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Quantifying the benefits of a 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 operating 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 the operation of coal and natural gas technologies contributed to these outcomes, and find that a large proportion of the daily operating cost savings was due to the synergies achieved through increased efficiency of operation of these two generation technologies.

1. Introduction

Locational, or nodal, price formation and settlement in electricity markets is a key component of an efficient electricity market design. Electricity supply industries in the United States and around the world have attempted to operate wholesale electricity markets that ignore real-time operating constraints on the physical network infrastructure in their operation, and in virtually all cases the cost of doing so has been high (Hogan, 2002). Zonal markets that ignore physical infrastructure constraints in setting prices and generation schedules not only result in inefficient real-time system operation, but incentivize offer behavior by suppliers that further increases the cost of meeting system demand. As a consequence, all formal wholesale markets in the United States now employ nodal or locational marginal pricing, but the majority of markets around the world still operate under a zonal pricing design.

We begin with an explanation of how a zonal electricity market structure leads to inefficient outcomes through the incentives it creates for participating generators. We provide discussion of why a nodal market design eliminates this source of market inefficiency. We then estimate the changes in economic and operational metrics in the Electric Reliability Council of Texas (ERCOT) electricity market associated with the change from a zonal to a nodal market design on December 1, 2010.

We employ a semiparametric conditional mean model to estimate the changes in the following four daily market performance metrics associated with the implementation of the nodal market: (1) operating cost of thermal generation units, (2) thermal generating unit starts, (3) total fuel heat input, and (4) CO2 emissions. For this study we use market outcome data from December 1, 2009 through November 30, 2011, one year before and one year after the transition to a nodal market design. Estimates from our preferred model specification indicate a 3.9% reduction in the total daily operating costs of fossil-fueled generation for the first year of operation of the nodal market. This translates into an estimated $323 million operating cost savings for the first 12 months of the nodal market. Our results do not provide any evidence against the null hypothesis that the number of total daily thermal unit starts did not change with the implementation of the nodal market. Our preferred specification also finds that expected total daily heat input increased by 1.3% while expected total daily CO2 emissions increased by 5.5% under the nodal market.

We then disaggregate our econometric model by fuel type and find that the response to nodal market implementation is markedly different for coal versus natural gas generation units. We find that for coal generating units, operating costs, heat input, and CO2 emissions increased, while for natural gas-fired units, all three metrics decreased.

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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. These results suggest that a large proportion of the total operating cost savings were the result of synergies achieved through more efficient operation of the generation fleet under a nodal market design.

Our findings emphasize the importance of nodal or locational marginal pricing as a key feature of an efficient electricity market design. Although a nodal market design provides gains in operating cost efficiency, our results demonstrate that a nodal market design does not necessarily achieve lower carbon emissions relative to a zonal market as was found by Wolak (2011) for California where virtually all thermal generation units burn natural gas. The increase in heat input and CO2 emissions found in this study were the result of changes in the operating behavior of natural gas and coal generation units that reduced total daily operating costs. 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.

The remainder of this paper is organized as follows. In Section 2 we summarize the operation of zonal versus nodal pricing markets, including a discussion of the mechanisms that lead to inefficient market outcomes under zonal pricing. Section 3 places our research in the literature on electricity market design and performance under zonal versus nodal pricing. In Section 4 we describe our econometric modeling framework. Section 5 describes the data used in our empirical analysis. Section 6 presents estimation results. Section 7 contains a number of sensitivity analyses and investigation of the mechanisms that led to our empirical results. Section 8 summarizes and discusses the implications of our results.

2. Historical context and background

2.1. Zonal electricity market design and US restructuring

During the initial stages of electricity industry restructuring in the United States, there was a contentious debate surrounding the issue of zonal versus nodal markets. Zonal markets were considered to be the more attractive option due to their relative simplicity. Proponents of this market design argued that the costs of making the generation schedules that emerged from a zonal market physically feasible would be small. These arguments prevailed and the initial implementation of wholesale electricity markets in California, the PJM Interconnection, New England, and Texas employed zonal designs. However, once these markets were implemented, the costs of obtaining physically feasible generation schedules accumulated rapidly. Differences between the operating constraints imposed in the zonal market and the physical infrastructure of the electricity system led to inefficiencies and unintended incentives for behavior by generation unit owners (Hogan, 2002).

Zonal markets employ simplified models of the transmission network to set prices and output levels for generation units in the day-ahead market. In a single zone market, generation unit offers are ordered from lowest to highest to construct an aggregate offer curve. Where this offer curve intersects the aggregate demand for electricity sets the single market-clearing price. All generation unit offers at or below this price are accepted to sell energy, regardless of their location in the transmission network. Multiple zone markets only impose across-zone transmission constraints on the market solution. In a two-zone market if the solution that ignores transmission constraints results in more flow across the transmission link connecting the two zones than its capacity, the price in the generation deficient zone must be increased and the price in the generation rich zone must be reduced until the flow between the two zones is equal to the transmission line's capacity. Intra-zonal transmission constraints are not respected in the zonal market solution, and because of these constraints, generation units that are unable to produce in real-time can be scheduled in the day-ahead market and generation units that must run in real-time may not be scheduled in the day-ahead market.

Under all market designs, secure real-time system operation is managed by the system operator respecting all relevant transmission network and generation unit operating constraints. To achieve physically feasible real-time generation unit operating levels under a zonal day-ahead market, a re-dispatch process occurs before real-time system operation.[1] If intra-zonal transmission or other reliability constraint violations are found in day-ahead market outcomes, the system operator will instruct certain generation units to increase their output and others to reduce their output to resolve these constraint violations. A unit is "INCed" when it is instructed to provide an incremental increase in energy output. Conversely, a unit is "DECed" when it is instructed to provide less energy–decremental energy. These re-dispatch instructions require payments to units that receive these INC and DEC instructions, with the costs ultimately passed on to load serving entities and borne by electricity consumers.

To understand how the re-dispatch process works, consider Fig. 1(a) which displays a day-ahead hourly market outcome from a single zone market. The aggregate offer curve is composed of quantity and price offers of market participants arranged from lowest to highest. The downward sloping demand curve represents the hourly market demand for energy. The market clearing price is P^* and the market clearing quantity is Q^*. Because this market mechanism does not account for transmission capacity constraints, the output levels for some generation units may be physically infeasible or violate system security constraints. If this is the case, during the re-dispatch process, certain units with offers above the market clearing price will be INCed, while some units with offers lower than or equal to the market clearing price will be DECed.

Fig. 1(a) shows a unit that is DECed. This unit cleared the day-ahead market but must buy back the energy sold because a transmission network or other operating constraint prevents the unit from producing in real-time. This figure also shows a generation unit that did not clear in the day-ahead market but is needed in real-time for incremental energy because it is the only unit available to meet a local energy need. In zonal markets, generation units typically settle as offered for INC energy and as bid for DEC energy. This means that INCing units are paid at their offer price for additional energy and DECing units pay their bid price to purchase decremental energy.[2]

Fig. 1(b) displays the variable profit for each generator as a result of this process. The generator that is DECed earns $P^* - P_{DEC}$ times the amount of decremental energy (Box A). The generator is paid P^* for the quantity of energy sold in the day-ahead market, but it must also buy this energy back at P_{DEC} before real-time system operation.[3] The unit that is INCed receives P_{INC} times the amount of incremental energy less the variable cost of producing this energy (Box B – variable cost). In this case energy is supplied in real-time so the unit owner incurs the marginal cost of generation per megawatt-hour (MWh) produced.

This re-dispatch process influences the offer behavior of generation unit owners in a zonal market. Generators that have a high probability of being DECed have a strong incentive to bid low in the day-ahead market to increase their chances of selling energy at the day-ahead market-clearing price that they subsequently buy back at a P_{DEC} that is less than P^*. Even units that have a marginal cost higher than the market clearing price may bid below their marginal cost in order to sell energy in day-ahead market if there is high probability they

[1] In the US this process was often referred to as "congestion management".

[2] Some European zonal markets use regulated costs for INC offers and DEC bids.

