Quantifying the Benefits of Nodal Market Design in the Texas Electricity Market

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ABSTRACT:

This study quantifies the economic and environmental impacts associated with the change from a zonal to nodal design in the Texas electricity market. To begin, we present a framework to understand the mechanisms that lead to inefficient outcomes under a zonal market model. Then, we estimate a semiparametric partially linear conditional mean function to quantify changes in selected market metrics for the same set of underlying system conditions after versus before the implementation of the nodal market design. We estimate that daily variable costs of thermal generation given the same level of daily output fell by 3.9% with the implementation of the nodal market design. In contrast, we find that total heat input and CO2 emissions increased with the market design change. We show how changes in operation of coal and natural gas technologies contributed to these outcomes, and find that a large proportion of the daily variable cost savings was due to the synergies achieved through increased efficiency of operation of these two technologies.

1 Introduction

Locational, or nodal, price formation and settlement in electricity markets is a key component of efficient electricity market design. Restructured electricity markets in the United States and around the world have made attempts to decouple economic transactions and constraints of the physical network infrastructure in their operation, and in virtually all cases the cost of doing so has been high.[1] Administering auctions in a day ahead market with zonal price formation, not only results in inefficient system operation and dispatch, but incentivizes bidding behavior among participants that increases the costs of electricity generation. Excessive costs due to these processes are ultimately borne by consumers of electricity. In the United States, all restructured markets now operate under a nodal market design but the majority of markets around the world still operate under a zonal design.

In this paper, we begin with an explanation of why a zonal electricity market structure leads to inefficient outcomes through incentives it creates for participating generators. We then discuss why a nodal market design eliminates this source of market inefficiency. We estimate the benefits associated with the change from zonal to nodal market design in the Electric Reliability Council of Texas (ERCOT) electricity market. ERCOT's nodal market was launched on December 1, 2010. Prior to the implementation of the nodal market, the ERCOT market operated under a zonal market model. Using selected economic and operational metrics before and after the launch of the nodal market we estimate the benefits accrued through the implementation of a nodal market model.

In order to estimate the benefits of this change in ERCOT. we estimate a semiparametric partially linear conditional mean model to estimate the changes in the following four metrics with the implementation of the nodal market: 1) total variable cost of thermal generation, 2) thermal generating unit starts, 3) total fuel heat input, and 4) CO2 emissions. For this study we use daily market data from December 1, 2009 through November 30, 2011. Results under our base case assumptions indicate an estimated 3.9% cost reduction in total daily variable costs of fossil-fueled generation for the first year of operation of the nodal market in ERCOT. Under our base assumptions the savings amount to an estimated $323 million in the first 12 months of nodal market operation. Our results do not provide strong evidence that unit starts changed with the implementation of the nodal market. Results suggest that under the base assumptions heat input increased by an estimated 1.3% while CO2 emissions increased by an estimated 5.5% under the nodal market.

We then disaggregate our model by fuel type finding that the effect of nodal market implementation was markedly different on coal and natural gas resources. We find that for coal generating units, variable costs, heat input, and CO2 emissions increased, while for natural gas-fired units, all three metrics decreased. We find that combined cycle units contributed greater portions of natural gas-fired generation, while coal units operated more flexibly in the first 12 months of the nodal market. Results suggest that a large proportion of the total variable cost savings were a result of synergies achieved through more efficient operation of these resource types under nodal market design.

The variable cost savings due to nodal market model implementation found in this study were considerable. The findings here emphasize the importance of locational pricing as a key characteristic of efficient electricity market design. Moreover, these results provide evidence that nodal market design removes significant sources of inefficiency in electricity market operation. Although nodal market design provides gains in variable cost efficiency, these results demonstrate that nodal market design will not necessarily achieve lower carbon emissions relative to a zonal market, and emissions may in fact increase with nodal market implementation, as we have found here. The increase in heat input and CO2 emissions found in this study were the result of changing operational patterns of the existing technology fleet in the ERCOT market at the time of market transition, and this is not an expected result of nodal market implementation more generally. If CO2 emission mitigation is an objective of policymakers, additional policy instruments (such as carbon pricing or an emissions trading scheme) would be necessary to address this externality. We do not address the question of appropriate CO2 emission mitigation instruments in a nodal market here and direct the reader to the wide range of academic literature available on this topic.

[1] See Hogan (2002) for some examples.[5]

2 Zonal Electricity Market Design and U.S. Restructuring

Electricity is unlike other, more conventional commodities in many ways, but three key differences are: 1) the need to instantaneously match supply and demand with very little ability to store electricity for later use, 2) the need for supply reliability (i.e. hospitals cannot go without power or substitute for other inputs when prices are high), and 3) the delivery of electricity follows Kirchhoff's laws flowing according to the laws of physics (rather than explicitly from buyer to seller) and thus the economics of the market are tied to the underlying physical fundamentals of the electric grid infrastructure.

Throughout the 20th century the electricity system of the United States expanded under a vertically integrated paradigm. Because of the economies of scale that characterize the electricity sector, power companies were treated as natural monopolies and the sector developed under a high degree of regulation. The Public Utility Regulatory Policies Act of 1978 (PURPA) led the way for the first major introduction of private power producers in the U.S. electricity sector. Under PURPA Section 210, a new legal type of small power plant (a qualifying facility, or QF) was created and these facilities were able to sell their output to power utilities. After the passage of PURPA, a large number of small-scale independent power producers emerged providing generation to the electricity system. Although prices for their output were administratively set, the incorporation of these actors in what was previously a complete monopoly demonstrated that although transmission and distribution may have have the characteristics of a regulated public utility, this service could be decoupled from the generation of electric power where market competition was possible. Nearly two decades later, in 1996, the Federal Energy Regulatory Commission's (FERC) landmark Order 888 required removal of barriers to competition in wholesale electricity markets, and electricity system operators in the United States began a process of market restructuring.[2] The notion of an independent system operator (ISO) or regional transmission operator (RTO) was established and various regions began planning stages of competitive electricity markets.

During the initial planning stages of this market restructuring process there was a contentious debate surround the issue of zonal versus nodal market structure. Zonal markets were an attractive option due to their relative simplicity. Under this model, auctions would be run in a day ahead market to settle financial transactions between buyers and sellers of electricity. A single price would be formed for an entire region, where all generators and loads settle at this price. Notably, under this market model zonal settlement prices clear the market disregarding transmission limitations of the physical infrastructure. Most markets had a multi-zone structure, such that market settlement was constrained by interzonal flow limits, however intrazonal transmission constraints were not respected in the market settlement. Following financial settlement in the day ahead market, during the operating day secure physical system operation could be managed by the system operator through power system engineering models with a real-time re-dispatch process.[3] If transmission constraint violations are found in the market clearing solution, the system operator could instruct certain units to ramp up and others to ramp down to resolve any constraint violations, requiring payments to units that receive altered dispatch instructions. These costs of re-dispatch are ultimately passed on to load serving entities and borne by consumers of electricity.

Proponents of a zonal day ahead market design model pointed to the fact that transmission congestion was relatively infrequent and costs associated with real-time re-dispatch could be expected to be small. Ultimately, arguments for zonal market design prevailed and the initial implementation of wholesale electricity markets in the U.S. in most cases took on a zonal day ahead market design. However, once these zonal markets were implemented, costs of re-dispatch accumulated rapidly. Differences between the financial market model and the physical infrastructure of the electricity system led to inefficiencies and unintended incentive structures for participating generators.

In the re-dispatch process, to resolve violations of physical constraints, certain generating units are given instructions to ramp up to provide incremental energy while others are given instructions to

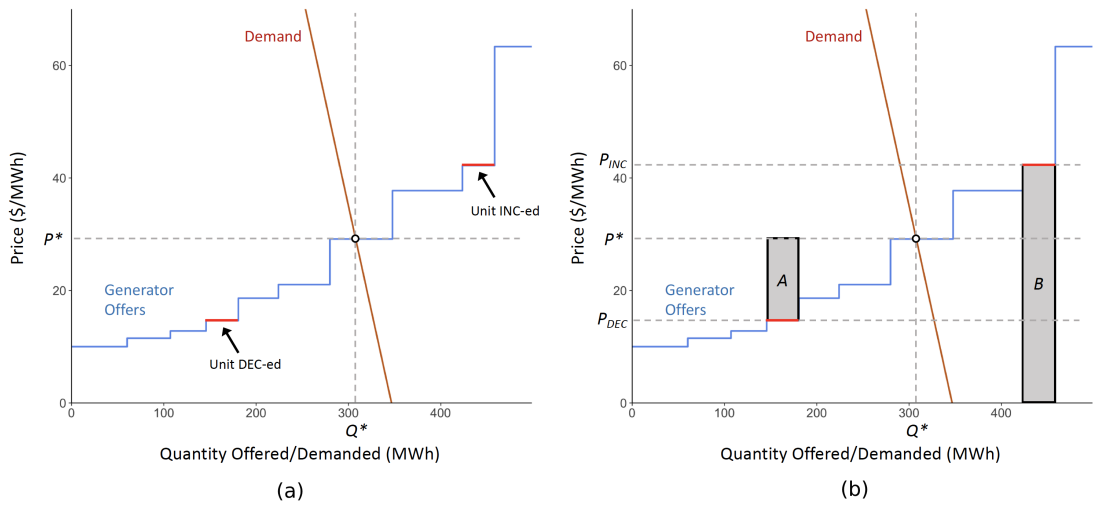
[2] Note that the ERCOT grid does not cross state lines, does not engage in interstate wholesale electricity trade, and thus is not subject to FERC jurisdiction. However, the state's market development did progress during a broader period of electricity market restructuring in the U.S.

