Fuel Prices, Restructuring, and Natural Gas Plant Operations

August 13, 2016

Abstract

Switching from coal-fired to natural gas-fired generation and increasing the thermal efficiency (energy generated per unit of energy burned) of fossil fuel fired electricity generation plants have been identified as ways of achieving meaningful emission reductions. In this study, we examine the fuel-price responsiveness across gas plant technologies and across the market structures in which the plants operate. We find that there are significant differences in the generation and efficiency responses of gas plants to fuel prices across generation technologies and market structures. Specifically, our results indicate that, regardless of market structure, generation from natural gas combined cycle (NGCC) plants is responsive to both coal and gas prices, but that generation from simple cycle (NGSC) plants only respond to gas prices. On the other hand, with respect to efficiency, we generally find that only NGCC plants operating in deregulated regions show statistically significant efficiency improvements in response to coal price increases and that, generally, neither NGCC or NGSC plants, regardless of market structure, respond in any significant way to gas prices. Finally, using these parameter estimates, we calculate emissions savings from efficiency improvements and fuel-switching possibilities.

1 Introduction

Recent regional environmental regulations, such as the Regional Greenhouse Gas Initiative or California's AB32 regulations, and federally proposed regulations, such as the Clean Power Plan (CPP), have prompted regulators and state officials to consider ways to reduce the CO_2 emissions intensity of states' electricity generation sectors. Two possible ways that a state may reduce the emissions intensity of its electricity sector in a meaningful manner is by improving the thermal efficiency (electricity generated per unit of energy burned) of its fossil-fueled plants and by switching generation from coal-fired plants to natural gas-fired plants. Indeed, the Environmental Protection Agency (EPA) has used the possibility for coal-to-gas switching and efficiency improvements in coal-fired plants as two of their "building blocks" to determine the CO_2 emissions intensity rates (emissions per MWh of generation) of states' electricity generation sectors under the proposed Clean Power Plan.

In terms of efficiency improvements, much of the EPA's attention, as well as that of several recent academic studies, has deservedly been focused on the potential for efficiency improvements in coal-fired plants. However, considerably less work has been directed toward incentives for efficiency gains from natural gas-fired plants. This may seem unnecessary given that gas plants have about half the CO_2 emissions intensity as coal plants and far less emissions of other regulated pollutants such as NO_X and SO_2. Despite lower emissions, relative to coal, gas plants do still emit roughly 0.5 tons of CO_2 per MWh. Additionally, the share of gas-fired generation has increased dramatically in the U.S. over the last several years, going from about 20 percent of total generation in the early 2000's to about 25 to 30 percent in recent years. We therefore take a focused look at drivers of thermal efficiency improvements among gas-fired plants in the U.S., paying particular attention to the impact of fuel prices across gas-fired technologies and regulatory status. Similarly, we also examine how fuel prices affect natural gas plant generation levels across technology types and regulatory status. We then use these estimates to shed light on how emissions pricing affects emission reductions via efficiency improvements and coal-to-gas switching and how market regulation and technology holdings across states may impact these reductions.

This paper is, of course, not the first to explore determinants of utilization rates and thermal efficiency. In particular, given the relatively recent fall in U.S. natural gas prices, several studies have explored how this price change has altered generation and emissions from the electricity sector. For example, Linn et al. (2014) use plant-level data to examine how generation responds to fuel prices, finding, as expected, that generally generation for coal-fired (gas-fired) plants increase (decrease) when gas prices increase and decrease (increase) when coal prices increase.[1] Relatedly, Knittel et al. (2015) examine how entities, considered at a plant and firm level, which operate both gas- and coal-fired units, alter their share of natural gas burned in response to coal and gas prices and how these results differ across entities operating in traditional cost of service regions and those with access to competitive wholesale markets. They find that natural gas shares in multi-fuel plants and for multi-fuel firms do respond in expected ways to coal and gas prices, though, somewhat surprisingly, they generally only find statistically significant price-responses in cost-of-service regulated regions.

Using higher frequency daily data, Fell and Kaffine (2014) and Holladay and LaRiviere

[1] Fuel price effects are also examined on the dependent variables fuel consumption and CO_2 emissions in Linn et al. (2014). The general results for these dependent variables largely follow that for the corresponding regressions using generation as the dependent variable

(2014) find that coal plants' generation response to the coal-to-gas price ratio increases when wind generation increases and that during the hydraulic fracturing-induced low-gas price regime has led to some significant changes to the dispatch order of coal and gas generation in some regions, respectively. Similarly, Holladay and Soloway (2013) explore the effect of fuel-switching behavior of oil-fired plants in the New York City area, finding that when the diesel prices are approximately \$4/MMBtu more than natural gas, oil-fired plants switch to burning natural gas.

Several other recent efforts have also explored the determinants of thermal efficiency in fossil-fuel power plants. Many of these studies explore the efficiency effects of electricity market deregulation. More specifically, in the 1990's many countries and several states in the U.S., began to dismantle large, integrated electric utilities that had delivered electricity as regulated monopolies under cost-of-service agreements. In the place of these integrated utilities, regulators set up electricity markets where ostensibly independent generators bid power into markets and distribution companies purchased the power, eventually selling it to end consumers. Economist argue that this market-based system should incentivize efficiency in generators relative to traditional cost-of-service regulation. However, empirical evidence of this hypothesized efficiency improvement has been somewhat mixed, with some studies finding no evidence of efficiency improvements (Fabrizio et al. (2007)), and others finding small, but statistically significant deregulation impacts on efficiency (Bushnell and Wolfram (2005) and Chan et al. (2013)).

In addition to the impacts of market regulation on efficiency, there is also a long literature examining how input prices drive efficiency. Empirical examples of this type of literature fall largely outside the electric power generation industry (e.g. Dubin and McFadden (1984), Metcalf and Hassett (1999), Linn (2008), Alcott and Wozny (2014)), but Linn et al. (2014) provides an example more in line with this paper. Using panel data on coal-fired plant operations from 1985 – 2009, Linn et al. (2014) estimate the relationship between plant heat rates (the inverse of thermal efficiency) and coal prices over five-year intervals. They find, under some specifications, that a 1 standard deviation increase in coal prices decreases heat rates (improves efficiency) by about 1.5 percent.

Our study combines elements of the efficiency and generation response studies mentioned above, but differentiates itself from previous efforts in several key ways. First, unlike those focusing directly on coal-fired plants or inclusive of all plants, we focus on the price responses of gas-fired plants, an increasingly important source of generation in the U.S. This helps remove possible confounding factors and, as we show is important, avoids over aggregation of responses that one may encounter if one is forcing common responses across all fossil-fuel plants or even if aggregating responses within generators that burn a common fuel type.[2] The focus on gas-fired plants and on technology- and market-disaggregated responses also differentiates us from most previous efforts exploring plant-level thermal efficiency. Given the possibility for general difference in operation costs across technologies and different incentives for efficiency across regulation structures, allowing for such response flexibilities is key to understanding gas plants' price responsiveness. Finally, by looking at both generation and efficiency price-responsiveness using the same data set and similar techniques, we can further highlight that while generation responses are largely as expected, efficiency responses have some less intuitive outcomes - a point we examine in our theoretical modeling framework.

[2]Note that Linn et al. (2014) and Knittel et al. (2015), the papers most similar to our with respect to exploring generation responses to fuel prices, do not disaggregate the results with respect to gas-fired technology.

Using annual plant-level data from 2002 - 2012, our results indicate that there is a generation and efficiency responsiveness to input-fuel prices for gas-fired plants and that there are considerable differences in the responses across natural gas generation technologies. More specifically, we find, similar to Linn et al. (2014), when estimating a restrictive model that forces the responsivenesses of net generation to natural gas and coal prices to be the same across generation technologies and regulatory structures that the responses are as expected; net generation negatively responds to increasing natural gas prices and positively responds to coal prices. When we allow for different responses across natural gas combined cycle (NGCC) and natural gas simple cycle (NGSC) technologies, we do find net generation of NGCC plants responds positively to rising coal prices and negatively to rising gas prices, both at statistically significant levels, whereas NGSC respond (negatively) only to gas prices.

With respect to thermal efficiency improvements, the results are perhaps less aligned with general expectations. We find that increasing coal prices drive efficiency improvements among NGCC plants in deregulated regions and, under some specifications and to a slightly lesser extent, among NGCC plants in regulated regions. This incentive for efficiency improvements does not appear to be present for NGSC plants in traditional cost of service regions or in more competitive markets as we find no statistically significant improvements to thermal efficiency in response to coal price increases. We also find that neither NGCC or NGSC plants, regardless of the regulatory status, have consistently significant thermal efficiency responses to changes in natural gas prices. This may seem odd as we often expect to see efficiency improvements across a wide range of industries in response to an increase in the price of a production input. However, as we show below in the basic model of efficiency choice, the somewhat unique set up of electricity supply leads to an ambiguous response of gas-fired plants' efficiency decisions with respect to gas price changes. The general intuition behind this result comes from the ability of an efficiency improvement to increase the number of inframarginal operating hours for a plant. When coal prices increase, lower cost gas plants, such as NGCC plants, have an incentive to increase efficiency in order to potentially become inframarginal during hours when coal plants are marginal. However, when gas prices increase, the ability to become inframarginal during periods when coal is on the margin is diminished even with heat rate improvements. Additionally, if the gas price increase is felt by all gas-fired plants and electricity demand is relatively inelastic, the period over which a plant is inframarginal when a gas-fired plant is on the margin will remain relatively constant even if the plant does not improve its heat rate. Both factors diminish the responsiveness of gas plant efficiency to natural gas prices.

Finally, to help put our estimates in context, we calculate implied net generation, efficiency, and emission changes under various CO_2 emissions taxes, which can equivalently be viewed as altering the cost of burning various fuels (see Cullen and Mansur (2014)). Our simulation results indicate that carbon taxes would increase generation from NGCC plants, both in regulated and deregulated regions, and decrease generation from NGSC plants, particularly in deregulated regions. A carbon tax also significantly improves thermal efficiency of NGCC plants in restructured regions, with our results implying a 10 percent improvement in thermal efficiency resulting from a $\$20/tCO_2$ tax. In terms of emission reductions, as one may expect, the increased generation from NGCC plants, assuming it displace coal generation, is the channel that leads to the most significant emission reductions. However, for NGCC plants in restructured regions, emission reductions due to efficiency improvements account for about 30 percent of the total NGCC-based emissions reductions.