[3] Note that the generation unit owner incurs no marginal cost of generation for this quantity of energy because no energy is produced from this unit in real-time.

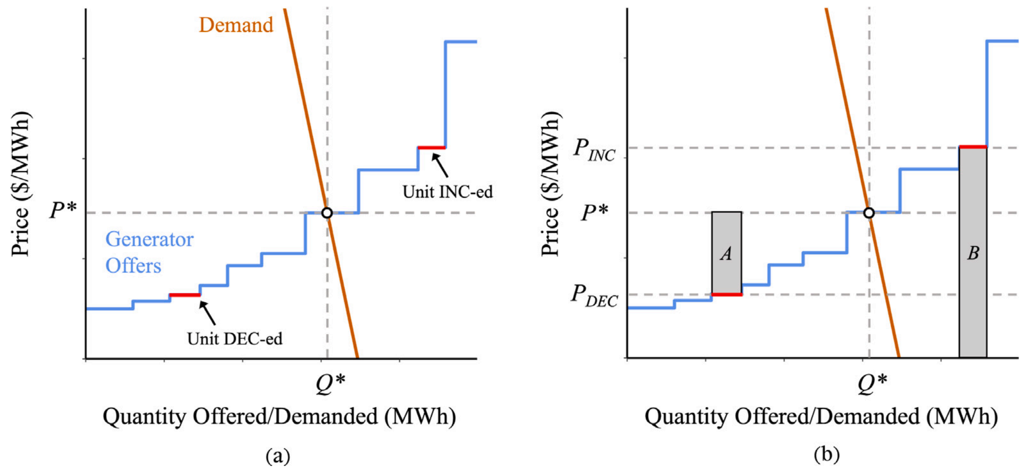

Fig. 1. An example hourly zonal market outcome. Notes: (a) Infeasible market outcome where one offer must be DECed and one offer must be INCed; (b) The same market outcome with the gross revenue resulting from each offer.

will be DECed before real-time system operation. They will receive $P^* - P_{DEC}$ for the quantity of energy sold in the day-ahead market, despite producing no energy in real-time. Similarly, units that have a high probability of being needed in real-time have a strong incentive to submit an offer price higher than the market-clearing price. Even low marginal cost units can increase their profits by submitting a high offer price in the day-ahead market in order to achieve higher revenues from producing energy if the probability of being INCed is sufficiently high. These incentives for offer behavior exist in all zonal markets. The resulting offer behavior of generation unit owners is referred to as the "INC-DEC game".

Graf et al. (2020) provide a quantitative analysis of the INC-DEC game for market participants in the Italian zonal market. The authors find that a 0.1 increase in the probability a unit is INCed predicts a €5/MWh increase in its offer price. A 0.1 increase the probability a unit is DECed predicts a €6/MWh decrease in its offer price.[4] The authors estimated that the cost of these re-dispatch actions was 9% of the cost of real-time demand valued at the day-ahead market price during their sample period. A number of zonal markets in Europe have even larger costs of obtaining physically feasible generation schedules.[5]

2.2. Locational pricing in the day-ahead market

Nodal electricity markets account for configuration of the transmission network and other relevant operating constraints in setting day-ahead generation unit output levels and locational marginal prices (LMPs). This means that a generation unit that is expected to be unable to operate because of a transmission network or other operating constraint will not be accepted in the day-ahead market. In addition, a generation unit that is expected to be required to operate because of a transmission network or operating constraint will be accepted in the day-ahead market. Consequently, generation schedules that emerge from a day-ahead nodal pricing market are expected to be physically feasible for real-time system operation.[6]

All US nodal market designs allow generators to submit three-part offers for each generation unit that include (i) start-up costs, (ii) minimum load costs, and (iii) an energy offer curve. The day-ahead market operator takes these three part offers and solves for the hourly output levels for all generation units that minimizes the as-offered cost of serving locational demands throughout the transmission network for all 24 hours (h) of the following day. Minimum safe operating levels, maximum output levels, and ramping constraints (the rate at which a generation unit can increase or decrease its output level) for all generation units as well as transmission network constraints are respected in the solving for these output levels. The price at each node is the increase the optimized value of the objective function from the market solution associated with withdrawing an additional MWh of energy at that node.

Under a nodal market, generation units have financial incentive to operate at the output level that emerges from the day-ahead market. Generators that under-supply in real-time must buy the difference between their day-ahead energy schedule and their actual output at the real-time LMP at their location. The fact that the generator under-supplies in real-time increases the likelihood that the day-ahead LMP at that location is lower than the real-time LMP at that location. Generation units that supply more than their day-ahead schedule in real-time will be paid the real-time LMP at their location for this additional energy. The fact that the generator over-supplies in real-time increases the likelihood that the real-time LMP is below the day-ahead LMP at that location.

There are a variety of reasons that a nodal market is likely to reduce the total operating cost of thermal generation units relative to a zonal market. First, the day-ahead nodal market accounts for as-offered start-up, minimum load, as well as energy production costs for all generation units in solving for the day-ahead energy schedules for all 24 h of the following day. Second, these optimal generation schedules respect all transmission network constraints and generation unit operating constraints. Third, there are strong financial incentives for suppliers to follow the day-ahead energy schedules that emerge from the nodal market. Finally, a nodal market design allows purely financial participants to improve the efficiency of system operation as discussed in Jha and Wolak (Forthcoming).

There are now seven nodal wholesale electricity markets in the United States: CAISO, MISO, ISO-NE, NYISO, PJM, SPP, and ERCOT. Although three of these markets started with a zonal market design, all

[4] The average day-ahead market price in the Italian market during the authors' sample period is €61.3/MWh.

[5] ENTSO-E (2018) documents the magnitude of the physical firmness costs in European zonal electricity markets from 2015 to 2018. During that time period, annual physical firmness costs averaged slightly less than 1 billion euros in the Germany, Austria and Luxembourg bidding zone, slightly less than 400 million euros in Great Britain, roughly 80 million euros in Spain, and roughly 30 million euros in Italy. See Figure 90 in ENTSO-E (2018).

[6] Changes in locational demands, renewable generation forecast error, the configuration of the transmission network, and generation unit outages between the close of the day-ahead market and real-time system operation can render some day-ahead energy schedules infeasible.

have now adopted a nodal market design. Internationally, zonal markets continue to be common practice, although several regions in Europe and Latin America are considering nodal market designs (see Eicke and Schittekatte (2022) and Right-Side-Decision-Tools (2021), respectively).

2.3. Launch of the nodal market in Texas

Formed as an independent system operator in 1996, ERCOT manages the generation and supply of electric power within much of the State of Texas, representing 90 percent of the state's load (ERCOT, 2020). A three-zone market was implemented in ERCOT on July 31, 2001 (Gauldin et al., 2003). After 2002, the market operated with four to five zones, with the number of zones reviewed on an annual basis (Zarnikau et al., 2014). Under the zonal system only one price was set for each zone in each settlement interval. In settlement intervals in which interzonal constraints were binding, prices differed between zones representing zonal supply and demand conditions. When zonal dispatch led to intra-zonal security constraint violations, the system would be redispatched to resolve the constraints through the INC and DEC process described above. The costs incurred due to this redispatch would be charged to load-serving entities (LSEs) as uplift costs (Zarnikau et al., 2014).

Under the zonal market design in ERCOT, the costs associated with redispatch due to intra-zonal transmission congestion were substantial and the zonal design made it difficult to appropriately assign costs to entities responsible for causing them (Zarnikau et al., 2014). Debates over the transition to a nodal design began in 2003 and in 2005 the Public Utility Commission of Texas ordered ERCOT's transition to a nodal network model (Zarnikau et al., 2014). ERCOT launched its nodal market on December 1, 2010.

Zarnikau et al. (2014) examined how pricing outcomes in ERCOT's nodal market compared to outcomes under the zonal design. The authors estimated that average energy prices were 2 percent lower under the nodal market than under the zonal design. In addition to lower energy prices, it has been noted elsewhere that the total costs of ancillary services also fell under the nodal market design (Cleary, 2011). In contrast to Zarnikau et al. (2014), instead of measuring changes in energy prices under the nodal market in this study we examine the change in total operating costs of electricity generation 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. Fig. 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 the capacity of other resources remained nearly constant.