[3] In the U.S. this process was often referred to as congestion management.

ramp down to sell back decremental energy. We say a unit is "INC-ed" when they are instructed to provide additional incremental energy. Conversely a unit is "DEC-ed" when they are instructed to provide less energy – decremental energy – in real-time.

Figure 1(a) displays an example day ahead hourly market outcome under a zonal market model. The ascending supply curve is composed of quantity and price offers of market participants arranged from lowest to highest. The downward sloped demand curve represents the hourly market demand for energy. The market clears at the intersection of the supply and demand curves resulting market clearing price P^* and market clearing quantity Q^*. Because this financial market model does not consider available transmission capacity, the outcome of this market my be physically infeasible or violate security constraints. If this is the case, during the real-time re-dispatch process, certain units with offers above the market clearing price will be needed to increase output, while some units with offers lower than or equal to the market clearing price will be required to reduce output. In the example of Figure 1(a) there is a unit indicated that is "INC-ed", this unit did not clear in the day ahead market but is needed in real-time for incremental energy. In the figure we have also indicated a unit that is "DEC-ed", this unit was cleared in the day ahead market but will need to sell back decremental energy in real-time. Here, units settle "as bid" for incremental or decremental energy.[4]

Figure 1: An Example Hourly Zonal Market Outcome



Notes: (a) Infeasible market outcome where one offer must be "DEC-ed" and one offer must be "INC-ed"; (b) The same market outcome with the gross revenue resulting from each offer

Figure 1(b) displays the revenue for each generator as a result of this process. The generator that was DEC-ed earns $P^* - P_{DEC}$ times the amount of decremental energy (Box A). Note, that for the quantity that is DEC-ed the generator is paid for energy that is not provided in real-time and thus incurs no marginal cost of generation for this quantity. The unit that is INC-ed received P_{INC} times the amount of incremental energy less marginal cost (Box $B-$ marginal cost). In the case of incremental energy provided, this energy is provided to the market in real-time and the generator does incur marginal cost associated with generation.

This process has significant influence on the bidding incentives of market participants. Generators that have a high probability of being DEC-ed have high incentive to bid low in the day ahead market to maximize their expected profit in real-time. Thus even units that have a marginal cost higher than the market clearing price may bid below this cost to clear in the day ahead market with the expectation that they will not have to provide energy in real-time but receive payment. Similarly, units that have a high probability of being needed in real-time have a strong incentive to bid higher. Even low marginal cost units can increase profits by bidding high in the day ahead to achieve larger

[4] "As bid" indicates that units are paid at their offer price for incremental energy, or charged at their offer price to sell back decremental energy. The majority of zonal markets settle "as bid" for incremental and decremental energy.

payments in real-time if the probability of being DEC-ed is high. In this scenario, generators have incentive to induce congestion through to maximize profits. For a Genco that holds multiple units and ability to exercise local market power, the ability to exploit this market structure is increased.

In practice, zonal market design has been recognized to offer participants ability to exercise unilateral market power taking advantage of the merit order and intrazonal congestion infeasibilities. The CAISO market was a known example of this type of behavior under its zonal market design before moving to nodal settlements in 2009. Nodal design can mitigate the ability of certain market participants to take advantage of the redispatch process to extract rents. In addition, nodal markets offer improved signals for investment in new generating resources.

These incentives and the resulting bidding behavior of generators in referred to elsewhere as the "INC-DEC Game." Graf, Quaglia, and Wolak (2020) provide an analysis of this behavior in the Italian zonal market.[3] In the study, the authors find that as probability of being INC-ed approached 1, generators increased offer prices by 50/MWh on average. Conversely, as probability of being DEC-ed approached 1 generators decreased offer prices by 60/MWh on average.[5] In this market, costs associated with re-dispatch were estimated to account for 9% of energy transactions in this market. Various other markets are known to also have large costs associated with the re-dispatch process including Germany, Spain, and the United Kingdom.

3 Locational Pricing in the Day Ahead Market

Nodal electricity markets are characterized by Locational Marginal Price (LMP) formation and energy settlement at electrical nodes in the system in a day ahead market. The LMP is the cost of serving an additional unit of load (MWh) at the associated electrical node in the corresponding settlement interval. By approximating power flow through a system of linear equations, locational pricing reflects the underlying physical and security constraints of the electrical system. In addition, under U.S. nodal market design generators have the ability to submit three-part offers that include i) start-up costs, ii) minimum load costs, and iii) an offer curve. Meanwhile, operational constraints, such as ramping limits are respected in the solving of the market. Because transmission and ramping constraints are included in the market solution, optimal dispatch respects the physical limitations of the electrical system. Thus a locational pricing model obviates the need to re-dispatch generating units due to transmission and ramping constraints.

In the day ahead forward market, all 24 hours of the operating day solve in a single optimization problem that includes three part offers, operational constraints, and transmission constraints. Inclusion of start-up costs and ramping limits in the market solution result in linkages between hours of the operating day that were not present under the zonal market structure. Under this model, no physically infeasible schedules will emerge from the day ahead solution. Importantly, generators then in general have incentive to operate as they have cleared in the day ahead market. Generators that under supply in real-time will have to buy the difference at real-time prices and any generators that over supply in real-time will be paid real-time prices. Importantly, because the day ahead market must be physically feasible, generators no longer have the opportunity to exploit the difference between the market model and the network model.

The theoretical basis for the economic efficiency of nodal, or locational, pricing in electricity markets is largely credited to the pioneering work of Schweppe et al. (1988) [11]. This work along with other economists and engineers laid the foundation for a methodology simplifying nonlinear power flow equations to a system of linear equations that allow for efficient locational price discovery. A nodal market structure is characterized by electricity price formation at all electrical nodes in the system, with many of these nodes designated as settlement points where energy transactions take place. These prices are referred to as LMPs and they are the shadow price on the energy balance constraint at the corresponding electrical node. More intuitively, LMPs are the cost of serving and additional increment of load (MWh) at the associated node. Stoft (2002) notes that LMP pricing and settlement has two key benefits: 1) "[t]hey cause suppliers to minimize the total cost of production, and are the only free-market prices capable of doing this", and 2) "they send the right price signals to

[5] For reference, average day ahead market price was 61.3/MWh in 2018

consumers" [12]. It should be noted however, that in nodal markets in the United States consumers of electricity usually do not participate directly in wholesale electricity markets, and are represented by load serving entities (LSEs) that procure energy on their behalf. LSEs, in general, do not pay nodal prices for electricity served but rather a load-weighted regional average, or load zone, price. In contrast, generators in nodal electricity markets most often have settlement points defined at their electrical point of interconnection where LMPs are formed and the energy generated is delivered to the wholesale market.

There are now seven wholesale electricity markets in the United States: CAISO, MISO, ISO-NE, NYISO, PJM, SPP, and ERCOT. Although many of these markets began under a zonal market models, all have now adopted a nodal market design. These restrucutred markets are in contrast to the vertically-integrated industry structure that was in place before electricity sector restructuring and still is still in practice in the remainder of the country. Internationally, zonal markets are common practice. Markets in Europe, Canada, Australia, and elsewhere currently operate under a zonal framework.

Evidence supporting the theory of superior efficiency of nodal market design has been presented elsewhere in empirical studies that have found increased efficiency in comparison to zonal markets in other regions. One such study by Wolak (2011) found that total variable costs reduced by 2.1 percent while heat input reduced by 2.5 percent after the introduction of nodal pricing the California market (CAISO) [14]. In the case of CAISO, variable costs and heat input changes were closely related because nearly all thermal generation was provided by natural gas in this market. In contrast, in the ERCOT market, during the period of market transition, dispatchable thermal generation was provided by coal and natural gas in nearly equal proportions. We find that this is an important difference, and led to a substantially different outcome than was observed in the CAISO market due to the interaction between coal and natural gas generation.

The extent to which the implementation of nodal pricing has an impact on market outcomes depends largely on the presence of intrazonal congestion in the zonal market framework. For zonal markets with high local transmission capacity where market settlements lead to few transmission constraint infeasibilities and inefficiencies are likely to be less acute. Moreover, the authors recognize that nodal market design does not eliminate all sources of market inefficiency. Suppliers of energy may have local market power and ability to set or influence prices. To address this, system operators in the United States have implemented offer mitigation schemes and independent market monitors that regularly investigate the degree to which market power is being exercise. In addition, implementation of explicit virtual bidding allowing financial participants to compete in the market reduces the ability of generators to manipulate pricing. For more on competitiveness of nodal markets under virtual bidding participation, see Jha and Wolak (2019) [6].

4 Launch of the Nodal Market in Texas

ERCOT is a large independent system operator that manages the generation and supply of electric power within the State of Texas representing 90 percent of the state's load [2]. ERCOT formed as an independent system operator in 1996. A multizonal market was implemented in ERCOT in 2002 where the market operated with four or five zones that were reviewed on an annual basis [15]. Under the zonal system only one price was realized for each zone in each settlement interval. In settlement intervals in which interzonal constraints were binding, prices would diverge between zones representing zonal supply and demand conditions. When zonal dispatch led to intrazonal security constraint violations, the system would be redispatched to resolve the constraints. Costs incurred due to this redispatch would be charged to LSEs as uplift costs [15].

