Wind Energy, Transmission, and Production Costs: Does Increased Connectivity Help All? *

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Abstract

We empirically examine the geographic variation in economic impacts of a significant electricity transmission capacity expansion project, the CREZ project in Texas, on the value of wind generation. Importantly, we extend the scope of canonical two-region trade models in economic theory onto multiple regions. We show that while, as predicted, the two regions directly affected by the expansion, the West and North zones, experience overall falling production costs and gains from trade, the marginal value of wind generation in the Houston zone declines post-CREZ. These effects are such that, across the region as a whole, the marginal value of wind with respect to production costs remains effectively the same before and after CREZ. Additionally, using machine learning classification techniques, we demonstrate that wind generation actually increases the likelihood of relatively higher prices in the Houston zone. These counter-intuitive generation cost and pricing patterns appear to be driven by changing power trade patterns and dynamic production constraints of thermal generators.

Keywords: Electricity Market, Market Integration, Renewable Energy

JEL Codes: L90, L94, P18, Q41, Q42

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1 Introduction

Renewable electricity generation, particularly wind generation, in the U.S. and other regions is often substantially concentrated in sparsely-populated, low electricity demand areas. With limited transmission capacity between these renewable-rich and high-demand regions, exports of low-to-zero marginal cost renewable power will be restricted. As standard economic theory predicts, and as demonstrated in electricity-specific contexts (e.g. Joskow and Tirole (2005)), lowering barriers of trade (i.e. increasing transmission capacity) will lead to falling production costs for importing regions in simple two-region models and gains from trade for both regions. The reality is that electricity market regions in the U.S. and elsewhere are often not well characterized as two-region geographies given the existence of multiple demand centers, spatial distribution of generation sources, and limited transmission corridors.[1] In addition, the non-storability of electricity, technical limitations on how quickly thermal generating units can vary production, and intermittent nature of some renewable generators provide further departures from standard trade models which often assume continuous and deterministic production capabilities of the regions. As such, price patterns and production costs throughout the region are likely more ambiguous and nuanced than simple models may predict.

The Competitive Renewable Energy Zone (CREZ) transmission project in the Electricity Reliability Organization of Texas (ERCOT) market region provides an appropriate setting to empirically explore some of these more nuanced outcomes of increased market connectivity and, thus, serves as the focus of this paper. As described in more detail below, the CREZ project was constructed with the goal of delivering power from the wind-rich West load zone of ERCOT to the more populated regions in the North, South, and Houston load zones (see Figure 1 for a map of the ERCOT zones). We construct detailed hourly data sets for various market outcomes and covariates related to the ERCOT market to demonstrate how this

[1]For example, the electricity market region covering most of Texas has traditionally be characterized as having four congestion or load zones, Houston, North, South, and West, in which power can more easily be transmitted within the zone but faces limitations across zones.

expansion leads to somewhat counter-intuitive results. Specifically, we show that while, as expected, the zonal generation costs decreases from ERCOT's eastern zones with more wind generation from the West zone, the effect of West-zone wind generation on ERCOT as a whole has remained relatively constant post-CREZ expansion. As we show, this is driven by zonal heterogeneity in production cost responses to wind generation post-CREZ expansion. In particular, we find that while wind generation from the West zone offsets more of the North zone's production costs after CREZ, wind generation from the West zone offsets less production costs in the Houston zone post-CREZ. The two effects effectively cancel each other out leading to no statistically significant change in the marginal value of wind with respect to production costs.

Additionally, using machine learning classification techniques, we show that eight years of hourly zonal electricity prices in ERCOT can be classified into one of six general patterns. Exploring how wind generation conditions and CREZ affect the likelihood of a given price-pattern state, we find that post-CREZ expansion wind generation actually increases the likelihood of the Houston zone having relatively higher prices. Combined with the production cost results, this suggests wind is less beneficial from an electricity cost perspective for Houston post-CREZ compared to pre-CREZ periods. We go on to demonstrate that these generation cost and pricing patterns appear to be driven by the CREZ-induced change in power trade patterns across ERCOT and dynamic production constraints of thermal generators. These counter-intuitive points are policy-relevant and timely in the context of electricity markets in the U.S, and other countries. Regulators are considering integrating regional electricity markets to complement increasing renewable energy penetration. Whereas the integration improves market outcomes in some regions, other regions can lose benefits due to integration. This cautionary tale can be relevant in other policy settings.

These results make several key contributions to the literature. While there has been several studies that have explored the impact of renewable generation on electricity prices (Ito and Reguant 2016; Woo et al. 2016; Würzburg, Labandeira and Linaresy 2013; Woo et al.

2011; Sensfuß, Ragwitz and Genoese 2008), these have largely been analyses of aggregated market regions. We, on the other hand, explicitly consider how renewable generation affects the spatial patterns of prices across the region and consider the mechanisms behind these patterns. Our research is more closely aligned in spirit to the work of Bushnell and Novan (2018), who explore the temporal variation in the effect of renewables on wholesale power prices in California, while we explore spatial variation in price effects.

Our work also aligns with the research exploring how renewable energy affects generation patterns from existing generators (Cullen 2013; Novan 2015; Fell and Kaffine 2018). Again, however, our research differs from these past efforts in that we are interested in how renewable generation affects production from fossil-fuel generators and how that effect changes in regionally-specific ways with transmission expansion. We are also interested in the response of more aggregate measures of regional production costs to renewable generation and how that changes after a significant transmission expansion project.

Finally, our work is also closely related to other recent analyses of the CREZ expansion project, namely Fell, Kaffine and Novan (2019) and Lariviere and Lu (2018). However, the focus of Fell, Kaffine and Novan (2019) is on role of grid congestion, or the alleviation thereof via transmission, on the environmental value of wind generation, whereas we are focused on market impacts. Lariviere and Lu (2018) is more similarly focused on the market benefits of the CREZ expansion, but they consider a more structural approach that assumes the more standard two-region model assumption, whereas we consider more reduced form explorations that explicitly considers heterogeneous impacts associated with CREZ and renewables across each of the four zones of ERCOT.

The remainder of the paper is organized as follows. Section 2 provides background about ERCOT market and the electricity dispatch process. Section 3 describes a conceptual theory model extending the scope of canonical two-region trade models onto multiple regions. Section 4 presents detailed hourly data sets for various market outcomes and covariates in ERCOT and generator-specific marginal costs. Section 5 describes our estimating framework using machine learning to identify zonal wholesale electricity price patterns and examines the evolution of the wind generation effect on the price patterns and zonal electricity production costs. Section 6 then examines the mechanisms behind the evolution of the wind effect. Section 7 concludes.

2 Background

2.1 ERCOT, Wind Generation, and CREZ

ERCOT is the independent system operator that oversees and organizes the electricity market that covers approximately 75 percent of the land area and about 90 percent of the power consumed in Texas. The market was originally balanced as zonal market with four "congestion management zones" or load zones, the Houston, North, South, and West zones, as shown in panel (a) of Figure 1.[2] The market design changed to a nodal market in December of 2010, where energy is priced at some 4,000 nodes across reflecting the cost of serving an additional unit of load at the given node. While nodal pricing data is available, we use zonal prices, which are load-weighted average of energy delivered to the given geographically-defined load zone based on the nodes physically located within the zones, in our analysis of price-pattern categorization for ease of computation and interpretation. Summaries of the hourly prices and loads across the 2011-2018 study period are given in Table 1. Not surprisingly, load is considerably larger in the Houston, North, and South zones as these areas contain the state's large population centers. However, average prices are actually highest in the West region during our study period. This is in part due to the relatively steep supply curve for generating facilities in West, which we will discuss in further detail below. In addition, it should be noted that there is considerable intra-day variation in prices as wind generation tends to be greatest at night while load decreases in these periods.

[2] In the electricity industry, demand for power is often assumed to completely inelastic and referred to as "load". For the purpose of this paper, we will interchangeably use load and demand to refer to fixed energy demand in the given time period.

Capacities by generation technology are given for each zone in Table 2. Estimates of supply curves (i.e. marginal cost curves) by zone, with overlaid distributions of hourly load, are shown in Figure 5. Several features are apparent from this table and figure. First, the the North zone has by far the most fossil fuel generation capacity, followed by South, Houston, and West zones. The North zone in particular has considerable coal-fired and natural gas combined cycle (NGCC) generation capacity, creating a largely flat supply curve with considerable excess supply relative to its distribution of load. Second, the Houston zone supply curve largely lies above the North and South zones' supply curves. As a result, the Houston zone relies heavily on imports from the South zone and, to an even greater extent, from the North.

With respect to renewable generation, wind-generated energy is by far the dominant source. ERCOT's installed wind generators increased by 127% from 2011–2018 and lead the nation in an installed capacity. Wind plants can offer power at low prices because they essentially have zero marginal costs. Furthermore, due to the revenue stream resulting from the production tax credit, which generates tax benefits whenever wind generates electricity, and payments from the state's renewable portfolio, wind plants can offer electricity at a negative price. However, the volumetric-based subsidies may excessively incentivize productivity and bias wind investments towards high-producing sites (Aldy, Gerarden and Sweeney 2018), which in the case of ERCOT, as can be seen from Figure 4, has led to the majority of the wind generation capacity being cited in the low-demand West zone. In addition, as can be seen in Figure 2, wind generation from the West zone frequently constitutes between 70 to 80 percent of ERCOT total wind generation. With considerable wind-generation in demand-poor regions far from high-demand centers and with limited transmission capacity, negative prices and even a curtailment of renewable generation become more likely. The region is also likely to experience more price spikes than other regions because once wind generation drops, lower-cost fossil fuel generators cannot ramp up or startup quickly enough to compensate for lost wind generation; therefore, they must instead activate high-cost generators temporarily.

A more integrated electricity market by increasing transmission capacity can alleviate the problems to more easily export this excess power and import generation from low cost units in other regions. This recognition of the efficiency gains from greater transmission motivated the CREZ transmission project.

The CREZ transmission project, with an estimated total cost of around $7 billion, was a massive transmission expansion project primarily aimed at moving wind power from West Texas to demand centers in East Texas. The project began in 2011, but saw most of the lines completed in 2013. By the end of April 2014, the project was completed. In the end, CREZ added 3,589 miles of transmission lines and eventually transmitted approximately 18,500 megawatts (MW) of wind power. A map of the added or enhanced transmission lines is shown in panel (b) of Figure 3. Note that the lines particularly increase the linkages between the West and North Zones, but does not directly link the West zone to the Houston zone. As we describe below, this build-out feature is key in explaining some of the changes in response to wind generation across several market outcomes in ERCOT.

2.2 Electricity Dispatch Process

Market operators in centralized wholesale electricity markets balance supply and demand to maintain stability of an electric grid. As electricity demand is highly variable and almost perfectly inelastic, the market clears mostly on the supply side. In addition, unlike most other goods, electricity cannot be cost-effectively stored and supply must meet demand at all times. If more power is being consumed than is being produced, then the reliability of the power grid is threatened. The imbalances falling outside of a narrow tolerance band, result in blackouts, complete loss of electrical service. Under a stylistic economic dispatch model, it is economically efficient to use generating units in the order of the lowest possible marginal cost among installed capacity to meet demand, which is known as “merit order”. Specifically, conventional generating units with lowest variable costs should be inframarginal and regularly produce close to their maximum capacity while high marginal cost generators are occasionally dispatched to meet peak levels of demand. However, there are a number of reasons that the realized cost-minimizing allocation of output deviates from the idealized power supply curves.

First, large units require time and fuel to substantially change their output (Cullen and Reynolds 2017; Cullen 2015; Reguant 2014; Kumar et al. 2012). With the dynamic constraints, large units may continue operating when price is less than their marginal costs to prevent having to pay larger start-up costs. Likewise, after idling, the units choose not to operate when the price exceeds the static production costs because a series of discounted expected profits from operation may be less than lumpy startup costs. Furthermore, even if they decided to startup, it takes a certain period of time to warm up generators and supply electricity to a grid after idling (a cold start). Engineering estimates of start-up delays range from a few minutes to several hours depending on the size and technology of the generator (U.S. Energy Information Administration 2017). Table 3 summarizes data for a few dynamic constraints that fossil units face. Large units in ERCOT require additional fuel and labor costs ranging from \$11,700 to \$88,182 on average to startup a turbine, which causes the entry/exit frctions of the unit. Therefore, even if the inframarginal units such as coal and combined-cycle operate during most of time, the generators are losing money in many of the periods in which they are operating.[3] These behaviors are clearly not consistent with static profit maximization.

Second, transmission constraints may make it infeasible for the least-cost units to meet local demand. The transmission of electricity is subject to the physical constraints of the electrical grid, such as thermal and voltage limits that constrain the quantity of electricity that can be transmitted. If congestion exists, regional prices in wholesale electricity markets

[3]However, the data do have some caveats. First, the electricity prices used in the model are not necessarily the prices the firm received for its output since some energy in this market is sold via bilateral contracts or day-ahead market. However, a firm can always have an option to shut down production and fulfill its contract by buying power in the balancing market. Second, some generators are paid to provide ancillary services for the market such as regulation and capacity reserve. These generators does not respond to price signals in the market, but are obligated to generate electricity when they are needed. However, such deployment is little share of actual generation.

will differ and provide a signal that transmission related issues are limiting an efficient flow of electricity. Based on the ERCOT data from 2011 to 2018, only 35.4% of time have the uniform regional prices. Third, on a regular basis, power plants must go off-line for maintenance, or are forced to shutdown unannounced, causing more expensive units to fill the gap. As a variety of other constraints in reality can create market outcomes that are not consistent with the static profit maximization, the dynamic constraints of conventional units and transmission inadequacy are particularly relevant when increased generation from intermittent renewables requires more frequent ramping, startups and shut downs of fossil fuel generators and drives changes in market prices and profits for all types of generators.

3 Two Region Model and Multiple Interconnections

When the lowest-cost dispatch of generating units in operation does not violate any transmission constraints, the market clears as a uniform-price and all nodal prices are equal. However, if this idealized power supply scenario would force a transmission line to exceed its carrying capacity, locational marginal prices deviate from the uniform price. Joskow and Tirole (2005) provide a theoretical framework with a two-region model to show how grid integration by transmission infrastructure alleviates congestion and facilitates price convergence. Reflecting the distribution of generation sources in Texas, specifically, if CREZ facilitates exporting wind generation from West to North, costs in North would be reduced by supplanting generation from fossil fuel units with output from zero marginal cost renewables. When exporting, the West also gains additional revenue beyond that the transmission constraint binded before the CREZ.

Panel (a) of Figure 6 plots the gains from trade between two areas based on Heckscher-Ohlin Theorem (Jones 1956). An increasing curve from left to right denotes a supply curve in North and a double arrow on a horizontal axis represents demand quantity. Superimposed on this is the mirror image supply and demand from West. The West supply curve contains a large wind capacity with zero marginal cost followed by a steep fossil fuel supply curve as ERCOT data indicates at Figure 5. If the two areas were to operate in autarky, a market clearing price in North would be p_0^N and West would have p^W. However, if CREZ enabled imports of wind generation from West, the solid vertical line shifts left to the dotted one and the North price would be p_1^N. Under this scenario, both North and West would be better off by the areas painted with light and dark blue. In addition, if the generators in North could be still in operation with the wind imports, an available capacity in North would be a thick line from the point of intersection between the dotted vertical line and the North supply curve.

We next expand this two region analysis to consider Houston market, and contrast two different market outcomes in Houston that the additional trades between West and North can create. Panel (b) of Figure 6 can reflect one possible outcome in Houston. If all units in North were still in operation after the wind imports from the West, a price in Houston would be reduced as output from additional lower-cost units in North supplant expensive generation units in Houston. However, Figure 7 plots another possible scenario, in which additional imports of wind generation reduce the North operating capacity more than its status quo capacity without trade. There are a number of reasons that can create this unpredicted result. First, considering diurnal patterns of wind generation, which are negatively correlated with electricity demand, the additional wind imports from West to North in low demand hours can lead to shutdowns of generators in the North because wind can meet most of demand in ERCOT during those hours. When Houston needs generation from the North in another time window, the idling units in North cannot swiftly return to the grid. Second, decreasing economic viability with reduced residual demand in North would make some generators more likely to be offline. Baseload generators having a large lumpy startup costs might not start up the generators even when a price exceeds the static marginal cost in the short-run. Third, more generally, CREZ is not a market integration between markets with all dispatchable units that a canonical two region model describes, but rather a market integration of intermittent renewables to a fossil fuel unit dominant system that is connected to another demand center. For this case, we would need a different model that incorporates an intermittency of renewables and dynamic production constraints of conventional units. As renewable energy penetration continues to increase across the U.S., it is also increasingly relevant because the spatial locations of renewables are similar to this particular case study of ERCOT.

