and Siddiqui 2017; Lee and Melstrom 2018).

Appendix C provides several robustness checks and analyses of heterogeneous effects. We find that the effect of updating on NGCC generation and NOx pricing on coal generation are largest during low-load periods, which is consistent with our finding of larger effects during overnight hours. We also find that our core results vary by NERC region[17] We see the largest effects in the NPCC NERC region and smallest in SERC, which has a large number of tradionally regulated states. Testing for deregulation directly provides evidence that units in competitive markets are more responsive to both the NOx emissions price and updating subsidy than are units in traditional monopoly settings, which is consistent with prior literature finding that deregulated units are managed more efficiently (Fabrizio, Rose, and Wolfram 2007; Borenstein and Bushnell 2015; Cicala 2017) . Finally, our core results are robust to varying the time window of our study period.

6 Conclusions

Regional policies are currently the primary mechanism of addressing greenhouse gas emissions. However, regional cap-and-trade systems can exacerbate existing market distortions such as market power, or lead to emissions leakage due to their smaller geographic scope. One proposed solution to address leakage and market power is updating or contingent allocation mechanisms, in which cap-and-trade allowance distributions depend on firms' actions.

We provide econometric evidence that electricity generators do respond to updating allocation mechanisms. More specifically, we use generator-level data and a multiple difference-in-difference approach to econometrically estimate the impact of the NOx Budget Plan on generator's decisions. The NBP used a mixture of updating and fixed allocation mecha-

[17] NERC regions are effectively regional electricity grid areas, a convenient way of subdividing the U.S. grid. A map is provided in Appendix C. The Northeast Power Coordinating Council (NPCC) covers New York, New England, and eastern Canada. SERC covers the southeastern U.S., excluding Florida, and extending west to Missouri and southern Illinois.

nisms, allowing us to disentangle the effect of the emissions constraint from the effect of the updating allocation.

Our analysis finds that an updating allocation led to an increase in capacity factors for lower polluting natural gas plants. We also find evidence that more emissions-intensive coal plants do not substantially respond to updating allocations, suggesting that the updating allocation may have led coal plants to be supplanted by less emissions-intensive gas generation.

Both the (relative) reduction in coal generation and (relative) increase in NGCC generation occur overnight, when electricity demand is lowest. NOx is regulated because it is a chemical precursor to ozone, which is a human health hazard (EPA 1999). The chemical process that leads to ozone occurs during the day, so reducing NOx overnight may be less effective at improving human health than reducing daytime NOx emissions (Skalska, Miller, and Ledakowicz 2010). In some cases, overnight NOx emissions actually act as an ozone sink, so reducing overnight emissions may actually increase ozone formation. These results suggest that there may be important welfare costs to cap-and-trade systems when the temporal scale of the externality is considerably different than the temporal scale of compliance.

Taken together, these results show that firms do respond to contingent allocation mechanisms as proposed in theoretical work (Fischer and Fox 2007; Fischer and Fox 2012; Gersbach and Requate 2004). Particularly in light of recent evidence of leakage from both national and subnational cap-and-trade systems (Aichele and Felbermayr 2015; Fell and Maniloff 2018), these policies may be an effective tool for environmental policymaking in a second-best setting. However, the precise response varies by facility and market characteristics. One important limitation to the generalizability of this study is that short-term demand elasticities for electricity are quite low, so the heterogeneous impacts may be more important in this case than in other contexts. This suggests that more research on sectoral, environmental, and economic impacts of these policies, particularly in light of the large shifts in electricity generation brought on by the fracking revolution and recent increases in renewable generation.

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A Overview of State Allocation Rules

States had substantial flexibility in choosing how they allocated allowances. Table A.1 describes states' allocation mechanisms. Most states chose some version of grandfathering - allocating allowances to emitters based on pre-period production or emissions levels. Eight states chose to use updating allocation. Some of those states based allocations on electricity generation (output-based), while others based allocations on energy (heat) input. This distinction has important effects for particularly efficient (or inefficient) generators.

Allocations were typically based on multi-year averages, for example the average generation over the previous three years. Equivalently, a change in generation (or energy input) in one year will change allocations in the subsequent three years. Finally, most states reserved a few percent of available allowances for allocation

For each generating unit in an updating state, we calculate the present value of the additional future allocation the unit (and thus its owner) would receive if it generated one more kWh of electricity. To do this, we calculate the total allowance value based on the state-level cap, that state's percentage of allowances set aside for allocation, and the price of allowances. We assume a discount rate of five percent.

Several states have particular details which are not well summarized in table form:

Connecticut has a somewhat complicated calculation, in which allowances are first allocated to specialized such as industrial generators, and then the remainder are proportionally allocated to electricity generators. We subtract each year's specialized allocations from the cap. We calculate specialized allocations based on EPA's EPA Allowance Details (Serial) Report.

Kentucky based allocation on the generators' average input in the highest two of the previous three years. We assume that each firm believes the current year will be one of the highest two of the subsequent three years.

New York reserved approximately 25% of allowance for non-electricity emitters (primarily cement kilns). The remainder is allocated to electricity generation units.

Pennsylvania, Virginia, and West Virginia have "control period" or "window" approaches. Allocations are set for multi-year "control periods". These allocations are based on pre-control-period heat inputs. In a given year, increasing heat input would thus lead to an increase in allocation 4-8 years subsequently. We discount appropriately.