The rest of the paper is organized as follows. In the next section, we present a basic model to help build intuition about expected price responses. In Section 3, we discuss the data and empirical methods employed. Section 4 reviews the data and section 5 presents the results from our main specification and across a variety of robustness checks, as well as explores policy implications through simple back-of-the-envelope type calculations. Concluding remarks are given in section 6.

2 Expected Responses

To begin, we construct a graphical representation of an electricity market model to gain simple insights into what we may expect to occur to net generation of different technologies given changes in input prices. Consider a simple electricity market with three generators; a coal-fired generator, a NGCC generator and NGSC generator, each with marginal costs of production (MC_i) such that our original setting is one where $MC_{coal} < MC_{NGCC} < MC_{NGSC}$. Consider also two different demand levels; high demand (D_H) and low demand (D_L). This market setting is represented in panel (a) of Figure 1 and labeled as our base case. Note under the low demand case, NGCC is the marginal generator and NGSC does not produce and under high demand NGSC is on the margin and NGCC produces its maximum level (i.e., NGCC is inframarginal).

Let us now consider what happens when natural gas prices drop. Holding all other factors constant, this natural gas price decrease lowers the MC's of NGCC and NGSC. The market clearing quantities under these lower MC's will move to the right of our base case scenario as shown in panel (b) of Figure 1 (the intersections of demand and the supply curve are to the right of the dashed vertical line which represents the equilibrium quantities under the base case). This then implies that if data was aggregated temporally such that it included both the high and low demand states, the net generations' of both NG technologies will appear to positively respond to a decrease in natural gas prices. Similarly, it is straightforward to show under this set up that an increase in natural gas prices, and thus increases in MC_{NGCC} and MC_{NGSC}, will lead to reduction in generation from NGCC and NGSC.[3]

If instead, coal prices increase such that $MC_{NGCC} < MC_{coal}$, as we show in panel (c) of Figure 1, then NGCC will become inframarginal under both high and low demand states. Again, if the temporal aggregation of data includes both demand states, then the net generation of NGCC will appear to have a positive response to increases in coal prices.[4] NGSC plants, on the other hand, will not appear responsive to coal prices.

This simple illustration thus shows that the net generation of some low-cost NG technologies (e.g. NGCC plants) may be responsive to both coal and natural gas prices, while other, more high-cost types (e.g. NGSC plants), may only be responsive to its own input price. Additionally, the setting for this simple illustration is a competitive supply and demand model, but is still relevant for those plants operating in a traditional cost-of-service regulated environment. More specifically, if the regulated utility has a mandate to provide power in a low-cost manner, they will set the dispatch order based on marginal cost of generation. If this is the dispatch ordering decision for the regulated utility, the responses will be the same as described above.

[3]Note that in this setting if we have perfectly inelastic demand, natural gas price changes will not affect the generation levels of NGCC or NGSC.

[4] If coal prices decreased in this setting, the NG generators would have no change in production. However, in a system that has a supply curve that does not so discretely jump from one producer type to another and one that allows more demand states it would possible that a drop in coal pries could lower generation from lower cost NG-fired generators.

Next, we develop a simple model of plant-level efficiency investment for a natural gas-fired plant in a competitive wholesale electricity market with the goal of displaying how fuel price changes affect incentives for a firm's efficiency. In competitive industries with approximately equivalent producers, we generally think of higher input prices as driving efficiency in the use of these inputs. The model below shows the result is not so simple within the context of electricity production.

We consider the behavior of a given natural gas plant. The plant chooses its change in thermal efficiency, measured as the change in heat rates as $\Delta HR = HR_0 - HR_1$ where HR_0 is the heat rate before any heat rate changes and $HR_1$is the ending heat rate, that will hold over some pre-determined planning horizon.[5] In this setting, $\Delta HR > 0$ is an improvement in efficiency as lower heat rates are associated with more efficient fuel use (more MWh's per MMBtu of fuel burned). The changing heat rate, along with natural gas prices, affects the plant's marginal cost of generation, $MC\left(\Delta HR, C^{NG}\right)$ where C^{NG} is the plant's per-unit cost of natural gas over the planning horizon and with $\frac{\partial MC}{\partial \Delta HR} < 0$, $\frac{\partial MC}{\partial C^{NG}} > 0$, and $\frac{\partial MC}{\partial \Delta HR \partial C^{NG}} < 0$.[6] While efficiency improvements can lower marginal costs of generation, heat rate alterations come at a cost, $C(\Delta HR)$ with $C'(\Delta HR) > 0$ and $C''(\Delta HR) \geq 0$.

Natural gas prices and heat rates also affect the generation level chosen by the firm. We

[5]Choosing heat rate levels over some planning horizon seems a reasonable assumption if efficiency improvement come largely in the form of capital improvements and/or contracted labor agreements.

[6]For example, a reasonable formulation such as$MC(\Delta HR, p^{NG}) = (HR_0 - \Delta HR) \times C^{NG}$ will lead to the partials described here. Note also we assume that marginal cost is constant with respect to generation levels. This omission is not relevant to the simple model here, but we do consider impacts that generation levels may play in heat rates, and thus marginal costs, in the empirical analysis.

assume that the firm chooses hour i production such that:

$$q_i = \begin{cases} q^m & \text{if } p_i \geq MC \\ \\ 0 & \text{otherwise} \end{cases} \tag{1}$$

where q^m is the capacity production at the gas power plant and p_i is hour i's electricity price.[7] Let us further assume that $H\left(C^C, C^{NG}, \Delta HR\right)$ is the number of operating hours over some evaluation horizon such that $H\left(C^C, C^{NG}, \Delta HR\right) = \sum_{i=1}^{N} 1(p_i \geq MC)$, where N is some number of hours over which a plant evaluates heat rate alterations, $1(\dot{})$ is an indicator function equal to one if $p_i \geq MC$, and C^C is the average cost of coal for competing plants over the evaluation horizon. These operating hours for a gas plant are a function of the plant's heat rate decisions, natural gas costs and coal costs, such that, ${}^{\partial H}/_{\partial C^C} \geq 0$, ${}^{\partial H}/_{\partial C^{NG}} \leq 0$, ${}^{\partial H}/_{\partial \Delta HR} \geq 0$, ${}^{\partial^2 H}/_{\partial \Delta HR \partial C^C} \leq 0$ and ${}^{\partial^2 H}/_{\partial \Delta HR \partial C^{NG}} \geq 0$.[8] Finally, let us define the average electricity price over the hours the plant is operating as $p(C^C, C^{NG})$, specifically $p(C^C, C^{NG}) = \frac{1}{H}\sum_{i=1}^{N} 1(p_i \geq MC)p_i$ with reasonable partials of ${}^{\partial p}/_{\partial C^C} \geq 0$ and ${}^{\partial p}/_{\partial C^{NG}} \geq 0$.[9]

[7] Note if $p_i = MC$ the firm may not be able to produce at its maximum level and still have the market clear, but without much loss of generality we ignore this possibility. We also ignore ramping constraints that may make it prohibitively expensive to go from zero production to q^m on an hourly basis. While this omission may be a considerable diversion from reality, adding more realistic ramping conditions appear unlikely to affect the general point of the model below.

[8] A functional form for $H(\dot{})$ is difficult to specify exactly, but these partial seem reasonable. For example, if a plant is just off the margin in some hours, increasing ΔHR should increase hours of operation. If a plant is near cost competitive with coal plants then an increase in coal prices should increase H. If a plant is the marginal plant some hours or inframarginal when coal is on the margin, gas price increases would lower H. The marginal benefit of improving heat rate in terms of increasing H seems likely to diminish as gas prices increase. Finally, the marginal benefit of improving heat rate in terms of increasing H seems likely to increase as coal prices increase, particularly for plants that are initially near cost-competitive with coal plants.

[9] Technically, p would also be a function of ΔHR. More specifically, we would expect ${}^{\partial p}/_{\partial \Delta HR} \leq 0$ because as effiency increases the plant is infra-marginal more hours and therefore adds more relatively low-priced hours to the average price calculation that defines p. However, if we assume a relatively continuous electricity

Given these definitions, we can define the firm's maximization problem as:

$$\underset{\Delta HR}{max} \pi = q^m \Big[p(C^C, C^{NG}) - MC(\Delta HR, C^{NG}) \Big] H(C^C, C^{NG}, \Delta HR) - C(\Delta HR) \tag{2}$$

The first order condition for maximization then implies:

$$\frac{\partial \pi}{\partial \Delta HR} = q^m \Big[(p - MC) \frac{\partial H}{\partial \Delta HR} - \frac{\partial MC}{\partial \Delta HR} H \Big] - \frac{\partial C}{\partial \Delta HR} = 0 \tag{3}$$

To assess the effect of an increase in coal prices on efficiency improvements we can differentiate the left hand side of (3) with respect to C^C to explore how NGCC plants may react to increasing coal prices. This leads to:

$$\frac{\partial^2 \pi}{\partial \Delta HR \partial C^C} = q^m \Big[\frac{\partial p}{\partial C^C} \frac{\partial H}{\partial \Delta HR} + (p - MC) \frac{\partial^2 H}{\partial \Delta HR \partial C^C} - \frac{\partial MC}{\partial \Delta HR} \frac{\partial H}{\partial C^C} \Big] > 0 \tag{4}$$

If we assume $\partial p / \partial C^C > 0$, $\partial H / \partial \Delta HR > 0$, $\partial H / \partial C^C > 0$, and $\partial^2 H / \partial \Delta HR \partial C^C > 0$, (4) implies that an increase in coal prices would increase the left-hand side of (3). Assuming a convex cost function for $C(\Delta HR)$ then we must also have ΔHR increase (i.e. efficiency increase) in response to an increase in coal prices to maintain the equality in (3). Of course, if the given plant has relatively high MC, as we generally assume is the case for NGSC plants, then the average price received by the plant and hours that the plant is operating will be unaffected

supply curve, then $\partial p / \partial \Delta HR \approx 0$ because the prices added to the average price calculation will be similar to those already included. We make such an assumption and ignore the affect of heat rate improvements on average electricity prices. One however could add this to the model and the results below will hold so long certain reasonable assumptions about marginal effects hold.

by coal prices. In this case, the heat rates will appear largely unresponsive to coal price changes.