Although natural gas nameplate capacity was much larger than that of coal, in terms of electricity generation, these two fuels 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.[7]

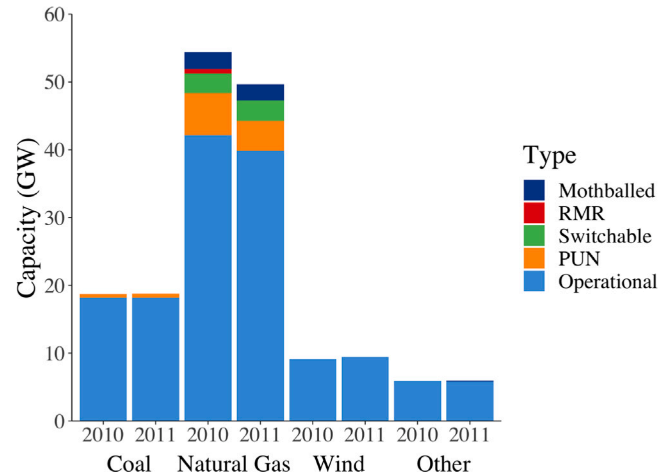

Fig. 2. ERCOT summer generating capacity by fuel for 2010 and 2011. *Sources:* ERCOT 2010 and 2011 Capacity, Demand and Reserves report

System load in the ERCOT market in the last 12 months of the zonal market was 320.0 TWh, increasing 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 for these two time periods, approximately a 4% increase. [8]

3. Literature review and research contribution

The debate over zonal versus nodal market designs has been an active area of research since the early stages of electricity market restructuring. The theoretical basis for the economic efficiency of nodal, or locational, pricing in electricity markets is largely credited to the pioneering work of Bohn et al. (1984) and Schweppe et al. (1988). This work laid the foundation for the implementation of locational marginal pricing in restructured electricity markets (Hogan, 1992).

The primary argument in favor of zonal pricing relied upon the relative simplicity of clearing a single price per zone and pricing transparency for market participants. Hogan (1999) discusses the flaws in the argument that zonal pricing is a simpler pricing regime than a nodal design. Hogan describes how the administrative processes to resolve intra-zonal congestion under a zonal regime, such as the INC-DEC process described above, quickly become much more complex than a nodal market design while distorting incentives of participating generators.

Under a zonal market design, when intra-zonal congestion is present, differences emerge between the physical energy market and the financial market. Market participants can then exploit these differences to increase profits through strategic behavior–the INC-DEC game described in Graf et al. (2020) for the Italian zonal market. Similar strategic behavior occurs in all zonal markets which employ an INC-DEC mechanism, as noted by Hirth and Schlecht (2019).

Proponents of a zonal market design relied on the assumption that intra-zonal transmission congestion would be infrequent and insignificant, however market outcomes of restructured markets in the United States revealed that this assumption often did not hold in practice (Hogan, 2002; Alaywan et al., 2004). Alaywan et al. (2004) provided evidence in support of the transition from a zonal to nodal market model in the California market context, noting that the frequency and severity of intra-zonal transmission congestion was much

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

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

greater in that market than was expected when a zonal design was implemented. In addition, the study describes the susceptibility of that market to inefficiencies that result from the INC-DEC game. A study by Ding and Fuller (2005) demonstrated that if a nodal model is used for dispatch but financial settlement occurs at zonal prices economic surplus may remain unchanged, but a redistribution of surplus will occur among participants and the pricing mechanism results in perverse incentives for generator investment.

A number of studies have focused on inefficiencies in European zonal electricity markets relative to a nodal pricing benchmark (Bjorndal and Jornsten, 2001; Brunekreeft et al., 2005; Ehrenmann and Smeers, 2005; Green, 2007; van der Weijde and Hobbs, 2011). Bjorndal and Jornsten (2001) provides an analysis of the zonal design in the Norwegian market showing how difficulty in determining zone definitions led to inefficiencies in that market and question whether a zonal design is actually a useful simplification of a nodal market. An overview of the competing market design considerations in European markets was provided by Brunekreeft et al. (2005). The authors discuss the efficiency benefits of a nodal market design relative to a zonal structure. The authors also discuss the political challenges of locational pricing in a European market, and discuss an integrated market coupling alternative.

The majority of studies focused on European markets have used simulation methods using simplified networks and under simplifying assumptions. For example, Green (2007) used simulation of a simplified network of England and Wales to estimate the operational inefficiency costs of zonal pricing in that market relative to nodal pricing. Leuthold et al. (2008) considered the benefits of locational pricing in the German electric grid under high levels of wind generation. van der Weijde and Hobbs (2011) use a market simulation involving a simplified network to investigate the potential benefits of nodal pricing in the European context under uncertainty of demand and wind forecasts. Bertsch (2015) analyzed nodal and zonal pricing regimes finding superior performance of nodal markets under most system conditions.

Various studies have investigated additional challenges that arise in a zonal pricing regime relative to nodal market design. Oggioni et al. (2014) and Aravena and Papavasiliou (2017) find major challenges with the integration of high levels of renewable energy in European zonal markets and greatly improved outcomes under a nodal design. Other studies have investigated improvement of methods for determining interzonal available transfer capacity (ATC), however these studies note that any improved ATC methodology is still a second-best solution relative to a nodal benchmark (Jensen et al., 2017; Aravena et al., 2021). Bertsch et al. (2016) and Lété et al. (2022) address long-term inefficiencies of a zonal market design relative to a nodal market due to inefficient investment incentives.

Although a large body of research exists on the inefficiency of a zonal market design using simulation methods, very little empirical work analyzing market outcome data has been conducted to quantify operating cost reductions that result from transitioning to a nodal market from a zonal market. One notable exception is Wolak (2011) which measured the operating cost savings in the California market (CAISO) as a result of nodal market implementation on April 1, 2009. The study found that total operating costs fell by 2.1% while total heat input reduced by 2.5% after the introduction of a nodal market design. In the case of CAISO, operating costs and heat input changes were closely related because nearly all dispatchable generation is provided by natural gas. 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 difference led to substantially different outcomes for total heat input and CO2 emissions than was observed in the CAISO market due to the interaction between coal and natural gas generation.

The current study contributes to this body of research by providing an estimate of variable operating cost savings due to a nodal market implementation in ERCOT based on a statistical analysis of market outcome data. The study provides operating cost savings estimates for a market with a heterogeneous fuel mix, and investigates the operational changes that occurred after nodal market implementation, shedding light on the fundamental drivers of these operating cost savings. We disaggregate our total thermal generation analysis by fuel type to investigate the operational changes that occurred for the two dominant fuel types in the market – coal and natural gas – with implementation of the nodal market design. In addition, we provide an estimate of the associated change in CO2 emissions.

The demonstrated efficiency of nodal pricing led to it being adopted as a key component of US Federal Energy Regulatory Commission's Standard Market Design. Many markets – notably virtually all markets of Europe – still operate under a zonal pricing regime. However, there is growing interest in nodal market design implementation in European markets. For example, the U.K. and Italy are actively investigating adoption of a nodal market design (Gosden, 2022). The work of Eicke and Schittekatte (2022) provides an overview of the current stakeholder arguments against the adoption of nodal pricing in the European context. Our work provides empirical evidence for significant economic gains in a large wholesale electricity market that has made this transition.

4. Methodology

We measure the change in the expected value of selected market performance metrics controlling for observable factors that lead to differences in daily market outcomes. Mathematically, we estimate a semiparametric conditional mean function that flexibly controls for variables that result in different daily market outcomes. Specifically we measure the difference in expected daily operating costs, thermal 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.