4 Data

To estimate the heterogeneous effect of market integration on regional markets, we compiled publicly-available data from ERCOT and U.S. Energy Information Administration (EIA) and proprietary data from ABB's Ventyx Suite.

4.1 Zonal Market Data and CREZ

We first assembled a dataset of an hourly zonal price and demand from ERCOT. ERCOT compiled eight different load-weighted zonal prices to set a financial settlement price that regional retailers have to pay to buy electricity in the wholesale market. However, we focused on four zonal prices for Houston, North, South, and West zones because the other four denote a price for municipalities operated by a vertically integrated utility.[4] ERCOT also has reported on hourly load data in its eight weather zones since April 2003 but load data by the four load zones, which cover the same areas for the four zonal prices, were available since June 2017. To complement the publicly available data from ERCOT, we also obtained load data for the four load zones from ABB, which were available from January 2011 to July 2016.[5] Table 1 describes the zonal price and demand by load zones and weather zones. One

[4]The other four zones are the Lower Colorado River Authority, San Antonio, Austin, and Rayburn zones (also referred as LCRA, CPS, AEN, and RAYBN). They are located in a small part of North and South Zones.

[5]Figure 3 show a map for the load zones we mainly consider throughout this paper. Figure S1 in appendix plots a map for the eight different weather zones.

remarkable thing from the first and second panels is that the North zone has the lowest price average and volatility while it is the largest demand center in ERCOT. West has, however, the lowest demand, but the highest price average. The static size of demand, as such, is not a key driving factor for the market prices, which we will discuss in more details in the following sections.

We next assembled a dataset of nodal generation at a 15-minute interval from ERCOT's daily 60-Day Security-Constrained Economic Dispatch (SCED) Disclosure Reports.[6] The daily report records unit-level bidding data and telemetered net generation from each unit to ERCOT grid at a 15-minute interval. There have been 838 different generating resource nodes in operation over the 2011 to 2018 study period. To obtain the geographical information of the nodes in the reports and subsequently match them to an area of load zone for our study, we took a series of additional procedures. First, we secured data containing node names and their geographical coordinates from a price contour map that ERCOT updates every 15 minutes on their website. Our goal is then to match the 697 unique node names with geographical coordinates from the contour map file onto the 838 resource node names in the SCED report. However, as some price node names from the SCED reports are either missing or slightly different from node names in contour map files, we next compiled another publicly available Daily Resource Decision-Making Entity List from ERCOT.[7] The list contains all company and plant names overseeing generation units and all resource node names for the units. This comprehensive set of resource node names associated with a power plant can identify a set of distinct node names in the SCED reports to the same power plant. This additional procedure finds geographical coordinates for 90% of the 838 resource nodes in the SCED reports.

[6] ERCOT entilied a detailed daily market report "60-Day SCED Disclosure Reports" because the release of each report is delayed 60 days to reduce the ability of firms to exercise market power by best-responding to observed offers of competitors.

[7] For example, a name recorded in the contour map files, "ATK_ATKG345", is different from the node names in SCED Disclosure report, which comprise "ATKINS_ATKINSG3", "ATKINS_ATKINSG4", "ATKINS_ATKINSG5" and etc., even though they basically denote the nodes in the same power plant and have the same geographic coordinates. Therefore, we needed another data identifying more comprehensive nodes names in a power plant to match the names in contour map files to the SCED names.

The remaining nodes are found through ERCOT Monthly Capacity Reports and a publicly available fuzzy string matching algorithm.[8] Again, the purpose of this process is to identify which nodes in SCED reports are grouped into the same power plant and in the same location. The capacity reports also contain resource node names related to a power plant, but most of the node names are also slightly different from the SCED node names. We employed a publicly available string matching algorithm that calculates similarity between texts and suggests the closest matching and found two distinct but closely related text strings for possible candidates. We next checked all the other specifications of the candidates such as generation capacity and technology types of the node to find an accurate match. Based on these sequential processes and abundant publicly-available data from a variety of different sources, we eventually could set up a large pool to identify the relations between different node names in the several files that actually denote the same generating resource.

Based on the geographic information of nodes, we aggregated the nodal generation within a zone to find zonal-level generation by all types of different technology, which particularly comprise all different types of fossil fuel units, nuclear, wind, and solar. These units have supported 99.2% of ERCOT demand on average from 2011 to 2018. Table 2 also summarizes the data. Average hourly generation from fossil fuel units in North and South zones meets 57% of demand in ERCOT (72% including generation from nuclear and wind from those two zones). Superimposing demand data in Table 1, one can observe that Houston should import electricity from North to meet the local demand. Specifically, generation in Houston has met 57.5% of their own demand on average from 2011 to 2018.

We also obtained CREZ progress report (PUCT 2014) from Public Utility Commission of Texas and denoted the progress as a monthly completion percentage. Specifically, we collected the time when each of 186 projects finished construction and the miles constructed by each project. Then, we formalized a variable indicating a percentage of the total CREZ completion by dividing the monthly accumulated miles by the total miles constructed by

[8] See a publicly available string matching program written in Python at https://github.com/seatgeek/fuzzywuzzy for more details.

CREZ (3,589 miles). As noted above, panel (b) of Figure 3 summarizes the progress.

4.2 Marginal Cost Estimation

To compile a panel data of monthly marginal costs for each unit in ERCOT, we next built a dataset of unit-level heat rate, fuel price of each unit, and estimates of unit-level variable operation and maintenance costs using EIA's Form-923 and ABB's Ventyx Suite database. The primary component of a generator's marginal cost is the cost of fuel. We calculated each unit's variable fuel cost as the product of the unit's average heat rate−the rate at which the unit converts fuel into electricity−and the fuel price. Specifically, we used EIA's Form-923 and calculated the average ratio of monthly fuel input to net generation to estimate average heat rate for each unit. As the EIA's Form-923 records the unit-level fuel price only for generators in a regulated market, we then obtained the ERCOT fuel price from ABB and matched the unit names in ABB to the ones in the EIA form. However, the monthly unit-level fuel prices in the dataset occasionally have oddly high or even negative values.[9] We dropped out those outliers from our data and calculated a nodal-generation-weighted-average of fuel prices to find a zonal level fuel price for each type of technology. We also compiled variable operation and maintenance (VOM) costs estimated by ABB to calculate each unit's monthly marginal cost. The VOM ranges from $0.66 to $1.99, depending on technology.[10] We finally estimated unit-level monthly marginal costs by multiplying unit-level heat rate by monthly zonal fuel prices for each technology type and adding them to unit-level VOM.

Table 2 reports an average of monthly marginal costs of fossil fuel units, which show significant variation in the cost by zones and technology. The units in Houston have the

[9]The unit-level fuel price data that EIA's Form-923 records for regulated market also contain oddly high and negative values. Based on a conversation with EIA, there are actually many reasons that the monthly fuel price have the odd values. First, the cost of fuel prices the plant pays will depend on any contracts they might have and the going market price. Also, the total fuel cost values on the EIA-923 can "Include any penalties/premiums paid or expected to be paid on the fuel delivered during the month in the delivered price for fuel shipped under contract." This means that a fuel supplier could end up providing a credit to the purchaser based on the amount of fuel purchased during the year. It also works in reverse, where a penalty can be applied to a buyer of fuel and then, a very large total fuel cost would be assumed in a given month.

[10]Examples of VOM costs are costs for raw water, waste and wastewater disposal expenses, chemicals, catalysts and gases, ammonia for selective catalytic reduction, and consumable materials and supplies.

highest costs over all types of technology as they have the largest heat rate and zonal fuel prices, while the units in north have the lowest. There is also a significant difference in costs between the different types of generating units within a zone. Coal is the most economical units, followed by natural gas combined cycle units. The other nimble, but expensive units are natural gas turbines and natural gas steam units. The gas turbines are more frequently used as a peaker unit, especially when integrating more renewables into electricity markets, because it needs the smallest startup costs and is equiped with a nimble startup and ramping (Bushnell and Novan 2018). However, the gas steam units are rarely used to meet peak demand in summer or supply capacity reserves in an ancillary service market because it has both high marginal costs and binding dynamic constraints, such as high startup costs and long startup delays.

To complement zonal supply curve, we also assembled two nuclear power plants in ERCOT. Comanche Peak power plant in North has 2509 MW capacity and South Texas plant in South has 2708 MW. The marginal cost of generation is very low at the nuclear plants, but their capital costs and operating expenses are larger than the other thermal units (Davis and Hausman 2016). We thus used average costs per MWh for the zonal supply curves.[11] We also assembled zonal wind generation and assumed the marginal costs were zero. Solar generators were dropped from the supply curve because of their negligible market share in ERCOT (0.06%).

5 Market Integration Anomalies

We explore the effect of wind generation from the demand-poor West zone on the ERCOT market and how that effect has evolved as the CREZ transmission project was constructed. More specifically, we look at the evolution of the wind generation effect on zonal wholesale electricity price patterns and zonal electricity production costs. We describe each of these

[11] According to ABB's estimated production cost data for two nuclear power plants in ERCOT, marginal costs are \$10.95/MWh and capital costs and operating expenses are \$ 12.49/MWh on average.

analyses in turn below.

5.1 Methods for Price Pattern Recognition and Results

As noted above, several studies have analyzed renewable energy effects on wholesale electricity prices. This is typically done region-by-region. However, because the focus of this research is to examine how transmission expansion alters the effects of renewable generation on outcomes across the whole market, we examine wind interactions with pricing patterns over the four zones of ERCOT. In this way, we are able to get sense about how renewable energy effects the zonal prices simultaneously and shed further light on possible unforseen pricing patterns with increased transmission capacity. To do this analysis we must first classify patterns in the hourly zonal prices across the ERCOT region. There are a variety of clustering algorithms in machine learning that can be used to implement this classification step. Recent papers in economics have also used the algorithms to reduce the dimensionality of data and make equilibrium computations more tractable (Reguant 2019; Mercadal 2019). In the context of our study, the clusterting method should learn how prices in different locations over various times are grouped into the same clusters and automatically classify hourly market outcomes into countable categories. Our main goal is then to formalize a discrete dependent variable reflecting hourly market conditions into a time series format for the further analysis.

Among the many different clustering algorithms, we chose Density-Based Spatial Clustering of Applications with Noise (DBSCAN) by its three main advantages (Ester et al. 1996). First, unlike other methods, such as a renowned k-means algorithm that literally finds k different classes, the DBSCAN algorithm does not require prior knowledge of the number of clusters. It particularly works well with our case because we have neither prior information about consistent patterns in interactively changing hourly prices nor prior preference over a number for different classes of market outcomes. Also, DBSCAN can automatically determine outliers that cannot join the other main clusters.[12] Second, the method can incorporate a large dataset. We have four dimensional price data from 2011-2018 with 58,176 hours. Third, the algorithm works well with a wide range of distance metrics that measure a distance between data points and subsequently estimate the overall density of the points inside the algorithm. One commonly used metric is the ordinary straight-line distance between two points in Euclidean space (Euclidean distance). For our analysis, however, as we are interested in the relative price differences between zones rather than their overall changes, we use a correlation coefficient as the metric. It automatically disregard the overall shift of four zonal prices between two different hours.[13]

Based on the settings, the data-driven clustering method DBSCAN identifies six different classes for consistent price patterns and one class for outliers in the data.[14] To get a better sense of what these price pattern classifications entail Figure S3 plots zonal price comparisons between each pair of zones in six different market conditions. The Figure shows a scatter plot of the hourly zonal prices assigned to the given class for each of the six zonal combination (e.g. North-West, South-West, Houston-West, North-South, Houston-South). Across the classifications, obvious patterns in Figure S3 emerge to give economic meaning to each classification. In the class we label as "Uniform" one can clearly see prices are equalized in each zone. In the class labeled "Low West" the West zone prices are the lower bound across

[12]The algorithm also needs two parameter specifications: a search radius (ϵ) and a minimum number of samples. If the distance between two data points is below the threshold ϵ, the two points are considered neighbors. The points in the same neighborhood comprise a cluster, only if the cluster has the minimum number of samples that a user defines. Otherwise, the data points are classified as outlier. We simply guess the minimum number as 1,000 because we are not interested in a small class that only contains less than 2% of observations in our data. Then, one strategy for estimating a value for ϵ is to generate a k-distance graph for the input data, in which k is 1,000 for our case. For each point in the data, find the distance to the k^{th} nearest point, and plot sorted points against this distance. The graph contains a knee, at which the distance rapidly increases. Based on the knee, we choose 0.05 for the distance. However, we find our results are very robust over different parameter specifications, such as ϵ ranging from 0.01 to 0.07 and minimum points ranging from 100 to 3,000.

[13]For example, let's assume we have four zonal price at a certain hour as \$20, \$23, \$20, and \$23 and call the data point as A. Then, a correlation coefficient between A and another synthetic data point B, simply multiplying A by α (any random number) is the same as a correlation between A and C, multiplying A by β (another random number). In other words, the data points A, B, and C are all considered same in our DBSCAN algorithm and should be clustered in one class.

[14]Footnote 12 explains details for DBSCAN specifications.

the zones and the remaining zones have quite similar prices. Similarly in the “High West” class, the West zone is the upper bound of prices and the other zones have similar prices. In the “High Houston” class, Houston zone exhibits higher prices than the other zones and the South zone is higher than the North and West regions.[15] In the “Low South” class, the South zone exhibits consistently lower prices in the other regions, while in the “High South” class the South prices are consistently higher than other zone.

Table 4 summarizes the frequency of the classifications as well as the average prices across the zones within each class. The Uniform condition comprises most hours of our sample (35.4%). Hours attributed to the Low West and High West classes occur at about the same frequency. Similarly, the classes High Houston, Low South, and High South account for about the same number of hourly observations in our sample, while DBSCAN set only about 5.3% of observations as outliers.

To get a sense of how these frequencies have changed over time and to foreshadow some of the results from the multinomial logit analysis, Figure 8 plots the monthly frequency of occurance for each class over the 2011 to 2018 study period. The monthly frequency in a vertical axis is calculated as a fraction of hours over about 700 hours in a month for each class to have happened and is denoted as a blue line in the figures. The black vertical line indicates the time when all 186 CREZ projects has been completed. We first observe from the figures that the frequency of Uniform price condition increased as CREZ developed, but started decreasing approximately after late 2015. Second, both Low West and High West conditions were significantly alleviated after CREZ. Low West condition, however, appeared to slightly increase after about 2016. Third, High Houston condition started coming out in the market as CREZ developed, but showed a remarkable increase after CREZ completion.

[15] For this “High Houston” class North is somewhat higher than West, though the difference is not as severe as the differences for other zone combinations.

5.2 Changes in Price Patterns by Wind and CREZ

Based on the classified market conditions by DBSCAN, we estimate a multinomial logistic regression to investigate how the CREZ expansion and an increase in wind generation influenced the likelihood of each type of market condition as shown in the following equation:

$$ln(\frac{Pr(Y_t = i^{th}Class)}{Pr(Y_t = I^{th}Class)}) = \alpha_i + \beta_{i1}C_t + \beta_{i2}C_tW_t^w + \sum_k \theta_{ik}f_k(W_t^w, W_t^s, W_t^n) + \sum_l \gamma_{il}X_{tl} + \eta_{mh} \tag{1}$$

$Pr(Y_t = i^{th}Class)$ is a probability of ERCOT market condition at time t to be i^{th} of six classes found by DBSCAN. The six classes include all classes except Uniform condition. $Pr(Y_t = I^{th}Class)$ is a probability of ERCOT market condition at time t to be a base class, Uniform condition. $ln(\frac{Pr(Y_t=i^{th}Class)}{Pr(Y_t=I^{th}Class)})$ denotes log odds of being in class i versus class I. Our two variables of interest are C_t, which is a percentage of CREZ completion, and W_t^w, which is hourly wind generation at West in GWh. We include the interaction of W_t^w and C_t as the CREZ project was primarily designed to deliver more West-zone wind to other parts of ERCOT. It is thus reasonable that the effect of West-zone wind generation on the likelihood of a given price pattern will change as CREZ is built out. We also include wind generation from other regions, W_t^s for South and W_t^n for North, though do not interact these variables with C_t as they are less likely to be affected by the transmission expansion. Each wind generation variable enters flexibly as a third-order polynomial. X_{tl} is a set of control variables for solar and regional nuclear generation, load at eight different weather zones, and the coal-to-natural gas fuel price ratio between. η_{mh} is month and hour fixed effects. Standard errors are clustered at month-year level.