To evaluate the impact of a change in natural gas prices on efficiency investments we can similarly differentiate (3) with respect to C^{NG}. This gives us:

$$\begin{aligned}\frac{\partial^2 \pi}{\partial \Delta HR \partial C^{NG}} =& q^m \Bigg[\left(\frac{\partial p}{\partial C^{NG}} - \frac{\partial MC}{\partial C^{NG}} \right) \frac{\partial H}{\partial \Delta HR} + (p - MC) \frac{\partial^2 H}{\partial \Delta HR \partial C^{NG}} \\ & - \frac{\partial^2 MC}{\partial \Delta HR \partial C^{NG}} H + \frac{\partial MC}{\partial \Delta HR} \frac{\partial H}{\partial C^{NG}} \Bigg] \gtreqless 0 \end{aligned} \tag{5}$$

Signing this cross-partial is not straightforward. Examining the first two terms in parentheses there is a positive subtracted from another positive. This first set of terms creates an ambiguous sign. We might assume that the electricity price change due to a change in natural gas costs might exactly off set the change in marginal costs, if a gas fired plant is on the margin and setting the market price for electricity. In this case, the first set of terms would become zero, however, even with this assumption the sign of the equation is still ambiguous.

The reason for this ambiguous sign is created by two opposing incentives faced by the power plant. The final two terms of (5) are the standard partial effects of the increase in an input fuel on the marginal benefit of increasing efficiency and are, as usual, positive.[10] However, the if marginal value of an efficiency improvement in terms of hours operating is declining as natural gas prices increase, so $\frac{\partial^2 H}{\partial \Delta HR \partial C^{NG}} < 0$ and, thus, the term $(p - MC) \frac{\partial^2 H}{\partial \Delta HR \partial C^{NG}} < 0$. To put it another way, this effect implies that with higher natural

[10] Again, assuming $\frac{\partial^2 MC}{\partial \Delta HR \partial C^{NG}} < 0$ and noting that both $\frac{\partial MC}{\partial \Delta HR}$ and $\frac{\partial H}{\partial C^{NG}}$ are negative leads to an overall positive sign on the last two terms of (5).

gas prices, improving efficiency is not going to be as effective in increasing the number of infra-marginal hours for the plant, so there is a diminished incentive to increase efficiency in this case. These two opposing forces, the value of improving efficiency in terms of its impact on marginal costs increases as natural gas prices go up and the value of improving efficiency in terms of its impacts on hours operating decreases as natural gas prices go up, is the root of the ambiguous sign impact of a natural gas price increase on the plant's incentive to increase efficiency. Note also that, unlike responses to the coal price changes, the described ambiguity in response to the natural gas price changes holds more generally for all types of natural gas plants.

3 Empirical Methodology

While the previous section lays out plausible responses of net generation and heat rates to changes in input prices across the two types of natural gas generation technologies, it remains an empirical question as to the magnitudes of these responses. Additionally, the previous theoretic section was largely set up in the framework of plants in a competitive market structure, but much of the electricity generation sector in the U.S. operates as regulated monopolies. Plants in these cost-of-service territories could have different incentives for efficiency and possibly for generation more generally. Thus, the aim of our empirical investigation is to identify the impacts of input fuel prices on both generation and efficiency decisions at natural gas power plants, allowing these responses to vary by generation technology and regulatory status.

We use a panel dataset with prime mover specific data on heat rates and net generation, plant level natural gas prices, regional coal prices, and various other prime mover, plant and regional characteristics. Our estimating equations can be encompassed in the general form as follows:

$$y_{it} = \sum_{j \in J} \beta_j D_i^j P_{it}^C + \sum_{j \in J} \theta_j D_i^j P_{it}^G + \boldsymbol{x'_{it}\gamma} + \alpha_i + \delta_t + \epsilon_{it} \tag{6}$$

The dependent variable y_{it} represents the log of net generation or log of heat rate. P_{it}^C, P_{it}^G are the logged values of coal and natural gas prices. Other time variant observable covariates are represented by the matrix $\boldsymbol{x'_{it}\gamma}$. We add in α_i and δ_t as plant and year fixed effects, respectively. ϵ_{it} is the stochastic error term.

Responsiveness of various technologies and market structures are incorporated through interaction dummies, D_i^j. In our most restrictive modeling form (Specification 1), we force the price responsiveness of all prime movers to be the same regardless of technology or market structure. In this case, $J = All$ is a single element set (i.e., $D_i^{All} = 1 \ \forall i$) and coal and gas price responsiveness measures are picked up by β_{All} and θ_{All}, respectively. Next (Specification 2), we allow for differing responses across technologies, broadly defined as CC and SC prime mover. In this case, $J = [CC, SC]$, with $D_i^{CC} = 1$ if plant i is an NGCC plant and 0 otherwise and $D_i^{SC} = 1$ if plant i is an NGSC plant and 0 otherwise. For Specification 3, we differentiate responses by technology class *and* market structure, defined as regulated (i.e. cost-of-service region) and restructured (i.e. competitive electricity market region). For this specification $J = [CC \times RST, CC \times REG, SC \times RST, SC \times REG]$, where $D_i^{CC \times RST} = 1$ if the NGCC plant is in a restructured region, $D_i^{CC \times REG} = 1$ for NGCC plants is in a regulated region, $D_i^{SC \times RST} = 1$ for NGSC plants in restructured regions, and $D_i^{SC \times REG} = 1$

for NGSC plants in regulated regions.

4 Data

For our analysis, we use a panel data set consisting of 756 natural gas power plants from 2002-2012, allowing us identification through variation cross-sectional plant differences and changes in operations within a plant over time. The data set is annual prime mover level data for gas-fired power plants in the contiguous United States. Additionally, we limit our analysis to power plants classified as "electric non-utility", "electric utility", or "NAICS-22 non-cogen." This excludes any co-generation power plants (i.e. combined heat and power) and any industrial or commercial power plants, for example, power plants owned and operated by one company for an internal purpose. We drop these power plants as their objective function may involve alternative motives other than selling generated electricity to the grid.[11]

We aggregate the data to an annual level for three main reasons. First, the cost data is split into monthly and annual respondents. Only gas plants with a nameplate capacity greater than 200 megawatts are required to report monthly. A monthly level analysis would exclude many of the small to medium sized gas plants from the analysis. Second, by using annual data we avoid gaps in the data at the monthly level, such as missing data due to a plant maintenance shut down or missing cost data if a plant did not receive any fuel deliveries for that month. Lastly, it would seem unlikely that plants are making many substantial short term (less than year) changes to heat rates and therefore the aggregation would be needed for identification.

[11] Note all non-binary variables described below are log-transformed in our analysis.

To form our data set, we first designate generation technologies as NGCC and NGSC generators. The technology, designated as the "prime mover", of the generating units, along with the fuel burned by the units, within a given plant are listed in the EIA-923 and EIA-860 forms. To form the various variables taken from these forms for a given "NGCC plant" we sum the variable in question across the units within a plant for the given time period that have a NGCC prime mover code.[12] A similar aggregation is done over the simple cycle prime movers to form NGSC plant observations.[13] This type of within-plant summing is used to form all the variables described below.

We also must designate the market structure for the given plant. To determine the market structure, we used information from the EIA's website on market restructuring. A total of 15 states in our sample are consider to have restructured competitive markets, based on the EIA's designation.[14] It is also important to recall that since our sample begins in 2002, which is post implementation of new market systems for all states that restructured, we avoid any ambiguity of when legislation was passed and the appropriate timeframe when power plants react to market restructuring.[15] In our robustness checks, discussed in more detail below, we also consider specifications where a restructuring designation as one where

[12]The prime mover codes in the EIA data that signify a combined cycle generating unit are CA (combined cycle steam part), CT (combined cycle combustion turbine part), CS (combined cycle single shaft), and CC (combined cycle - total unit).

[13]Generating units that form our NGSC plant observations have the following prime mover code designations: ST (steam turbine) or GT (combustion gas turbine). For our sample, combustion gas turbine are by far the most common simple cycle prime mover.

[14]Based on the EIA-generated map provided at `http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html`, we consider CA, CT, DE, IL, MA, MD, ME, MI, NH, NJ, NY, OH, PA, RI & TX as restructured electricity markets. We do not consider Oregon to be restructured because their residential electricity services are still provided under a traditional rate of return regulation. We do consider power plants operating within California's ISO (CAISO) as restructured since CAISO runs a day ahead and real time markets which generators can sell power. Other than California, states that started restructuring and ultimately suspended their restructuring legislation are considered regulated.

[15]Additionally, most of the NGCC capacity entered in 2000 and 2001, so we have a more balanced panel by starting our analysis with year 2002 data.

the plant in question falls under the service territory of an Independent System Operator (ISO) or Regional Transmission Operator (RTO) as has been done in other related works (e.g. Knittel et al. (2015) and Savage and Craig (2014)).

In some robustness specifications we also control for ownership type. We distinguish between plants being investor owned or publicly owned, which includes ownership by a municipality, state, or federal government. Ownership information for the plants was taken from the EIA-860 form data.

To form our dependent variables, net generation and heat rate, we gather data on net generation and fuel consumption from the EIA-923 form. This data is monthly and is therefore aggregated to the annual level. The heat rate variable is then formed by the annual fuel consumption (in MMBtu's) divided by annual net generation (in MWh's).

The key independent variables in all of our specifications are fuel cost. This cost information is currently collected by the EIA-923 form, however, prior to 2008, cost data for utilities was collected primarily by the FERC-423 form and cost data for non-utilities was collected by the EIA-423 form. Cost data for non-utilities across all years is not publicly available, but has been provide by the EIA for this research through a non-disclosure agreement. This data is given in terms of monthly or annual deliveries of fuel, broken down by fuel type and reported in MMBtu's, to the plant and the cost of the deliveries. We therefore form a given year's delivered natural gas price for the plant in question as the total annual cost of natural gas deliveries divided by the sum of MMBtu's delivered.[16] To get the coal price for a given

[16]Note that this data is given at the plant level, not generating unit level. Therefore if a plant has both NGCC prime mover and NGSC prime movers the NGCC-plant observation and NGSC-plant observation derived from this plant will be assigned the same fuel prices. In addition, using delivered prices further distinguishes our work from that of Linn et al. (2014) who use regional average input prices for both coal and gas. While they give several reasons for this choice a clear reason for using the delivered price where possible is that it reduces the measurement error that may be associated with a regional average price.

plant we use the average quantity weighted delivery cost for coal to power plants within the balancing authority area (BAA) of the NGCC- or NGSC-plant in question.[17] Figure 2 shows a map of the BAA in the U.S. We choose to aggregate coal cost to this level since power plants within a BAA compete most directly with each other, however if aggregation at the BAA is unavailable, for example if there are no coal plants within the BAA, then a state average is used.[18]

The remaining regressors, included in $\boldsymbol{x_{it}}$ in regression equation (6), vary across dependent variable specification. For regressions using heat rate as the dependent variable, we control for the number of starts (the number of times in a year a generating units gross generation goes from zero one hour to a positive value the next) a plant has in a year. Starting a plant after it has been shutdown generally consumes some energy and thus lowers a plant's efficiency. To the extent that a plant has more starts due to, for instance, more variable intermittent generation (e.g. wind and solar) or more variable load, then its thermal efficiency will decrease. Capacity utilization can also affect the thermal efficiency of a plant, so we include the plant's log of net generation and log of capacity.[19] However, including the net generation variable may create an endogeneity issue due the simultaneity of net generation and heat rates - higher net generation may increase plant efficiency, but more efficient plants have lower operating costs and are therefore reasonably dispatched more frequently which leads to higher net generation levels. Similarly, the number of starts may be endogenous

[17]A BAA is defined as an electric power system or systems to which a common automatic control scheme is applied to match generation supply to power demand.