Table A.1: Summary of State Allocation Rules

State	Method	Metric	Calculation Time	% of Allowances Available
Alabama	Fixed	N/A	N/A	No formal set-aside amount
Connecticut	Updating	Output	2 years	95
Delaware	Fixed	N/A	N/A	No formal set-aside amount
Georgia	Fixed	N/A	N/A	No formal set-aside amount
Illinois	Fixed	N/A	N/A	95
Indiana	Fixed	N/A	N/A	93.7
Kentucky	Updating	Input (BTU)	Highest 2 of last 3 years	95 for 2004 to 2006, 98 after
Maryland	Fixed	N/A	N/A	No formal set-aside amount
Massachusetts	Updating	Output	3 year average	90
Michigan	Fixed	N/A	N/A	98.1 for 2004-2006, 95 after
Missouri	Fixed	N/A	N/A	90
New Jersey	Updating	Output	Last 3 years	85
New York	Updating	Input (BTU)	Last 3 years	92
North Carolina	Fixed	N/A	N/A	No formal set-aside amount
Ohio	Fixed	N/A	N/A	95 in 2004 and 2005, 93 after
Pennsylvania	Updating	Input (BTU)	Control Period	95 in 2004 and 2005, 98 after
Rhode Island	Fixed	N/A	N/A	No formal set-aside amount
South Carolina	Fixed	N/A	N/A	97
Tennessee	Fixed	N/A	N/A	95 in 2004 and 2005, 98 after
Virginia	Updating	Input (BTU)	Control Period	95 for 2004-2008 and 98 after
West Virginia	Updating	Input (BTU)	Control Period	95

Notes: Information taken from each state's State Implementation Plan.

B Additional Controls

Tables B.1 and B.2 list the control variables from the regressions described in Figures 3-6.

Point estimates are generally as expected.

Table B.1: Effect of NOx Price and Subsidy on Capacity Factor, Part 1

	NGCC		Coal	
	(1)	(2)	(3)	(4)
log(load)	32.71***	31.79***	24.18***	24.25***
	(2.583)	(2.515)	(1.285)	(1.309)
RPS	-45.05	-43.67	-31.13	-33.77
	(64.38)	(64.88)	(21.37)	(21.12)
coal/gas	618.6	696.4	230.7	187.5
	(584.8)	(599.8)	(196.8)	(200.9)
$(\text{coal/gas})^2$	-4491.6	-4981.1	-2034.1	-1668.6
	(4199.3)	(4303.8)	(1631.1)	(1672.7)
$(\text{coal/gas})^3$	16534.7	17996.9	8127.7	6985.4
	(14088.1)	(14419.5)	(6204.6)	(6379.1)
$(\text{coal/gas})^4$	-28376.1	-30472.2	-14332.9	-12796.6
	(22122.0)	(22606.8)	(10832.2)	(11153.3)
$(\text{coal/gas})^5$	17859.1	19010.8	9048.8	8300.0
	(13000.7)	(13266.2)	(6927.5)	(7137.2)
OTC	4.603	4.513	1.624	2.170
	(2.572)	(2.637)	(1.484)	(1.196)
week 15	-0.702*	-0.727*	-0.362	-0.416*
	(0.352)	(0.355)	(0.192)	(0.197)
week 16	-1.573***	-1.515***	-0.703**	-0.728**
	(0.457)	(0.450)	(0.250)	(0.254)
week 17	-3.031***	-2.768***	-1.358***	-1.459***
	(0.776)	(0.641)	(0.382)	(0.344)
week 18	-3.419***	-3.066***	-1.798***	-1.875***
	(0.830)	(0.635)	(0.459)	(0.389)
week 19	-4.861***	-4.447***	-2.278***	-2.391***
	(1.066)	(0.900)	(0.501)	(0.429)
week 20	-3.832***	-3.453***	-2.868***	-2.967***
	(1.057)	(0.866)	(0.543)	(0.462)
week 21	-5.187***	-5.027***	-3.361***	-2.789***
	(1.453)	(1.290)	(0.905)	(0.831)
week 22	-6.744***	-6.584***	-2.808**	-2.264*
	(1.551)	(1.312)	(0.997)	(0.941)
week 23	-5.895***	-5.722***	-3.048**	-2.450*
	(1.533)	(1.315)	(1.029)	(0.981)
2004	-12.64***	-12.04***	-2.079*	-2.288*
	(2.210)	(2.169)	(1.031)	(1.053)
2005	-9.085***	-9.281***	-0.246	0.0153
	(1.546)	(1.573)	(0.802)	(0.756)
2006	-2.301	-2.476	-0.0983	0.306
	(1.411)	(1.430)	(0.635)	(0.623)
2007	-3.579*	-3.599*	-0.421	-0.312
	(1.420)	(1.434)	(0.716)	(0.713)
2008	0.322	0.298	0.834	0.646
	(1.220)	(1.226)	(0.630)	(0.641)
R^2	0.203	0.200	0.118	0.120
Observations	664089	660601	3280464	3207484

Notes: +,*, **, *** denote statistical significance at at least the 15, 10, 5, and 1 percent levels, respectively. Standard errors clustered at the plant level are given in parentheses below the parameter estimates. Week of year is abbreviated as "week". "coal/gas" denotes the coal-gas price ratio.