Results of the marginal effects of West-zone wind generation at various levels of CREZ completion on the probability of a given class are given in Table 5.[16] Many of these marginal effects are as one might expect given the prediction of a standard two region trade model with falling barriers to trade. For example, West wind generation has a diminishing negative

[16] A more complete description of the marginal effects of all variables on the probability of a given class is presented in the appendix in Table S1.

effect on the likelihood of having uniform wholesale electricity prices across the zones as CREZ is built out. Similarly, as CREZ is built out, West wind generation is less likely to create market conditions with low prices in the West. The flip of that is, however, the completion of CREZ makes West wind generation less of a buffer against relatively high prices in the West zone. Conversely, CREZ completion does little to alter the impact of West wind generation on the likelihood of relatively low prices in the South zone and now makes West Wind generation an inconsequential determinant of the likelihood of relatively high prices in the South.

The more surprising result from this analysis shows that the marginal effect of West wind generation on the likelihood of relatively high prices in Houston goes from effectively zero to a positive and significant effect as CREZ is completed. This suggests that, in terms of wholesale electricity prices, after the expansion of CREZ, West wind generation disproportionately benefits other regions of ERCOT compared to the Houston zone.

Because we allow for a flexible specification of West wind generation, the marginal effects will also vary by West wind generation levels. To get a more complete sense of the marginal effects of West wind generation over a range of generation and CREZ completion levels, we create heatmaps of marginal effects as shown in Figure 9. As can be seen from this figure, high West-zone wind generation reduced the likelihood of Houston having relatively high prices in the periods when CREZ was largely incomplete. However, heat maps now show that the positive marginal effect of West wind generation on the likelihood of relatively high prices in the Houston zone is relatively constant over ranges of West wind generation. The figure also displays that for most other price classes, the completion of CREZ has largely had an attenuating effect of West wind generation, regardless of the level of wind generation. The exception to this feature would be for the "Low South" class, which, again, has a marginal response to West wind generation that remained largely unchanged over the range of wind generation levels and CREZ completion levels.

5.3 Effects on Zonal Production Costs

The classification of prices are best viewed as categorization of relative, not absolute, prices (e.g. "High West" is characterized by relatively high prices in the West zone). To get a better sense of the absolute changes in supply conditions, we next explore the effect of West-zone wind generation and its evolution as the during and after the completion of the CREZ project on the zonal production costs. Hourly production costs of a unit are calculated by the monthly unit-level marginal cost of generation multiplied by hourly unit generation. The hourly production costs are then summed over each zone to define zonal production costs.

It does not include additional costs associated with start-ups or ramping of a generating unit or any capital costs incurred over the study period. The estimated relationship is similar to the specification used for the analysis of the describing drivers of wholesale price classifications, namely:

$$Cost_{it} = \alpha_i + \beta_{i1}C_t + \beta_{i2}C_tW_t^w + \sum_k \theta_{ik}f_k(W_t^w, W_t^s, W_t^n) + \sum_l \gamma_{il}X_{tl} + \eta_{mh} \quad (2)$$

where $Cost_{it}$ is the production cost of zone i in hour t. The remaining variables in (2) are the same as those described for (1).

The marginal effects of West-zone wind generation at various levels of CREZ completion on zonal production costs are given in Table 7. The patterns from this table are quite clear. The North zone see the marginal effect of West wind generation increase in magnitude as CREZ is completed, such that post-CREZ West-zone wind generation reduces North-zone production costs by a greater amount than it did pre-CREZ. This is as expected given that much of the transmission capacity of CREZ increased connections from the West to the North zones. Similarly as expected, West zone wind generation reduces West zone wind generation costs to a lesser extent in the post-CREZ period as the West-zone wind generation can be exported more easily to higher price regions with the expanded transmission. Likewise, given the transmission networks added in CREZ and in line with the price pattern results above, the South zone maintains a negative relationship between production costs and West wind generation that appears unchanged with the construction of CREZ.

Perhaps more surprising, though in line with the price pattern results above, we find that while West wind generation reduces production costs in the Houston zone, that effect has attenuated as CREZ has been completed. The magnitude reduction of this effect, combined with the reduction in the size of the effect in the West zone, is such that for ERCOT as a whole the marginal effect of West-zone wind generation on production costs is negative though effectively unchanged, if not attenuated, with the completion of CREZ. Again, this result is quite different than what one would expect from a simple two region model with increased trade capacity between a low production cost region and a higher production cost region.

Table 8 gives a more complete picture of the marginal effects of West-zone wind generation by displaying these marginal effects over both varied levels of CREZ completion and West-zone wind generation. The results are in line with those from Table 7, but also reveal the diminishing returns to West wind generation in terms of reduced production cost. That is, consistently we find the marginal effect of West-zone wind attenuates at higher levels of wind generation, though patterns across levels of CREZ completion remain the same. The diminishing returns are likely driven by a diurnal patterns of wind generation, which are negatively correlated with electricity demand. As wind generation is generally high during nighttime, the wind generation is more likely to supplant lower cost baseload units and its impacts on production costs are lower. The higher returns to West wind generation at lower wind generation level can be addressed by wind patterns in daytime.

6 Mechanisms

The generation cost patterns and production cost patterns appear to indicate that the West and North zones are experiencing the benefits of expanded trade in much the way the standard two-region trade model would predict. The Houston zone, on the other hand, appears to be benefiting less, and, with respect to generating cost, appears to be adversely effected by the expanded transmission capacity. This suggests trade-flow patterns have shifted in a way that limits the ability of the North zone to spread the benefits of the transmission expansion to the Houston zone. In the following sections, we empirically examine changes in the import/export flows of each zone as the CREZ project was built out. We further examine how wind generation effects the generating capacity available for producing and how that relationship has changed with the CREZ expansion.

6.1 Trade between Zones

We begin by examining how trade flows have been altered with expanding transmission between the West and the North zones. However, we do not explicitly observe trade-flows between zones and the connection between zones are not limited interconnection points that link, for example, ISO/RTO regions or interconnection regions. We do observe generation from all the generating facilities within a zone and the demand or load in each zones.[17] The ratio of the zonal production to zonal demand effectively gives us the hourly import/export status of the zone with the zone importing when the ratio is less than one and exporting when the ratio is greater than one.

The plots of each zones hourly generation-to-demand ratio over the period 2011-2016 is given in Figure 11. Each panel of Figure 11 also displays a solid vertical line to denote the date of CREZ completion. We also include simple linear trend lines of the ratios for the pre- and post-CREZ completion periods.

The figure displays several interesting aspects of the ERCOT market and the CREZ project. First, pre-CREZ at least, the North, South, and West zones are on average exporters of electricity, while the Houston Zone is imports electricity. Second, the trend of average export rates in the North zone, and to a lesser extent in the South zone, appears to be

[17] Zonal load data is taken from ABB Velocity Suite product. We have access to the data up through 2016.

declining in the post-CREZ period. Though, the mean level of the generation-to-load ratio appears near equivalent over the study period. On the other hand, as expected, exports appear to be trending upwards in the West zone after CREZ completion. Finally, and perhaps more surprising, the declining rate of Houston's generation-to-load in the pre-CREZ-completion period appears to level-off after the completion of CREZ.

In total, this figure gives some general sense of changing trade patterns for each zone. The figure is somewhat obscured by the fact that it plots total generation over load for a zone, so changes may be due to changing renewable generation that was not driven by CREZ. To more systematically examine how West zone wind generation effects the ratio of zone-specific fossil fuel generation-to-load and how that relationship changes as CREZ is constructed we estimate following equation for each zone separately:

$$Ratio_{it} = \alpha_i + \beta_{i1} C_t + \beta_{i2} C_t W_t^w + \sum_k \theta_{ik} f_k(W_t^w, W_t^s, W_t^n) + \sum_l \gamma_{il} X_{tl} + \eta_{mh} \tag{3}$$

We specify the additional covariates as was done in previously described estimations. Table 9 and Table 10 provide the marginal effect of wind generation from the West zone at verious levels of CREZ completion and wind generation levels.

The basic pattern of the effect are largely as expected for most zones. For the West zone, West-wind generation lowers the ratio of fossil fuel generation to load, but that negative effect gets smaller in magnitude as CREZ is completed because more of the wind generation can be exported to higher value regions. Conversely, the negative impact of West-wind generation on the ratio of fossil fuel generation to load in the North zone increases in magnitude as CREZ is completed. This highlights the direct transmission linkages that CREZ provided between the North and the West zones and is in line with the standard two-region trade model.

On the other hand, the impact of West-wind generation on the ratio of Houston-zone fossil generation to load attenuates as CREZ is completed. Why? The completion of CREZ does not physically limit the direct transmission links between the Houston and West zones. Rather, the main conduit for responses in the Houston zone to generation changes in the West zone, has been, and continues to be, via the North zone. On a load-weighted basis, the results presented in Tables 9 and 10 show that fossil generation in the North is turned down at a higher rate post-CREZ with more wind generation. This would lead one to believe that more North-zone fossil-fuel capacity should be available to export to the Houston zone. However, if the increased imports of West-zone wind forces more units in the North zone to turn off or otherwise change production such that physical dynamic production constraints of those units are unable to make their spare capacity available to increased demand in the Houston zone, then the Houston zone will not benefit from this excess capacity in the North. For instance, if CREZ increased the amount of zero-marginal-cost West-wind generation coming into the North zone such that the profit maximizing solution for some NGCC generators was to simply turn off the unit for some period, then those units would be idle, but unavailable for contemporaneous export to Houston. As a result, the quantity of available capacity freed up for export in the North may decline with more wind post-CREZ and thus the ratio of fossil-fuel generation to load in Houston may decline by a smaller amount in response to increasing wind.

6.2 Impacts on Capacity in Operation

As noted above, because of physical ramping constraints, if some fossil-fuel generators are completely shut off (have generation go to zero) they will not be available for production in the near term.[18] Also as noted above, these dynamic constraints may alter the export availability of generators and thus alter how the production cost and price benefits of renewable generation are spatially propagated through a market. To further explore how wind generation from the West zone affects the amount of capacity in operation (capacity having

[18]The time it takes for a generator to go from being turned off to being able to produce at full capacity varies considerably across technologies and by how long the generator was turned off. For example, a coal-fired generator typically takes several hours to go from “off” to being able to produce at full capacity. Start-ups are costly as well as the plants have to burn energy without putting power on the grid.

non-zero generation) we estimate the following equation separately for each technology and zone:

$$Capacity_{ijt} = \alpha_{ij} + \beta_{ij1} C_t + \beta_{ij2} C_t W_t^w + \sum_k \theta_{ijk} f_k(W_t^w, W_t^s, W_t^n) + \sum_l \gamma_{ijl} X_{tl} + \eta_{ijt} \quad (4)$$

where $Capacity_{ijt}$ is the sum of nameplate capacity of technology i in zone j at hour t across generators with positive generation (i.e. the generating capacity in "operation"). We use this distinction of having positive generation to proxy for the generation capacity of a given technology type that is available to serve load (either within the zone or exporting to another zone) in the very short-run. The possible technologies considered are coal, NGCC, and other NG units (i.e. gas and steam turbine units that are not part of a combined cycle generator). The remaining variables are the same as described above for other estimating equations. Results of the marginal effects of West-zone wind generation on different technologies and at various levels of CREZ completion are given in Table 11.

For coal generators, the effect of wind on generating capacity in operation is noisy and often statistically insignificant. This is expected at the hourly level given that coal generators are shutdown for relatively longer durations (days) and that there are relatively few generating units in each zone. NGCC generators show a much clearer pattern. Namely, as one would expect with a greater capacity to export wind generation, the negative effect of West-zone wind generation on West-zone NGCC is attenuated as CREZ is completed. On the other hand, increased wind generation reduces the quantity of NGCC capacity in operation in the North and South zones and that reduction increases in magnitude as CREZ is completed. The result is particularly severe in the North zone where the negative marginal effect of West zone wind generation on NGCC capacity in operation more than doubles in magnitude as CREZ goes from initial phases to completion. This suggests that wind generation in the West zone is leading more capacity of NGCC in the North to be shut off altogether, and thus not available for contemporaneous export to other zones. That is, while wind generation from the west displaces more NGCC capacity post-CREZ that displaced capacity is not all available for export in the very short-run as it is turned off completely.

Conversely, in the Houston zone, the effect of wind generation on NGCC capacity in operation is negative, but attenuated as CREZ is completed. To the extent that the displaced NGCC capacity in operation in the Houston zone was substituted with lower cost NGCC capacity in the North or South zones, then the attenuation of the West wind effect on Houston zone NGCC capacity in operation would increase production costs and relative wholesale electricity prices in Houston.

With respect to the other, non-NGCC natural gas units, the West wind generation effect on capacity of these units in operation remains relatively constant in the South zone as CREZ is completed. In the other regions, the completion of CREZ attenuates the negative effect of wind generation on the capacity in operation for these typically higher-cost natural gas units. For the West zone, this attenuated effect may be as expected since CREZ facilitates more export of wind energy and thus more generation from fossil generators in that zone will be needed to cover the zonal load. For the Houston zone, if the post-CREZ West-zone wind generation reduces a growing share of the North zone NGCC capacity that was previously available for export to Houston, then just as with Houston-zone NGCC, the West-zone wind effect on Houston's capacity in operation for other NG units will also attenuate. For the North zone, the attenuating effect is less obvious - if West-zone wind generation offset more NGCC capacity in operation in the North zone post-CREZ, why would it not offset more of the higher cost NG units capacity in operation as well? This apparent paradox may be explained by the additional roles of non-NGCC units in ERCOT. Namely, given the fast ramping generation characteristics of non-NGCC generators, these units often bid into ancillary service markets which the system operators require to keep the grid balanced in real-time. As ERCOT's wind generation capacity has grown along with the completion of CREZ, the demand for these ancillary services has grown. Thus, while the expansion of CREZ allows wind generation from the west to offset more generators in other zones, to the extent CREZ increases capacity it will also require more generating units to be used for ancillary services.

7 Conclusion

Standard two-zone models of trade suggest that lowering the barriers to trade leads to gains from trade as the lower-cost production region exports more goods to the higher-cost region. This general framework has been extended to the electricity market, where one would generally expect the reduction in barriers to trade via transmission expansion to generally the similar results in terms of gains from trade. However, many electricity markets may not be well-characterized by two zone models given the linkages across large geographic regions. In addition, dynamic production constraints may be such that benefits of increased linkages between any two zones in an electricity market region may not lead to shared benefits in other areas across the market.

We empirically investigate one specific transmission expansion project, the CREZ expansion project in ERCOT, to highlight how reductions in barriers to trade does not necessarily benefit all market areas. We specifically explore how the CREZ expansion has altered the response to wind generation from the West zone of ERCOT across multiple market outcome dimensions. These empirical examinations show a couple of interesting and, to our knowledge, unmentioned effects of CREZ. First, despite the fact that CREZ was built to deliver zero-marginal cost wind generation from the sparsely populated West zone to the population centers in the east portions of ERCOT, we find that the marginal effect of wind generation on production costs for ERCOT as a whole has changed little, to attenuated slightly, post-CREZ. This runs in direct counter to two-zone trade model predictions where one would expect the increased transmission capacity would allow the West wind generation to offset more high-cost generation than it previously could. Upon closer inspection, this result appears to be driven by the result that while the wind generation from the West reduced production costs in the North zone by an increasing amount post-CREZ, the effect of West wind geneation on Houston zone production cost was attenuated by a comparable amount. That is, while the North zone gained from CREZ in terms it allowing West wind generation to lower its production costs more, the Houston zone saw a reduction in the value of West wind generation post-CREZ in terms of its ability to reduce production costs.

Turning our attention to price patterns across ERCOT and the effect of West wind generation on those patterns, we find several results that are one would expect from a two-zone model. Specifically, we find that with more transmission capacity, West-zone wind generation has less of an impact on the likelihood of low prices in the West zone and less of an impact on the likelihood of a deviation from uniform prices across the zones of ERCOT. On the other hand, we find that more wind generation in the West zone increases the probability of relatively high prices in the Houston zone and that this marginal effect increases post-CREZ. This again suggests that the transmission expansion project is not equally benefiting all regions of the market.