Under the zonal market design in ERCOT, the costs associated with redispatch due to intrazonal transmission congestion were substantial and the zonal design made it difficult to appropriately assign costs to entities responsible for causing them [15]. In addition, zonal price aggregation was inefficient in providing signals to market participants for both short term operation and longer term investment decisions. In the 2004 Public Utility Commission of Texas (PUCT) "Order Adopting New §25.501" the expected benefits of the implementation of the ERCOT nodal network model included:

reduction in local congestion costs; reduced opportunities for gaming and manipulation in the wholesale electricity market; increased price transparency and liquidity in the wholesale electricity day-ahead energy market; increased locational price transparency for resources; more efficient and transparent dispatch of resources in real-time; improved siting of new resources; and a reduction in the amount of new transmission facilities needed to support the reliability of, and competition in, the wholesale electricity market.

Debates over the transition to a nodal design began in 2003 and in 2005 the PUCT ordered ERCOT's transition to a nodal network model [15]. ERCOT launched its nodal market on December 1, 2010. System-wide load-weighted average real-time price of energy increased 35% in the 2011 calendar year from 2010. However, according to the ERCOT market monitor, the increase in prices was due primarily to two periods of extreme weather events that occurred in February and August of 2011 that resulted in operating reserve deficiencies causing real-time energy prices reaching the system-wide offer cap for a number of trading intervals. Despite these events, for nearly all levels of load the implied heat rate (real-time energy price divided by the price of natural gas) was lower in 2011 than in 2010 which the ERCOT market monitor suggested is likely attributed to the efficiency improvements due to the nodal market implementation [9].

The first of the two extreme weather events that occurred during the first year of the ERCOT nodal market operation occurred in the morning hours of February 2, 2011. On this day extremely cold temperatures occurred across ERCOT leading to seasonal record levels of demand combined with various generator outages. Operating reserve levels became extremely low and Emergency Interruptible Load Service was deployed to shed load for a number of hours. During this time, real-time energy prices reached the system cap of $3,000/MWh for multiple real-time settlement intervals. The second extreme event occurred in the summer of the same year which, at the time, was the hottest on record for the ERCOT region and led to extremely high load through the summer months. For a period in August, peak load reached very high levels during many hours leading to low levels of operating reserves and prices reaching the system wide offer cap for a total of more than 17 hours [9].

Zarnikau, Woo, and Baldick (2014) examined how pricing outcomes in ERCOT's nodal market compared to outcomes under the zonal design [15]. The authors found that average prices were 2 percent lower under the nodal market than expected prices under the zonal design. In addition lower energy prices, it has been noted elsewhere that costs of procurement of ancillary services also reduced under the updated nodal market design [1]. In contrast to the Zarnikay et al. study, in this study we examine changes in total variable costs under the nodal design.

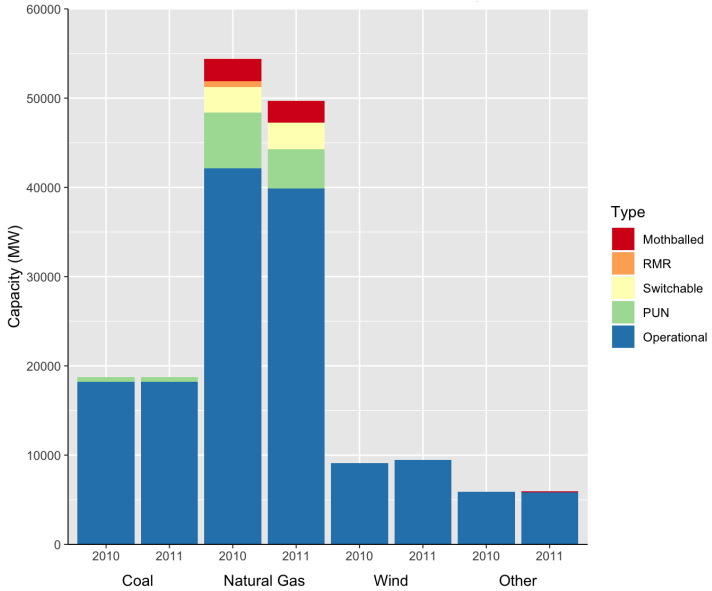
At the time of the launch of the nodal market electricity generation in ERCOT was predominantly supplied by coal and natural gas-fired generation. Figure 2 shows total nameplate capacity by fuel in ERCOT for the summer of 2010 and summer of 2011. Operational coal capacity remained virtually unchanged over the period at 18,194 MW in 2010 and 18,199 MW in 2011. Meanwhile, operational natural gas capacity fell approximately 5.4% from 42,142 MW in 2010 to 39,850 MW in 2011. Wind capacity increased 3.7% while capacity of other resources remained nearly constant.

Although natural gas nameplate capacity was much higher than that of coal, in terms of electricity generation, each accounted for nearly equal shares of the overall fuel mix. For the 12 month zonal market period included in this study, coal and natural gas accounted for 39.3% and 38.7% of total generation, respectively. In the first 12 months of the nodal market, total coal generation rose by 5.1% while natural gas generation rose by 5.5%, bringing coal and natural gas shares of total generation up to 39.6% and 39.2%, respectively. Nuclear and wind generation supplied significant, but much smaller amounts of generation. Nuclear generation was 13.0% and 12.3% of the total in the two periods, while wind rose from 7.5% to 8.6%. Since 2011 wind generation has grown dramatically in the ERCOT territory. Note that for the time horizon of this study, increases in wind nameplate capacity and wind generation were modest. Generation from other fuels fell in the nodal period, but accounted for only a small fraction (less than 2%) of total output in both periods.[6]

Load in the ERCOT market in the last 12 months of the zonal market was 320.0 TWh increasing

[6] Data available at: http://www.ercot.com/gridinfo/generation

Figure 2: ERCOT Summer Generating Capacity by Fuel for 2010 and 2011



Sources: ERCOT 2010 and 2011 Capacity, Demand and Reserves Report

approximately 4% in the next 12 months to 332.9 TWh. In addition, hourly peak load increased from 65,713 MW to 68,318 MW in over the same time periods also increasing approximately 4%.

In order to appropriately compare costs from the year of zonal market operation in this study to the first year of nodal market operation, we must control for the differences described here. In addition to temporal controls, we control for the amount of load served by thermal generation, the generation of non-dispatchable resources, and fuel prices. In addition, we provide the results of a variety of sensitivity analyses to test whether our findings are robust to our set of assumptions.

5 Methodology

In this study, we measure the change in the selected metrics while controlling for variables that lead to differences in daily conditions. Thus we estimate a conditional mean function that can as flexibly as possible control for variables that result in different daily conditions. Specifically we measure the difference in expected daily variable costs, unit starts, heat input, and CO2 emissions under the nodal market given a level of thermal generation, level of non-dispatchable generation, fuel prices, and temporal controls.

In order to estimate the average difference in the dependent variable under nodal market operation with respect to the zonal market, we estimate the following conditional mean function, as in Robinson (1988) [10]:

$$y_t = X_t'\beta + \theta(Z_t) + \epsilon_t \tag{1}$$

where data is assumed to be i.i.d. and $\mathbb{E}(\epsilon_t|X_t, Z_t) = 0$, $\forall t \in T$ (where T is the number of observations). The formulation allows for heteroskedastic errors of unknown form: $\mathbb{E}(\epsilon_t^2|X, Z) = \sigma^2(X, Z)$ [7]. Here, β is an unknown slope coefficient vector of length p and θ is an unknown function of Z_t. (X_t, Z_t) is a $\mathbb{R}^p \times \mathbb{R}^q$-valued random variable. The elements of vector X_t are assumed to be linearly related to the dependent variable. The elements of Z_t are non-parametric variables, related to y_t by function $\theta : \mathbb{R}^q \to \mathbb{R}$. In this study X_t consists of only categorical indicator variables (nodal indicator, month, and day of week) while all continuous numerical variables are treated as non-parametric

[6] Data available at: http://www.ercot.com/gridinfo/load/load_hist/

elements of Z_t. This formulation allows for high flexibility in estimating the relationship between these variables and the dependent variable y_t.

To proceed with estimation in this setting, we take the expected value of Equation (1) with respect to Z_t and subtract the result from the same equation yielding:

$$y_t - \mathbb{E}(y_t|Z_t) = (X_t - \mathbb{E}(X_t|Z_t))'\beta + \epsilon_t \tag{2}$$

Note that we have eliminated the unknown function θ from the equation. A two-step process is used to proceed with estimation of the vector β. First, we use data-driven kernel methods to estimate the conditional expectations in Equation (2).[7]We can then use conventional OLS on the result to obtain estimates of the vector β [7].