[18]With the exception of plant fuel cost data, which was provided by the EIA through a non-disclosure agreement, all other EIA & CEMS data used for this paper is provided by ABB through their Velocity Suite software.

[19]We include these terms separately as it provides more flexibility than including the log of capacity utilization itself. Additionally, there is sufficient variation in capacity to identify its effect within a plant-FE estimation framework.

due to simultaneity - less efficient plants are more likely to be pushed off the margin and thus may have more starts in a year. To instrument for net generation, we include demand shifting variables, including state-level cooling and heating degree days (CDD and HDD) and gross state product (GSP), that are likely to increase a plant's net generation, but are generally exogenous to a plant's efficiency choice.[20] To instrument for starts, we include standardized load variability in a plant's transmission zone and the plant's state-level wind generation.[21]

For the net generation equations, our $\boldsymbol{x}'_{it}$ vector includes a control for generation capacity (summed MW of nameplate capacity for units with the same prime mover classification within the plant). We also control for regional demand conditions. Specifically, we include annual load at the North American Electric Reliability Council (NERC) subregion level.[22] A map of the subregions is given in Figure 3. Because the subregions are of varying size and populations we normalize the load from each subregion by its mean over the sample observed.[23]

[20]State CDD and HDD are collected by the National Oceanic and Atmospheric Administration (NOAA) at `http://www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp#`. Data for GSP is publicly available from the Bureau of Economic Analysis website at `http://www.bea.gov/itable/iTable.cfm?ReqID=70&step=1#reqid=70&step=1&isuri=1`

[21]A transmission zone is defined by the data-aggregation firm ABB and refers to a geographic "load pocket" that is highly correlated with the plant's generation. ABB calculates the standardized load volatility from data reported from FERC Form 714. State-level wind generation is available through the EIA at `https://www.eia.gov/electricity/data/state/`. We include wind generation because the increase in the major intermittent source of generation in the US likely increases net load (load minus wind generation) volatility in the region.

[22]We also considered specifications that controlled for load at the geographically broader NERC-region level and the geographically narrower transmission zone level. Results from these specifications are similar, both in terms of marginal effect magnitudes and statistical significance, to what is presented below.

[23]One might still be concerned that there are other time-varying plant-specific unobservables that could be correlated with generation or heat rate and the gas prices plants receive, such as managerial quality. For example, better managers may be more effective bargainers for fuel prices and may also get more generation out of their plants. While this seems plausible, Cicala (2015) shows no discernible difference in the natural gas purchase price of plants across regulated and deregulated plants, a distinction where we would expect the managers of deregulated plants to have more incentive to bargain for lower prices. Cicala asserts that this result is a product of the relative homogeneity of natural gas as input fuel. This suggests that the potential for bargaining in gas prices is not as possible as it is for coal or other similarly heterogenous inputs.

Across both dependent variable specifications we also include time-varying plant level characteristics. These include average-unit age, emissions control equipment dummies, and dummies controlling for enrollment in NOx emissions regulation.[24] This plant level data is taken from EIA-860 form data.

Table 1 provides mean statistics for the NGCC and NGSC power plants across the two market structures. From these statistics it is clear that NGCC plants are more efficient with a mean heat rate a little under 8,000 btu's per kWh. Simple cycle plants have a mean heat rate of roughly 12,500 btu's per kWh. Plants located in restructured states are slightly more efficient for both types of technology. Summed combined cycle prime mover capacity are about two times larger than NGSC capacity. This is not surprising since by definition combined cycle plants combine a both a gas turbine and steam turbine to generate electricity. In conjunction with higher nameplate capacities NGCC plants also produce much more electricity. NGCC capacity factors are also much higher than NGSC. This is expected and supports the fact that NGSC plants are mainly used to meet peak demand. It should also be noted that NGSC plants are usually older as measured by their average generating units age. This is due to the fact that combined cycle technology is relative new and has had a lot of investment over the pass 20 years.

We do face a few data limitations. First, the cost data prior to 2008 only required power plants with a nameplate capacity greater than 50 megawatts to report fuel costs. Therefore, several plants enter our analysis in 2008 as a result of the stricter response requirements. Additionally the CEMS data only monitors generating units over 25 megawatts. Due to

[24]The nameplate capacity variable is the sum of capacity from all generating units within a plant and are of the same generation technology, NGCC or NGSC. The average unit age is the average age of the units that are summed to make the "plant" observation. Emission control dummies are set to one if any of the units within the "plant" observation have emissions control equipment.

this, we do not have start data on power plants that utilize units under 25 megawatts, even if the summed nameplate capacity of the units is above 25 megawatts for the whole power plant. Due to these limitations, several plants, typically small NGSC plants, are dropped from the analysis. Additionally, in calculating price and heat rate variables we observed many extreme outliers that are likely data entry errors. We therefore drop observations with heat rates and natural gas price values in the extreme percentiles (1 and 99) and those with capacity factors greater than 1.20.

5 Results

To begin, we present the various marginal effects of natural gas and coal prices on net generation estimated from variations of equation (6).[25] Table 2 gives the price responses based on the specification that estimates common responses for all gas plants (row labeled "Combined"), where the responses are broken out by technology types NGCC and NGCS (rows labeled "CC" and "CS", respectively), and, finally, where responses are further broken out by technology and market structure (rows labeled "CC×RST" and "SC×RST" for NGCC and NGSC plants, respectively, in restructured regions and those labeled "CC×REG" and "SC×REG" for NGCC and NGSC plants, respectively, in regulated regions).

When the responses are restricted to be fixed across all plants, we find that plants respond significantly (both statistically and economically) to gas prices, with a parameter estimate that implies about a seven percent increase in net generation given a 10 percent decline in

[25] The full set of parameter estimates from these base specifications with the log of net generation as the dependent variable, as well as those with log of heat rate as the dependent variable, are given in Appendix A.

gas prices. The net generation response to coal prices is also statistically significant, though at about half the magnitude of the gas price response with marginal effects implying a 10 percent increase in coal prices lead to almost a four percent increase in net generation from gas plants in aggregate.[26]

When we further break the response out by technology type, both CC and SC plants respond similarly to gas prices, with parameter estimates again implying about a seven percent increase in net generation from both types given a 10 percent decline in prices. However, by allowing for heterogenous fuel-price responses by technology our estimates now show that CC plants respond in a statistically significant fashion to coal prices, with a parameter estimate that implies about a 6.5 percent increase in CC net generation given a 10 percent increase in coal prices, while SC plants have a smaller and statistically insignificant response to coal prices. This is as the simple dispatch exposition described above would predict.

Finally, when breaking out responses by technology and market type, we find that the market-type distinction matters little - responses to gas prices across technologies and market structure varies somewhat, though not at statistically significant levels, and the response to coal prices by NGCC plants in regulated and deregulated regions is approximately equivalent. This suggests that dispatching decisions, at least with respect to gas plants, are similar across market structures.

The response of heat rates with respect to fuel prices are given in Table 3. The format of this table is similar to that of Table 2. Here we find when the thermal efficiency response to

[26] As a point of comparison, (Linn et al. 2014) find that gas plants in aggregate respond to both gas and coal prices in a statistically significant fashion.

coal and gas prices are constrained to be constant across technologies and market structures ("Combined" row) estimated marginal responses to coal prices is small in magnitude and statistically insignificant. The response to gas prices is also small, but positive and significant at the 10 percent level. This result that higher gas prices leads to lower thermal efficiency of gas plants seems somewhat counterintuitive. This may occur, however, if higher cost plants do, for example, ramp capacity utilization rates up and down more frequently in high gas-price periods due to their position on the supply curve.[27]

Breaking the heat rate responses out by technology we find that NGCC plants again appear unresponsive to fuel prices. NGSC plants are also unresponsive to coal prices and somewhat positively responsive to gas prices. Given that we find slight significance in the gas-price responsiveness of only the NGSC plants, this would lend support to the idea that as gas prices increase the higher cost plants (i.e., NGSC plants) in high gas price periods will be pushed off the margin or running at inefficient capacity utilization levels more frequently leading to a positive relationship between heat rates and gas prices.

Finally, when we further disaggregate responses across technologies and market structures we find that NGSC plants in both restructured and traditionally regulated regions, as well as NGCC plants in regulated regions, have small and statistically insignificant responses to fuel prices. Heat rates of NGCC plants in restructured regions are also unresponsive to gas prices. However, NGCC plants in restructured regions do respond, at a statistically significant level, to coal prices such that increases in coal prices *increase* the thermal efficiency of these plants.