To explore the mechanisms behind these results more closely, we look at the CREZ-driven changing effect of West-zone wind generation on production-to-load ratios and fossil-fuel generation capacity availability across the zones of ERCOT. More specifically, we find that, as expected, wind generation from the West zone reduces the share of the load in each zone served by fossil-fueled generators in those zones. This effect is increasing in magnitude in the North zone post-CREZ - West-zone wind reduces the share of North load served by North fossil generators by an even larger amount post-CREZ. However, this effect is attenuated in the Houston zone. That is, the Houston zone share of load served by Houston zone fossil generators is reduced by a smaller amount post-CREZ compared to pre-CREZ. This suggests a limitation in the propagation in the gains from trade - the transmission expansion freed up fossil generation capacity in the North, but this did not lead to more of that capacity exporting power to the Houston zone. To further explore this issue, we further examined the effect of West-zone wind generation on technology-specific generation capacity available to produce in the short-run. We find that West-zone wind generation offsets an increasing share of the NGCC capacity available to produce in the short-run as CREZ is completed. Conversely, the effect of West-zone wind generation on available NGCC capacity in the Houston zone attenuates as CREZ is completed. This suggests that post-CREZ, wind generation from the West zone leads more NGCC units in the North zone to shut off completely, rendering them unable to export power to the Houston zone even if they have lower marginal costs than some producing in the Houston zone. This highlights the importance of dynamic constraints in considering trade flows in electricity markets.

Overall, our results suggest the analysis of transmission expansions in electricity markets is more nuanced than is frequently mentioned. In particular, when the transmission expansion is such that the low marginal cost renewable generators have increased access to the regions that traditionally export to other regions of the market, other regions may receive limited benefits or have potentially adverse outcomes from the expansion. The results also highlight the need to consider greater detail of the transmission network and dynamic constraints of generating units likely effected by the transmission expansion.

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Tables

Table 1: Price and Demand in Load Zones.

Variables	Mean	St. Dev.	Min	Max
Price				
Houston ($/MWh)	30.37	71.79	-23.18	4371.74
North ($/MWh)	28.78	65.11	-23.17	4515.99
South ($/MWh)	30.81	70.86	-29.19	4381.70
West ($/MWh)	31.90	71.57	-36.59	4547.07
Demand by Load Zones				
Houston (MWh)	10472	2465	6131	19403
North (MWh)	14610	3912	2180	28630
South (MWh)	10556	2661	1818	18958
West (MWh)	3256	566	717	5179
Demand by Weather Zones				
Coast (MWh)	11210	2592	6457	20101
East (MWh)	1398	331	762	2621
Far West (MWh)	1923	393	1111	3164
North (MWh)	839	183	509	1564
North Central (MWh)	12988	3529	7010	25626
Southern (MWh)	3238	806	1666	6176
Southern Central (MWh)	6411	1714	3525	12345
West (MWh)	1115	232	632	1964

Note: Load weighted average of nodal prices and aggregate demand within a load zone and weather zone span June 30, 2011 through February 16, 2018.

Table 2: Summary of Zonal Generating Units by Technology

Variables	**Coal**	**Gas-CC**	**Gas-ST**	**Gas-Turbine**
Avg. Marginal Costs				
Houston ($/MWh)	28.50	45.62	95.65	79.16
North ($/MWh)	22.97	31.62	59.41	54.15
South ($/MWh)	24.07	34.19	49.79	67.34
West ($/MWh)	26.88	41.01	-	61.97
Avg. Generation (Total Capacity)				
Houston (MWh)	1673 (2593)	3605 (7049)	281 (3653)	450 (1495)
North (MWh)	6778 (10544)	5907 (13805)	222 (5240)	596 (1957)
South (MWh)	4082 (5998)	4184 (8392)	257 (3168)	456 (2214)
West (MWh)	324 (675)	620 (1826)	-	43 (1330)
Avg. Hourly Capacity in Operation			*Steam and Turbine*	
Houston (MW)	2176	6946	1578	
North (MW)	9780	9717	1842	
South (MW)	5323	7163	1642	
West (MW)	706	1069	92	

Note: Unit-level marginal costs in the first panel are calculated by a sum of marginal fuel costs and variable operation and management costs. The unit-level marginal fuel costs are based on a heat rate of each unit multiplied by monthly fuel prices for each technology in a zone. An average zonal generation in the second panel is an average over a sum of all units' hourly nodal generation within a zone by technology. Total generation capacity in parentheses is based on the maximum generation by technology in a zone during our data period. In the third panel, the hourly capacity in operation is a sum of unit capacity that has generated more than 0 MWh at an hour interval. All data span June 30, 2011 through February 16, 2018.

Table 3: Dynamic Constraints by Technology

Variables	**Coal**	**Gas-CC**	**Gas-ST**	**Gas-Turbine**
Avg. Capacity per Power Plant (MW)	1184	661	539	173
Avg. Capacity per Unit (MW)	621	150	210	66
Avg. Startup Costs ($/MW)	142.11	78.32	63.51	47.78
Avg. Startup Delay (Hours)	11.2	1.1	5.1	1.1
On (%)	72.5	58.9	14.0	18.0
On and P<MC (%)	31.8	47.4	12.1	16.4

Note: This table reports generator specifications that are related to dynamic production constraints of fossil fuel units. An average startup delay and nameplate capacity for a unit and a power plant are based on Form EIA-860 data from 2013 to 2017. Startup costs are based on bidding data from daily 60-Day Security-Constrained Economic Dispatch (SCED) Disclosure Reports by ERCOT. Operating percentage by technology and market conditions are author's calculations based on hourly nodal generation and price data from ERCOT. On (%) denotes a percentage of time that a unit has generated more than 0 MWh.

Table 4: Clustering by DBSCAN

	Uniform	Low West	High West	High Houston	Low South	High South	Outliers
Fraction of Hours	35.4%	16.6%	14.0%	10.5%	9.8%	8.4%	5.3%
Houston ($/MWh)	25.67	21.54	36.30	43.44	30.11	32.04	45.73
North ($/MWh)	25.67	21.94	36.90	25.16	30.55	31.52	48.98
South ($/MWh)	25.67	20.98	36.85	32.41	28.21	53.53	45.65
West ($/MWh)	25.67	14.01	67.83	26.01	30.60	32.22	47.72

Note: This table summarizes DBSCAN results for zonal price data from 2011 to 2018. A fraction of hours is calculated by the total number of hours that each market class has happened divided by the total hours in data (58,176). The prices for each class are average zonal prices.

Table 5: Marginal Effects of West Wind on Market Conditions

Variables	(1) Uniform	(2) Low West	(3) High West	(4) High Houston	(5) Low South	(6) High South
CREZ = 20%	-0.0850***	0.219***	-0.0884***	0.00881	-0.0259***	-0.0179**
	(0.0126)	(0.0224)	(0.0150)	(0.0104)	(0.00443)	(0.00896)
CREZ = 40%	-0.0687***	0.150***	-0.0563***	0.0191**	-0.0302***	-0.00773
	(0.00960)	(0.0127)	(0.00915)	(0.00882)	(0.00348)	(0.00595)
CREZ = 60%	-0.0500***	0.0919***	-0.0342***	0.0280***	-0.0317***	-0.00109
	(0.00753)	(0.00737)	(0.00555)	(0.00650)	(0.00319)	(0.00417)
CREZ = 80%	-0.0343***	0.0496***	-0.0202***	0.0344***	-0.0304***	0.00229
	(0.00628)	(0.00565)	(0.00360)	(0.00447)	(0.00387)	(0.00316)
CREZ = 100%	-0.0242***	0.0228***	-0.0118***	0.0377***	-0.0267***	0.00333
	(0.00641)	(0.00428)	(0.00277)	(0.00502)	(0.00504)	(0.00284)

Note: This table shows average marginal impacts of 1GWh West wind generation on a probability of being in a market condition classified by DBSCAN. For examples, -0.0850 in the first row of column (1) denotes 8.5% decrease in probability. All values are estimated at an average wind generation level and different levels of CREZ specified in the first column in the table. Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table 6: Marginal Effects of West Wind on Market Conditions under Different Conditions

Variables	(1) Uniform	(2) Low West	(3) High West	(4) High Houston	(5) Low South	(6) High South
Wind at 25^{th} Percentile						
CREZ = 20%	0.0565***	0.0218***	-0.120***	0.0241***	-0.0193***	0.0303***
	(0.0115)	(0.00516)	(0.0155)	(0.00454)	(0.00537)	(0.00660)
CREZ = 60%	0.0505***	0.0150***	-0.0819***	0.0253***	-0.0269***	0.0183***
	(0.00834)	(0.00174)	(0.0105)	(0.00268)	(0.00553)	(0.00419)
CREZ = 100%	0.0393***	0.00435*	-0.0439***	0.0238***	-0.0279***	0.00948***
	(0.00899)	(0.00247)	(0.00868)	(0.00375)	(0.00802)	(0.00304)
Wind at 50^{th} Percentile						
CREZ = 20%	-0.0465***	0.145***	-0.0873***	0.0201**	-0.0260***	-0.00172
	(0.0118)	(0.0168)	(0.0147)	(0.00994)	(0.00451)	(0.00844)
CREZ = 60%	-0.0252***	0.0621***	-0.0390***	0.0308***	-0.0314***	0.00423
	(0.00664)	(0.00524)	(0.00564)	(0.00547)	(0.00333)	(0.00398)
CREZ = 100%	-0.0113*	0.0164***	-0.0155***	0.0351***	-0.0275***	0.00444*
	(0.00628)	(0.00337)	(0.00310)	(0.00478)	(0.00515)	(0.00268)
Wind at 75^{th} Percentile						
CREZ = 20%	-0.0961***	0.284***	-0.0660***	-0.0364***	-0.0109***	-0.0500***
	(0.0123)	(0.0161)	(0.0148)	(0.00680)	(0.00261)	(0.00805)
CREZ = 60%	-0.121***	0.226***	-0.0315***	-0.00751	-0.0291***	-0.0239***
	(0.00821)	(0.0157)	(0.00433)	(0.00718)	(0.00255)	(0.00379)
CREZ = 100%	-0.0651***	0.0614***	-0.00629***	0.0375***	-0.0264***	-0.000765
	(0.00772)	(0.00984)	(0.00240)	(0.00662)	(0.00445)	(0.00295)

Note: This table reports marginal effects of 1 GWh West wind generation increase on a probability of being in a market condition classified by DBSCAN. For examples, -0.0565 in the first row of column (1) denotes 5.65% decrease in probability. All values are estimated at each quartile of wind generation ($Q_1 = 1.3GWh, Q_2 = 3GWh, Q_3 = 5.1GWh$) with different levels of CREZ developments specified in the first column of the table. Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table 7: Marginal Effects of West Wind Generation on Production Costs

Variables	(1) Total	(2) Houston	(3) North	(4) South	(5) West
CREZ = 20%	-32.13***	-10.19***	-11.21***	-6.623***	-4.108***
	(3.117)	(1.618)	(1.065)	(0.796)	(0.254)
CREZ = 40%	-31.40***	-9.180***	-11.97***	-6.643***	-3.603***
	(2.211)	(1.168)	(0.807)	(0.567)	(0.195)
CREZ = 60%	-30.66***	-8.168***	-12.73***	-6.664***	-3.099***
	(1.402)	(0.777)	(0.610)	(0.368)	(0.156)
CREZ = 80%	-29.93***	-7.156***	-13.50***	-6.684***	-2.594***
	(0.975)	(0.583)	(0.543)	(0.275)	(0.152)
CREZ = 100%	-29.20***	-6.144***	-14.26***	-6.704***	-2.090***
	(1.357)	(0.755)	(0.649)	(0.377)	(0.187)

Note: This table shows how additional West wind generation (1MWh) changed market-wide and zonal hourly production costs of electricity ($). Results in each column are estimated by an individual regression with the same regressors. All values are estimated at an average West wind generation level and different levels of CREZ specified in the first column in the table. Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table 8: Marginal Effects of West Wind Generation on Production Costs under Different Conditions

	(1)	(2)	(3)	(4)	(5)
Variables	Total	Houston	North	South	West
Wind at 25^{th} Percentile					
CREZ = 20%	-40.90***	-13.50***	-13.13***	-10.07***	-4.200***
	(3.899)	(1.951)	(1.206)	(0.921)	(0.392)
CREZ = 60%	-39.43***	-11.47***	-14.66***	-10.11***	-3.191***
	(2.892)	(1.247)	(1.122)	(0.790)	(0.342)
CREZ = 100%	-37.97***	-9.450***	-16.19***	-10.15***	-2.182***
	(3.025)	(1.132)	(1.368)	(0.951)	(0.362)
Wind at 50^{th} Percentile					
CREZ = 20%	-33.77***	-10.90***	-11.52***	-7.221***	-4.121***
	(3.086)	(1.635)	(0.975)	(0.755)	(0.253)
CREZ = 60%	-32.30***	-8.879***	-13.05***	-7.261***	-3.112***
	(1.425)	(0.798)	(0.546)	(0.354)	(0.160)
CREZ = 100%	-30.84***	-6.855***	-14.58***	-7.301***	-2.103***
	(1.471)	(0.762)	(0.676)	(0.432)	(0.195)
Wind at 75^{th} Percentile					
CREZ = 20%	-28.06***	-7.965***	-10.64***	-5.360***	-4.094***
	(3.524)	(1.659)	(1.399)	(0.971)	(0.300)
CREZ = 60%	-26.59***	-5.942***	-12.16***	-5.400***	-3.085***
	(1.897)	(0.820)	(0.946)	(0.545)	(0.198)
CREZ = 100%	-25.13***	-3.918***	-13.69***	-5.441***	-2.076***
	(1.550)	(0.756)	(0.803)	(0.396)	(0.199)

Note: This table reports how additional wind generation (1MWh) affects production costs of electricity. Results in each column are estimated by an individual regression with the same regressors. All values are estimated at each quartile of wind generation ($Q_1 = 1.3GWh, Q_2 = 3GWh, Q_3 = 5.1GWh$) with different levels of CREZ developments specified in the first column of the table. Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table 9: Marginal Effects of West Wind Generation on Ratio (Fossil Units)

Variables	(1) Houston	(2) North	(3) South	(4) West
CREZ = 20%	-0.0233***	-0.0314***	-0.0256***	-0.0442***
	(0.00158)	(0.00165)	(0.00173)	(0.00279)
CREZ = 40%	-0.0221***	-0.0325***	-0.0255***	-0.0375***
	(0.00137)	(0.00139)	(0.00152)	(0.00231)
CREZ = 60%	-0.0209***	-0.0336***	-0.0253***	-0.0309***
	(0.00128)	(0.00125)	(0.00148)	(0.00204)
CREZ = 80%	-0.0197***	-0.0348***	-0.0252***	-0.0243***
	(0.00135)	(0.00125)	(0.00164)	(0.00206)
CREZ = 100%	-0.0185***	-0.0359***	-0.0250***	-0.0177***
	(0.00155)	(0.00142)	(0.00193)	(0.00238)

Note: This table shows average marginal effects of a West wind generation increase (1GWh) on the ratio, $\frac{ZonalGeneration}{ZonalDemand}$. Zonal generation is aggregated over all types of fossil fuel generators. Results in each column are estimated by an individual regression with the same regressors. All values are estimated at an average wind generation level and different levels of CREZ specified in the first column in the table. Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table 10: Marginal Effects of West Wind Generation on Ratio (Fossil Units) under Different Conditions

	(1)	(2)	(3)	(4)
Variables	Houston	North	South	West
Wind at 25^{th} Percentile				
CREZ = 20%	-0.0234***	-0.0265***	-0.0247***	-0.0377***
	(0.00221)	(0.00222)	(0.00243)	(0.00356)
CREZ = 60%	-0.0210***	-0.0288***	-0.0244***	-0.0244***
	(0.00197)	(0.00204)	(0.00236)	(0.00327)
CREZ = 100%	-0.0186***	-0.0311***	-0.0241***	-0.0112***
	(0.00211)	(0.00224)	(0.00275)	(0.00372)
Wind at 50^{th} Percentile				
CREZ = 20%	-0.0234***	-0.0304***	-0.0254***	-0.0430***
	(0.00156)	(0.00161)	(0.00168)	(0.00268)
CREZ = 60%	-0.0210***	-0.0327***	-0.0251***	-0.0298***
	(0.00126)	(0.00123)	(0.00147)	(0.00196)
CREZ = 100%	-0.0186***	-0.0349***	-0.0248***	-0.0166***
	(0.00153)	(0.00144)	(0.00196)	(0.00239)
Wind at 75^{th} Percentile				
CREZ = 20%	-0.0224***	-0.0355***	-0.0264***	-0.0481***
	(0.00173)	(0.00189)	(0.00209)	(0.00339)
CREZ = 60%	-0.0200***	-0.0378***	-0.0261***	-0.0349***
	(0.00142)	(0.00138)	(0.00166)	(0.00255)
CREZ = 100%	-0.0177***	-0.0400***	-0.0258***	-0.0217***
	(0.00163)	(0.00137)	(0.00187)	(0.00257)