Table B.2: Effect of NOx Price and Subsidy on Capacity Factor, Part 2

	NGCC		Coal	
	(1)	(2)	(3)	(4)
hour 1	1.350***	1.278***	-0.779***	-0.813***
	(0.254)	(0.240)	(0.107)	(0.104)
hour 2	1.870***	1.643***	-0.897***	-0.989***
	(0.384)	(0.373)	(0.166)	(0.160)
hour 3	1.948***	1.464*	0.0735	-0.0385
	(0.581)	(0.580)	(0.199)	(0.191)
hour 4	3.009***	2.389**	2.830***	2.721***
	(0.794)	(0.762)	(0.270)	(0.258)
hour 5	6.090***	5.360***	5.657***	5.582***
	(0.881)	(0.832)	(0.354)	(0.347)
hour 6	7.322***	6.833***	7.240***	7.208***
	(0.941)	(0.884)	(0.415)	(0.407)
hour 7	6.610***	6.372***	7.962***	7.986***
	(1.114)	(1.028)	(0.460)	(0.448)
hour 8	6.732***	6.641***	8.421***	8.437***
	(1.238)	(1.135)	(0.493)	(0.479)
hour 9	7.411***	7.361***	8.573***	8.603***
	(1.243)	(1.142)	(0.500)	(0.490)
hour 10	8.496***	8.398***	8.450***	8.492***
	(1.137)	(1.058)	(0.494)	(0.486)
hour 11	9.045***	8.935***	8.285***	8.331***
	(1.096)	(1.024)	(0.485)	(0.479)
hour 12	9.459***	9.428***	8.192***	8.232***
	(1.095)	(1.016)	(0.477)	(0.472)
hour 13	9.447***	9.401***	7.916***	7.975***
	(1.114)	(1.026)	(0.470)	(0.465)
hour 14	9.318***	9.306***	7.634***	7.722***
	(1.127)	(1.032)	(0.461)	(0.457)
hour 15	9.178***	9.213***	7.617***	7.695***
	(1.117)	(1.022)	(0.451)	(0.446)
hour 16	8.748***	8.796***	7.324***	7.426***
	(1.112)	(1.019)	(0.448)	(0.442)
hour 17	8.114***	8.132***	6.881***	6.992***
	(1.097)	(1.009)	(0.443)	(0.434)
hour 18	7.928***	7.909***	6.683***	6.812***
	(1.087)	(1.002)	(0.440)	(0.431)
hour 19	8.816***	8.828***	7.463***	7.534***
	(1.050)	(0.979)	(0.448)	(0.441)
hour 20	6.159***	6.077***	7.259***	7.337***
	(1.092)	(1.028)	(0.448)	(0.436)
hour 21	-0.517	-0.774	5.505***	5.654***
	(1.247)	(1.159)	(0.390)	(0.378)
hour 22	-3.014**	-3.218***	3.111***	3.271***
	(0.939)	(0.879)	(0.275)	(0.264)
hour 23	-2.412***	-2.463***	1.155***	1.243***
	(0.483)	(0.450)	(0.142)	(0.135)
Constant	-255.5***	-252.5***	-137.4***	-136.9***
	(38.16)	(38.30)	(13.64)	(13.84)

Notes: +,*, **, *** denote statistical significance at at least the 15, 10, 5, and 1 percent levels, respectively. Standard errors clustered at the plant level are given in parentheses below the parameter estimates. Hour of day is abbreviated "hour".

C Additional Specifications

This section provides several robustness checks and analyses of heterogeneous effects. We find that the effect of updating on NGCC generation and NOX pricing on coal generation are largest during low-load periods, which is consistent with our finding of larger effects during overnight hours. We also find that our core results vary by NERC region[18] We see the largest effects in NPCC and smallest in SERC, which has a large number of traditionally regulated states. Testing for deregulation directly provides evidence that units in competitive markets are more responsive to both the NOx emissions price and updating subsidy than are units in traditional monopoly settings, which is consistent with prior literature finding that deregulated units are managed more efficiently (Fabrizio, Rose, and Wolfram 2007; Borenstein and Bushnell 2015). Finally, our core results are robust to varying the time window of our study period.

C.1 Heterogeneity by Load

In Section 5, we found that both the NBP emissions price and updating subsidy effects were largest overnight. We hypothesized that this was because demand (load) is lowest overnight, leaving more flexibility for generation sources to adjust. This section provides additional evidence in support of this hypothesis. Here, we create an indicator for whether an hour was within the lowest third of hours of load for each load region. We then interact the NBP price and updating effects with the low load indicators instead of allowing the price and updating effects to vary by hour of day.

[18] NERC regions are effectively regional electricity grid areas, a convenient way of subdividing the U.S. grid.

Table C.1: Heterogeneity by load

	NGCC		Coal	
	(1)	(2)	(3)	(4)
Low Load	-1.424**	-1.377**	-0.725**	-0.589*
	(0.475)	(0.505)	(0.232)	(0.246)
NBP Cost	-5.940		-2.552*	
	(11.44)		(1.159)	
NBP Cost * Low Load	29.31		-7.279***	
	(16.68)		(1.565)	
Updating Subsidy	0.566		-1.375	
	(3.037)		(1.955)	
Updating Subsidy * Low Load	7.526*		3.419	
	(3.174)		(3.034)	
I(NBP)		-1.057		-0.499
		(1.358)		(0.643)
I(NBP) * Low Load		-1.378		-3.084***
		(1.330)		(0.727)
I(Updating)		1.695		-0.537
		(1.399)		(0.812)
I(Updating) * Low Load		5.339**		0.907
		(1.724)		(1.451)
N	660601	664089	3207484	3280464

Notes: *, **, *** denote statistical significance at at least the , 10, 5, and 1 percent levels, respectively. Standard errors clustered at the plant level are given in parentheses below the parameter estimates.