We estimate the following conditional mean function, using the method described in Robinson (1988):

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

where $\mathbb{E}(\epsilon_t|X_t, Z_t) = 0$, $\forall t \in \{1,\ldots,T\}$ (where T is the number of observations). This formulation allows for heteroskedastic errors of an unknown form: $\mathbb{E}(\epsilon_t^2|X, Z) = \sigma^2(X, Z)$ as noted by Li and Racine (2007). 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 $p+q$-dimensional random vector. The elements of the vector X_t are assumed to be linearly related to the dependent variable. The elements of Z_t are nonparametric variables, related to y_t by the function $\theta : \mathbb{R}^q \to \mathbb{R}$. In this study X_t consists of only categorical variables (a nodal market indicator and month and day of week controls) while all continuous numerical variables are treated as elements of Z_t. This formulation allows for substantial functional form flexibility in estimating the relationship between these variables and the dependent variable y_t.

The first step of the estimation takes the expected value of Eq. (1) with respect to Z_t and subtracts 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. We use kernel regression methods to estimate the conditional expectations in Eq. (2).[9] We can then use conventional OLS on the result to obtain a consistent and asymptotically normal estimate of β, as shown in Li and Racine (2007).

[9] Gaussian kernels were used in the estimation of the conditional expectations in Eq. (2). For more details on the kernel estimation procedure see Li and Racine (2007).

OLS applied to Eq. (2) yields $\hat{\beta}$ which has following asymptotic distribution under the regularity conditions in Li and Racine (2007):

$$\sqrt{T}(\hat{\beta} - \beta) \xrightarrow{d} N(0, \Phi^{-1}\Psi\Phi^{-1}) \tag{3}$$

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 $\tilde{X}_t = X_t - \mathbb{E}(X_t|Z_t)$.

We estimate this semiparametric conditional mean function for four different definitions of the dependent variable, y_t: (1) the natural logarithm of daily operating costs in dollars, (2) the number of daily warm and cold starts, (3) the natural logarithm of daily heat input in MMBtu, and (4) the natural logarithm of tons of CO2 emissions. 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 a value of 1 for all intervals after the launch of the nodal market on Dec 1, 2010 and zero otherwise), month-of-the-year indicator variables, and day-of-week indicator variables.[10] The elements of the vector Z_t include the natural logarithm of daily fossil-fuel generation in MWh, the natural logarithm of daily non-dispatchable generation in MWh, the natural logarithm of the monthly price of coal in \$/MMBtu, and the natural logarithm of the daily price of natural gas in \$/MMBtu. The unit of observation is at the daily level, beginning one year before the launch of the nodal market on December 1, 2009 and ending one year after the launch on November 30, 2011.[11]

5. Summary of data used in the analysis

In this section we describe the data that were used to estimate the parameters of the conditional mean functions. This 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) daily natural gas and coal fuel prices, and (iv) ERCOT wind and nuclear generation. Observations at the daily level are used to estimate all regressions with the exception of a sensitivity analysis provided in Appendix A where we provide the results of the same models fit to hourly data. A summary of the daily-level data used in this analysis is presented in Table 1.

Generating unit-level hourly gross MWh output, heat input, and CO2 emissions are taken from the EPA's Air Markets Program Data (AMPD).[12] ERCOT's 2010 and 2011 Summer Capacity, Demand and Reserves (CDR) reports were used to determine which units were participating in the market during the study's sample period. 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 or approximately 1.5% of total natural gas capacity. Total coal generation capacity from the same CDR report amounted to 18,194 MW. Complete generation unit level data was available for this total amount of coal capacity.[13]

ERCOT wind and nuclear generation by settlement interval were available from the ERCOT ISO website.[14] Hourly unit level CO2 emissions data (tons CO2) were retrieved from the EPA AMPD dataset. For a small number of units in the study, these data were 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.[15]

Table 1
Summary of input data (T = 730).

Variable (units)	Mean (S.D.)
Operating costs - base assumptions ($M)	21.460 (6.805)
Operating costs - PUN units included ($M)	24.325 (7.231)
Operating costs - alternative O&M cost assumptions ($M)	19.636 (6.115)
Unit starts - base assumptions (count)	78.032 (33.603)
Unit starts - PUN units included (count)	82.230 (35.145)
Heat input - base assumptions (million MMBtu)	6.235 (1.461)
Heat input - PUN units included (million MMBtu)	6.815 (1.518)
CO2 emissions - base assumptions (thousand tons)	544.95 (107.69)
CO2 emissions - PUN units included (thousand tons)	579.47 (110.98)
Thermal generation - base assumptions (GWh)	680.03 (161.43)
Thermal generation - PUN units included (GWh)	737.45 (168.40)
Non-dispatchable generation (wind only) (GWh)	71.824 (33.510)
Non-dispatchable generation (wind and nuclear) (GWh)	184.169 (35.329)
Natural gas price ($/MMBtu)	4.226 (0.627)
Coal price ($/MMBtu)	1.891 (0.055)

Note: Observations are at the daily level with time horizon: 12/1/2009 through 11/30/2011. Base operating cost assumptions are from Mann et al. (2017); alternative operating cost assumptions are from Tidball et al. (2010).

Hourly fuel prices are displayed in Fig. 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 sample, reaching over \$6/MMBtu, before falling to below \$3/MMBtu near the end. However, from mid-2010 to mid-2011 natural gas prices do 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 analysis 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 similar for this restricted sample (see the appendix for more details). Fig. 3(b) displays daily generation by fuel type over the sample. Here we observe little change in generation patterns in the zonal and nodal periods.

Variable O&M costs for our base case (\$/MWh) are taken from Mann et al. (2017). The assumed values are \$6.33/MWh for coal, \$4.73 for

[10] Hourly regressions included in the appendix also include hour-of-day indicator variables.

[11] The regressions for this study were performed using the np package in the R statistical computing language (Hayfield and Racine, 2008).

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

[13] These total capacity values natural gas and coal include only fully participating units. Private use network, Reliability Must Run (RMR), and switchable resources are not included in these totals. 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.

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

[15] 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.

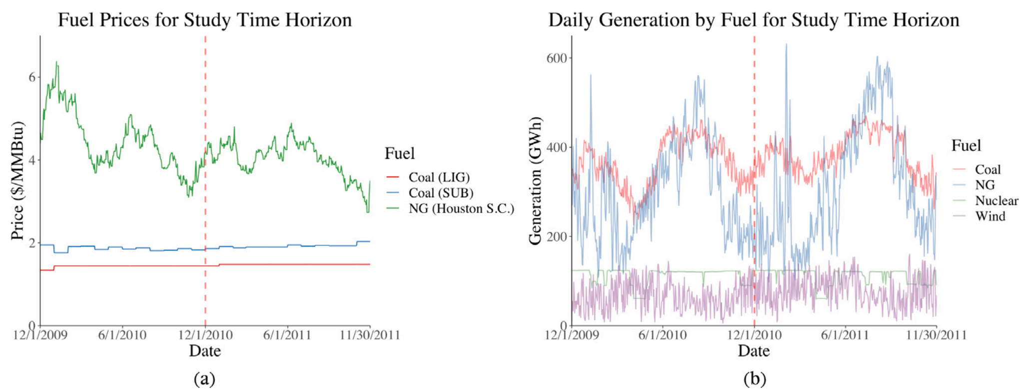

Fig. 3. Fuel prices and generation by fuel over study time horizon. Notes: Data is pictured for 12/1/2009 through 11/30/2011. The dashed red line indicates the implementation of the nodal market on 12/1/2010.
Data sources: Bloomberg LP, EIA, and ERCOT.

CCGT and CCGTCHP units, $13.40/MWh for OCGT and OCGTCHP units, and $15.40/MWh for ST units.[16] In order to examine the sensitivity of the results to these O&M cost values, for an alternative analysis we assume variable O&M cost values presented in Tidball et al. (2010). These are $4.59/MWh for coal, $2.00/MWh for CCGT and CCGTCHP units, $3.17/MWh for OCGT, OCGTCHP, and ST units. Total operating cost is computed as the sum of fuel costs and variable O&M costs for each unit. Fuel costs are the product of the assumed fuel price ($/MMBtu) times heat input (MMBtu). Variable O&M costs are the product of the assumed costs per unit of output ($/MWh) and the unit level gross generation (MWh).