Note: This table shows average marginal effects of a West wind generation increase on the ratio, $\frac{ZonalGeneration}{ZonalDemand}$. Zonal generation is aggregated over all types of fossil fuel generators. Results in each column are estimated by an individual regression with the same regressors. All values are estimated at each quartile of wind generation ($Q_1 = 1.3GWh, Q_2 = 3GWh, Q_3 = 5.1GWh$) with different levels of CREZ developments specified in the first column of the table. Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table 11: Marginal Effects of West Wind Generation on Capacity in Operation

	(1)	(2)	(3)
Variables	Coal	NGCC	Other NG Units
Houston			
CREZ = 20%	0.203	-69.35***	-39.16**
	(14.28)	(11.09)	(14.92)
CREZ = 60%	0.673	-55.82***	-22.50**
	(8.942)	(6.468)	(8.827)
CREZ = 100%	1.143	-42.30***	-5.834
	(7.671)	(7.051)	(9.858)
North			
CREZ = 20%	-38.39	-79.77*	-116.5***
	(28.62)	(43.13)	(25.26)
CREZ = 60%	-17.56	-129.2***	-83.50***
	(22.45)	(26.70)	(13.12)
CREZ = 100%	3.266	-178.6***	-50.50***
	(25.17)	(25.53)	(13.48)
South			
CREZ = 20%	66.60***	-41.85*	-55.34***
	(16.85)	(21.38)	(19.62)
CREZ = 60%	44.29***	-53.54***	-53.22***
	(12.64)	(12.92)	(10.76)
CREZ = 100%	21.98*	-65.23***	-51.10***
	(13.07)	(13.39)	(10.97)
West			
CREZ = 20%	14.18*	-113.7***	-28.88***
	(8.331)	(10.60)	(4.564)
CREZ = 60%	1.232	-76.64***	-19.28***
	(5.909)	(6.496)	(2.466)
CREZ = 100%	-11.72**	-39.57***	-9.677***
	(5.852)	(6.239)	(2.310)

Note: This table indicates impacts of West wind generation (1GWh) onto a fossil fuel unit capacity in operation by hour. Results in each column are estimated by an individual regression with the same regressors. All values are estimated at an average wind generation level and different levels of CREZ specified in the first column in the table. Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Figures

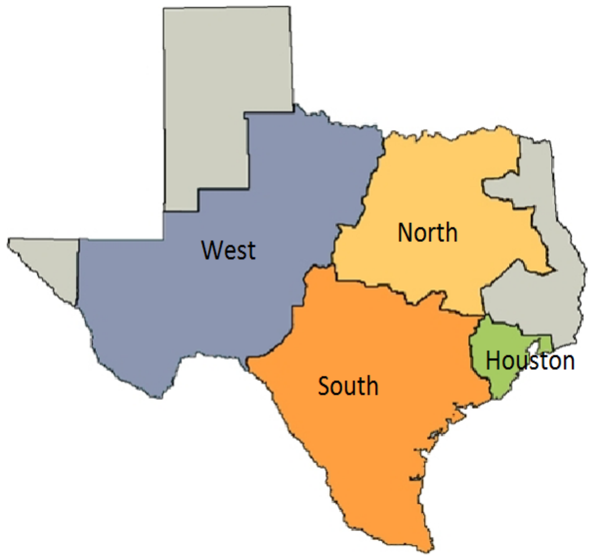


Figure 1: ERCOT Load Zones

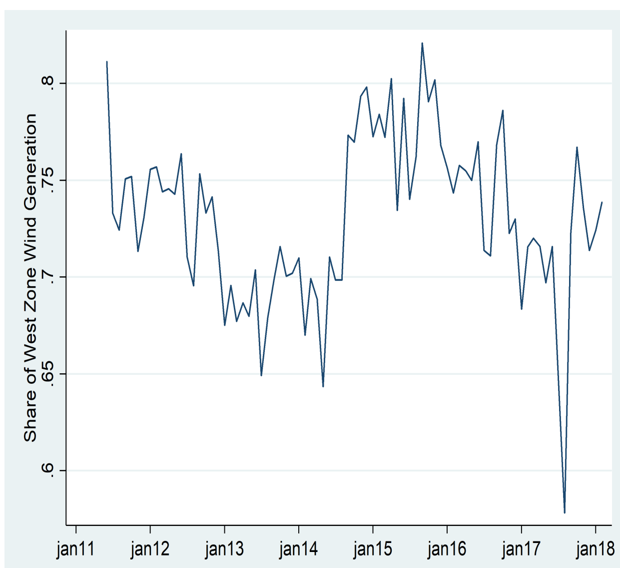
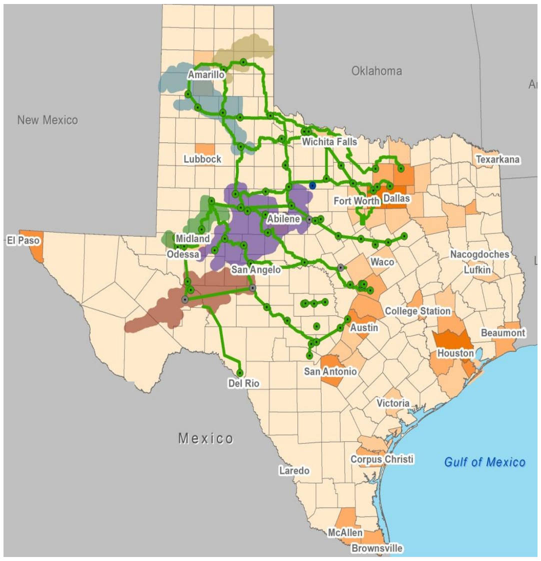
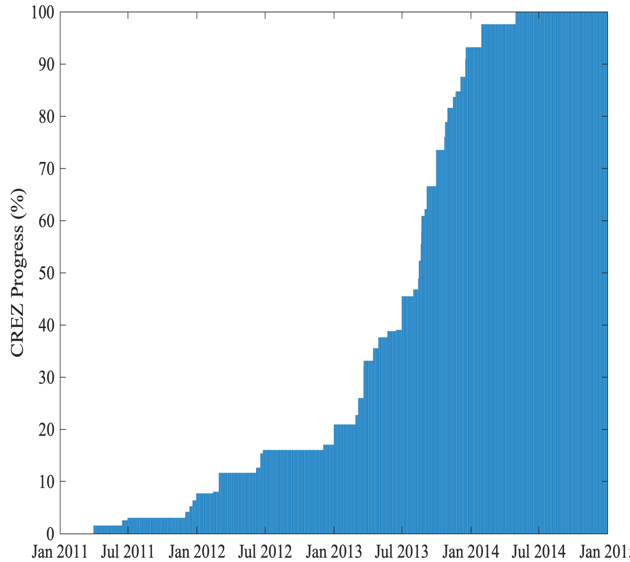


Figure 2: Share of Wind Generation from West Zone



(a) CREZ Transmission Lines



(b) CREZ Completion

Figure 3: Load Zones and CREZ Project in Texas Electricity Market

Note: Panel (a) shows the locations of transmission line buildouts by CREZ. Panel (b) indicates a timeline of CREZ progress.

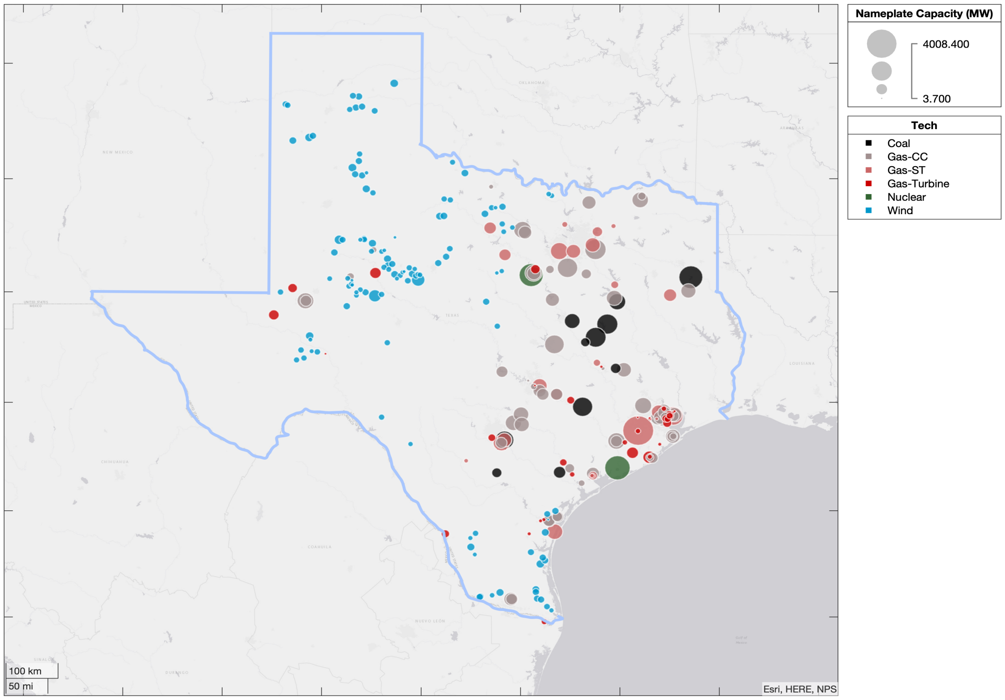


Figure 4: Geographic Locations of Generators in ERCOT

Note: This figure plots geographic locations of generators in ERCOT. A unit capacity, denoted as a different size of bubbles, is based on ERCOT capacity report in January of 2018. Each color of the bubbles denotes different types of technology. See the text for details.

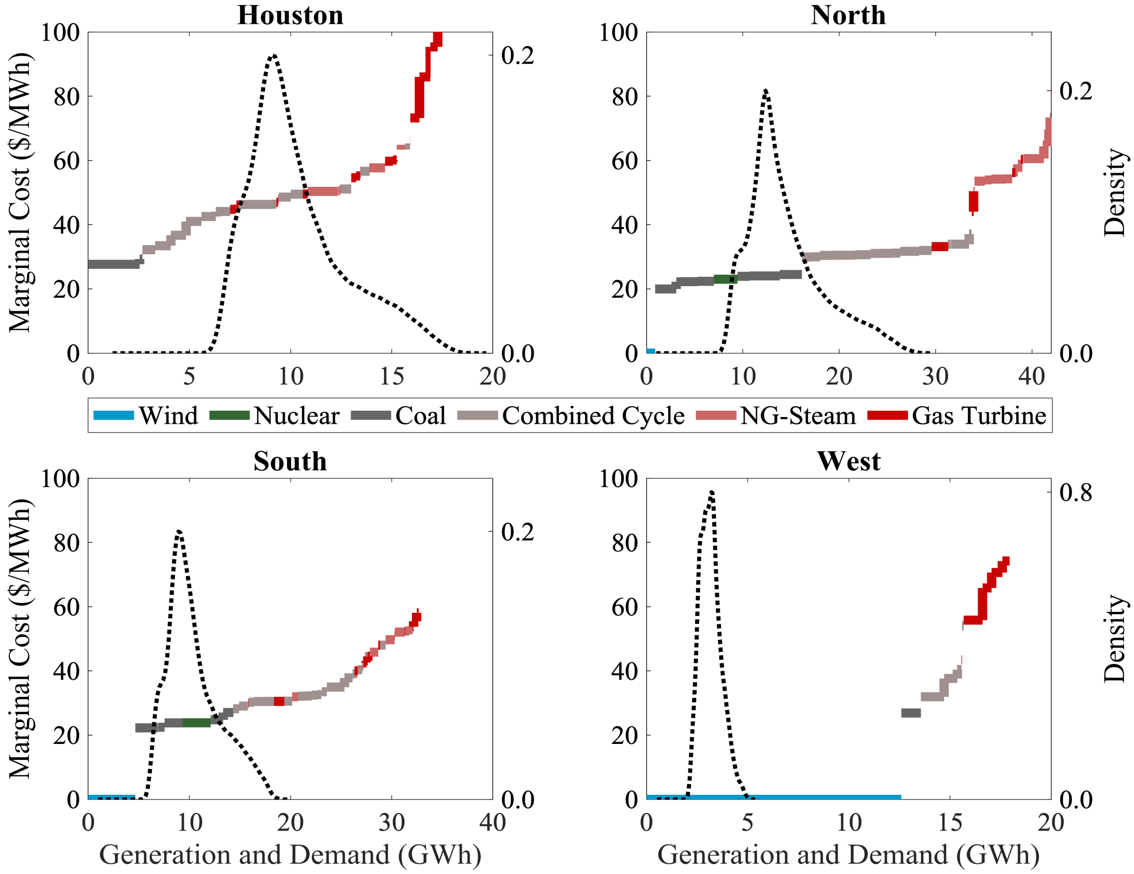
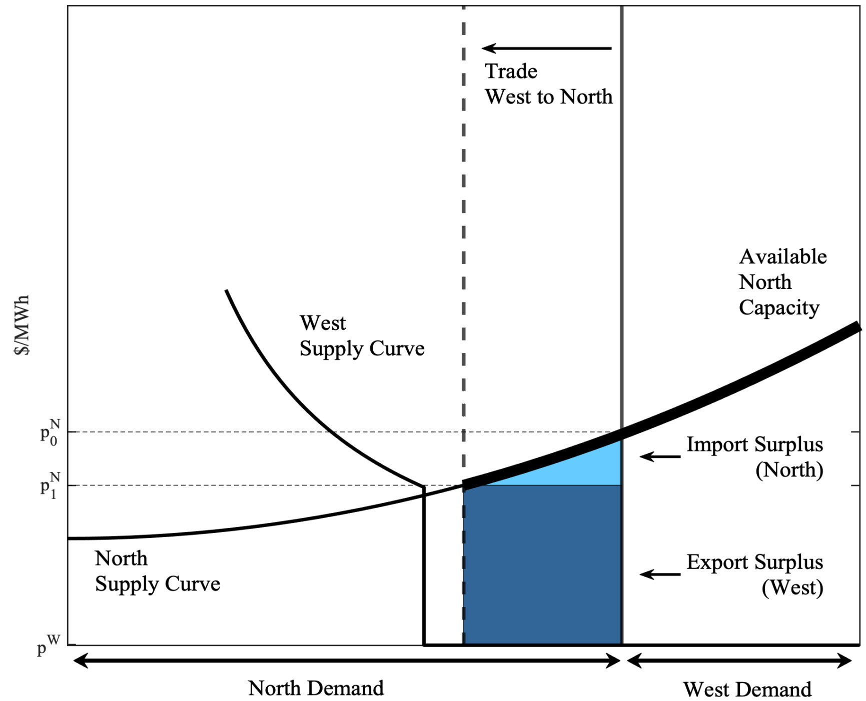
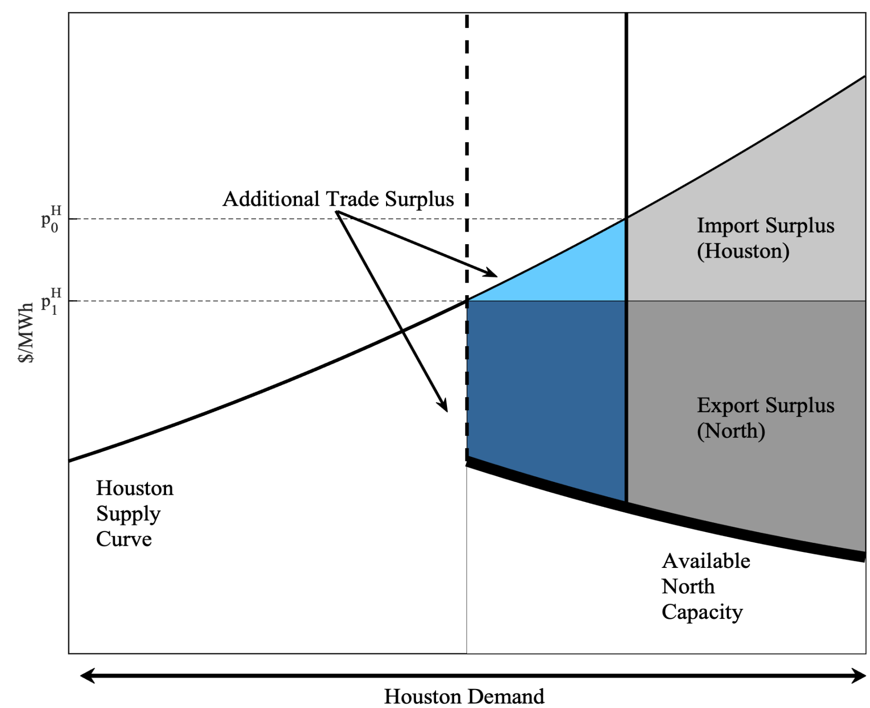


Figure 5: Generating Capacity and Demand Distribution

Note: Each figure in four panels indicates a zonal supply curve based on a unit-level generating capacity and an average marginal cost of each unit calculated by the authors. See the text for individual color notation for different type of technology. Dotted line indicates a kernel density of zonal demand from 2011 to 2018. The left side of vertical axis denotes marginal cost ($/MWh) and the right indicates density (0-1). The scaliling of horizonal axis and the right vertical axis differs across regions, reflecting heterogeneous zonal generation capacity and zonal demand clusters.