Results are presented in Table C.1. Our results are consistent with Figures 3-6. Columns 1 and 2 describe NGCC results, while Columns 3 and 4 describe coal results. Columns 1 and 3 use continuous measures of the emissions price and updating subsidy, while columns 2 and 3 use treatment indicators. We see that coal generation decreases under the allowance price, and that this effect is much larger when load is low. We also see that NGCC generation increases under the updating subsidy, and that this effect is much larger when load is low. Generally, we cannot reject the null hypothesis that generation units do not respond to either the emissions price or the updating subsidy when load is above its 33rd percentile.

C.2 Heterogeneity by NERC Region

Here we allow the effects of the NOx price and updating subsidy to vary by NERC regions. A map is in Figure C.1. The NBP includes the NPCC, RF(C), and SERC regions. For NGCC, we include all three regions. For coal, we only show results for RFC and SERC because there are no coal units in updating states of the NPCC.

We see striking variation by region. For NGCC, we see results consistent with our core results in the RFP and NPCC regions, but a different pattern in SERC. For coal, we see relatively little response to the emissions price in SERC, and the response seems to be fixed over the day. Conversely in RFC, we see results consistent with our core results.

One possible reason that units in SERC appear to respond differently is that SERC is dominated by traditionally regulated utilities. Therefore we test the impact of traditional regulation and deregulation in Appendix C.3.