For natural gas prices, daily volume weighted average Houston Ship Channel prices ($/MMBtu) were retrieved from Bloomberg (2020). For weekends and holidays, when trading prices are not available, the price of the most recent past trading day is used. In the appendix we present a sensitivity analysis using alternative natural gas prices.

Monthly average coal prices ($/MMBtu) are taken from the EIA Electric Power Monthly Update. The EIA's reported monthly average cost of coal delivered for electricity generation for Texas is the fuel price assumed for all subbituminous coal units. For lignite units, the EIA's Annual Energy Review annual price in $/short ton is used. The annual average heat content is the volume weighted average heat content of all coal used in Texas reported in EIA's Form 923 data, Schedule 5. These prices are used to compute the operating costs of lignite coal units, but annual prices were not used as controls in the regression due to the fact that they only varied on an annual basis.

In addition to the generation units listed in these reports, data was available for a number of industrial private use network (PUN) generating units. In ERCOT, there are 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 (Mann et al., 2017).

In times of high prices in the ERCOT market, PUN plants have strong incentive to provide electricity to the grid. The EPA AMPD data includes hourly operational data for PUN units in the ERCOT territory.

[16] 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.

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

Table 2
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

However, data are not available to determine what fraction of a PUN unit's output is made available to the ERCOT grid. In our base case we exclude PUN units, but we include them in an alternative case.

To compute the number of daily thermal unit starts we make the following assumptions. 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 a 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.

6. Results

Here we present empirical results under four sets of assumptions. Additional sensitivity analyses are available in the appendix. For each set of assumptions, regressions were performed for each of the four definitions of y_t described in Section 4. All regressions include 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. For all results, in addition to the nodal market indicator variable, we include indicator variables for month of the year and day of the week. The non-parametric control variables are natural log of thermal generation, natural log of non-dispatchable generation, natural log of the natural gas price, and natural log of subbituminous coal price. The description of each model is summarized in Table 2.

Table 3 displays the estimates of β_{nodal} (the element of the vector β corresponding to the nodal market indicator variable) and the associated standard errors for the four definitions of y_t. For the total daily operating cost definition of y_t, we find a negative point estimate of β_{nodal} across all four sets of assumptions. The estimated standard

Table 3
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)
Operating cost[a]	−0.040 (0.0059)	−0.034 (0.0051)	−0.034 (0.0055)	−0.032 (0.0054)
Unit starts	−4.979 (5.6987)	−6.196 (5.9883)	– –	−4.758 (4.7724)
Heat input[a]	0.013 (0.0033)	0.011 (0.0035)	– –	0.012 (0.0026)
CO2[a]	0.053 (0.0051)	0.050 (0.0048)	– –	0.046 (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).
[a]Dependent variable is log-transformed.

errors imply that the data provide strong evidence of operating cost reductions under the nodal market. Regression 1, corresponding to our base case, results in an estimate of −0.040 implying a 3.9% decrease in operating costs of natural gas and coal units with the implementation of the nodal market.[18] Across the four sets of assumptions there was an average estimated operating cost decrease of 3.4% with a minimum of 3.1% decrease and maximum of 3.9%.

For y_t defined as daily thermal unit starts, we find a negative point estimate of β_{nodal} across all sets of assumptions, with a point estimate of −4.98 in the base regression. For reference, average daily thermal unit starts are 78.0 (SD = 33.6) for the sample period.[19] Natural gas units average 77.4 starts per day and coal units 0.6 starts per day. The estimated standard errors of the estimator of β_{nodal} across all sets of assumptions imply that the data provide no evidence against the null hypothesis that changing to a nodal market design had no impact on the daily number of unit starts.[20]

For y_t defined as the natural logarithm of total daily heat input, the point estimate of β_{nodal} is positive across all sets of assumptions. Under each set of assumptions the estimated standard errors imply that the data provide strong evidence that the conditional mean of daily heat input for thermal generation increased with the implementation of the nodal market. Under our base case, the estimate of the nodal market indicator coefficient is 0.013, implying an increase of 1.3% in the conditional mean of daily heat input for thermal generation. Across the three sets of assumptions we find an average estimate of 1.2% and a minimum estimate of 1.1%.

Finally, for y_t defined as the natural logarithm of total CO2 emissions, the positive estimate of β_{nodal} and associated standard errors indicate that the conditional expectation of daily CO2 emissions increased under the nodal market implementation across all sets of assumptions. Under the base case, the estimate of the nodal market indicator coefficient is 0.053, implying that expected daily CO2 emissions increased by 5.5%. The lowest estimate was in Regression 4 where nuclear generation was included in the definition of non-dispatchable generation. Here, the estimated increase in CO2 emissions was 4.7%. Across the three sets of assumptions we find an average 5.1% increase in daily CO2 emissions.

Comparing results of Regression 2 to Regression 1 reveals the effect of including PUN generating plants in the analysis on our results. All included PUN units are natural gas-fired. The estimated operating cost savings decreased from 3.9% to 3.3% as result of including them in the analysis. In addition, the estimated heat input and CO2 increases reduced from 1.3% to 1.1% and 5.5% to 5.1%, respectively. Although the estimated operating cost savings decreased, this set of results demonstrates that our findings are robust to inclusion or exclusion of the PUN units.

Regression 3 shows the impact of our variable O&M assumptions estimated operating costs savings. The variable O&M cost assumptions reported in Tidball et al. (2010) resulted in the estimated operating cost savings falling from 3.9% to 3.3%. These results demonstrate that the finding of significant savings under the nodal market design is robust to alternative variable O&M cost assumptions.

Regression 4 illustrates the impact of including both nuclear generation and wind generation in the non-dispatchable generation variable. 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 typically run at or near full output when operational. Total nuclear generation is also much greater than wind output over this time period in ERCOT. Consequently, maintenance outages of a single nuclear generation unit have a large impact on the variability in this 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 on maintenance outage. We find that the estimated operating cost savings falls from 3.9% to 3.1% when we include nuclear generation in our definition of non-dispatchable generation, not a significant difference in the estimated impact of the transition to a nodal market.

Note that for all four regressions the conditional expectation of daily operating costs fell while the conditional expectation of daily heat input and CO2 emissions increased after the implementation of the nodal market. Fuel costs are a major component of total operating costs, so it may be surprising that a reduction in total operating costs is associated with an increase in heat input and CO2 emissions. This directional difference between the operating cost results and heat input and CO2 emissions results is due to how the implementation of the nodal market impacted the operation of coal versus natural gas resources.

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 operating costs but a much lower share of total heat input. The operating costs of natural gas generation are 46.6% higher than that of coal under the base case. However, the total heat input for coal is 44.1% higher than natural gas. Across the sample period, coal generation had an average heat rate of 9829 Btu/kWh while the average natural gas heat rate was 8358 Btu/kWh. Although coal units require a higher heat input per unit of generation, the price of natural gas per MMBtu is considerably higher. The average of daily natural gas price for the sample period was \$4.23 per MMBtu while the average prices of 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 operating 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

[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 because Regression (3) only differs from Regression (1) in operating cost assumptions.

[21] Average prices reported reflect the average of assumed prices in the base case as described in Section 5.

Table 4
Estimates of β_{nodal} (for coal and natural gas generation) with standard errors shown in parentheses.

Definition of y_t	Coal	Natural gas
Operating cost[a]	0.012 (0.0014)	−0.025 (0.0029)
Unit starts	0.142 (0.1634)	−0.439 (2.4498)
Heat input[a]	0.010 (0.0017)	−0.023 (0.0029)
CO2[a]	0.009 (0.0014)	−0.023 (0.0029)

Note:
[a]Dependent variable is log-transformed.

million tons while coal emissions amounted to 287 million tons, more than two and a half times that amount.

To further explore the impact of the transition on coal and natural gas generation we estimated Eq. (1) separately for the two technologies. For the coal regressions, we define y_t as the total daily operating cost for coal generation only. The vector X_t is defined as above, and Z_t now includes only the natural logarithm of daily coal generation, daily wind generation, and the coal price. The equation is estimated similarly for the natural gas-fueled generation. The estimated values of β_{nodal} for these regressions are presented in Table 4.