Under appropriate regularity conditions the estimator $\hat{\beta}$ has been shown to be a $\sqrt{T}$-consistent estimator of β:

$$\sqrt{T}(\hat{\beta} - \beta) \xrightarrow{d} N(0, \Phi^{-1}\Psi\Phi^{-1})$$

where $\Psi = \mathbb{E}[\sigma^2(X_t, Z_t)\tilde{X}_t\tilde{X}_t{}']$, $\Phi = [\mathbb{E}(\tilde{X}_t\tilde{X}_t{}')]$, and $\tilde{X}_t = X_t - \mathbb{E}(X_t|Z_t)$ [7].[8]

We estimate the conditional mean function for four different definitions of the dependent variable, y_t: 1) the natural logarithm of daily variable costs ($), 2) daily warm and cold starts, 3) the natural logarithm of daily heat input (MMBtu), and 4) the natural logarithm of CO2 emissions (tons CO2). Each definition includes data for coal and natural gas generating units in the ERCOT region. The vector X_t includes a nodal market indicator (with value 1 for all intervals after the launch of the nodal market on Dec 1, 2010 and zero otherwise), month of year indicator variables, and day-of-week indicator variables.[9] The elements of vector Z_t include the natural logarithm of daily fossil-fueled generation (MWh), the natural logarithm of daily non-dispatchable generation (MWh), the natural logarithm of the monthly price of coal ($/MMBtu), and the natural logarithm of the daily price of natural gas ($/MMBtu). The unit of observation is at the daily level with 730 observations beginning one year before the launch of the nodal market (December 1, 2009), through one year after the launch (November 30, 2011). The regressions for this study were performed using the `np` package in the `R` statisitical computing language. [4] Supporting data and `R` code is available in an online github repository.[10]

6 Data Input Summary

In this section we describe the data that were used to estimate the parameters of the conditional mean functions. Data includes: i) generating unit level gross heat input, gross MWh generation, warm and cold unit starts, and CO2 emissions, ii) technology-specific variable operations and maintenance (O&M) costs, iii) natural gas and coal fuel prices, and iv) ERCOT wind and nuclear generation. Daily data were used for all regression results presented in this study with exception of the hourly results presented in the appendix.

Generating unit-level hourly gross MWh output, heat input, and CO2 emissions were taken from the EPA's Air Markets Program Data (AMPD).[11] ERCOT's 2010 and 2011 Summer Capacity, Demand and Reserves (CDR) reports were used to determine which units were participating in the ISO during the study's time horizon. The ERCOT 2010 Summer CDR report indicates 42,142 MW of available natural gas capacity. Of this capacity, data were not available for a number of units that were 75 MW and below. The generating capacity for which data was not available amounted to 641.9 MW

[7]Second order Gaussian kernels were used in the estimation of the conditional expectations in Equation (2). For more details on the kernel estimation procedure see Li and Racine (2002) [7].

[8]For further details on regularity conditions and inference in a semiparametric setting see Li and Racine (2002).

[9]Hourly regressions included in the Appendix also include an hour of day indicator variable.

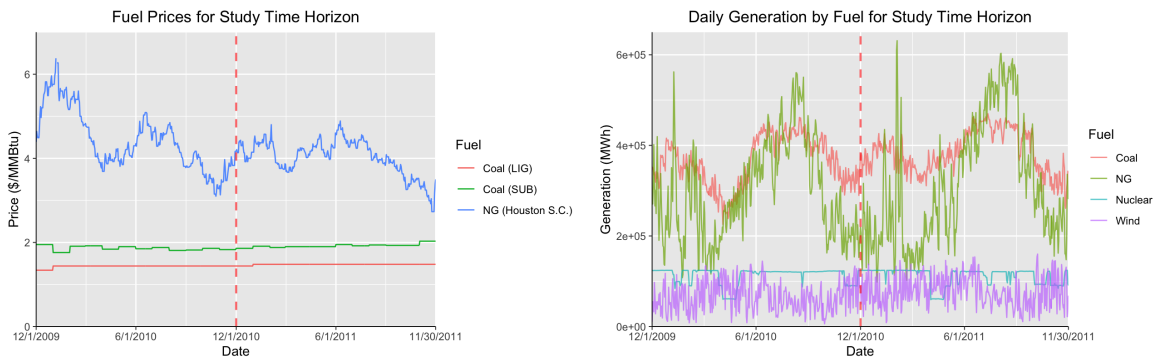
[10]Available at: https://github.com/rtriolo22/NodalMarket-ERCOT

[11]Available at: https://ampd.epa.gov/ampd/

or approximately 1.5% of total natural gas capacity. Coal generation capacity from the same CDR report amounted to 18,194 MW, complete unit level data was available for this capacity and these were included in the study.[12] ERCOT Wind and nuclear generation by settlement interval were available from the ERCOT ISO website.[13] Hourly unit level CO2 emission data (tons CO2) was retrieved from the EPA AMPD dataset. For a small number of units in the study this data was not available. For these units, hourly CO2 emissions were calculated based on the unit's hourly heat input and the average emissions factor of other generating units of the same technology in the dataset.[14]

Hourly fuel price assumptions are displayed in Figure 3(a). Note that coal prices are much lower than natural gas prices on a $/MMBtu basis, and exhibit less variation. Natural gas prices were relatively high at the beginning of the time horizon, reaching over $6/MMBtu falling to below $3/MMBtu near the end of the time horizon. However, throughout the middle of the time horizon natural gas price does not exhibit a discernible trend. To address the concern that the high prices at the beginning of the time horizon and low prices at the end influence the results of the study, in the appendix we provide a sensitivity that includes only data after the first day that natural gas drops below $4/MMBtu to the last day that natural gas is above $4/MMBtu. We find that our results are relatively unchanged under this sensitivity (see the appendix for more details). Figure 3(b) displays daily generation by fuel over the study time horizon. Here we observe little change in generation patterns in the zonal and nodal periods under study.

Figure 3: Fuel Prices and Generation by Fuel over Study Time Horizon



(a) (b)

Notes: Data is pictured for 12/1/2009 through 11/30/2011. The dashed red line indicates the implementation of the nodal market on 12/1/2010.

Variable O&M cost assumptions for the base case ($/MWh) were taken from Mann et al. (2017). [8]. The assumed values were $6.33/MWh for coal, $4.73 for CCGT and CCGTCHP units, $13.40/MWh for OCGT and OCGTCHP units, and $15.40 for ST units.[15]In order to test the sensitivity of the results to these assumed costs, in Regression 3 we assume variable O&M costs presented in Tidball et al. (2010). [13] These assumed values were $4.59/MWh for coal, $2.00 for CCGT and CCGTCHP units, $3.17/MWh for OCGT, OCGTCHP, and ST units. Total variable cost was computed as the sum of fuel costs and variable O&M costs for each unit. Fuel costs are the product of the assumed fuel price ($/MMBtu) times heat input (MMBtu). Variable O&M costs are the product of the assumed per unit output costs ($/MWh) and the unit level gross generation (MWh).

[12]Capacity values here include only fully participating units. Private use network, RMR, and switchable resources are not included. Data for RMR units were available and these units were included in the study. Data for the Tenaska-Frontier and Tenaska-Gateway switchable units were available and these were also included in the study.

[13]Available at: http://www.ercot.com/gridinfo/generation

[14]Hourly CO2 emissions data was not available (or only available for a subset of the time horizon) for 47 turbines at 7 generating units, all of which were natural gas-fired units. An emissions factor of 0.05946 tons/MMBtu was assumed for these units to compute hourly and daily CO2 emissions. This assumption was based on the simple average of emissions factors for all other natural gas units in the dataset.

[15]CCGT: combined-cycle gas turbine; CCGTCHP: combined heat and power combined-cycle gas turbine; OCGT: open cycle gas turbine; OCGTCHP: combined heat and power open cycle gas turbine; ST: steam turbine

For natural gas prices, daily volume weighted average prices (USD/MMBtu) were retrieved from Bloomberg (2020). For weekends and holidays, where trading prices were not available, price of the most recent previous trading day was assumed. In our base assumptions, Houston Ship Channel settlement prices were assumed for all natural gas units. In the Appendix we provide results of sensitivity analysis of this assumption using alternative natural gas price assumptions.

Monthly average coal prices (USD/MMBtu) were taken from the EIA Electric Power Monthly Update.[16]The EIA's reported monthly "average cost of coal delivered for electricity generation" for Texas was assumed for all subbituminous coal units. The natural logarithm of these data were used as the nonparametric coal price control. For lignite units, the EIA's Annual Energy Review annual prices (USD/short ton) were assumed where annual average heat content was computed from the volume weighted average heat content of all coal used in Texas reported in EIA's Form 923 data, Schedule 5. These prices were used to compute the variable costs of lignite coal units, but annual prices were not used as controls due to the lack of variation in annual data.

In addition to units listed in these reports, data was available for a number of industrial private use network (PUN) generating units. In ERCOT, there exist a number of industrial cogeneration plants that provide heat and electricity for local use, and are referred to as PUN facilities.[17] These cogeneration plants produce heat for industrial applications and use excess heat to generate electricity. The electricity generated may be used locally or exported to the ERCOT grid. The fraction of output that is made available to the grid may be only fraction of a single plant's output, but for all PUN units combined, the contribution to the ERCOT grid may be substantial at certain times.[8] In times of high prices in the ERCOT market such plants have high incentive to provide electricity to the market. EPA AMPD include hourly operational data for PUN units in the ERCOT territory, however data are not available to determine what fraction of output was made available to the ERCOT system. In our base case assumptions we have excluded PUN units, but we include these as an alternative case.

We define a unit startup to be a unit being switched "ON" after a certain number of continuous hours of that unit being "OFF". For coal units, we required the unit to be off for eight consecutive hours, for natural gas we required the unit to be off for four hours. These were considered "warm" or "cold" starts. For downtime less than this length, startups were considered "hot" startups and not counted as unit starts for the purposes of this analysis. The algorithm used for classifying a unit in a given hour as "ON" or "OFF" is described in the Appendix.

7 Results

Here we present the results of regressions performed under four differing sets of assumptions as part of this study. Results of additional sensitivity cases are available in the Appendix of this paper. For each set of assumptions, regressions were performed for each of the four definitions of y_t described in Section 5. All regressions include 730 daily observations for the ERCOT market from December 1, 2009 through November 30, 2011. This includes 365 observations before the implementation of the nodal market and 365 following the implementation. The semiparametric conditional mean function estimated is defined above in Equation (1). For all results, in addition to the nodal market indicator variable, we include parametric control variables for month and day of week, and non-parametric control variables natural log of thermal generation, natural log of non-dispatchable generation, natural log of natural gas price, and natural log of subbituminous coal price. The description of each model is summarized below in Table 1.