Figure C.1: Map of NERC Regions

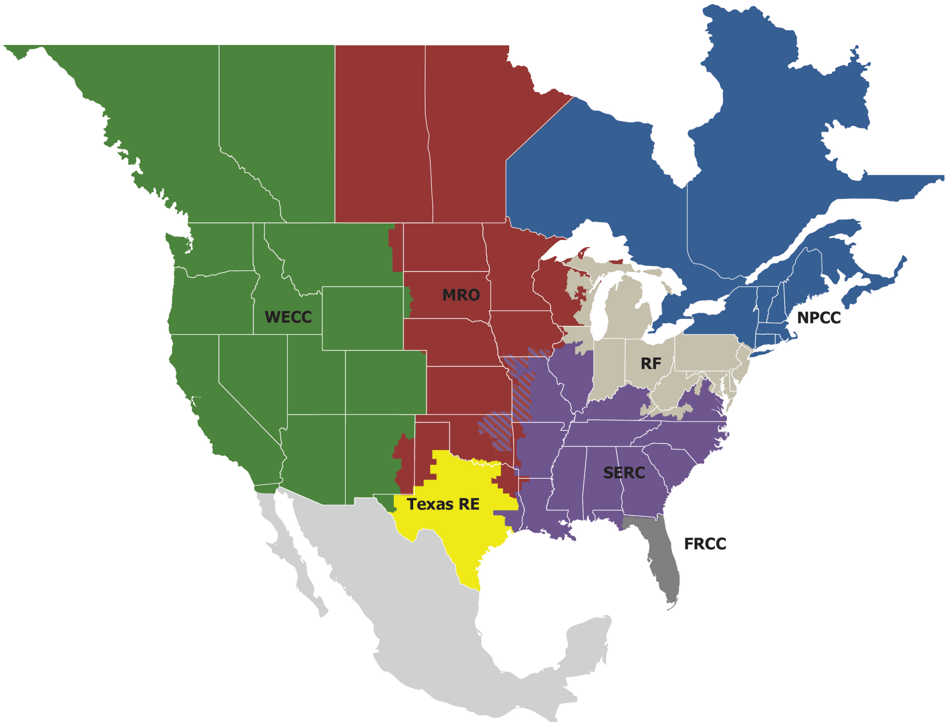


Figure C.2: NGCC Updating by NERC region

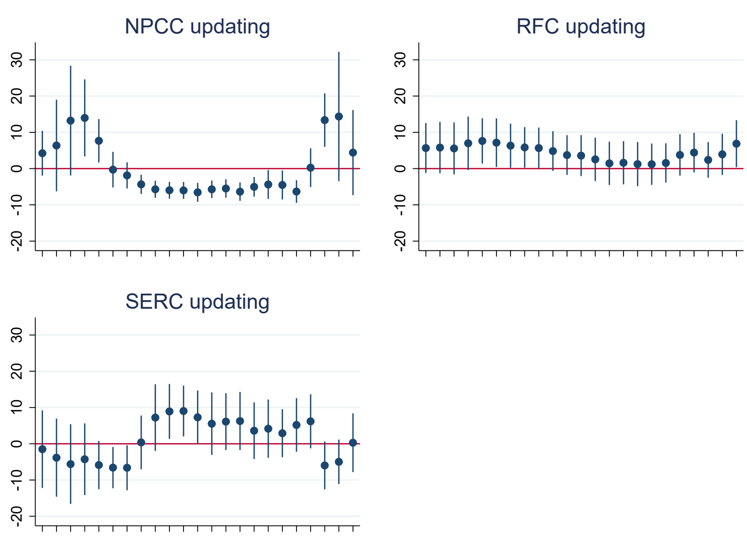


Figure C.3: NGCC NOx Price by NERC region

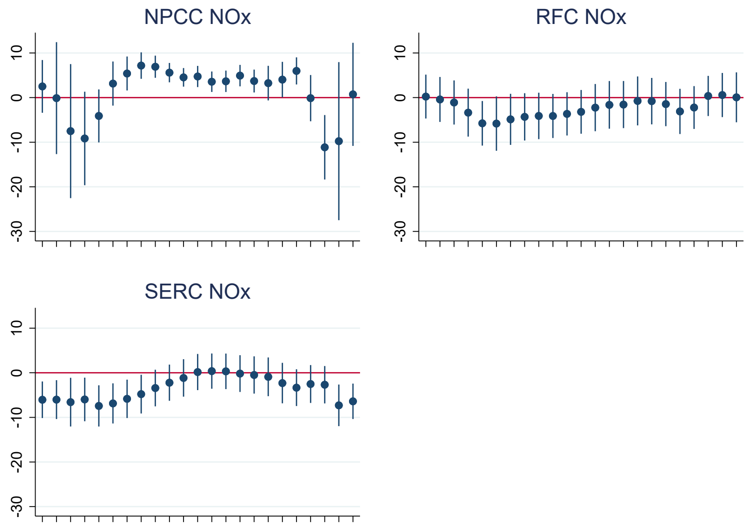


Figure C.4: Coal Updating by NERC region

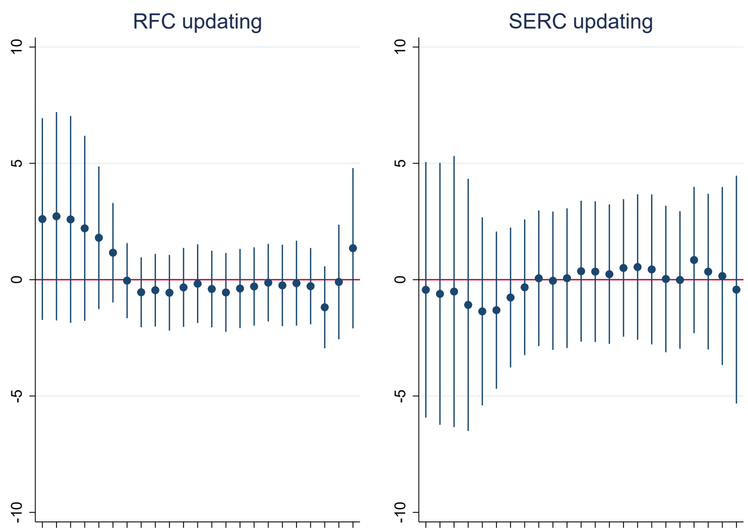
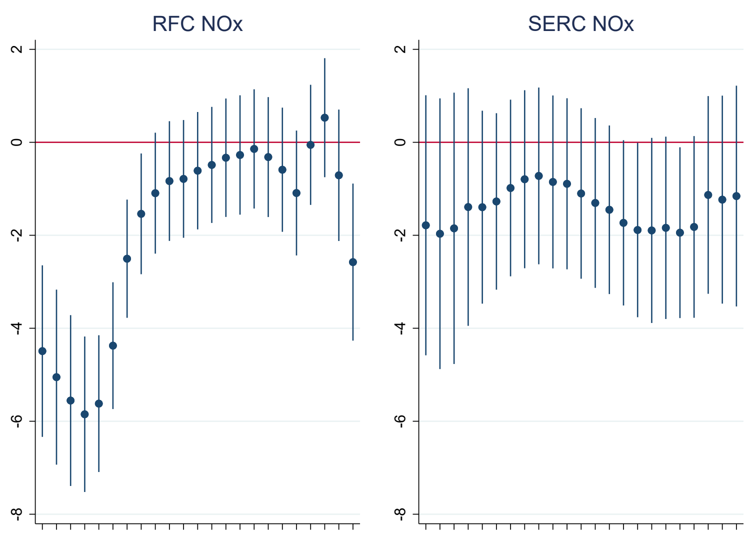


Figure C.5: Coal NOx Price by NERC region



C.3 Heterogeneity by Deregulation Status

This section tests whether firms' responses to the NOx price and updating subsidy varied by their deregulation status. Many states deregulated their electricity markets in the late 1990's and early 2000's, generally shifting generation into competitive markets. Other states still have traditional monopoly generators. Prior work has used this pseudo-experimental variation and found that deregulation was associated with efficient operations at generating units (Fabrizio, Rose, and Wolfram 2007). In this section, we repeat the core analysis of Figures 3 and 4, but allow the effects to vary by whether a plant is in a deregulated state.[19] For brevity, we only use the treatment indicator in this section.

First let us consider the NOx price. Figures C.6 and C.7 provide evidence that deregulated generation units and regulated units respond similarly to the emissions constraint. While the differences are generally not statistically significant, it does appear that deregulated units may respond more strongly to the emissions price than regulated plants. This would be consistent with prior literature - regulated units can pass their costs through to customers, so face weaker incentives (Fabrizio, Rose, and Wolfram 2007; Borenstein and Bushnell 2015; Cicala 2017). The left panel of Figure C.6 suggests that deregulated NGCC plants reduce overnight generation in response to the NOx price, although only for a few hours.

Now consider the updating subsidy. In the left panel of Figure C.8, we see that deregulated NGCC units seem to increase overnight generation in response to the subsidy. Conversely, on the right panel see see that regulated plants may increase daytime generation.

[19] We assume that a generation unit is deregulated if it is in CT, DE, IL, MA, MD, ME, MI, MT, NH, NJ, NY, OH, PA, RI, or TX. We also treat all deregulation is equal. This is a simplification of the actual rules.

Again, regulated facilities face weaker profit-maximization pressures than deregulated facilities.

Finally, in Figure C.9, the effect of updating on coal generation is not significant. However, Figure C.9 does suggest that deregulated coal plants may increase overnight generation in response to the subsidy while regulated plants do not seem to respond.