These results indicate that conditional expectation of the operating cost of coal generation increased in the nodal market by an estimated 1.2% while the operating costs for natural gas generation decreased by 2.5%. We can infer from these results that changes in dispatch under the market change led to decreased cost efficiency of coal operation while natural gas dispatch became considerably more efficient.

However, 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 operating cost of coal and natural gas generation fell by an estimated 3.9% 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 coal unit starts is slightly positive, while the point estimate for natural gas is slightly negative. However, the large standard errors again imply 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 2.3% for natural gas. Note that here the estimated change in heat input and CO2 emissions corresponds much more closely to the change in operating costs because we measure changes separately for generation units with the same input fuel. Comparing these results to Table 3 where we find that for all thermal generation heat input increased by 1.3% and CO2 emissions increased by 5.5% 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 under the nodal market. 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 examine 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 sample periods. For regressions using hourly data we find considerably greater estimates of β_{nodal} in absolute value for the measurement of operating cost changes implying greater operating cost reductions than we found with the daily data. The direction and magnitude of the estimated effect of nodal market implementation varies little across the other sensitivity cases for each definition of y_t implying that the results presented in this section are robust to a variety of alternative assumptions. See the appendix for more details on these additional sensitivity analyses.

7. Discussion

Under the base case assumptions in this study, total operating 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 operating costs of thermal generation reduced by 3.9% after the implementation of the nodal market. Under these assumptions, the estimated operating cost savings were greater than $300 million in the first 12 month period of nodal market operation in the ERCOT region. Aligning day-ahead market operation with the real-time operation of the transmission network through increased spatial granularity of pricing under the nodal market resulted in improved efficiency of system operation.

With the implementation of the nodal market qualified scheduling entities (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 that yield least cost day-ahead market schedules for all 24 h of the following day that are closer to real-time operating levels makes it more likely that CC units will provide more output in more hours of the day 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. Fig. 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 Eq. (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 is 12.8% higher under the nodal market period ($\hat{\beta}_{\text{nodal}} = 0.121$, S.E. = 0.0037). The greater 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 emissions of natural gas generation.

Under a nodal market we expect that three-part offers, reduced incentive for bidding above or below marginal cost, and a solution that is optimized across all 24 h 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] Fig. 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 in the nodal period. In the same figure, for natural gas, daily ramping appears to have changed less than it had for coal in percentage terms. Results presented in Table 4 indicate that changes in operation

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

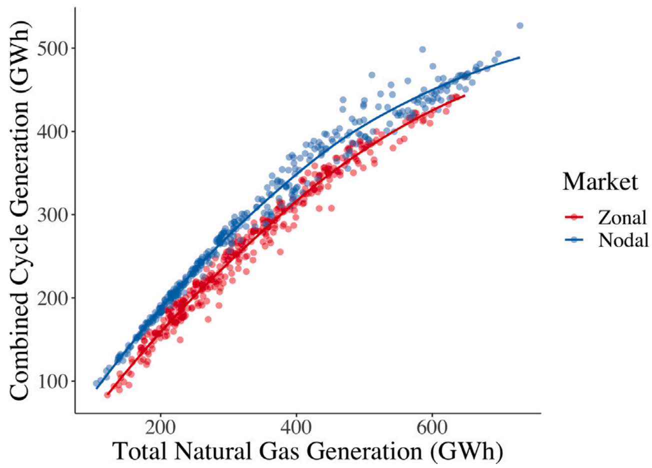

Fig. 4. Combined cycle generation vs. total natural gas generation (Daily)
Data source: ERCOT. A local regression (LOESS) trendline is pictured.

of coal units under the nodal market resulted in increased operating 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 considerable cost efficiency improvement reducing total operating costs of coal and natural gas operations when taken together, as found in Table 3. Comparing the results of Tables 3 and 4 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.

Daily ramping of coal generation increased after controlling for net load ramping, with net load defined as ERCOT system load less wind and nuclear generation.[23] Fig. 6(a) and (b) show daily ramping of coal and natural gas, respectively, versus daily net load ramping for the zonal and nodal market periods. The trend lines presented are fit by local linear regression. For coal units, we see that daily ramping does not appear to be highly correlated with net load ramping. In addition, the local linear regression line shows that coal ramping is greater during the nodal period than during the zonal period for nearly all load ramping levels.

Natural gas ramping is highly correlated with net load ramping. This is to be expected because natural gas units are often load following. Although change in this relationship with the implementation of the nodal market is less apparent than it is for coal generation, the local linear regression line is lower for nearly all levels of net load ramping. We again estimate a semiparametric conditional mean function as in Eq. (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-fired generation ramping increased 18.0% in the nodal period given the level of net load ramping ($\hat{\beta}_{\text{nodal}} = 0.165$, S.E. = 0.0366). The expected value of natural gas-fired generation ramping decreased 4.7% given a level of net load ramping ($\hat{\beta}_{\text{nodal}} = -0.049$, S.E. = 0.0126). 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 services. This suggests that the increased flexibility of coal generation was able to reduce the need for some natural gas ramping leading to increased cost efficiency for natural gas and greatly increased coal and natural gas generation cost efficiency.

Fig. 7 plots the daily average cost of generation ($/MWh) versus daily generation by fuel type.[24] Comparing the units on vertical axes of Fig. 7(a) and (b) finds that for coal generation, daily average costs lie in a significantly narrower range and are lower than natural gas generation. The local linear regression 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 natural gas, the local linear regression curve implies relatively high costs for very low levels of daily generation in the zonal period. However, after the implementation of the nodal market the curve implies a nearly monotonically increasing relationship between daily generation and average costs. Results presented above in Table 4 indicate that operating costs for coal increased approximately 1.2% while natural gas decreased approximately 2.5% when including controls for temporal indicators, fuel prices, non-dispatchable generation, and generation by fuel. From Fig. 7 we observe that increasing the cost of the cheaper source of generation (coal) by a small amount enabled larger cost reductions of natural gas generation, with this effect largest for days where total natural gas generation was relatively low.

In Fig. 8 we display daily average cost versus aggregate generation ramping by fuel type. The pictured local linear regressions 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 Fig. 8(a) we observe that coal generation exhibits relatively constant average costs for varying levels of ramping. In contrast, in Fig. 8(b) average daily costs of natural gas do not appear to be constant for different levels of natural gas ramping. In the zonal period the local linear regressions implies a U-shaped relationship where both low and high levels of ramping exhibit higher daily average costs with lowest average cost near the middle of the range of values. With the implementation of the nodal market, daily average costs and daily ramping appear to have a positive relationship across the range of values. Here the increased ability of combined-cycle units to supply more generation in lower demand days likely led to lower costs of generation in the nodal market.

We should emphasize that the increase in CO2 emissions is not a necessary result of the transition to a nodal market. The aim of nodal market design is to increase cost efficiency of electricity generation and the carbon emission externality is not internalized into market transactions any more or less under a nodal market relative to zonal design. In California total heat input decreased in the transition to nodal pricing in a market with a single dominant fuel type – natural gas – implying a reduction in associated emissions with the implementation of a nodal market design (Wolak, 2011). Whether carbon emissions increase or decrease relative to a zonal market design will depend on the fuel mix and concentration of generation ownership in the market.

Under a high renewable penetration future we expect that the inefficiencies in zonal market operation described in Section 2 are likely to be exacerbated. First, because net load is less predictable under a high penetration of intermittent renewable generation, the costs associated with re-dispatch are likely to increase. Second, with greater variability of net load there is increased need for units to efficiently ramp up or down to match supply and demand. As we have found in the case of ERCOT, the nodal market enables and incentivizes greater flexibility in operation to accommodate 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. In nodal markets in the United States, 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 (Forthcoming).

[23] "Net load ramping" is defined as maximum hourly net load minus minimum hourly net load on a given day.