(a) Gains from Trade between West and North



(b) Gains from Trade between North and Houston

Figure 6: Production Cost Changes from Trades in Electricity Markets

Note: Without dynamic constraints of conventional generators, additional trades between West and North, driven by either additional wind generation from West or additional electricity flows by CREZ, can create additional social benefits for all regions. Figure (a) shows how the increased surplus from trades between West and North can be realized. Figure (b) shows how the additional operating capacity in North can meet more demand in Houston and create additional benefits to North and Houston.

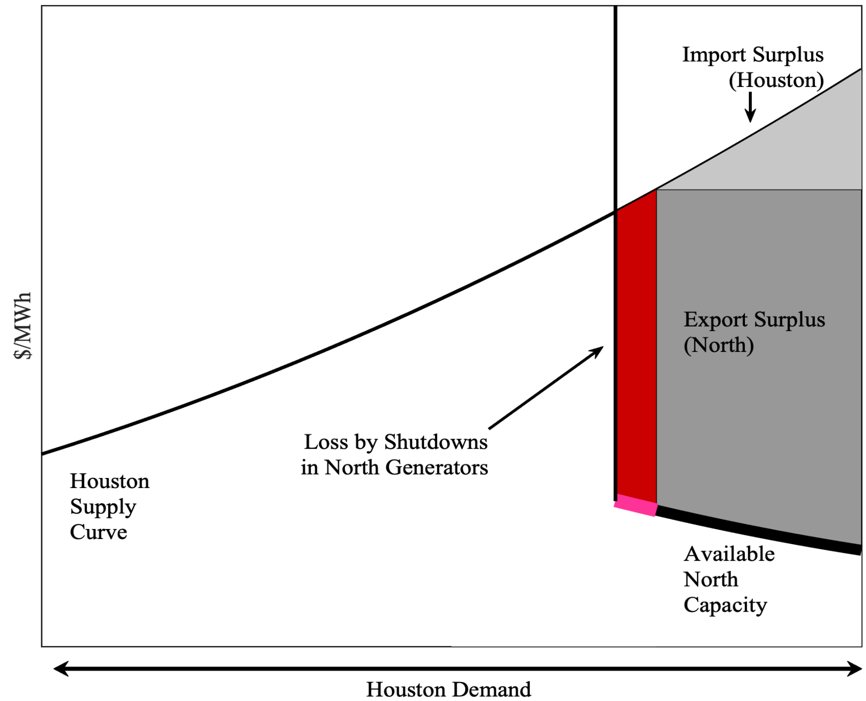


Figure 7: Possible Production Cost Increase by Shutdown of North Generators

Note: This figure shows possible loss to Houston, if some of low cost generating units in North shutdown, possibly caused by an increase in intermittent wind generation in West and additional flows of the generation from West to North by CREZ. If the additional imports from West to North lead to shutdowns of generators in North because of dynamic constraints of North generators and transmission constraints in North, the impacts of trade between West and North on Houston should be obscure.

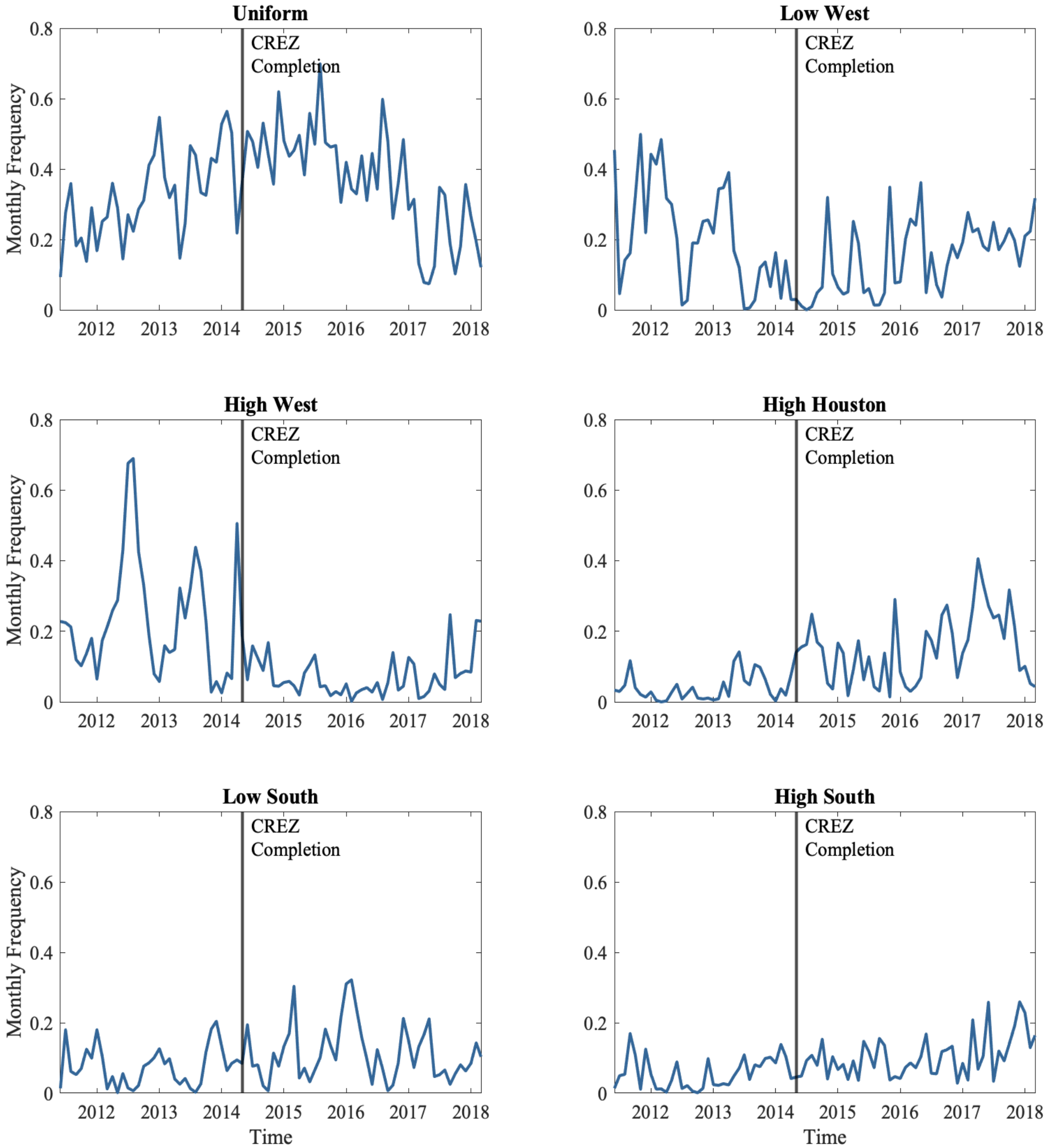


Figure 8: Time Trend of Market Conditions by DBSCAN Clustering

Note: Each panel shows a fraction of hours in a month for each of six different classes, which have been classified by DBSCAN method. CREZ has been completed by the end of April, 2014.

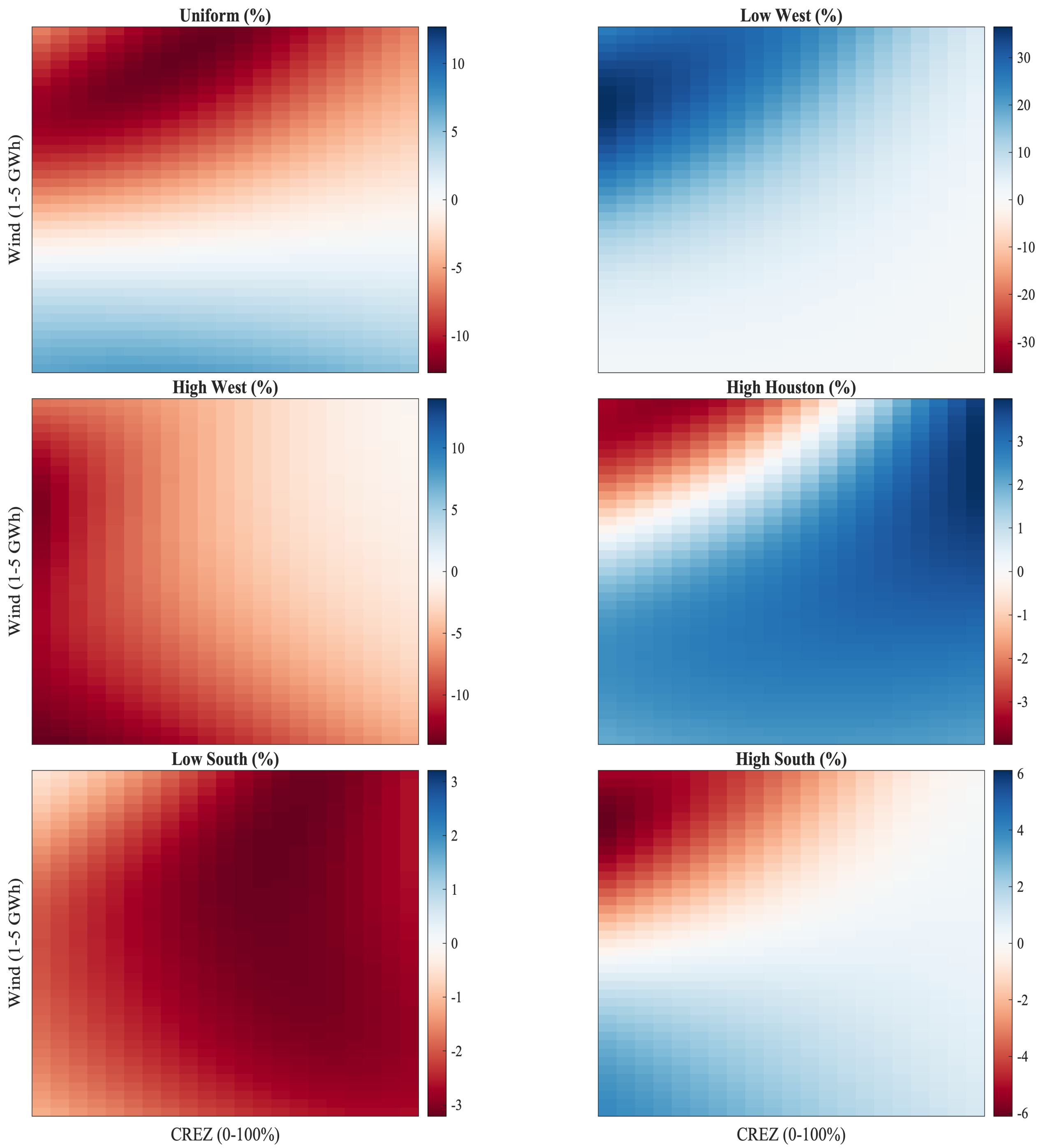


Figure 9: Average Marginal Impacts of West Wind Generation on Market Conditions

Note: These figures paint marginal effects of 1 GWh West wind generation increase on a probability of being in each of six market conditions, classified by DBSCAN. The effects are estimated at grid points, each of which denotes different levels of West wind generation and CREZ values. Wind value escalates in 100 MWh increments from 1GWh to 5 GWh in the y-axis and CREZ increases by 5% from 0 to 100% in the x-axis. The impacts are painted by different colors. Red color is for negative values and blue is for positive impacts. The scaliling of the colorbars denoting the magnitudes of the impacts differs across market conditions.

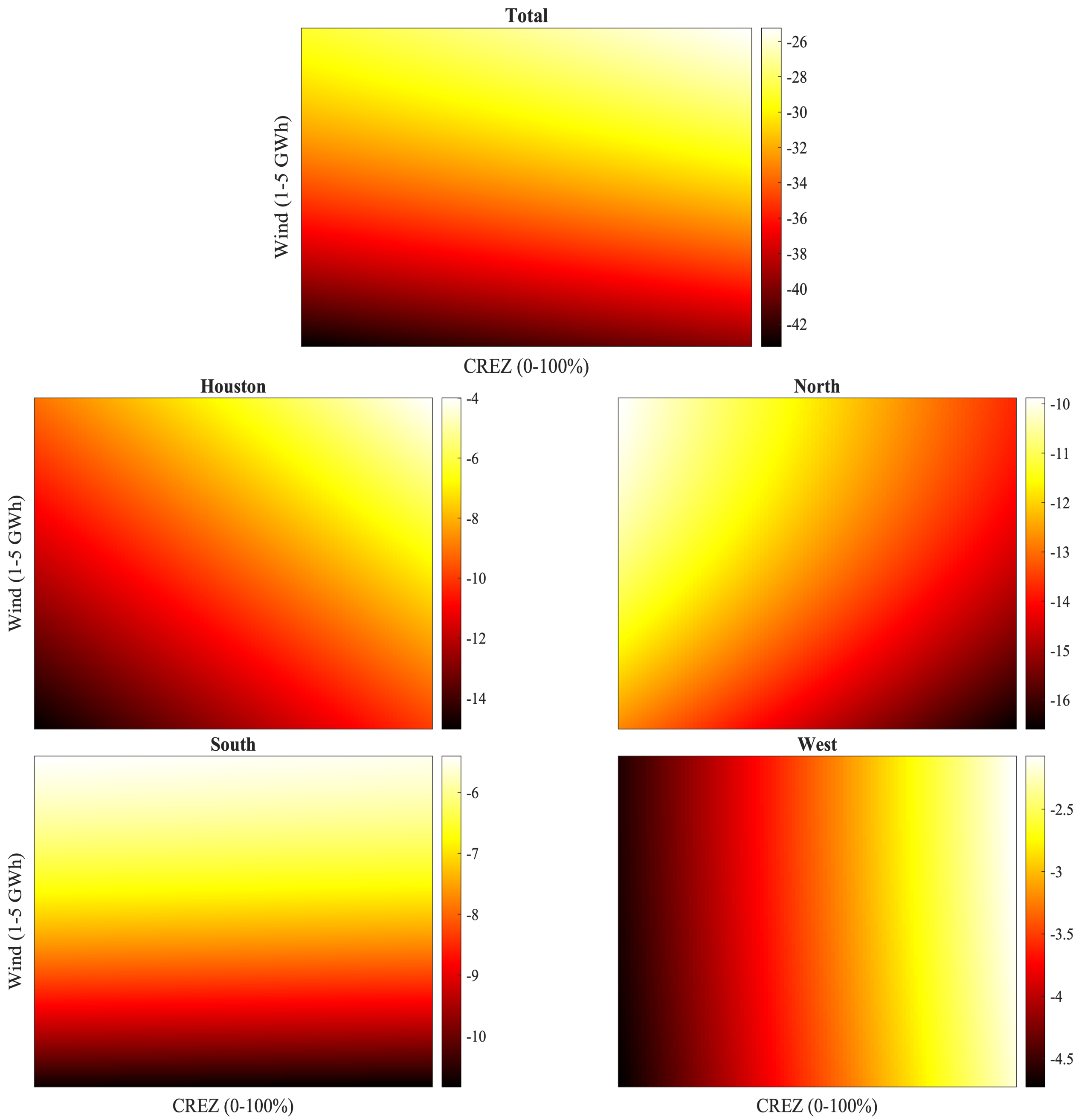


Figure 10: Average Marginal Impacts of West Wind Generation on Production Costs

Note: These figure plot how 1 MWh increase in wind generation in West affects production costs of electricity in ERCOT. The effects are estimated at grid points, each of which denotes different levels of West wind generation and CREZ values. Wind value escalates in 10 MWh increments from 1GWh to 5 GWh in the y-axis and CREZ increases by 1% from 0 to 100% in the x-axis. The impacts are painted by different colors. Darker red color denotes more negative impacts and lighter yellow denotes less impacts. The scaliling of the colorbars denoting the magnitudes of the impacts differs across load zones.