The estimated response of restructured NGCC plants to coal prices is also relatively large

[27] Ramping production or "cycling" is known to affect the thermal efficiency of power plants (see Kumar et al. (2012)). While we attempt to proxy for ramping through including the number of "starts" a plant has in a year, effectively capturing the degree of ramping using annual data is not straightforward.

in magnitude, with our estimates implying a 10 percent increase in coal prices reduces heat rates by about two percent. Or, to put this in a similar context to that of Linn et al. (2014), who found that a 1-standard deviation increase in coal prices decreased heat rates of coal plants by 1.5 percent, our estimates imply a 1-standard deviation increase in coal prices decreases heat rates of NGCC plants in restructured regions by about six percent.[28]

5.1 Robustness Checks

To assess the robustness of our primary results, we run our analysis on a number of different data restrictions and variable assignments, presented in Tables 4 and 5. In the first of these robustness checks we restrict our sample to those plants that are investor-owned plants ("IOU" column), as opposed to plants that are owned by municipal, state, or federal governments. One may want to exclude these publicly owned plants from the sample because in many instances, even when operating in restructured regions, these plants may operate in a way more consistent with those operating within a traditional vertically integrated utility. The second data restriction we apply is to look at the sample for the years 2006 - 2012 ("2006-2012" column). We consider this cut of the data because in the early years of our whole sample, a large amount of NGCC capacity was still coming into operation. By restricting the sample to later years we are able to get a more balanced sample while still retaining a large cross-sectional dimension. The third robustness check presented ("NERC$\times$Year" column) removes several of the control variables and replaces them with

[28] This calculation is based off of the observation that in our data set a one standard deviation increase in coal prices relative the the mean price is equivalent to an approximate 33 percent increase in prices. This calculation appears to be similar to how Linn et al. (2014) derive their 1.5 percent value.

more general NERC×Year fixed effects.[29] The final robustness check we present ("ISO" column) considers a re-assignment of the restructuring dummy. More specifically, we consider a plant as operating in a restructured region if it falls within a region with a grid managed by an Independent System Operator (ISO) or Regional Transmission Organization (RTO). A map of these ISO/RTO regions is included in Figure 4. One may consider this a more appropriate designation of restructuring because these ISO and RTO managed regions do typically operate wholesale electricity markets even though they may span regions with states that still operate under more traditional cost-of-service regulations.[30] Also, as noted above, this designation of restructuring is more in line with the work of Knittel et al. (2015) and Dean and Savage (2013).

For each of these different estimations, we present results based on the model specification that allows for fuel price responses to vary by technology and market structure. Table 4 presents the marginal responses of net generation to gas and coal prices for the different groups. In each of these robustness checks we again find that both plant technologies across both market structures have a negative and significant response to gas prices. The magnitude of these responses to gas prices are also quite similar across the different checks, as well as close to those presented in our base specification. With respect to coal prices, we again find that the net generation of NGCC plants respond positively in both regulated and restructured across these various robustness checks. NGSC plants have statistically significant responses to coal prices in some specifications (positively for regulated NGSC plants

[29] For this robustness check, beyond the fuel prices, plant and NERC×Year fixed effects, we control for participation in RGGI and the NO_x trading programs and capacity across both equations. Additionally we control for net generation in the heat rate equation.

[30] For example, Minnesota falls within the Midcontinent Independent System Operator (MISO) territory, though Minnesota still operates as a rate-regulated region with a largely regulated, vertically-integrated utility, Xcel.

when considering the "ISO" specification and negatively for NGSC plants in restructured regions for the "NERC×Year" specification) though these responses are not consistent across specifications.

Table 5 presents the robustness checks for the heat rate equations. Here we again find that natural gas prices have small and statistically insignificant effects on thermal efficiency of gas plants across technology types and market structures. With respect to coal prices, we continue to find negative and statistically significant impacts for NGCC plants across specifications that are similar in magnitude to our base results. The one exception may be the case where restructuring is defined as being in an ISO/RTO region where we find a somewhat smaller-in-magnitude effect. This may be expected as some plants in ISO/RTO regions are still operating under traditionally-regulated, vertically-integrated utilities that may lack some incentives for efficiency improvements. Additionally, in our "2006-2012" specification, we find that NGCC plants in regulated regions have a statistically significant (10 percent level) and negative response to coal prices. It should be noted that there was expansion of some ISO/RTO territories into regions that are traditionally regulated toward the later part of our sample, which may have led to increased competition in these regions and greater incentive for efficiency improvements. Overall, these robustness checks largely align with our base specification results. This provides additional evidence of a consistent pattern of generation and efficiency price responsiveness across gas generators.

5.2 Policy Implications

To help put our estimates in context, we explore implications of various CO_2 taxes on generation, thermal efficiency, and emissions savings. More specifically, as pointed out in Cullen and Mansur (2014) one can view imposing a carbon tax as changing the implicit cost of coal and gas since burning both fuels emit CO_2, though an MMBtu of coal is roughly twice as carbon intensive as that for natural gas.[31] We can therefore calculate how a carbon tax changes the implicit \$/MMBtu costs of coal and natural gas. Based on our parameter estimates we can determine how these price changes change NGCC and NGSC net generation, heat rates, and, with some assumptions, electricity sector emissions relative to a no-carbon pricing baseline.

With a carbon tax of P^{CO_2}, the modified effective coal price would be $P^C_{tax} = P^C + P^{CO_2} \times 0.1028$ and, similarly, the modified natural gas price would be $P^G_{tax} = P^G + P^{CO_2} \times 0.0585$. Given these implicit tax-induced changes in fuel prices, we can calculate a change in net generation or heat rates relative to a no-carbon-pricing baseline. More specifically note that for generator j with $j \in [NGCC, NGSC]$ changes in the dependent variables can be written as:

$$\begin{aligned}&\bar{Y}_j(P^C_{tax}, P^G_{tax}) - \bar{Y}_j(P^C, P^G) = \\ &\qquad \left(\exp\left[\hat{\beta}_k\left(\log\left(P^C_{tax}\right) - \log\left(P^C\right)\right) + \hat{\theta}_k\left(\log\left(P^G_{tax}\right) - \log\left(P^G\right)\right)\right] - 1\right)\bar{Y}_j(P^C, P^G) \quad (7)\end{aligned}$$

[31] Based on EIA estimates given at `http://www.eia.gov/environment/emissions/co2_vol_mass.cfm` and `http://www.eia.gov/coal/production/quarterly/co2_article/co2.html`, bituminous coal, the most common coal burned, has an average emissions factor of 0.10285 tons of CO_2 per MMBtu, while carbon intensity of natural gas is only 0.0585 tons of CO_2/MMBtu.

where $\bar{Y}_j$ is some average net generation or heat rate value (in levels) for generator class j and $\hat{\beta}_k$ and $\hat{\theta}_k$ are the marginal responses to coal and natural gas prices, respectively, for generator-market structure k with $k \in [NGCC \times RST, NGCC \times REG, NGSC \times RST, NGSC \times REG]$.[32] Thus in this specification we are essentially examining how a carbon price would change generation or heat rates for an average NGCC or NGSC plant if it were in a restructured region and if it were in a regulated region.

We base our carbon tax exploration on 2012 averages. To begin, we take 2012 average \$/MMBtu prices of coal and gas, P^C and P^G respectively.[33] Similarly, $\bar{Y}_j$ is formed as the 2012 average net generation or heat rate (in levels) for technology j based on plants in our sample. Note that (7) is a nonlinear transformation of random variables $\hat{\beta}_k$ and $\hat{\theta}_k$. Therefore to get confidence intervals for our estimated changes in dependent variables, we numerically simulate these distributions. To do this we first take 10,000 draws of $\hat{\beta}_k$ and $\hat{\theta}_k$ values from the assumed multivariate normally distributed parameters estimated in our base specification that breaks out responses by technologies and market structures. From each of these draws, and given the average price levels, tax level, and net generation or heat rate levels, we can calculate 10,000 differences in dependent variables. These simulated differences are then used to form our confidence intervals.

The top panel of Table 6 reports the average per-plant percent changes in net generation $\left(\left(\bar{Y}_j(P^C_{tax}, P^G_{tax}) - \bar{Y}_j(P^C, P^G)\right)/\bar{Y}_j(P^C, P^G)\right)$ by technology and market structure for various emission taxes. As one would expect given the parameter estimates, the NGCC plants are expected

[32] Equation (7) is based off the assumption that $\bar{Y}_j(P^C_{tax}, P^G_{tax})$ and $\bar{Y}_j(P^C, P^G)$ have the same values for all non-fuel-price variables.

[33] Note that these average prices are formed as the averages across all plants in our sample regardless of generation technology or market structure. We did this so that one could more directly compare outputs across plant types based on differences in fuel-price responses. Additionally, from Table 1 that fuel prices across technologies and market structures are quite similar.

to increase generation and NGSC plants are expected to decrease generation in response to a carbon pricing scheme. Across market structures we see that the NGCC plant responses are quite similar, but the NGSC-restructured plants appear to turndown generation more aggressively than NGSC-regulated plants do in response to the carbon tax. However, with across all plant types our 95 percent confidence intervals, shown in brackets below the mean estimates, indicate that none of the expected responses to the taxes are significant at the five percent significance level. This is due to the tax creating opposing incentives on generation - the tax increases implied coal prices which, at least among NGCC plants, increases net generation, but it also somewhat increases gas prices which drives down generation across all gas plant types.

The bottom panel of Table 6 presents the average per-plant percentage changes in heat rates for the various tax levels. The carbon tax results in rather large efficiency improvements (heat rate decreases) for the NGCC plants, particularly the NGCC plants in restructured regions and effectively no changes in efficiency for NGSC plants. Additionally, the calculated 95 percent confidence intervals indicate that the expected heat rate decrease brought on at each tax level examined is statistically different from zero at the five percent significance level.

Finally, to further put these generation and heat rate changes into an environmental context, we calculate per-plant average emission savings from the different channels under the various carbon taxes. With respect to the changes in net generation channel, we assume that the increased generation from NGCC plants displaces generation from coal plants. We also assume that reductions in generation from NGSC plants represent changes in quantity demanded and are therefore not compensated for by generation from other technologies. For the heat rate channel, we calculate emissions savings from NGCC plants, the only plants that showed non-neglible heat rate responses, as the difference between what emissions would have been under generation levels (including the tax-induced generation increases) and at the no-tax heat rate levels (i.e. 2012 average heat rates) and the emissions under those same generation levels but at the tax-adjusted heat rates.

The results from these emissions reduction calculations are presented in Table 7. Note that these values, except for the "Total" column are based on average per plant changes. As one may suspect the biggest emission reductions from a carbon tax that occur via the natural gas generators comes from the coal-to-gas switching. The average NGCC plant in a restructured region will up its generation more than that same plant in a restructured region by a small margin, so consequently our estimates predict more emissions reductions from an NGCC plant due to coal-to-gas switching in regulated regions. On the other hand, the larger heat rate response of NGCC plants in restructured regions leads to significantly more tax-induced emission reductions from that channel in the restructured regions than in the regulated regions. The emission reductions due to heat rates are quite large. In fact, our estimates imply that with a $\$30/tCO_2$ emissions about 30 percent of the NGCC-related emission reductions in the restructured regions come via tax-induced heat rate improvements. With respect to the NGSC plants, we see that the tax-induced reduction in generation and thus emissions is relatively small. Totaling these reductions across all plants in the restructure and regulated regions, we see that the total gas-fired related emissions reductions are similar across the regions though slightly larger in the regulated regions. This is due to the fact that there are more NGCC and NGSC plants in the regulated regions relative the restructured regions.