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

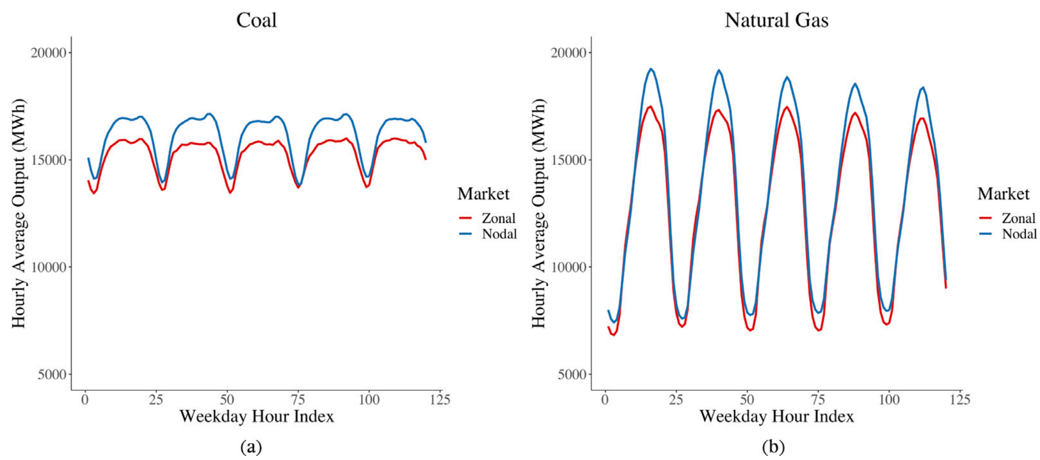

Fig. 5. Weekday average hourly aggregate coal and natural gas generation.

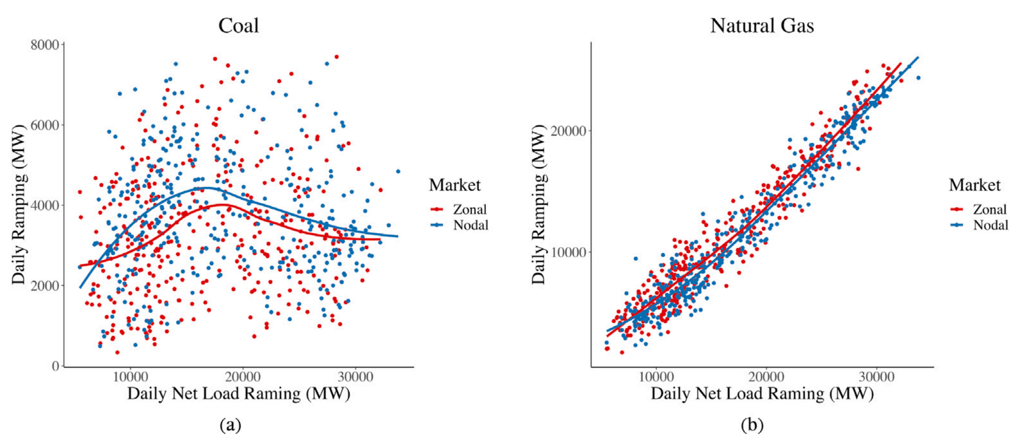

Fig. 6. Thermal ramping vs. net load ramping. A local regression (LOESS) trendline is pictured.

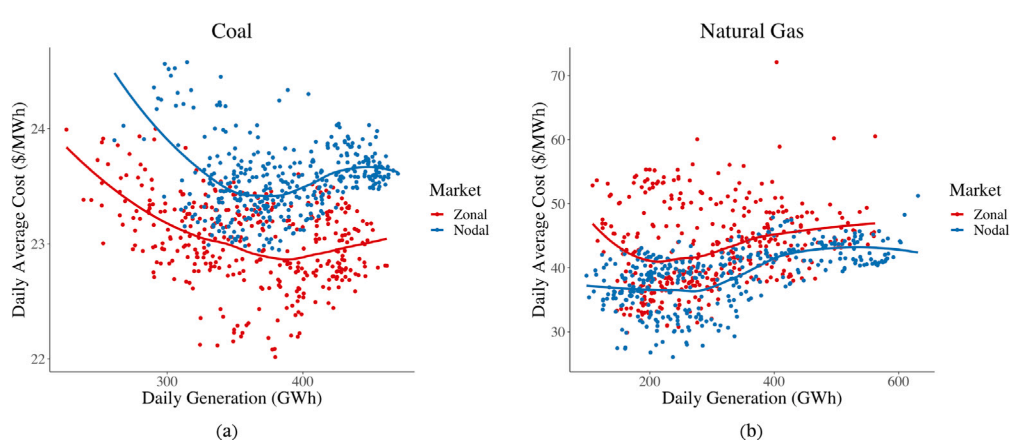

Fig. 7. Thermal daily average cost vs. daily generation. A local regression (LOESS) trendline is pictured.

8. Concluding remarks

We began by describing mechanisms by which a zonal market design results in market inefficiencies. Through analysis of the ERCOT market transition from a zonal to a nodal market design, we provide empirical evidence that nodal market design materially affects generation unit operating behavior 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 a zonal to a nodal market design resulted in considerable operating cost savings. We estimate a 3.9% average daily operating cost savings for coal and natural gas generation, which translates to an estimated $323 million operating cost savings in the first 12 months of the nodal market. Second, a large proportion of the realized cost savings accrued as a result of synergies between coal and gas generation unit 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 changes in generator operation with the implementation of the nodal market due to altered participation incentives and improved day-ahead planning

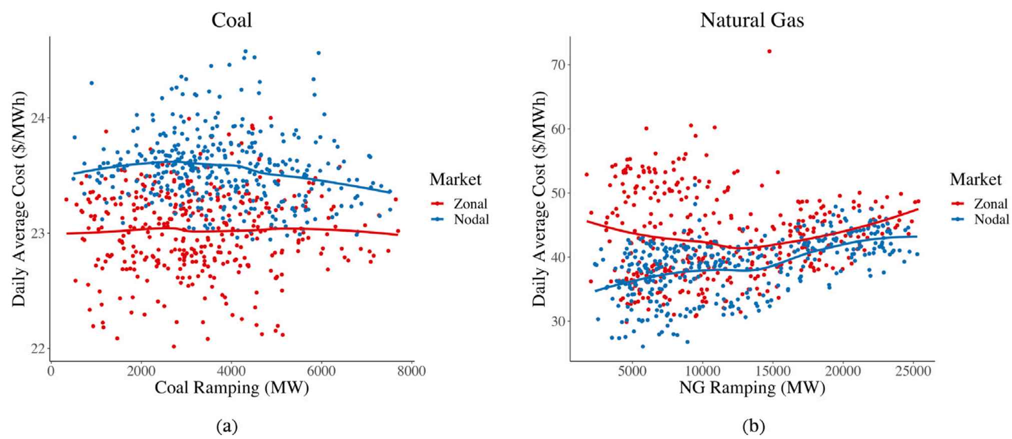

Fig. 8. Thermal daily average cost vs. daily ramping. A local regression (LOESS) trendline is pictured.

led to significantly lower operating 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. A nodal market design encourages operating cost efficiency, but without a pricing mechanism for associated CO2 emissions, profit-maximizing participants make decisions based only on operating 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 a 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 operation of the grid. 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 market, among others.

CRediT authorship contribution statement

Ryan C. Triolo: Conceptualization, Methodology, Software, Validation, Formal analysis, Investigation, Data curation, Writing – original draft, Visualization. **Frank A. Wolak:** Conceptualization, Methodology, Writing – original draft, Writing – review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Hourly observational data sensitivity

The estimates presented in Table A.5 are obtained using the same assumptions as those in Regressions (1)–(4) described in Section 6 but using data at the hourly level. In the hourly level dataset we have 8760 hourly observations for the zonal period and 8760 observations for the nodal period for the same time horizon as the daily regressions. The semiparametric conditional mean function in Eq. (1) is estimated for each set of assumptions and each definition of the dependent variable y_t. In the hourly data regressions, indicator variables for each hour of the day are included in the vector X_t. The vector of non-parametric control variables Z_t is the same as in Regressions (1)–(4).