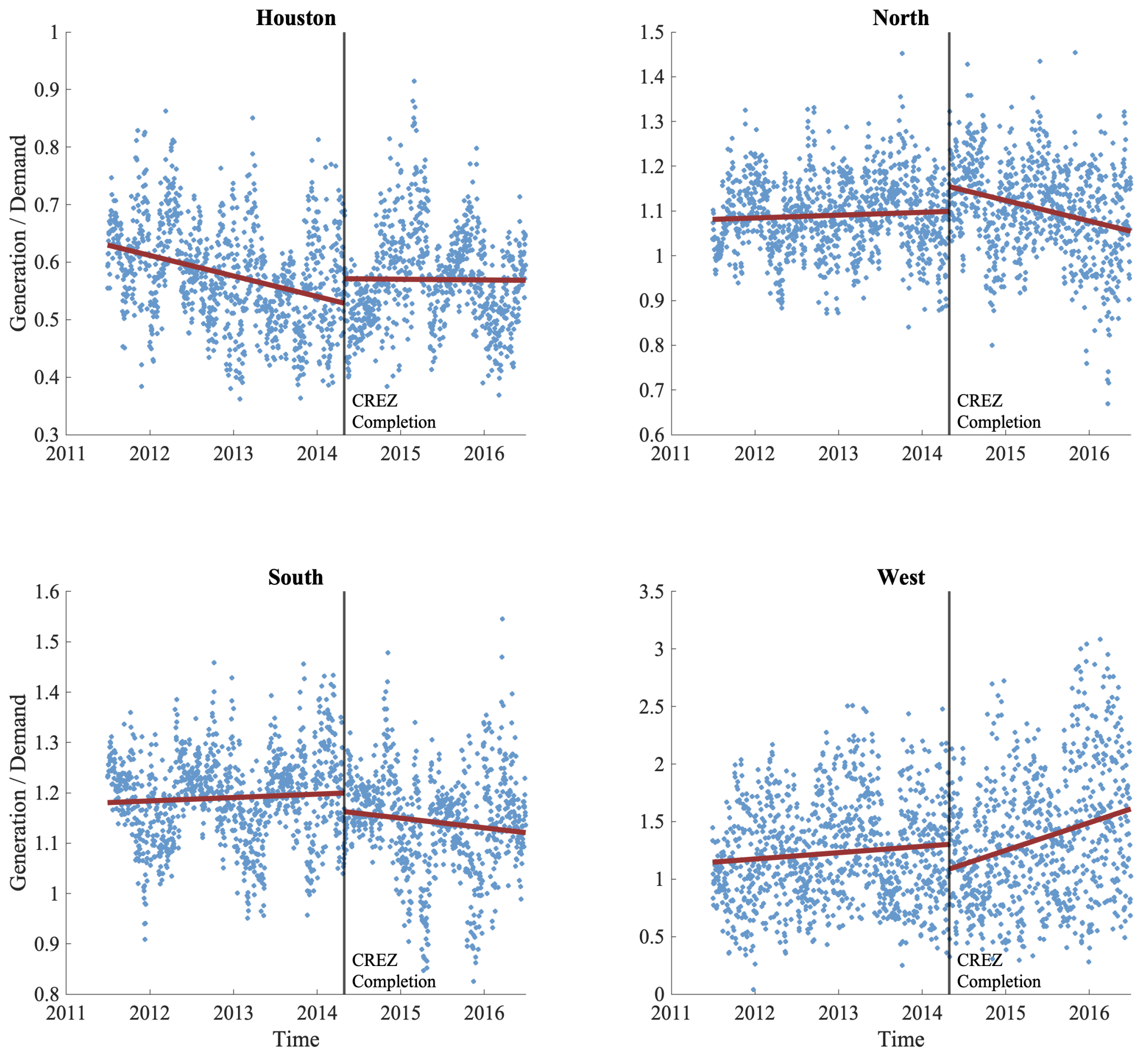


Figure 11: Ratio of Total Zonal Generation to Demand

Note: Four panels show a time trend of the ratio, $\frac{ZonalGeneration}{ZonalDemand}$, before and after CREZ completion. Zonal generation is aggregated over all types generators. CREZ has been completed by the end of April, 2014. Dotted points denote daily average of the ratio and a red reference line shows a regression result of the daily values over an uniformly increasing time variable before and after the CREZ completion. The scailing of y-axis differs across regions.

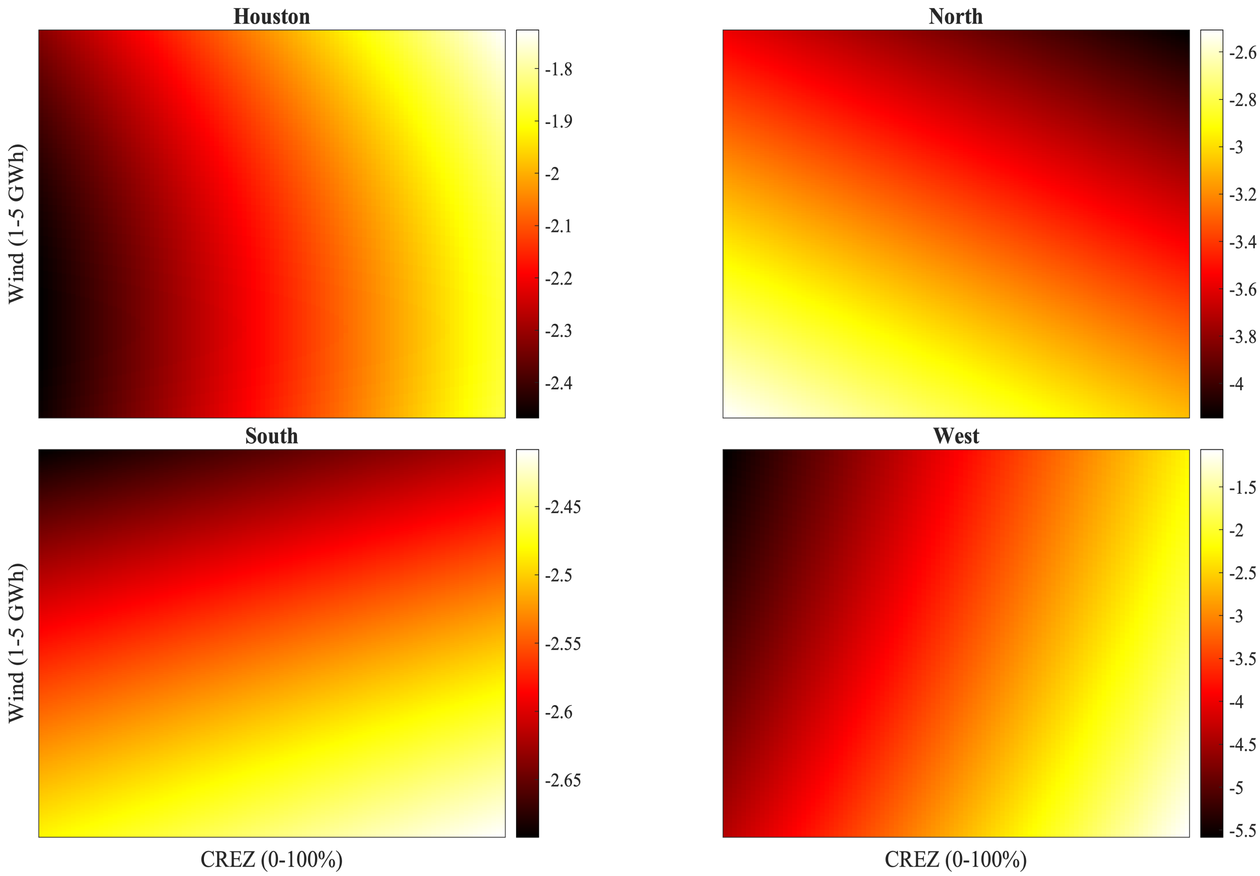


Figure 12: Average Marginal Impacts of West Wind Generation on Ratio (Fossil Units)

Note: These figures paint average marginal impacts of wind generation (1 GWh) on the ratio, $\frac{ZonalGeneration}{ZonalDemand}$. The zonal generation is aggregated over all types of fossil fuel generators in a zone. The effects are estimated at grid points, each of which denotes different levels of West wind generation and CREZ values. Wind value escalates in 10 MWh increments from 1GWh to 5 GWh in the y-axis and CREZ increases by 1% from 0 to 100% in the x-axis. The impacts are painted by different colors. Darker red color denotes more negative impacts and lighter yellow denotes less impacts. The scaliling of the colorbars denoting the magnitudes of the impacts differs across load zones.

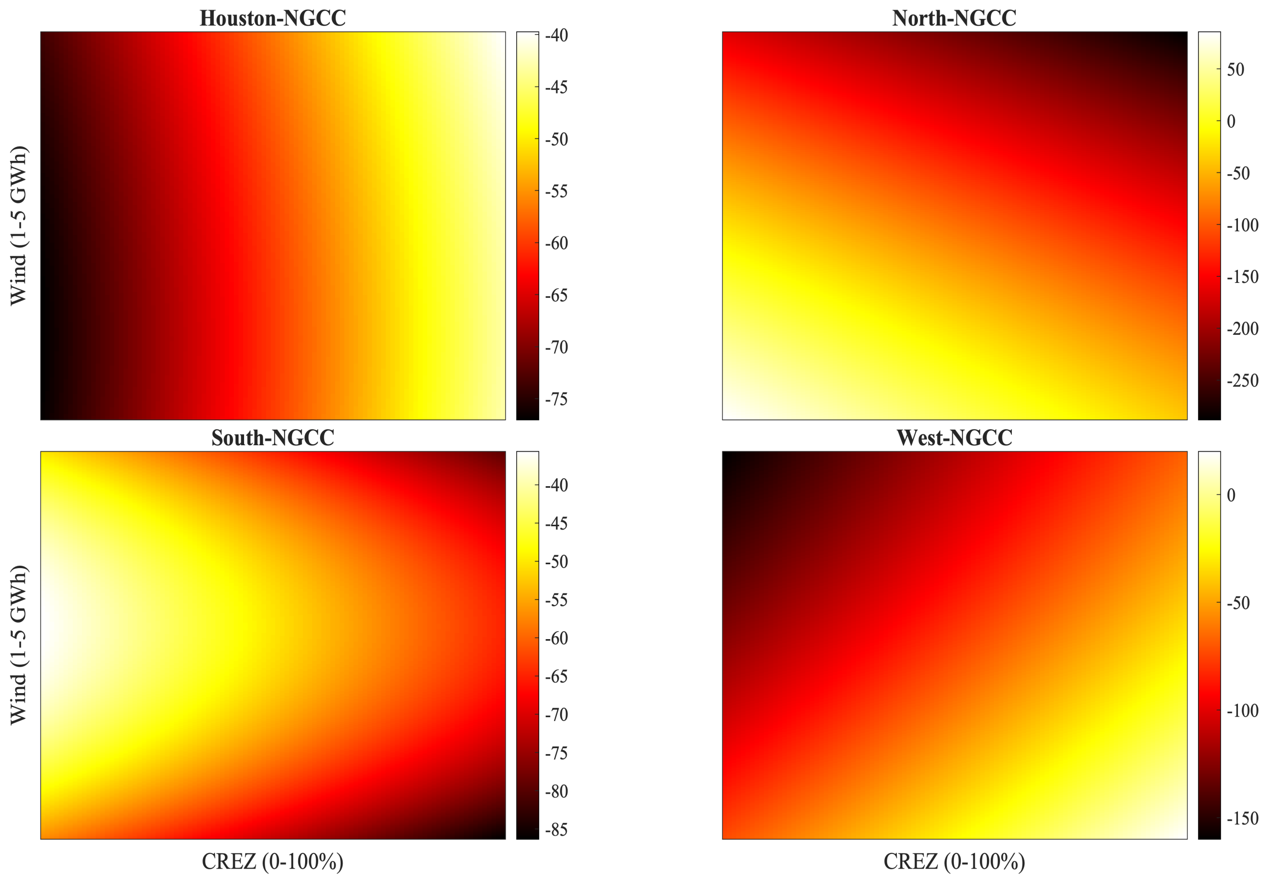


Figure 13: Average Marginal Impacts of West Wind Generation on Capacity in Operation

Note: These figures plot average marginal impacts of 1 GWh West wind generation increase on hourly operating capacity of combined cycle units. The effects are estimated at grid points, each of which denotes different levels of West wind generation and CREZ values. Wind value escalates in 10 MWh increments from 1GWh to 5 GWh in the y-axis and CREZ increases by 1% from 0 to 100% in the x-axis. The impacts are painted by different colors. Darker red color denotes more negative impacts and lighter yellow denotes less impacts. The scaliling of the colorbars denoting the magnitudes of the impacts differs across load zones.

Appendices

Table S1: Marginal Effects on Market Conditions

VARIABLES	(1) Uniform	(2) Low West	(3) High West	(4) High Houston	(5) Low South	(6) High South	(7) Outliers
Percent	0.301***	-0.369***	-0.185***	0.0975**	0.193***	-0.0280	-0.00893
	(0.0458)	(0.0336)	(0.0461)	(0.0446)	(0.0286)	(0.0224)	(0.0184)
wdGWw	-0.0192***	0.0753***	-0.0531***	0.0215***	-0.0249***	0.00473**	-0.00425*
	(0.00466)	(0.00243)	(0.00492)	(0.00250)	(0.00245)	(0.00205)	(0.00239)
wdGWs	-0.0652***	-0.000862	0.0315***	-0.0354***	0.119***	-0.0557***	0.00699
	(0.0139)	(0.00749)	(0.00743)	(0.00955)	(0.00773)	(0.00845)	(0.00707)
wdGWn	-0.0822**	-0.116***	0.186***	-0.0282	0.0354	0.0418**	-0.0366**
	(0.0418)	(0.0290)	(0.0402)	(0.0218)	(0.0268)	(0.0176)	(0.0163)
solarGW	-0.335***	0.344***	-0.0876	0.0739**	0.00262	-0.0206	0.0220
	(0.0853)	(0.0792)	(0.0738)	(0.0315)	(0.0443)	(0.0309)	(0.0238)
NUC_S	1.95e-05	5.18e-06	-1.62e-05	-4.63e-05***	7.65e-06	2.36e-05**	6.56e-06
	(1.63e-05)	(1.11e-05)	(1.37e-05)	(1.35e-05)	(8.64e-06)	(1.07e-05)	(5.85e-06)
NUC_N	1.95e-05	-2.57e-05	1.57e-05	-2.83e-06	-2.04e-05*	1.52e-05*	-1.39e-06
	(2.29e-05)	(1.62e-05)	(2.44e-05)	(1.29e-05)	(1.14e-05)	(8.88e-06)	(7.12e-06)
COAST	-4.05e-05***	-6.39e-07	-7.09e-06	6.95e-05***	-7.90e-07	-2.05e-05***	1.23e-07
	(9.94e-06)	(7.78e-06)	(8.25e-06)	(6.07e-06)	(6.82e-06)	(4.94e-06)	(3.91e-06)
EAST	-0.000117	-8.07e-06	5.11e-05	6.38e-05	1.88e-05	-3.62e-05	2.75e-05
	(7.37e-05)	(5.76e-05)	(6.64e-05)	(4.63e-05)	(5.05e-05)	(5.61e-05)	(3.25e-05)
FAR_WEST	2.50e-05	-4.94e-05	8.38e-05	3.24e-05	-0.000198***	0.000125***	-1.87e-05
	(6.18e-05)	(3.57e-05)	(5.70e-05)	(3.11e-05)	(3.94e-05)	(2.45e-05)	(2.38e-05)
NORTH	-0.000105	-0.000110	3.94e-05	-1.30e-05	0.000233*	-3.02e-05	-1.44e-05
	(0.000185)	(0.000127)	(0.000146)	(0.000102)	(0.000120)	(9.12e-05)	(5.41e-05)
NORTH_C	2.80e-05**	2.16e-05**	-1.47e-06	-4.45e-05***	-3.93e-06	-8.27e-06	8.55e-06*
	(1.17e-05)	(8.49e-06)	(8.16e-06)	(7.17e-06)	(6.98e-06)	(5.08e-06)	(4.58e-06)
SOUTHERN	2.99e-05	-3.73e-05**	-3.04e-05	2.65e-05	-0.000104***	0.000133***	-1.74e-05**
	(2.66e-05)	(1.82e-05)	(2.30e-05)	(1.69e-05)	(1.76e-05)	(1.26e-05)	(7.98e-06)
SOUTH_C	-4.30e-05**	2.98e-05**	-2.55e-05*	-1.61e-05	3.57e-05***	1.69e-05*	2.29e-06
	(1.95e-05)	(1.46e-05)	(1.45e-05)	(1.34e-05)	(9.96e-06)	(1.00e-05)	(5.63e-06)
WEST	-0.000270**	-0.000217***	0.000377***	-9.90e-06	0.000166**	-8.57e-05	3.85e-05
	(0.000130)	(7.42e-05)	(0.000100)	(7.95e-05)	(7.27e-05)	(7.32e-05)	(4.82e-05)
Coal_NG_P_ratio	0.0319	-0.627**	-0.000183	0.869***	-1.403***	0.651***	0.479***
	(0.418)	(0.267)	(0.471)	(0.291)	(0.269)	(0.139)	(0.136)
Observations	58,176	58,176	58,176	58,176	58,176	58,176	58,176