6 Conclusion

Natural gas-fired generation has rapidly gained market share in many parts of the U.S. such that it now represents roughly a third of total generation. It is therefore important to understand how input fuel prices affect operations of these increasingly important generation technologies to not only understand how future price movements may alter our generation mix and plant efficiency, but also to understand how various environmental policies that effectively change the cost of burning certain fuels will alter the electricity generation landscape. While others have looked at this question to some degree, our work distinguishes itself from the other related studies in that we pay particular attention to the difference in fuel-price responsiveness across different gas-fired generation technologies and across market structures.

Using a panel data set of gas-fired power plants from 2002 - 2012 that includes confidential cost information, our results indicate that there is substantial heterogeneity in response to coal and gas prices across generation technologies and across market structures. More specifically, we find that generation from NGCC plants responds at statistically significant levels to both coal and gas prices in ways one would expect - rising coal prices increases generation and rising gas prices decreases generation. On the other hand, NGSC plants' generation have stistically significant responses to gas prices only, such that increasing gas prices decrease NGSC production. These results are consistent for both restructured and traditionally regulated regions. Furthermore, our results show that restricting the net generation responses to be the same across all technology types, as others have done, obscures the more nuanced response to fuel price movements.

With respect to thermal efficiency improvements, our results are less obvious. More specifically we find that gas plants, regardless of generation technology and market structure, do not significantly alter their thermal efficiency in response to natural gas prices. However, we do find that the thermal efficiency of NGCC plants in restructured regions does respond to coal prices in a statistically significant manner, such that higher coal prices improves the efficiency of these NGCC plants. Again, this finding is lost if one confines the responses to be constant across technology and market structures.

To further put these results in context, we also use our parameter estimates to determine how a price on carbon would affect generation and efficiency of gas-fired plants and the implied emission reductions brought about by these changes. Our results indicate that the carbon price would increase NGCC generation and decrease NGSC generation, though generally not at statistically significant levels. On the other hand, we find that a carbon tax would increase the efficiency of NGCC plants in restructured regions and this results appears statistically significant at the 5 percent level. Calculating the implied emissions reductions from these changes we find that the largest gas-fired generation related emissions reductions would come from coal-to-gas switching brought about by tax-induced increases in NGCC generation. Although, our results also show that the emissions savings from improved thermal efficiency of NGCC plants in restructured regions also adds considerably to the emissions reductions generated by those plants. In fact, our simulation indicates that about a third of the tax-induced emissions reductions for NGCC plants in restructured regions are due to thermal efficiency improvements among those plants.

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Table 1: Summary Statistics

	NGCC		NGSC	
	Restructured	Regulated	Restructured	Regulated
Net Generation (GWh)	2,214	2,223	313	307
	(17,932)	(24,408)	(5,428)	(6,556)
Heat Rate ($\frac{btus}{KWh}$)	7,859	7,925	12,574	12,815
	(1,080)	(1,246)	(3,041)	(3,024)
NG Cost ($\frac{cents}{mmbtu}$)	609	600	642	613
	(206)	(207)	(226)	(233)
Coal Cost ($\frac{cents}{mmbtu}$)	212	204	191	191
	(66)	(76)	(54)	(74)
Nameplate Capacity (MW)	682	710	481	374
	(394)	(512)	(430)	(364)
Capacity Factor (%)	36.1	33.5	7.0	7.7
	(20.1)	(20.1)	(8.5)	(9.8)
Average Unit Age (years)	7.4	7.9	25.6	24.0
	(6.8)	(7.6)	(18.)	(18.4)
Starts	144	122	220	149
	(151.)	(143.6)	(329.5)	(241.)
Plant Count	123	165	203	316

Notes: Standard deviations are given in the parentheses below the means. "Plant Count" includes plants that have both CC and SC prime movers.

Table 2: Marginal Effects of Fuel Prices on Net Generation

	NG Price Responses			Coal Price Responses		
Combined	-0.734***			0.379**		
	(0.070)			(0.154)		
CC		-0.738***			0.651***	
		(0.080)			(0.164)	
SC		-0.720***			0.231	
		(0.073)			(0.168)	
CC×RST			-0.758***			0.572***
			(0.097)			(0.217)
CC×REG			-0.722***			0.618***
			(0.084)			(0.167)
SC×RST			-0.640***			-0.006
			(0.082)			(0.191)
SC×REG			-0.773***			0.293
			(0.082)			(0.186)

*Notes: *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. All specifications have 5,895 observations.*

Table 3: Marginal Effects of Fuel Prices on Heat Rate

	NG Price Responses			Coal Price Responses		
Combined	0.042*			-0.035		
	(0.023)			(0.062)		
CC		0.046			-0.093	
		(0.040)			(0.068)	
SC		0.036*			-0.008	
		(0.021)			(0.065)	
CC×RST			0.049			-0.197**
			(0.041)			(0.095)
CC×REG			0.044			-0.066
			(0.040)			(0.061)
SC×RST			0.038			-0.011
			(0.025)			(0.066)
SC×REG			0.033			-0.029
			(0.024)			(0.072)

*Notes: *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. All specifications have 5,895 observations.*

Table 4: Robustness Checks - Net Generation

NG Price Responses

	IOU	2006-2012	NERC×Year	ISO
CC×RST	-0.745***	-0.835***	-0.640***	-0.754***
	(0.112)	(0.117)	(0.116)	(0.089)
CC×REG	-0.631***	-0.791***	-0.497***	-0.679***
	(0.104)	(0.095)	(0.085)	(0.082)
SC×RST	-0.701***	-0.687***	-0.494***	-0.644***
	(0.098)	(0.102)	(0.100)	(0.076)
SC×REG	-0.723***	-0.718***	-0.530***	-0.822***
	(0.103)	(0.101)	(0.084)	(0.092)

Coal Price Responses

	IOU	2006-2012	NERC×Year	ISO
CC×RST	0.444**	0.221	0.572**	0.692***
	(0.221)	(0.253)	(0.265)	(0.178)
CC×REG	0.536***	0.414**	0.683***	0.559***
	(0.176)	(0.195)	(0.195)	(0.164)
SC×RST	0.035	-0.178	-0.625**	0.117
	(0.199)	(0.237)	(0.245)	(0.166)
SC×REG	0.343	0.262	-0.183	0.329*
	(0.215)	(0.253)	(0.228)	(0.183)
Obs	4530	4186	5895	5895

*Notes: Results display marginal responses of net generation to natural gas (NG) and coal prices. Column headers "IOU", "2006-2012", "NERC×Year", and "ISO" refer to models that only consider IOU plants, restrict the sample to years 2006-2012, drop most controls and include NERC-by-year fixed effects, and designate plants as being in a restructured region if they fall within an ISO or RTO region, respectively. *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. "Obs" provides the number of observations for each specification.*

Table 5: Robustness Checks - Heat Rate

NG Price Responses

	IOU	2006-2012	NERC×Year	ISO
CC×RST	0.048	0.029	0.029	0.059
	(0.054)	(0.023)	(0.039)	(0.039)
CC×REG	0.057	-0.015	0.004	0.013
	(0.050)	(0.026)	(0.037)	(0.034)
SC×RST	0.031	0.004	0.046	0.033
	(0.027)	(0.021)	(0.032)	(0.022)
SC×REG	0.033	-0.007	0.029	0.038
	(0.028)	(0.021)	(0.038)	(0.025)

Coal Price Responses

	IOU	2006-2012	NERC×Year	ISO
CC×RST	-0.210**	-0.163*	-0.195**	-0.135*
	(0.106)	(0.097)	(0.097)	(0.074)
CC×REG	-0.050	-0.124*	-0.086	-0.079
	(0.065)	(0.063)	(0.076)	(0.059)
SC×RST	0.011	0.013	0.012	-0.009
	(0.064)	(0.088)	(0.082)	(0.061)
SC×REG	0.016	-0.065	0.001	-0.008
	(0.076)	(0.060)	(0.081)	(0.069)
Obs	4530	4186	5895	5895

*Notes: Results display marginal responses of net generation to natural gas (NG) and coal prices. Column headers "IOU", "2006-2012", "NERC× Year", and "ISO" refer to models that only consider IOU plants, restrict the sample to years 2006-2012, drop most controls and include NERC-by-year fixed effects, and designate plants as being in a restructured region if they fall within an ISO or RTO region, respectively. *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. "Obs" provides the number of observations for each specification.*

Table 6: Carbon Tax Impacts

% Change in Generation

Tax ($^{\$}/_{tCO_2}$)	NGCC-RST	NGCC-REG	NGSC-RST	NGSC-REG
10	8.91	11.18	-9.33	-1.49
	[-7; 26]	[-1; 25]	[-21; 4]	[-14; 12]
20	14.76	18.87	-16.46	-3.76
	[-13; 48]	[-4; 46]	[-34; 5]	[-24; 20]
30	18.86	24.48	-22.16	-6.21
	[-18; 66]	[-6; 63]	[-44; 6]	[-31; 25]

% Change in Heatrate

Tax ($^{\$}/_{tCO_2}$)	NGCC-RST	NGCC-REG	NGSC-RST	NGSC-REG
10	-5.88	-1.60	0.23	-0.47
	[-12; -0.16]	[-5; 2]	[-4; 5]	[-5; 5]
20	-9.88	-2.67	0.50	-0.70
	[-19; -0.23]	[-9; 4]	[-7; 9]	[-9; 8]
30	-12.85	-3.45	0.80	-0.83
	[-25; -0.21]	[-11; 5]	[-10; 13]	[-12; 11]

Notes: Taxes are in $\$/tCO_2$. All other reported values are per plant average changes relative to a case with no carbon price and using 2012 average prices and 2012 average production or heat rates for NGCC or NGSC plants for the baselines. The 95% confidence bands are shown in brackets below the mean estimate.