Table A.5
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			
	(1a)	(2a)	(3a)	(4a)
Operating cost[a]	−0.079 (0.0058)	−0.070 (0.0052)	−0.065 (0.0058)	−0.041 (0.0084)
Unit starts	−2.100 (1.1112)	−1.973 (1.1492)	– –	0.464 (1.6064)
Heat input[a]	0.003 (0.0034)	0.004 (0.0031)	– –	0.003 (0.0049)
CO2[a]	0.050 (0.0036)	0.049 (0.0035)	– –	0.028 (0.0051)

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

When measuring the change in operating cost in the nodal market at the hourly level, the estimates of β_{nodal} and associated standard errors indicate that the data provide strong evidence of a reduction in hourly operating costs under the nodal market across the four sets of assumptions. The estimates from the hourly data regressions are greater in absolute value than the daily observation results reported in Table 3. In Regression 1a, corresponding to our base case, for y_t defined as the natural log of hourly operating cost we estimated the value of β_{nodal} to be −0.079 which implies a cost reduction of 7.6% under the nodal market. This is compared to the 3.9% operating cost reduction when measuring at the daily level. This was the maximum operating cost reduction found across the four sets of assumptions. The smallest estimated hourly operating cost reduction was found in Regression 4a, including nuclear generation in the definition of non-dispatchable generation. Here, we find an estimated the value of β_{nodal} of −0.041 corresponding to an estimated reduction of 4.0%.

For y_t defined as the number of hourly thermal unit starts, we again do not find strong evidence of a change in expected value with the implementation of the nodal market. For y_t defined as the natural log of hourly heat input we also do not find strong evidence that the β_{nodal} coefficient is non-zero. This is in contrast to the daily data regressions that found evidence of modest increases in heat input across all sets of assumptions.

For y_t defined as the natural log of hourly CO2 emissions, estimates of β_{nodal} and associated standard errors across all sets of assumptions imply that the data provide strong evidence of increased emissions

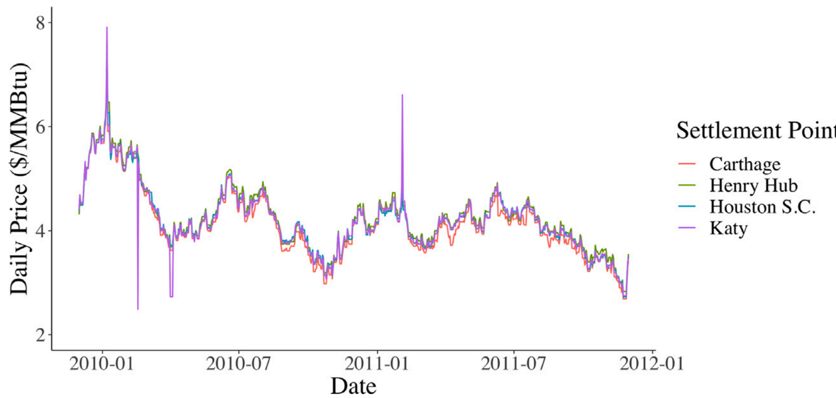

Fig. B.9. Daily natural gas price (12/1/2009–11/30/2011)
Data source: Bloomberg (2020).

under the nodal market. Under our base case we find an estimated value of β_{nodal} of 0.050, corresponding to an estimated 5.1% increase in hourly CO2 emissions in the nodal market. This is compared to the 5.5% increase found when measuring based on daily data. The smallest estimated CO2 emission increase measured at the hourly level was found in Regression 4a, where we find an estimated the value of β_{nodal} of 0.028 corresponding to an estimated reduction of 2.8%.

The largest differences in the estimates found in Table A.5 in comparison to the daily data results reported in Table 3 are the magnitudes of $\hat{\beta}_{\text{nodal}}$ for y_t defined as the log of operating cost across the four sets of assumptions. Here, using hourly data to compute an estimate of β_{nodal}, we estimate the hourly effect conditional upon control variables (thermal generation, non-dispatchable generation, and fuel prices) only in the corresponding hour. Importantly, this formulation does not take into account conditions in other hours of the operating day. There are two reasons why we believe it is important to measure changes in operating cost at the daily level of observation. First, the day-ahead market is solved on a daily basis, solving for generation schedules for all units for all 24 h of the day in one optimization problem. Thermal generation units provide offers and clear in the day-ahead energy market for the 24 h of the operating day one day in advance, and the market clearing solution respects dynamic constraints such as ramping limits, minimum up time, and minimum down time. Second, there may be costs associated with large changes in output across hours when ramping constraints are binding or startup costs are incurred. Thus we argue that the daily regression results yield a more appropriate estimate of operating cost reduction of thermal generation under the implementation of the nodal market. We provide hourly results here to show how our estimates change when measured at the hourly level.

Appendix B. Natural gas price sensitivity

The base case in this study assumes that natural gas generators pay the Houston Ship Channel spot natural gas price. In practice the natural gas price is often different at various natural gas settlement points. Fig. B.9 below displays the daily price of natural gas over the study's time horizon at four major settlement points in and around Texas. Three additional sensitivities were performed to ensure that the natural gas price assumptions in the study did not drive the results. Table B.6 displays Regression (1) described in Section 6 with different daily natural gas price. Four different natural gas price points are considered. Note that the Houston Ship Channel (Houston S.C.) results displayed here correspond to the base case. Table B.6 shows that our results are relatively insensitive to the alternative natural gas price assumptions.

Table B.6
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
Operating cost[a]	−0.040 (0.0059)	−0.043 (0.0062)	−0.047 (0.0057)	−0.038 (0.0068)
Unit starts	−4.979 (5.6987)	−6.130 (5.8567)	−8.109 (5.6545)	−10.030 (5.9446)
Heat input[a]	0.013 (0.0033)	0.014 (0.0033)	0.016 (0.0033)	0.011 (0.0034)
CO2[a]	0.053 (0.0051)	0.055 (0.0052)	0.059 (0.0052)	0.048 (0.0052)

Notes: Houston S.C. results correspond to base assumptions in this study.
[a]Dependent variable is log-transformed.

Appendix C. 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 a trend in natural gas prices are not driving our results. Extreme pricing events in ERCOT occurred in February and August of 2011. The first sensitivity result (Sensitivity 1) removes observations from all of February and August of 2010 and 2011. In the second sensitivity (Sensitivity 2) we address the concern that a declining natural gas price trend could impact the results. Fig. B.9 shows that relatively high natural gas prices were present in the beginning of our sample period and that gas prices appeared to be declining toward the end of the sample period. Consequently, 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. These results are displayed below in Table C.7. Our empirical results are in general insensitive to these alternative assumptions. The largest estimated change is shown in Sensitivity 2 where the estimated operating cost savings falls to 3.4% from 3.9%. However, overall these results demonstrate that our findings are robust to these extreme pricing events in ERCOT and the natural gas price trend.

Appendix D. 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. Therefore we include

Table C.7
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
Operating cost[a]	−0.040 (0.0059)	−0.040 (0.0062)	−0.035 (0.0054)
Unit starts	−4.979 (5.6987)	−8.816 (6.0434)	−5.552 (5.8323)
Heat input[a]	0.013 (0.0033)	0.014 (0.0039)	0.013 (0.0036)
CO2[a]	0.053 (0.0051)	0.054 (0.0057)	0.053 (0.0053)

Notes: "Sensitivity 1" excludes all daily observations from the months of February and August during both the zonal period and the nodal period; "Sensitivity 2" includes only daily observations from March 25, 2010 through September 5, 2011, inclusive.
[a]Dependent variable is log-transformed.

thermal unit starts as one metric of operating performance. In order to estimate changes in thermal unit starts we had to determine when units were started based on the operational data retrieved from the EPA's Air Markets Program Data. The EPA's gross output data in certain hours during the study time horizon records very low levels of non-zero output when ERCOT data reports that units are providing zero net output. We sought to classify units as OFF when net output to the ERCOT market was zero. However, ERCOT unit level data was not available before the implementation of the nodal market.

Thus, 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 consecutive OFF hours for coal units and four consecutive OFF 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 below which 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 units the minimum sustained output level was taken from Mann et al. (2017). 50% of this level was used as the cutoff point below which units were classified as OFF.

Appendix E. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.eneco.2022.106154.

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