Table 2 displays the estimates of β_{nodal}, the element of the vector β corresponding to the nodal market coefficient estimator and the associated standard errors for the four definitions of y_t. For the total daily variable cost definition of y_t, across all regressions we a find a negative and significant point estimate of the coefficient. Regression 1, corresponding to base assumptions, results in an estimate of -0.040 implying a 3.9% decrease in variable costs of natural gas and coal units with the implementation

[17]More generally, PUN units are not limited to cogeneration technology, but in practice, nearly all are of this type. All PUN units included in this study are natural gas-fired cogeneration units.

Table 1: Regression Descriptions

Regression #	Description
1	Variable O&M costs given by Mann, et al. (2017) Exclude industrial PUN CHP generators Non-dispatchable generation defined as wind output only
2	Include industrial PUN CHP generators Other assumptions as in Regression #1
3	Variable O&M costs given by Tidball, et al. (2010) Other assumptions as in Regression #1
4	Non-dispatchable generation defined as nuclear and wind output Other assumptions as in Regression #1

of the nodal market.[18]Across the four sets of assumptions there was an average estimated variable cost decrease of 3.4% with a minimum of 3.1% decrease and maximum of 3.9%.

For the daily unit starts definition of y_t, we find a negative point estimate of β_{nodal} across all regressions, with a point estimate of -4.98 in the base regression. For reference, average daily thermal unit starts were 78.0 (SD = 33.6) over the study time horizon.[19] Of this average 77.4 is accounted for by natural gas with coal units averaging only 0.6 starts per day. The estimated standard error of the estimator of β_{nodal} implies that a 95% confidence interval of the estimate of β_{nodal} includes zero for all three sets of assumptions.[20] Thus, the data do not provide strong evidence that the effect of changing to a nodal market design had a non-zero impact on the number of daily unit start ups.

For y_t defined as the natural logarithm of total daily heat input, the point estimate of β_{nodal} was positive, with a 95% confidence interval that does not include zero under two of the three sets of assumptions. Results in the expected value of average daily heat input increased under the nodal market. Under the base assumptions we estimate an increase of 1.3% with an estimated increase of 1.2% in Regression 4.

Finally, for y_t defined as the natural logarithm of total CO2 emissions, the positive estimate of β_{nodal} indicates that the conditional expectation of daily CO2 emissions increased under the nodal market implementation across all sets of assumptions, and was a significant result in each. Under the base assumptions, expected daily CO2 emissions increased by 5.8%. The lowest estimate was in Regression 2 where PUN CHP units were included in the analysis. Here, the estimated increase in CO2 emissions was 4.9%. For daily CO2 emissions the 95% confidence interval does not contain zero under any of sets of assumptions, providing evidence that CO2 emissions did increase under the nodal market holding all control variables constant.

Comparing results of Regression 2 to Regression 1 we observe the effect of including PUN generating plants in the analysis. All PUN units included were natural gas-fired generation. Including the units in the analysis, the estimated variable cost savings increase from 3.8% to 4.1%. In addition, the estimated heat input and CO2 increases are mitigated.

In Regression 3 we observe the impact that our variable O&M assumptions have on estimated savings in the study. When adopting the variable O&M cost assumptions reported in NREL (2010) we find that the estimated variable cost savings fall from 3.8% to 3.3% [13]. Although the point estimate

[18]Note that for regressions where the dependent variable y_t is a natural logarithm the estimated percent change under the nodal market is $100 \cdot (\exp(\hat{\beta}_{\text{nodal}}) - 1)$ where $\hat{\beta}_{\text{nodal}}$ is the estimated value of β_{nodal}

[19]This average excludes PUN units.

[20]Note that for unit starts, heat input, and CO2 emissions, there are only three sets of assumptions as Regression (3) only differs from Regression (1) in variable cost assumptions.

Table 2: Estimates of β_{nodal} (coefficient of nodal market indicator) with standard errors shown in parentheses

Definition of y_t	Regression Number (1)	(2)	(3)	(4)
Variable Cost (log)	-0.040	-0.034	-0.034	-0.032
	(0.0059)	(0.0051)	(0.0055)	(0.0054)
Unit Starts	-4.979	-6.196	–	-4.758
	(5.6987)	(5.9883)	–	(4.7724)
Heat Input (log)	0.013	0.011	–	0.012
	(0.0033)	(0.0035)	–	(0.0026)
CO2 (log)	0.053	0.050	–	0.046
	(0.0051)	(0.0048)	–	(0.0043)

Notes: (1): Base assumptions; (2): PUN generating units included; (3) alternative O&M costs; (4) include nuclear generation; for Regression (3) '–' indicates that for this result there is no difference in assumptions from Regression (1)

of variable cost savings under the nodal market is sensitive to the variable O&M assumptions, the results here demonstrate the result of significant savings under the nodal market design is robust to alternative variable O&M cost assumptions.

In Regression 4 results we see the impact of including both nuclear generation and wind generation as non-dispatchable generation. Nuclear plant operation may be considered non-dispatchable as it does not generally ramp up and down in response to market conditions in a similar fashion to conventional thermal units. Nuclear units in general run at full output when operational. Note that total nuclear generation is much greater than wind output over this time period in the ERCOT region. Maintenance outages of single nuclear generator outages have a large impact on the variability of this control variable. Nuclear operation was similar across both periods with the slightly lower nuclear generation observed in the nodal period due mostly to a higher number of hours with one nuclear unit maintenance outage. Although the magnitude of the point estimate of variable cost savings under these assumptions is smaller than the base assumptions, this results again demonstrates that the finding of efficiency gains under the nodal market is robust to the non-dispatchable generation definition assumption.

Note that across all regressions expected daily variable costs reduced while heat input and CO2 emissions increased under the implementation of the nodal market. Fuel input, measured in dollars per unit of heat content, is a primary component of total variable costs it may be unexpected that results indicate a reduction in variable cost with an increase in heat input and CO2 emissions. This divergence in variable cost and heat input results are due to the different way in which nodal market implementation affected coal and natural gas resources. Because coal generation has lower marginal cost, higher heat rates, and higher CO2 emission factors relative to natural gas generation, changes in dynamics of operation of these technologies result in cost savings even with increased heat requirements.

Although coal and natural generation account for similar levels of total generation over the study's time horizon, natural gas units account for a much larger share of total fossil fuel generation variable costs but a much lower share of total heat input. Variable costs of natural gas generation are 46.6% higher than that of coal under the base assumptions. However, the total heat input for coal is

44.1% higher than natural gas. Across the time horizon coal generation had an average heat rate of 9,829 Btu/kWh while the average natural gas heat rate was 8,358 Btu/kWh. Although coal units require a higher heat input per unit of generation, the price of natural gas per unit of heat content is considerably higher. The simple average of daily natural gas price for the time horizon was $4.23 per MMBtu while the simple average prices for subbituminous and lignite coal were $1.89 and $1.45, respectively.[21] While the change in operation of coal and natural gas generation under the nodal design achieved lower variable costs, the higher heat requirement for coal generating units led to a net increase in heat input.

Coal generation also has a much higher CO2 emissions factor per unit of fuel input. While the natural gas units in this study had an average emission factor of 118.1 lbs per MMBtu, coal generating units had an 80.9% higher emissions factor of 236.2 lbs per MMBtu. As a result, CO2 emissions are much higher for coal generation than for natural gas. Over the 24 month period, natural gas emissions were 110 million tons while coal emissions amounted to 287 million tons, more than two and a half times that amount.

To further explore the dynamics between coal and natural gas generation we have estimated Equation 1 separately for coal and natural gas-fueled generation. Here, for the coal regressions, we define dependent variable y_t as total daily variable cost for coal generation only, vector X_t is defined as above, and Z_t now includes only the natural logarithm of daily coal generation, daily wind generation, and coal price as non-parametric variables. The equation is estimated similarly for the natural gas-fueled generation. The estimated values of β_{nodal} for these regressions are presented below in Table 3.

Table 3: Estimates of β_{nodal} (for coal and natural gas generation) with standard errors shown in parentheses

Definition of y_t	Coal	Natural Gas
Variable Cost (log)	0.011 (0.0056)	-0.022 (0.0028)
Unit Starts	0.142 (0.1634)	-0.439 (2.4498)
Heat Input (log)	0.010 (0.0017)	-0.023 (0.0029)
CO2 (log)	0.009 (0.0014)	-0.013 (0.0028)

These results indicate that average variable cost of generation increased for coal generation in the nodal market by an estimated 1.1% while variable costs for natural gas generation decreased by 2.2%. We can infer from these results that changes in dispatch under the market change led to decreased efficiency of coal operation while natural gas dispatch became considerably more efficient.

These results for each generation technology considered independently does not tell us how much efficiency was gained through synergies of coal and natural gas operational dispatch under the nodal market. More efficient operation of coal and natural gas resources together in the nodal market appeared to have a considerable impact. We saw above that combined variable cost of coal and

[21] Average prices reported reflect the average of assumed prices in the base case as described in Section 6

natural gas generation fell by 3.8% in the nodal period. This implies that a large portion of the efficiency gains were realized due to the improved synergistic operations of available resources.

For unit starts, the point estimate for daily starts is slightly positive, while the point estimate for natural gas is slightly negative. However, the large standard error implies that the data do not provide strong evidence that there was a change in unit starts with the implementation of the nodal market.