Figure C.6: NGCC NOx Price by Deregulation Status

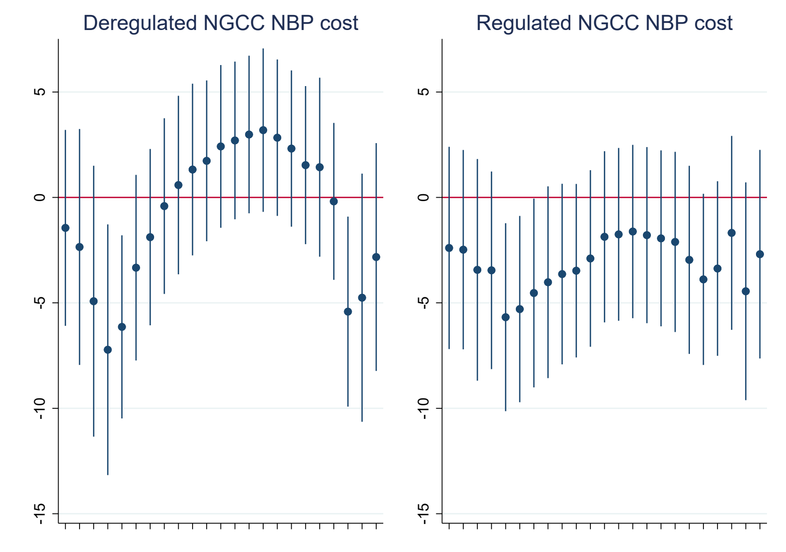


Figure C.7: Coal NOx Price by NERC region

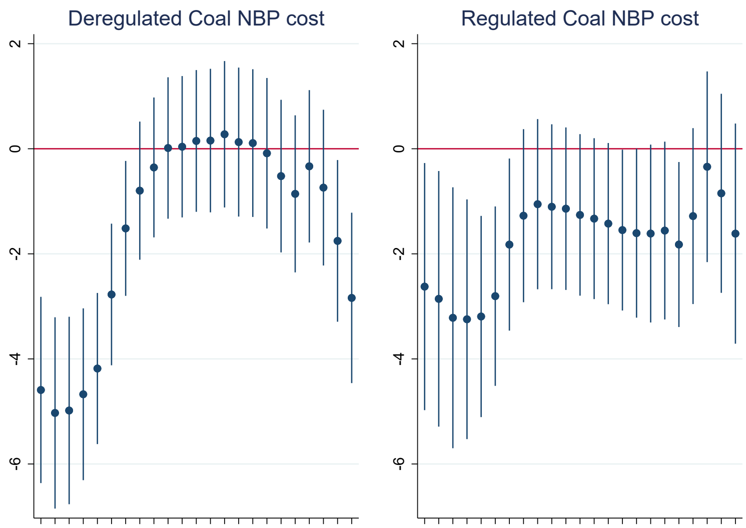


Figure C.8: NGCC Updating by Deregulation Status

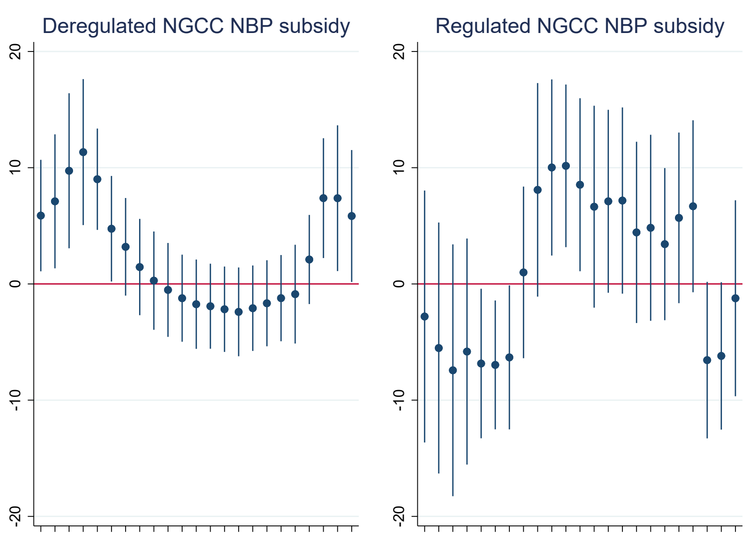
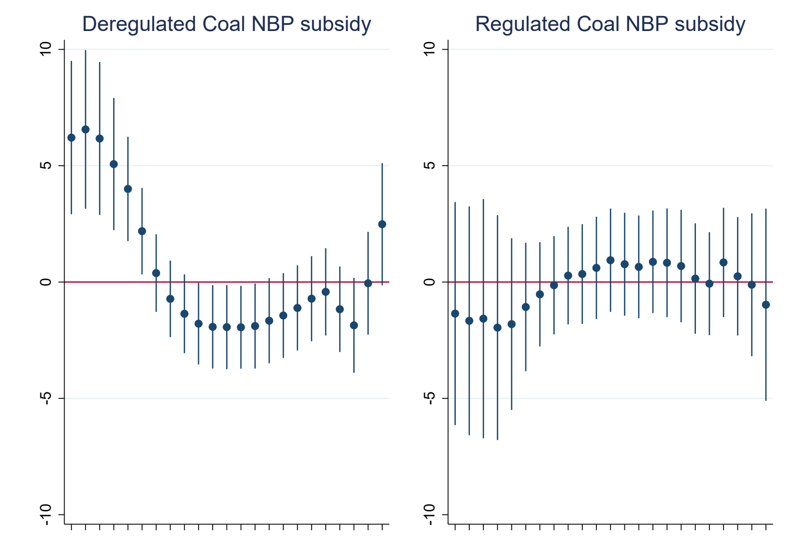


Figure C.9: Coal Updating by Deregulation Status



C.4 Time Window

Our core specifications used a window of three weeks before and after the start of each NOx season. This is chosen in somewhat ad-hoc fashion. Here we estimate our core model using a narrower 10 day window and a broader 6 week window before and after the start of NOx season - that is, half and twice the baseline time window. Results are generally similar to our core results.