Table 7: Carbon Emissions Saving (tons of CO_2 per plant)

	Tax ($^{\$}/_{tCO_2}$)	NGCC Coal Displacement	NGCC Effic Improvement	NGSC Gen. Reduction	Total (million tCO_2)
Restructured					
	10	118,147	65,752	883	24.7
	20	195,722	116,220	1,557	41.9
	30	249,987	156,629	2,096	54.7
Regulated					
	10	148,223	18,332	141	30.1
	20	250,141	32,563	356	51.2
	30	324,566	43,960	588	66.7

Notes: Taxes are in $\$/tCO_2$. Emissions savings for all columns except "Total (millioin tCO_2)" are average per-plant values relative to 2012 averages with no carbon price. The "Total (millioin tCO_2)" sums up the average per plant emissions savings across all plants in the given region, restructured or regulated. From our sample we have; 133 restructured NGCC; 181 regulated NGCC; 290 NGSC restructured; and 425 NGSC regulated plants. These counts are used to calculate total emissions savings (column "Total")

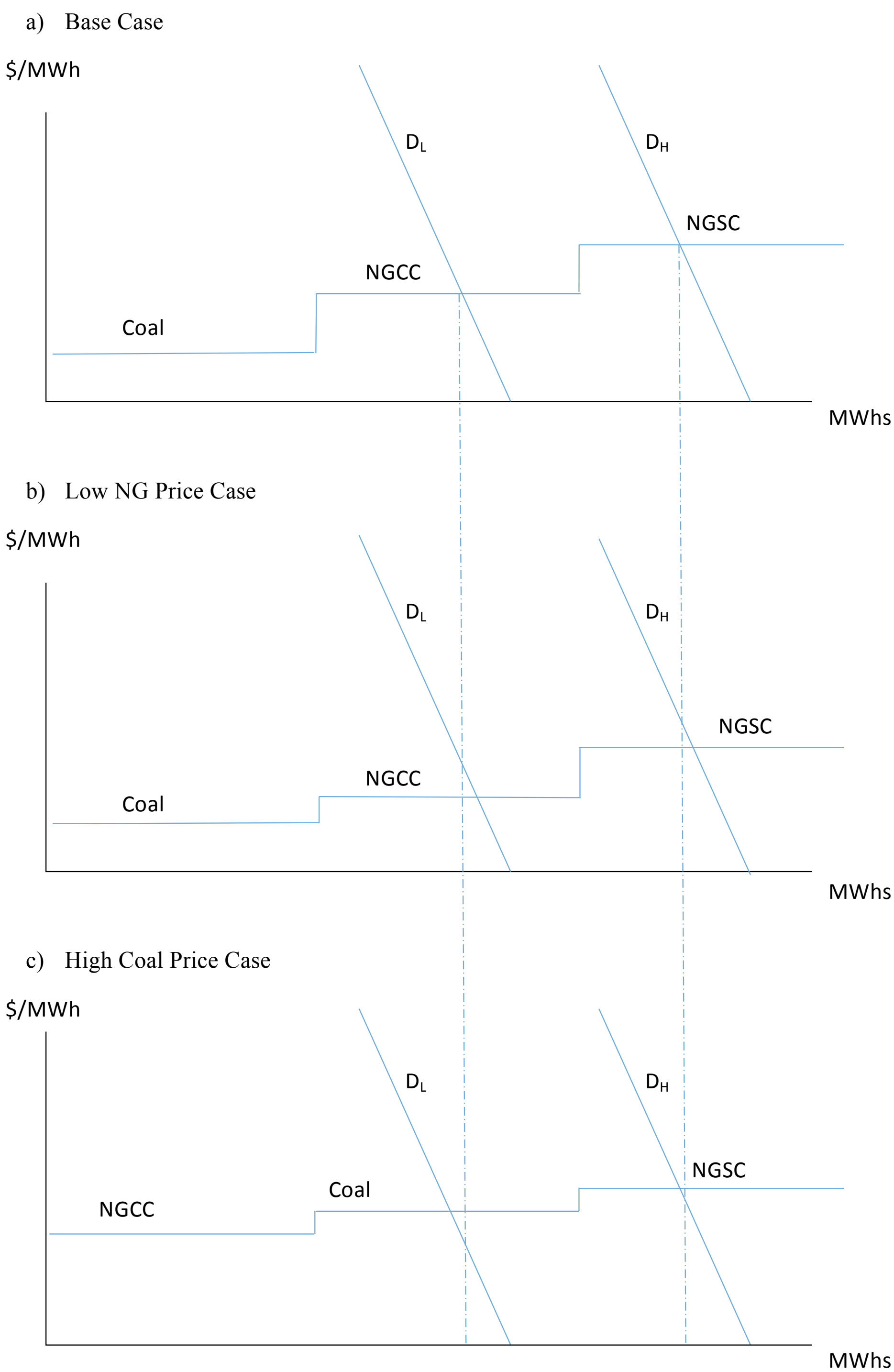

Figure 1: Net Generation Responses

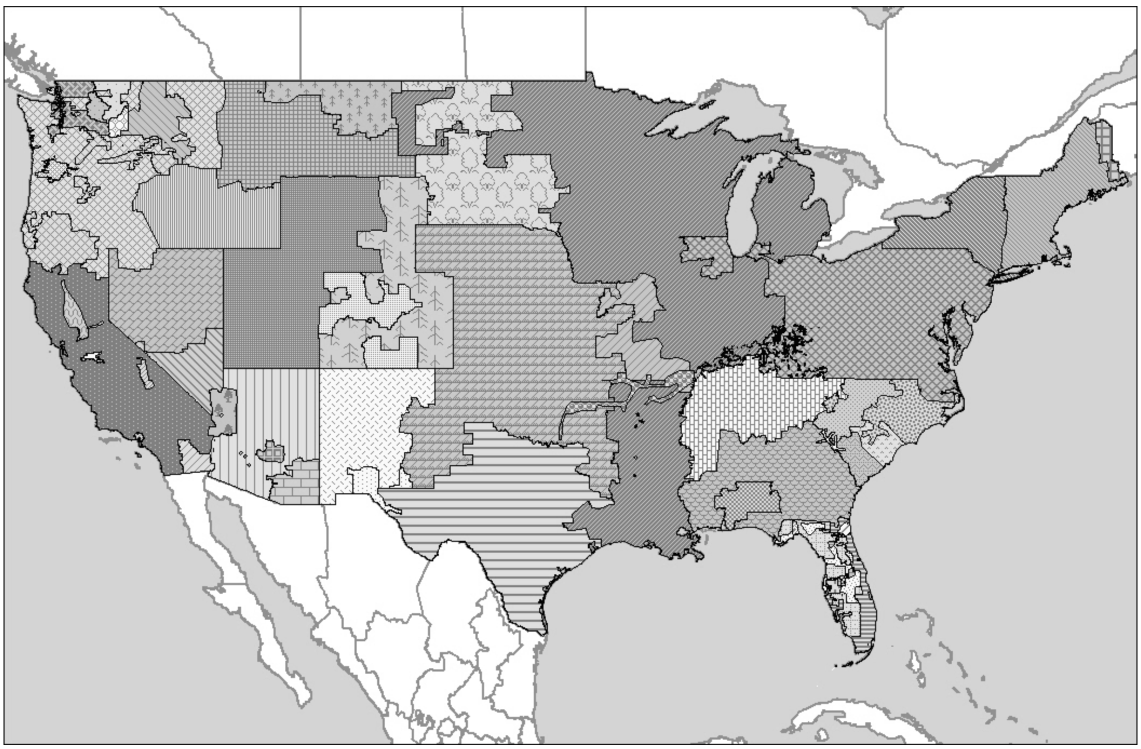

Figure 2: U.S. Balancing Authority Areas

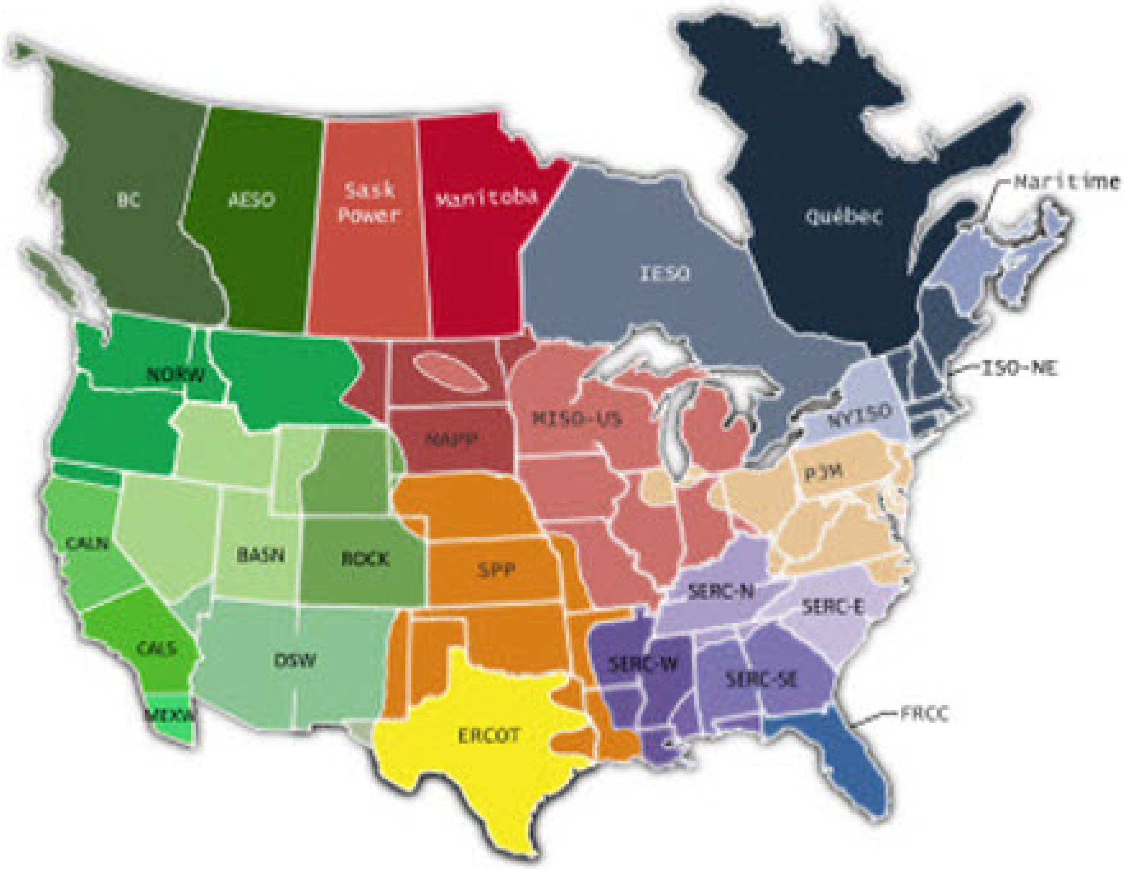

Figure 3: NERC Subregion Map

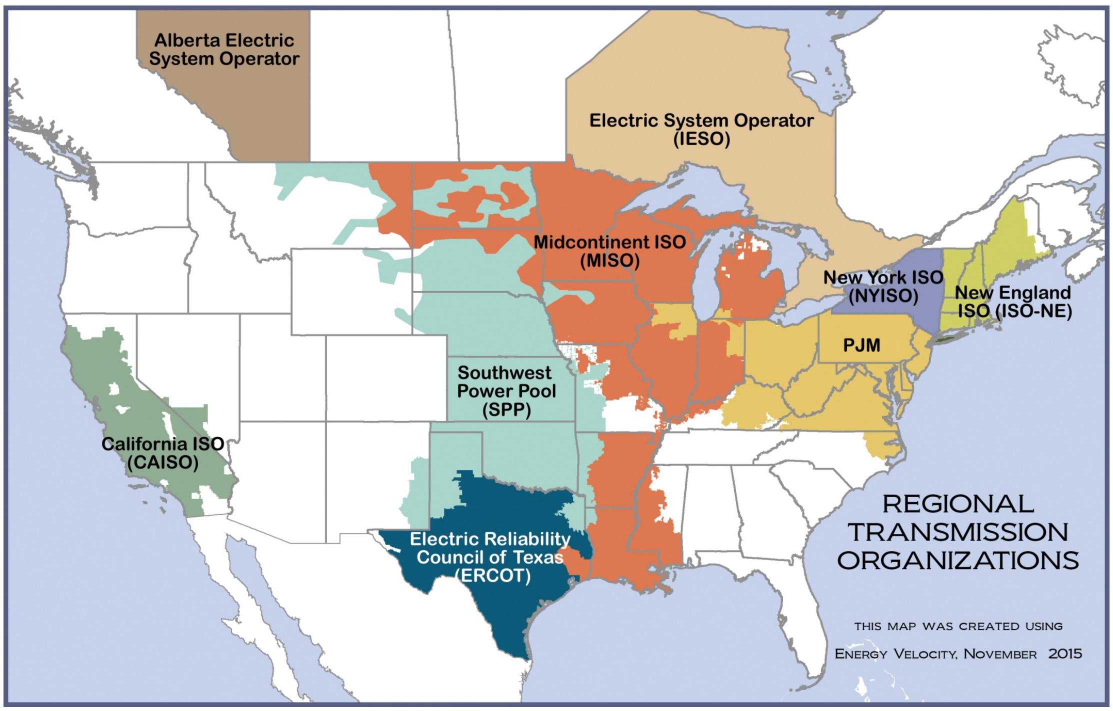

Figure 4: ISO/RTO Map

A Full Parameter Estimates

Table 8: Net Generation

	(1)	(2)	(3)
NG Cost × (CC; CC × RST)	-0.734***	-0.738***	-0.758***
	(0.070)	(0.080)	(0.097)
NG Cost × SC		0.018	
		(0.058)	
NG Cost × CC × REG			0.036
			(0.088)
NG Cost × SC × RST			0.118
			(0.093)
NG Cost × SC × REG			-0.016
			(0.089)
Coal Cost × (CC; CC × RST)	0.379**	0.651***	0.572***
	(0.154)	(0.164)	(0.217)
Coal Cost × SC		-0.420***	
		(0.143)	
Coal Cost × CC × REG			0.047
			(0.177)
Coal Cost × SC × RST			-0.578***
			(0.200)
Coal Cost × SC × REG			-0.279
			(0.209)
Capacity	0.801***	0.760***	0.763***
	(0.117)	(0.116)	(0.115)
Age	0.403***	0.326***	0.326***
	(0.050)	(0.056)	(0.056)
NERC Sub-region Load	0.567***	0.561**	0.515**
	(0.220)	(0.219)	(0.216)
RGGI Dummy	0.102	0.066	0.075
	(0.074)	(0.075)	(0.079)
NO_x Dummy	0.308***	0.355***	0.365***
	(0.081)	(0.082)	(0.081)
FE Year	Yes	Yes	Yes
Observations	5895	5895	5895

*Notes: *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. provides the number of observations for each specification.*

Table 9: Heat Rate

	(1)	(2)	(3)
NG Cost × (CC; CC × RST)	0.042*	0.046	0.049
	(0.023)	(0.040)	(0.041)
NG Cost × SC		-0.009	
		(0.040)	
NG Cost × CC × REG			-0.005
			(0.024)
NG Cost × SC × RST			-0.011
			(0.050)
NG Cost × SC × REG			-0.016
			(0.040)
Coal Cost × (CC; CC × RST)	-0.035	-0.093	-0.197**
	(0.062)	(0.068)	(0.095)
Coal Cost × SC		0.085**	
		(0.038)	
Coal Cost × CC × REG			0.131**
			(0.064)
Coal Cost × SC × RST			0.186**
			(0.081)
Coal Cost × SC × REG			0.168***
			(0.064)
Net Gen	-0.017	-0.017	-0.014
	(0.031)	(0.030)	(0.030)
Starts	-0.039	-0.044	-0.047
	(0.057)	(0.054)	(0.053)
Capacity	0.020	0.031	0.030
	(0.060)	(0.060)	(0.059)
Age	-0.050***	-0.033**	-0.032**
	(0.019)	(0.016)	(0.016)
RGGI Dummy	0.037	0.044	0.060
	(0.053)	(0.054)	(0.058)
NO_x Dummy	0.030	0.023	0.022
	(0.031)	(0.032)	(0.031)
FE Year	Yes	Yes	Yes
LMP	0.000	0.000	0.000
HJP	0.751	0.640	0.766
Observations	5895	5895	5895

*Notes: P-values are shown for the underidentification test in row "LMP" [Kleibergen-Paap rk LM statistic∼ $X(4)$] and overidenticifaction test in row "HJ" [Hansen J statistic∼ $X(3)$] for the excluded instrumental variables. *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. provides the number of observations for each specification.*

B Extended Theory Model

In this appendix we expand upon the model in the paper. Here we recognize that the average electricity price a gas plant receives over it's evaluation horizon is not only a function of fuel costs, but also the heat rate a plant chooses. To analyze this effect we allow the average electricity price ($\bar{p}$) received by the gas plant to be a function of coal costs (C^C), natural gas costs (C^{NG}), and a plant's heat rate decision (ΔHR). Intuitively, as a gas plant improves it efficiency it moves further inframarginal and operates more hours. The additional operating hours gained are hours where lower costs firms on the margin are setting the market price, therefore, decreasing the overall average price ($\bar{p}$). This implies $\frac{\partial \bar{p}}{\partial \Delta HR} < 0$. All other partial derivatives for the average electricity prices are the same before, $\frac{\partial \bar{p}}{\partial C^C} \geq 0$ and $\frac{\partial \bar{p}}{\partial C^{NG}} \geq 0$.