For coal generation, we estimate a 1.0% increase in heat input, while for natural gas we find a decrease of 2.3%. Similarly, for CO2 emissions we find an increase of 0.9% for coal generation and a decrease of 1.3% for natural gas. Comparing these results to Table 2 where we find that for all thermal generation heat input increased by 1.3% and CO2 emissions increased by 5.8% suggests that increases in heat input and CO2 emissions were driven by coal-fired generation. The higher heat rate and high emission factor of coal generation resulted in an aggregate net increase in heat input and CO2 emissions. We provide more discussion of operational changes of coal and natural gas generation in the following section.

In the appendix to this paper, we provide a range of sensitivity analyses to test the robustness of our findings to a variety of assumptions. The sensitivities include: i) hourly level observations, ii) alternative natural gas price assumptions, and iii) alternative study time horizon. The magnitude of the estimated effect of nodal market implementation varies little across the sensitivity cases. See the appendix for more details on sensitivity analyses.

8 Discussion

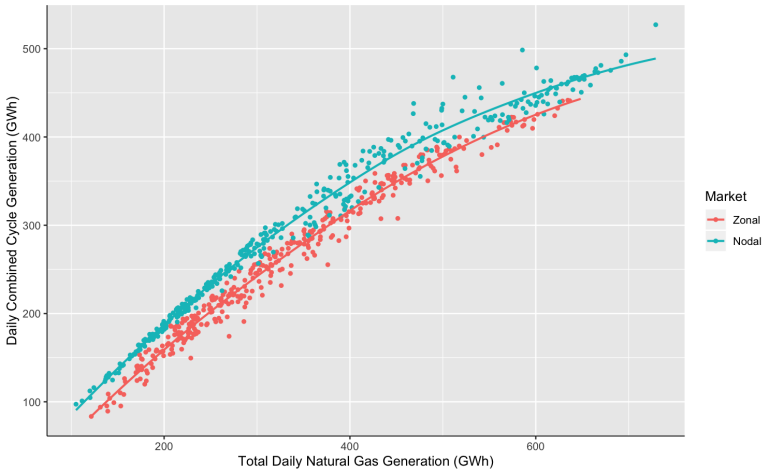
Under the base case assumptions in this study, total variable costs of generation for coal and natural gas generation for the 12 month period from December 1, 2009 through November 30, 2010 amounted to approximately USD$8 billion. The results presented here imply that the expected daily variable costs of thermal generation reduced by 3.8% after the implementation of the nodal market. Under these assumptions, the variable cost savings were greater than $300 million on an annual basis for the ERCOT region. The alignment of the day ahead market model with the physical network and increased spatial granularity of pricing under the nodal market resulted in improved efficiency of market settlement and system operation.

With the implementation of the nodal market qualified scheduling entitities (QSEs) that hold electric generating units offer energy into the ERCOT Day Ahead Market each day for the following operating day. Resource specific three-part offers with locational price formation allow for increased certainty in Day Ahead operating plans for generating resources. For combined cycle (CC) natural gas units, the ability to provide three-part offers and a market solution that is closer to real-time operation provides greater certainty in real-time operations after the clearing of the day-ahead market. Because of this, we expect that CC units will be more likely to provide more output in more hours under the nodal market.

ERCOT data shows that in terms of net generation provided to the market, CC units accounted for 78.1% of total natural gas generation in the 12-month zonal period under study while accounting for 84.4% in the nodal period. Figure 4 displays the total amount of daily CC generation versus total daily natural gas generation. Here, we observe higher levels of CC generation given an amount of natural gas generation in the nodal market. We estimate a semiparametric conditional mean function as in Equation (1) to estimate the change in CC generation given a level of total natural gas generation under the nodal market. Here y_t is defined as the natural logarithm of daily combined cycle natural gas generation. The vector X_t includes only the nodal market indicator, and Z_t includes only the natural logarithm of total daily natural gas generation. Results indicate that the expected level of daily CC generation given a level of total daily natural gas generation was 12.1% higher under the nodal market period. The higher contribution of CC generation with lower heat rates (relative to simple cycle combustion turbines) contributed to the reduced costs, reduced heat input, and reduced CO2 emission of natural gas generation.

Under the nodal market model we expect that generator three-part offers, reduced incentive for

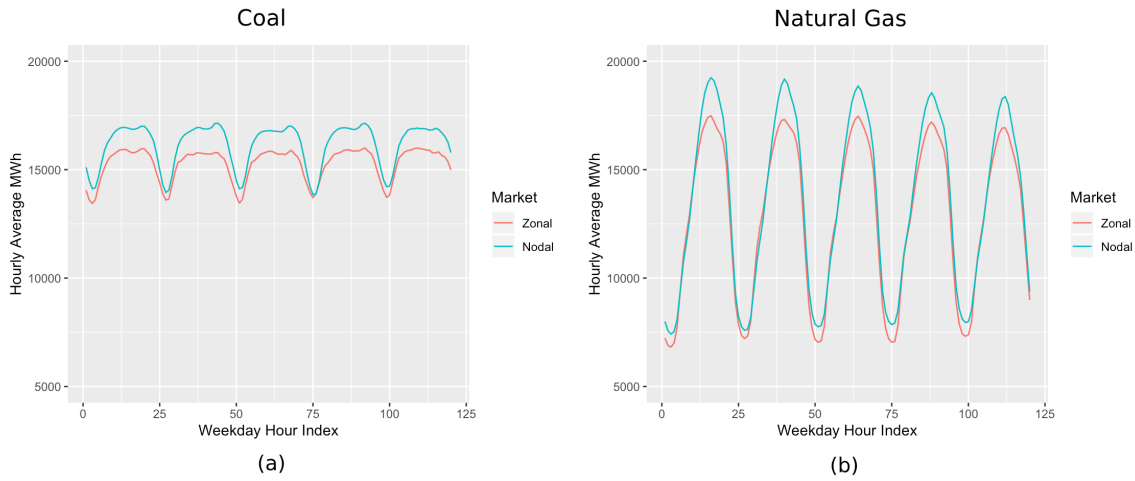
Figure 4: Combined Cycle Daily Generation vs. Total Natural Gas Generation



Data source: ERCOT. A local regression (LOESS) trendline is pictured.

bidding above or below marginal cost, and a solution that is optimized across all 24 hours of the day will lead to more efficient scheduling of coal and natural gas units. In fact, we observe a notable change in coal and natural gas ramping after the implementation of the nodal market.[22] Figure 5 displays average hourly coal and natural gas generation on weekdays. In this figure we can see that coal unit operation changed significantly from the zonal to the nodal period. For aggregate coal generation, average weekday daily ramping increased notably. Results presented in Table 3 indicate that this change in operation resulted in increased variable costs, increased heat input, and increased CO2 emissions in expectation per unit of output. However, combined operation of coal and natural gas units achieved a significant cost efficiency improvement reducing total variable costs of coal and natural gas operations when taken together as found in Table 2. Comparing the results of Table 2 and Table 3 we observe that the efficiency gain of the combined operation of coal and natural gas resources was large relative to the cost savings achieved by increased efficiency of natural gas unit operation alone.

Figure 5: Weekday Average Hourly Coal and Natural Gas Generation

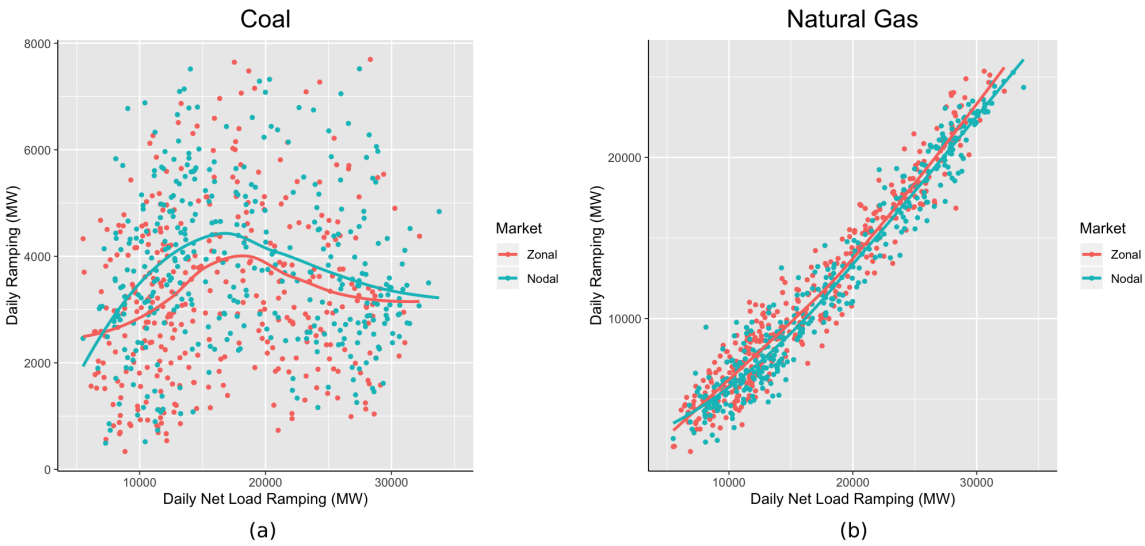


Data suggest that daily ramping of coal generation increased when controlling for net load ramping. Figure 6(a) and Figure 6(b) show daily ramping of coal and natural gas, respectively, versus daily net

[22] In this paper, we define "daily ramping" as maximum hourly output - minimum hourly output on a given day.

load ramping for the zonal and nodal market periods. The trend lines presented are local regression (LOESS) fitted values. For coal units, we see that coal ramping does not appear to be highly correlated with net load ramping. Although, the LOESS smoothing line plotted indicates that the moving average of coal ramping was higher during the nodal period than during the zonal period for nearly all load ramping levels. In particular, the greatest difference is in relatively lower net load ramping days, that occur with highest frequency, where coal increased ramping substantially. On the other hand, we see that natural gas ramping is highly correlated with net load ramping. This is to be expected as natural gas units are often the load following marginal units. Although the change with the implementation of the nodal market is less apparent than it is for coal generation, the LOESS estimation is lower for nearly all levels of net load ramping. We estimate a semiparametric conditional mean function as in Equation (1) to estimate the change in ramping for aggregate coal and natural gas generation controlling for the amount of load ramping. Here y_t is defined as the natural logarithm of daily aggregate coal (natural gas) ramping. The vector X_t includes only the nodal market indicator, and Z_t includes only the natural logarithm of daily load ramping. Results indicate that the expected value of daily coal ramping increased 16.5% in the nodal period given a level of net load ramping. The expected value of natural gas ramping decreased 4.9% given a level of net load ramping. These results suggest that coal generation operated with a higher degree of flexibility under the nodal market compared to the zonal period, with natural gas generation providing somewhat less load following. This suggests that the increased flexibility of coal generation was able to reduce the need for the least efficient natural gas ramping leading to increased cost efficiency for natural gas and greatly increased combined efficiency.