Figures C.10-C.13 report results for the 10 day window. We see a similar pattern to Figures 3-6 - the updating subsidy was associated with an increase in NGCC generation and the NOx price was associated with a decrease in coal generation. Some results had weaker statistical significance than our core results, especially those of Figure C.12. This likely reflects the smaller sample size dominating the more homogenous nature of the sample.

Figures C.14-C.17 report results for the 6 week window. Comparing them to to Figures 3-6, the results are quite similar. Generally the standard errors are smaller, but we still see evidence that NGCC units increase overnight generation under the subsidy and coal units decrease overnight generation under the NOx price.

One surprise is that in some hours, α_U^h is positive and statistically significant ($p < 0.05$) in C.14. This may be due to SUTVA violations. Notably, we do not see this effect in Figure C.16, which uses a continuous measure of the NBP cost.

Figure C.10: NGCC Results with Discrete Treatment, 10 day window

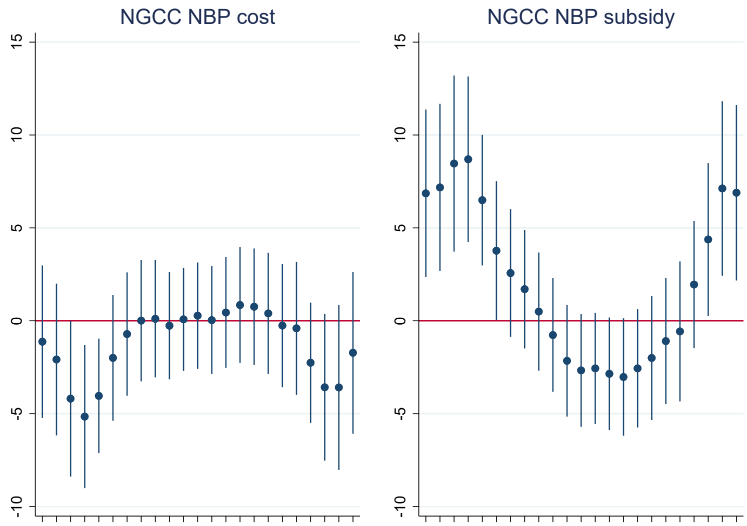


Figure C.11: Coal Results with Discrete Treatment, 10 day window

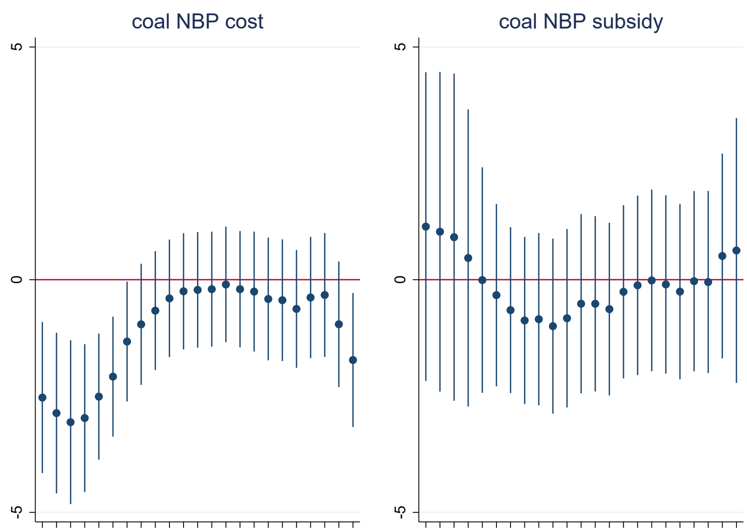


Figure C.12: NGCC Results with Cost Measure, 10 day window

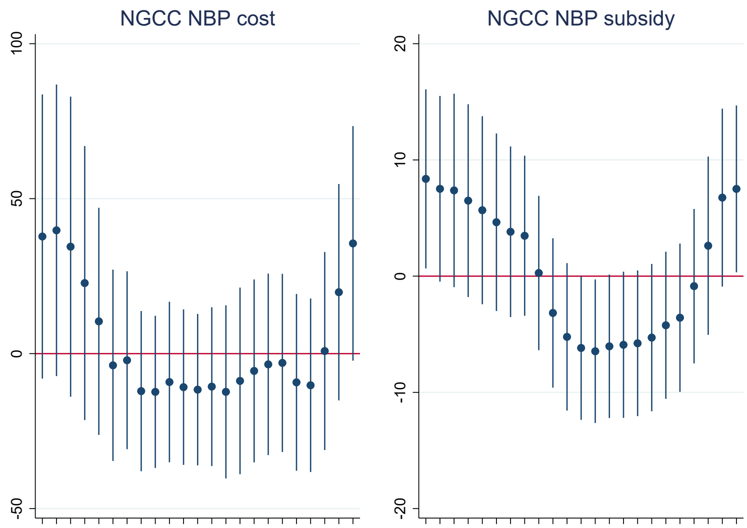


Figure C.13: Coal Results with Cost Measure, 10 day window

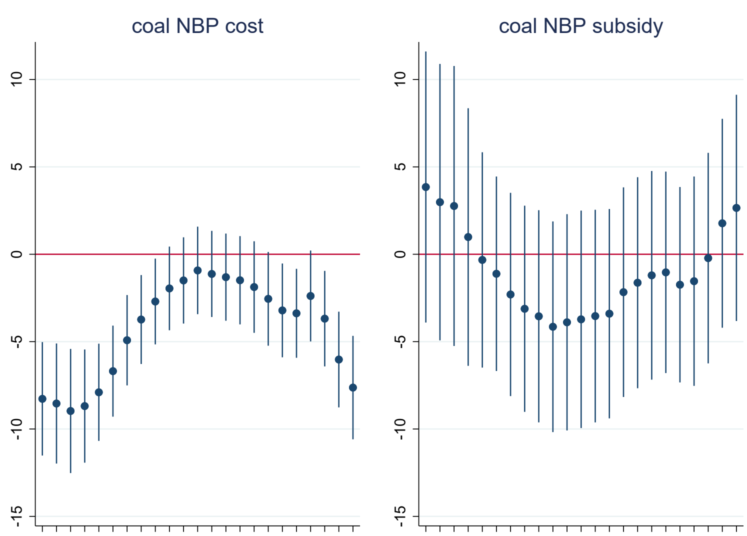


Figure C.14: NGCC Results with Discrete Treatment, 6 week window

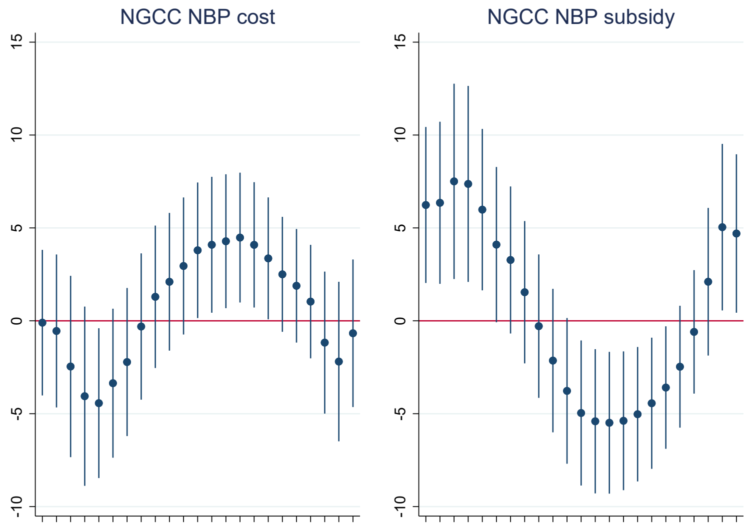


Figure C.15: Coal Results with Discrete Treatment, 6 week window

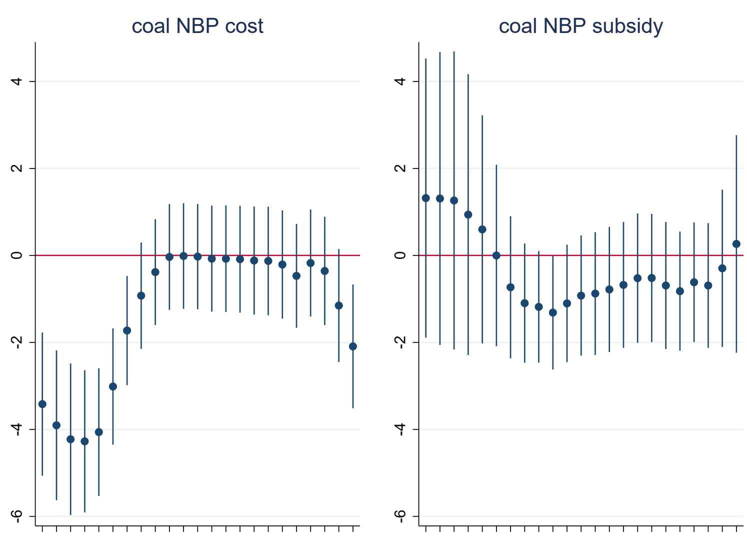


Figure C.16: NGCC Results with Cost Measure, 6 week window

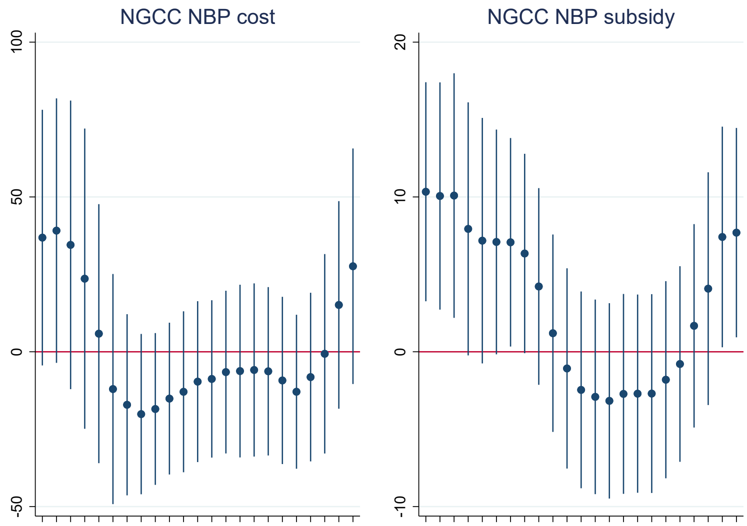


Figure C.17: Coal Results with Cost Measure, 6 week window