The firm's maximization problem is as before, except for the modified ($\bar{p}$):

$$\begin{aligned} \underset{\Delta HR}{max} \pi = q^m \Big[\bar{p}(C^C, C^{NG}, \Delta HR) - MC(\Delta HR, C^{NG})\Big] H(C^C, C^{NG}, \Delta HR) - C(\Delta HR) \\ s.t. : \Delta HR \leq \Delta HR^m \end{aligned} \tag{8}$$

The first order condition is now:

$$\frac{\partial \pi}{\partial \Delta HR} : q^m \left[(\bar{p} - MC) \frac{\partial H}{\partial \Delta HR} + \left(\frac{\partial \bar{p}}{\partial \Delta HR} - \frac{\partial MC}{\partial \Delta HR} \right) H \right] = C' + \lambda \tag{9}$$

where λ is the multiplier associated with the $\Delta HR \leq \Delta HR^m$ constraint. We can differentiate the left side of (9) with respect to C^C.

$$\begin{aligned} \frac{\partial^2 \pi}{\partial \Delta HR \partial C^C} : q^m \Bigg[& (\bar{p} - MC) \frac{\partial^2 H}{\partial \Delta HR \partial C^C} + \frac{\partial \bar{p}}{\partial C^C} \frac{\partial H}{\partial \Delta HR} \\ & + \left(\frac{\partial \bar{p}}{\partial \Delta HR} - \frac{\partial MC}{\partial \Delta HR} \right) \frac{\partial H}{\partial C^C} + \frac{\partial^2 \bar{p}}{\partial \Delta HR \partial C^C} H \Bigg] > 0 \end{aligned} \tag{10}$$

We can sign equation 10 as greater than zero given two reasonable assumptions:

$$\begin{aligned} &(1) \qquad \left(\frac{\partial \bar{p}}{\partial \Delta HR} - \frac{\partial MC}{\partial \Delta HR} \right) > 0 \\ &(2) \qquad \frac{\partial^2 \bar{p}}{\partial \Delta HR \partial C^C} > 0 \end{aligned} \tag{11}$$

Both terms in assumption (1) are negative, however, the change in the average price must be less than the change marginal cost. Since the marginal power plant sets the price, anytime the power plant is infra marginal it receives a higher price than its marginal cost. Improving efficiency lowers the marginal cost and lowers the average price, however, higher prices when the plant is infra marginal causes the change in the average price to decrease less than the decrease in the marginal cost. Given this assumption (1) is positive.

For assumption (2), the change in average prices due to a change heat rates is negative.

This effect diminishes as coal prices increase. This is because coal plants will be on the margin more often if coal prices increase setting a higher market price. This causes assumption (2) to be positive. With these two assumptions equation 10 is positive.

Using this more generalized model, we show that the left hand side of equation (9) is increasing with coal prices. If this is the case the right and side must also be increasing in coal prices. If the constraint is non-binding and λ is zero, gas plants must be improving their efficiency.

We perform the same exercise to see the response to natural gas prices and differentiate the left hand side of (9) with respect to C^{NG}.

$$\frac{\partial^2 \pi}{\partial \Delta HR \partial C^{NG}} = q^m \Bigg[(\bar{p} - MC) \frac{\partial^2 H}{\partial \Delta HR \partial C^{NG}} + \left(\frac{\partial \bar{p}}{\partial C^{NG}} - \frac{\partial MC}{\partial C^{NG}} \right) \frac{\partial H}{\partial \Delta HR} + \left(\frac{\partial \bar{p}}{\partial \Delta HR} - \frac{\partial MC}{\partial \Delta HR} \right) \frac{\partial H}{\partial C^{NG}} + \left(\frac{\partial^2 \bar{p}}{\partial \Delta HR \partial C^{NG}} - \frac{\partial^2 MC}{\partial \Delta HR \partial C^{NG}} \right) H \Bigg] \gtrless 0 \tag{12}$$

Here we are unable to sign equation 12 due to opposing incentives faced by the power plant. Intuitively, as gas prices increase the plant has an incentive to become more efficient in order to lower its marginal cost and save costs on each MWh generated. On the other, hand as gas prices increase it becomes less competitive with coal and is less likely to gain additional hours of operation through efficiency improvements.