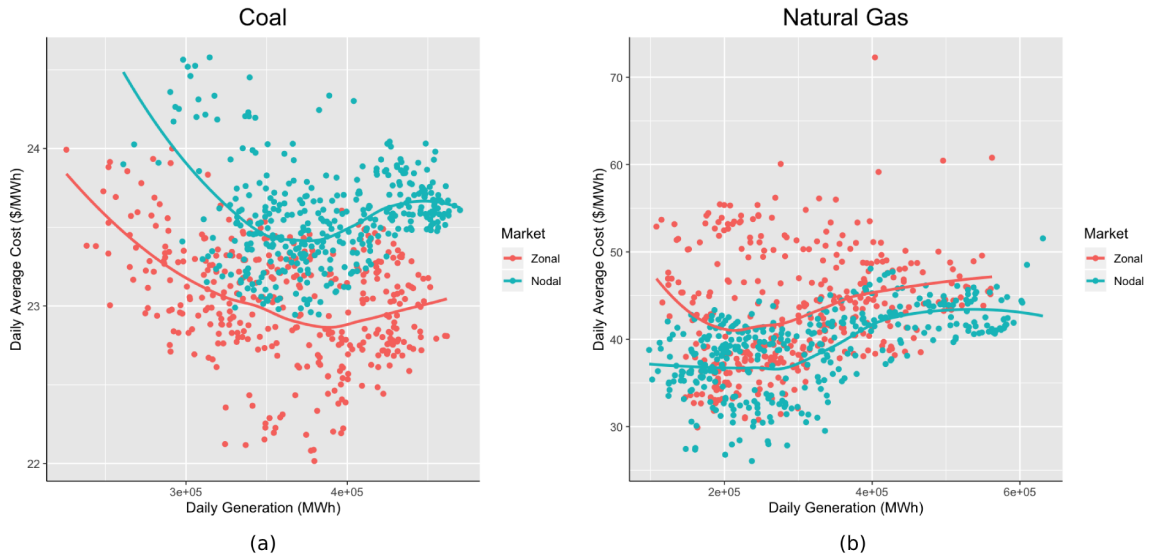
Figure 6: Thermal Ramping vs. Net Load Ramping



In Figure 7 we have plotted the daily average cost of generation ($/MWh) versus daily generation by fuel.[23]Comparing Figure 7(a) and Figure 7(b) we observe that for coal generation, daily average costs fall in a narrower range and lower than natural gas generation. The LOESS curves indicate that coal generation had highest average costs for the lowest levels of generation, with costs increasing also at the upper end of daily generation values. For natrual gas, the LOESS curve indicates high costs for low levels of daily generation in the zonal period, however after the implementation of the nodal market we observe a nearly monotonically increasing relationship between daily generation and average costs. Results presented above in Table 3 indicated that variable costs for coal increased approximately 1.1% while natural gas decreased approximately 2.2% when including controls for temporal indicators, fuel prices, non-dispatchable generation, and generation by fuel. From Figure 7 we observe that increasing the cost of the cheaper source of generation (coal) by a small amount enabled larger gains in cost reduction of natural gas generation, with the effect largest for days where

total natural gas generation was relatively low.

Figure 7: Thermal Daily Average Cost vs. Daily Generation



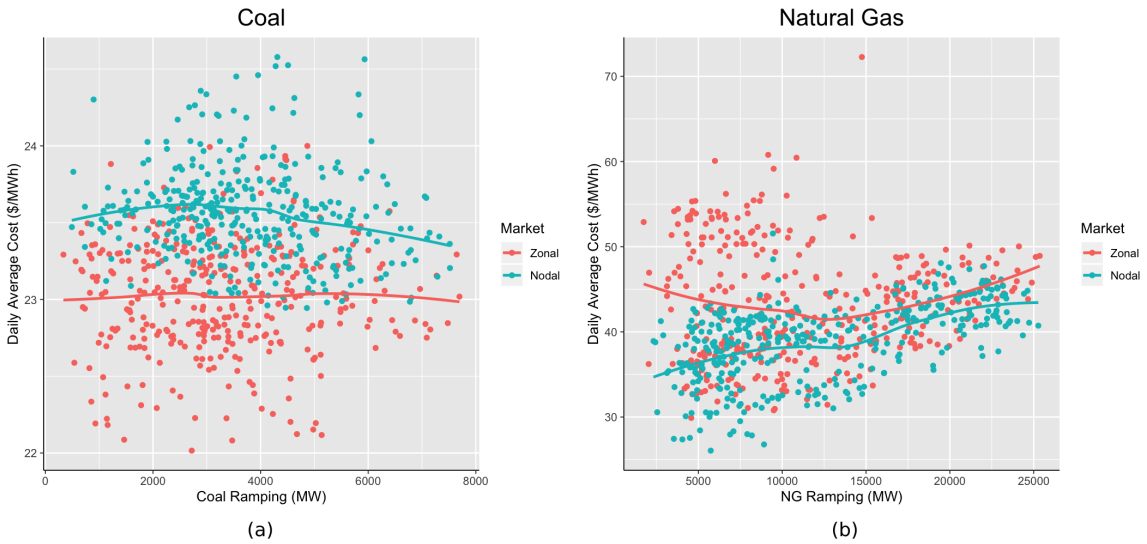
In Figure 8 we display daily average cost versus aggregate generation ramping by fuel type. The pictured LOESS smoothers indicate increased average costs for coal under the nodal market with decreased average costs for natural gas. Note again the narrower range of daily average costs for coal generation compared to that of natural gas. In Figure 8(a) we observe that coal generation exhibits relatively constant average costs for varying levels of ramping. In contrast, in Figure 8(b) average daily costs of natural gas do not appear to be constant for changing levels of natural gas ramping. From the LOESS smoother pictured, for the zonal period we observe a U-shaped relationship where both low and high levels of ramping exhibit higher daily average cost with lowest average cost near the middle of the range of values. With the implementation of the nodal market, daily average cost and daily ramping appear to have a positive relationship across the range of values. Here the the increased ability of combined-cycle units to supply more generation in lower demand days likely significantly reduced costs of generation in the nodal market.

Two points are important for the reader to consider when interpreting these results. First, the increase in CO2 emissions is not a necessary result of nodal market operation. The aim of nodal market design is to increase cost efficiency of electricity generation in the region and the carbon emission externality is not internalized into market transactions and is a side-effect of market operation. It has been shown elsewhere that total heat input (and therefore associated emissions) has decreased in other territories, such as California, with the implementation of a nodal market. [14] Whether carbon emissions increase or decrease relative to zonal operation will depend on the fuel mix in the market and the dynamics of the market. In order to reduce or limit carbon emissions under a change in market design, complementary policies would be necessary, such as a carbon tax, renewable portfolio standard, or carbon trading scheme.

A second point is that although we observe a short-run carbon emissions increase, it may be the case that in the longer run the nodal design accelerated the retirement of coal generation in ERCOT. As seen in the results above, variable costs of natural gas decreased while they increased for coal generation. In the years following this study, low natural gas prices and increased wind generation deployment led to lower prices in the ERCOT region. The increased variable costs of coal generation would reduce profits to coal units in the region. Many coal units retired in the years following the transition. Although, the retirements are not solely due to the market design change, it may be the

[23] Daily average cost includes fuel and variable O&M costs. Variable O&M costs assumed are those assumed in Regression (1) of this paper.

Figure 8: Thermal Daily Average Cost vs. Daily Ramping



case that the reduced competitiveness of coal generation led to earlier retirement than would have occurred under the zonal market.

Moreover, under a high renewable penetration future we expect that the problems in a zonal market described above are likely to be exacerbated. First, because net load is less predictable under high penetration of variable output renewable generation, costs associated with re-dispatch are likely to increase. Second, with greater variability of net load the need for units to efficiently switch on and off is greater. As we have found in the case of ERCOT, the nodal market enables and incentivizes greater flexibility in operation to accomodate this variability.

Issues of market power can still arise under a nodal electricity market where a generator or a fleet of resources hold local market power. Market power is greatly reduced through mechanisms such as market power mitigation and the presence of explicit virtual bidding (EVB). For more details on how EVB mitigates exercise of market power in electricity markets see Jha and Wolak (2020).[6]

9 Concluding Remarks

In this study we began by describing mechanisms by which zonal market design results in market inefficiencies. Through analysis of the ERCOT market transition from zonal to nodal market design, we provide empirical evidence that nodal market design with locational pricing materially affects market operation and outcomes, and is a first-order important consideration in electricity market design. The following are three important high-level results of this study. First, the transition from zonal to nodal market design resulted in significant cost-efficiency savings. We estimate the savings in terms of variable cost of coal and natural gas generation at 3.8%, an estimated $300 million in the first 12 months of the nodal market. Second, a large proportion of the realized cost savings accrued due to synergies between coal and gas operation. In particular, we find that coal generation increased the flexibility of its operation while combined cycle units were able to provide more output as a proportion of total natural gas generation. These significant changes in generator operation with the implementation of the nodal market due to altered participation incentives and improved day ahead planning led to considerably lower variable costs. Third although a nodal market can achieve greater cost efficiency relative to a zonal market, it will not necessarily reduce CO2 emissions. This point should not be surprising due to the lack of incentives for emission reductions. Nodal market design encourages variable cost efficiency, but without a pricing mechanism for associated CO2 emissions, profit-maximizing participants make decisions based only on cost considerations. In order to achieve

carbon intensity reductions, carbon pricing or other policy instruments would be necessary.

Locational pricing is a key component of efficient electricity market design. In this paper we have argued that market design that does not take into account the physical network and other operating constraints in pricing leads to inefficient system operation and provides opportunities for participants to profit by taking advantage of the differences between the market model and the physical model. Results presented here provide evidence that electricity systems in regions that currently operate under a zonal framework, or have not yet gone through the process of restructuring, will likely be able to achieve considerable cost reductions through adoption of a nodal market design. The magnitude of cost savings will be affected by many factors such as the amount of re-dispatch costs in the market, frequency and severity of transmission congestion, the fuel mix in the region, and the size of the region, among others. Although implementation of nodal market requires an increased complexity for system operators, the analysis here provides evidence that cost efficiency gains of locational pricing in comparison to a zonal structure are likely to be substantial.

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A Appendix

A.1 Hourly Observational Data Sensitivity

The following estimates were obtained using the same assumptions as those in the Regressions (1)-(4) described in Section 7 but using data at the hourly level. Here we have 8760 hourly observations for the zonal period and 8760 observations for the nodal period. The estimated variable cost reduction is much higher in these sensitivity cases than in regressions using daily data.

Table 4: Estimates of β_{nodal} (coefficient of nodal market indicator) for hourly level data with standard errors shown in parentheses

Definition of y_t	Regression Number			
	(1)	(2)	(3)	(4)
Variable Cost (log)	-0.081	-0.089	-0.069	-0.057
	(0.0057)	(0.0051)	(0.0055)	(0.0082)
Unit Starts	-1.915	-2.00	–	0.392
	(1.1182)	(1.1521)	–	(1.6319)
Heat Input (log)	-0.001	-0.014	–	-0.005
	(0.0042)	(0.0037)	–	(0.0061)
CO2 (log)	0.050	0.038	–	0.0255
	(0.0046)	(0.0041)	–	(0.0065)

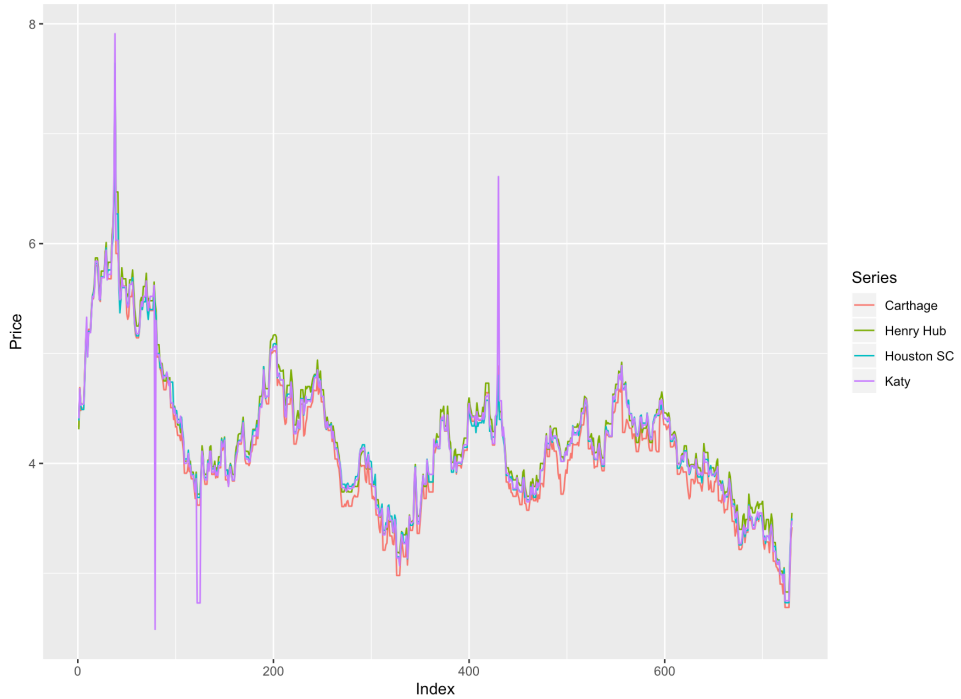
A.2 Natural gas price sensitivity

The base assumptions in this study assume that natrual gas generators pay the Houston Ship Channel spot natural gas price for fuel inputs. In reality the natural gas price is often different at various natural gas settlement points. Figure 9 below displays the daily price of natural gas over the study's time horizon at four major settlement points in and around the Texas region. Three additional sensitivities were performed to ensure that the natural gas price assumptions in the study did not drive the results. Table 5 displays the result of regressions under assumptions of Regression (1) in this analysis with the exception of the natural gas price. Here, four different natural gas settlement points are considered. Note that Houston Ship Channel (Houston S.C.) results displayed here correspond to the base assumptions, and results are also displayed here for comparison. As can be seen in the table, the results are relatively insensitive to the alternative settlement point assumptions.

A.3 Time horizon and extreme event sensitivity

Here we provide results from regressions where certain observations were removed from the dataset to ensure that two extreme events and natural gas price trend are not driving the results observed. As described above in Section 4 extreme pricing events occurred in February and August of 2011. In the first sensitivity result presented here, we remove observations from all of February and August of 2010 and 2011. In the second sensitivity we address the concern that a declining natural gas price trend could impact the results. In Figure 9 we may observe that relatively high natural gas prices were present in the beginning of the time horizon and price appeared to be declining toward the end of the time horizon. Here, we consider only the time period from where the Houston Ship Channel daily price first fell below \$4/MMBtu through the last day that it was above \$4/MMBtu. This includes daily observations from March 25, 2010 through September 5, 2011, inclusive.

Figure 9: Daily Natural Gas Price (12/1/2009 - 11/30/2011)



A.4 Unit startup assumptions

Additional operational costs are incurred when large thermal generating units need to be started relative to ramping up of a generating unit that is already running. The extra costs are due to increased fuel requirements to bring a generating unit online. In order to estimate changes in unit starts under the nodal market we had to determine when units were starting based on the operational data retrieved from EPA's AMPD webpage. The gross output data in certain hours records very low levels of non-zero output when ERCOT data reports that units are providing zero net output. However, unit level data was only available in the nodal market period.

For every generating unit, we determined a level of output above which the unit was classified as "on" and below which it was classified as "off". A startup was defined as an hour in which a unit was on after eight hours of consecutive "off" hours for coal units and four hours for natural gas. For units where turbine specific data was available from both the EPA and ERCOT a classification tree was used to determine the level of output that most accurately classified units as "off" when ERCOT output was zero. For some natural gas units, this one-to-one correspondence was not available (for example various CC units were provided as multiple turbines in EPA data while only one unit in ERCOT). For these unit the minimum sustained output level was taken from Mann et al. (2017) [8]. 50% of this level was used as the cutoff point below which units were classified as "off".

Table 5: Natural gas sensitivity estimates of β_{nodal} (coefficient of nodal market indicator) with standard errors shown in parentheses

Definition of y_t	NG Settlement Point			
	Houston S.C.	Henry Hub	Carthage	Katy
Variable Cost (log)	-0.035	-0.036	-0.038	-0.033
	(0.0056)	(0.0062)	(0.0056)	(0.0064)
Unit Starts	-4.979	-6.101	-7.070	-7.962
	(5.6987)	(5.8463)	(5.5206)	(5.6918)
Heat Input (log)	0.013	0.014	0.016	0.011
	(0.0033)	(0.0033)	(0.0032)	(0.0033)
CO2 (log)	0.057	0.058	0.062	0.050
	(0.0051)	(0.0053)	(0.0051)	(0.0052)

Table 6: Extreme event and time horizon sensitivity estimates of β_{nodal} (coefficient of nodal market indicator) with standard errors shown in parentheses

Definition of y_t	Sensitivity Case		
	Base Case	Sensitivity 1	Sensitivity 2
Variable Cost (log)	-0.038	-0.046	-0.036
	(0.0060)	(0.0067)	(0.0058)
Unit Starts	-4.979	-14.822	-5.552
	(5.6987)	(6.3734)	(5.8323)
Heat Input (log)	0.013	0.011	0.013
	(0.0033)	(0.0041)	(0.0036)
CO2 (log)	0.057	0.057	0.056
	(0.0051)	(0.0061)	(0.0055)