Note: Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table S2: Estimation of Production Costs

VARIABLES	(1) totalpc	(2) pc_houston	(3) pc_north	(4) pc_south	(5) pc_west
Percent	-36,429	-32,274**	15,501	-16,016*	-3,639
	(27,990)	(15,301)	(10,367)	(8,631)	(3,478)
wdMWw	-48.85***	-16.70***	-14.21***	-13.14***	-4.804***
	(6.244)	(2.985)	(2.167)	(1.567)	(0.686)
c.wdMWw#c.wdMWw	0.00300***	0.000852**	0.000792	0.00131***	4.35e-05
	(0.00102)	(0.000423)	(0.000483)	(0.000324)	(0.000130)
c.wdMWw#c.wdMWw#c.wdMWw	-1.34e-07**	-1.17e-08	-4.79e-08*	-7.15e-08***	-3.06e-09
	(5.68e-08)	(2.82e-08)	(2.75e-08)	(1.97e-08)	(7.84e-09)
wdMWs	-8.475	5.431	-12.13**	-5.321	3.546*
	(12.34)	(5.924)	(5.280)	(3.748)	(1.790)
c.wdMWs#c.wdMWs	-0.0149*	-0.0113***	0.00108	-0.00178	-0.00292**
	(0.00810)	(0.00415)	(0.00365)	(0.00258)	(0.00120)
c.wdMWs#c.wdMWs#c.wdMWs	2.50e-06*	2.34e-06***	-2.19e-07	-1.02e-08	3.86e-07
	(1.39e-06)	(7.72e-07)	(6.72e-07)	(4.67e-07)	(2.43e-07)
wdMWn	-44.73***	-8.649*	-18.96***	-16.64***	-0.488
	(8.938)	(4.999)	(5.244)	(3.666)	(1.871)
c.percent#c.wdMWw	3.661	5.059**	-3.819**	-0.101	2.523***
	(4.882)	(2.487)	(1.592)	(1.256)	(0.399)
solarMW	4.504	-5.615	-16.31	19.08**	7.350
	(28.50)	(15.46)	(12.17)	(8.207)	(4.576)
NUC_S	-33.70***	-9.376**	-14.49***	-8.767***	-1.070
	(5.004)	(3.586)	(2.221)	(2.347)	(0.985)
NUC_N	-41.79***	-10.57**	-20.95***	-9.371***	-0.897
	(8.224)	(4.711)	(5.399)	(2.412)	(1.185)
COAST	38.08***	21.18***	6.722***	10.19***	-0.00498
	(4.910)	(2.206)	(2.325)	(1.487)	(0.545)
EAST	38.73	0.557	18.15	6.552	13.47***
	(25.97)	(13.87)	(15.29)	(9.086)	(5.078)
FAR_WEST	44.12	3.274	35.26***	5.437	0.153
	(27.86)	(14.58)	(13.09)	(9.629)	(3.927)
NORTH	203.6**	134.0**	19.06	32.62	17.90**
	(101.2)	(61.85)	(28.06)	(29.53)	(7.998)
NORTH_C	25.21***	2.696	17.02***	4.649***	0.836*
	(4.431)	(2.542)	(1.757)	(1.388)	(0.473)
SOUTHERN	26.94*	-7.283	17.49***	13.14***	3.590**
	(14.68)	(6.443)	(6.530)	(4.486)	(1.549)
SOUTH_C	40.66***	14.44***	11.14***	13.32***	1.764
	(6.100)	(3.360)	(3.273)	(2.101)	(1.233)
WEST	44.28	12.06	0.520	27.28	4.413
	(49.23)	(27.09)	(22.40)	(16.59)	(6.111)
Coal_NG_P_ratio	3.387e+06***	936,041***	1.355e+06***	947,062***	148,443***
	(154,430)	(83,505)	(66,818)	(62,203)	(22,461)
Observations	58,176	58,176	58,176	58,176	58,176
R-squared	0.959	0.837	0.945	0.934	0.741

Note: Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table S3: Estimation of Ratio

VARIABLES	(1) Ratio_Houston	(2) Ratio_North	(3) Ratio_South	(4) Ratio_West
Percent	-0.0601**	0.0287	0.00402	0.0128
	(0.0259)	(0.0187)	(0.0254)	(0.0513)
wdGWw	-0.0241***	-0.0226***	-0.0244***	-0.0395***
	(0.00384)	(0.00391)	(0.00435)	(0.00618)
c.wdGWw#c.wdGWw	-0.000300	-0.00122	-0.000201	-0.00226
	(0.000915)	(0.000984)	(0.00109)	(0.00149)
c.wdGWw#c.wdGWw#c.wdGWw	5.22e-05	-1.29e-05	-6.80e-06	8.38e-05
	(7.05e-05)	(7.65e-05)	(8.30e-05)	(0.000105)
wdGWs	-0.0392***	-0.0653***	-0.0448**	0.0130
	(0.0121)	(0.0108)	(0.0171)	(0.0222)
c.wdGWs#c.wdGWs	0.0114	0.0241**	0.00777	-0.0190
	(0.0108)	(0.00923)	(0.0134)	(0.0193)
c.wdGWs#c.wdGWs#c.wdGWs	-0.00333	-0.00344	-0.000778	0.00319
	(0.00284)	(0.00242)	(0.00328)	(0.00514)
wdGWn	-0.0200	-0.0152	-0.0671***	0.0108
	(0.0165)	(0.0141)	(0.0208)	(0.0248)
c.percent#c.wdGWw	0.00592**	-0.00568**	0.000738	0.0331***
	(0.00223)	(0.00226)	(0.00271)	(0.00401)
solarGW	0.263	0.290	-1.999**	2.168*
	(1.020)	(0.719)	(0.955)	(1.255)
NUC_S	-2.63e-05***	-3.46e-05***	-2.67e-05***	-5.26e-06
	(7.09e-06)	(5.88e-06)	(8.76e-06)	(1.22e-05)
NUC_N	-3.12e-05***	-3.34e-05***	-3.13e-05***	-2.99e-06
	(1.02e-05)	(6.62e-06)	(1.02e-05)	(1.91e-05)
COAST	-3.17e-05***	2.13e-05***	2.25e-05***	1.49e-06
	(2.60e-06)	(2.57e-06)	(3.93e-06)	(4.37e-06)
EAST	9.89e-05***	1.24e-05	3.48e-05	9.93e-05***
	(2.33e-05)	(2.23e-05)	(2.93e-05)	(3.62e-05)
FAR_WEST	8.46e-05**	7.62e-05**	-5.27e-05	-0.000196***
	(3.86e-05)	(3.34e-05)	(4.08e-05)	(6.75e-05)
NORTH	6.74e-05	-3.26e-05	-2.57e-05	3.40e-05
	(7.27e-05)	(6.24e-05)	(6.55e-05)	(9.55e-05)
NORTH_C	1.03e-05***	-2.39e-05***	2.15e-05***	1.10e-05**
	(3.55e-06)	(3.27e-06)	(4.01e-06)	(4.72e-06)
SOUTHERN	2.07e-05***	4.84e-05***	-2.23e-05**	3.21e-05**
	(6.56e-06)	(6.50e-06)	(9.33e-06)	(1.22e-05)
SOUTH_C	1.90e-05***	-7.42e-06	-5.78e-05***	1.93e-05*
	(5.19e-06)	(5.36e-06)	(5.70e-06)	(1.05e-05)
WEST	2.58e-06	1.50e-05	9.17e-05	-5.33e-05
	(4.74e-05)	(5.00e-05)	(5.85e-05)	(7.57e-05)
Coal_NG_P_ratio	-0.673***	0.288*	0.0659	0.246
	(0.157)	(0.157)	(0.227)	(0.301)
Observations	43,872	43,872	43,872	43,872
R-squared	0.669	0.755	0.658	0.574

Note: Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table S4: Estimation of Capacity in Operation - Houston

VARIABLES	(1) houston_coal_oper	(2) houston_ngcc_oper	(3) houston_ngothers_oper
Percent	-66.16	-15.92	-42.06
	(170.7)	(84.37)	(150.3)
wdGWw	-2.301	-75.88***	-21.50
	(24.59)	(21.51)	(26.36)
c.wdGWw#c.wdGWw	0.463	-0.630	-6.720
	(4.841)	(4.554)	(4.976)
c.wdGWw#c.wdGWw#c.wdGWw	-0.0263	0.115	0.572*
	(0.315)	(0.283)	(0.308)
wdGWs	-28.71	-170.2**	9.634
	(66.14)	(65.54)	(99.97)
c.wdGWs#c.wdGWs	-21.56	49.92	-97.28
	(41.88)	(42.20)	(66.32)
c.wdGWs#c.wdGWs#c.wdGWs	8.062	-3.941	20.53*
	(7.562)	(7.551)	(11.98)
wdGWn	-41.31	55.28	58.72
	(98.30)	(64.69)	(82.91)
c.percent#c.wdGWw	1.176	33.81**	41.66*
	(17.92)	(16.68)	(22.63)
solarGW	59.00	-276.3	-74.13
	(119.2)	(173.6)	(133.4)
NUC_S	0.0421	-0.0752*	-0.130**
	(0.0794)	(0.0406)	(0.0555)
NUC_N	-0.0674	-0.160***	-0.0450
	(0.0768)	(0.0417)	(0.0807)
COAST	-0.00498	0.0605***	0.204***
	(0.0217)	(0.0189)	(0.0293)
EAST	0.0545	0.460***	-0.289
	(0.168)	(0.139)	(0.181)
FAR_WEST	0.114	-0.349***	-0.219*
	(0.197)	(0.108)	(0.127)
NORTH	-0.286	-0.265	1.471**
	(0.413)	(0.326)	(0.600)
NORTH_C	0.00937	0.0679***	0.0609**
	(0.0246)	(0.0206)	(0.0289)
SOUTHERN	0.0756	0.166***	-0.160**
	(0.0675)	(0.0447)	(0.0692)
SOUTH_C	-0.0248	0.0394	0.124***
	(0.0426)	(0.0293)	(0.0417)
WEST	0.341	-0.00303	-0.513
	(0.327)	(0.209)	(0.348)
Coal_NG_P_ratio	4,715***	-6,226***	-1,992
	(1,644)	(730.3)	(1,404)
Observations	58,176	58,176	58,176
R-squared	0.289	0.639	0.629

Note: Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table S5: Estimation of Capacity in Operation - North

VARIABLES	(1) north_coal_oper	(2) north_ngcc_oper	(3) north_ngothers_oper
Percent	-516.9	1,379***	111.7
	(393.1)	(339.9)	(267.8)
wdGWw	-122.4*	129.5	-165.2***
	(64.75)	(80.57)	(43.84)
c.wdGWw#c.wdGWw	16.04	-20.05	4.240
	(16.50)	(17.63)	(7.218)
c.wdGWw#c.wdGWw#c.wdGWw	-1.047	-1.250	0.0752
	(1.186)	(1.246)	(0.442)
wdGWs	-62.02	-918.4***	96.04
	(155.7)	(186.5)	(119.2)
c.wdGWs#c.wdGWs	144.1	274.5**	-160.3*
	(97.94)	(131.1)	(83.63)
c.wdGWs#c.wdGWs#c.wdGWs	-27.62	-31.66	29.48*
	(18.62)	(25.09)	(15.72)
wdGWn	354.3	-93.32	119.1
	(235.4)	(227.0)	(106.9)
c.percent#c.wdGWw	52.07	-123.5**	82.49**
	(37.28)	(58.25)	(38.54)
solarGW	-266.5	-139.6	-861.4***
	(338.2)	(414.7)	(274.3)
NUC_S	-0.444***	-0.114	0.163**
	(0.149)	(0.108)	(0.0719)
NUC_N	0.00910	-0.631***	-0.142
	(0.200)	(0.171)	(0.0863)
COAST	0.145***	-0.139*	0.257***
	(0.0502)	(0.0800)	(0.0416)
EAST	-2.279***	3.059***	-0.461
	(0.561)	(0.742)	(0.288)
FAR_WEST	2.230***	0.682	-1.259***
	(0.498)	(0.512)	(0.263)
NORTH	-0.459	-2.779**	4.023***
	(1.030)	(1.078)	(0.838)
NORTH_C	0.195***	0.242***	0.0674
	(0.0578)	(0.0669)	(0.0469)
SOUTHERN	0.0653	0.766***	-0.0388
	(0.154)	(0.165)	(0.143)
SOUTH_C	0.0943	-0.121	0.138
	(0.114)	(0.111)	(0.0956)
WEST	-3.059***	1.212	0.565
	(0.839)	(0.776)	(0.597)
Coal_NG_P_ratio	14,275***	-21,779***	-6,728***
	(3,648)	(2,860)	(2,068)
Observations	58,176	58,176	58,176
R-squared	0.644	0.738	0.746

Note: Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table S6: Estimation of Capacity in Operation - South

VARIABLES	(1) south_coal_oper	(2) south_ngcc_oper	(3) south_ngothers_oper
Percent	-403.6*	1,125***	-224.4
	(230.8)	(250.3)	(241.7)
wdGWw	40.66	-81.08	-11.53
	(35.42)	(49.30)	(35.99)
c.wdGWw#c.wdGWw	8.437	14.21	-11.43
	(8.854)	(11.13)	(7.149)
c.wdGWw#c.wdGWw#c.wdGWw	-0.594	-1.482*	0.954**
	(0.644)	(0.759)	(0.463)
wdGWs	-117.1	-283.0**	-204.5**
	(94.58)	(124.2)	(97.95)
c.wdGWs#c.wdGWs	23.09	70.39	61.92
	(58.25)	(82.08)	(62.96)
c.wdGWs#c.wdGWs#c.wdGWs	1.811	-16.16	-9.687
	(10.47)	(15.74)	(11.58)
wdGWn	-542.7***	-189.6	-52.43
	(137.3)	(167.9)	(114.9)
c.percent#c.wdGWw	-55.77***	-29.22	5.307
	(20.57)	(30.75)	(29.26)
solarGW	-94.96	202.2	93.98
	(144.8)	(315.2)	(265.0)
NUC_S	-0.149*	-0.0763	0.168**
	(0.0878)	(0.0995)	(0.0742)
NUC_N	-0.175**	-0.179	-0.0251
	(0.0794)	(0.122)	(0.0704)
COAST	0.0595	-0.0568	0.225***
	(0.0380)	(0.0576)	(0.0319)
EAST	-0.345	2.001***	-0.637***
	(0.333)	(0.621)	(0.224)
FAR_WEST	0.437	-1.093***	-0.729***
	(0.306)	(0.376)	(0.224)
NORTH	-1.050*	-0.769	2.298***
	(0.542)	(0.749)	(0.659)
NORTH_C	0.0454	0.0115	0.0297
	(0.0298)	(0.0465)	(0.0315)
SOUTHERN	0.0894	0.476***	-0.0882
	(0.0796)	(0.0854)	(0.100)
SOUTH_C	-0.0307	-0.00426	0.336***
	(0.0512)	(0.0677)	(0.0634)
WEST	0.237	2.648***	0.00465
	(0.394)	(0.626)	(0.387)
Coal_NG_P_ratio	8,094***	-12,547***	-4,421**
	(2,272)	(2,326)	(1,904)
Observations	58,176	58,176	58,176
R-squared	0.548	0.690	0.762

Note: Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

Table S7: Estimation of Capacity in Operation - West

VARIABLES	(1) west_coal_oper	(2) west_ngcc_oper	(3) west_ngothers_oper
Percent	106.3	96.06	-213.7***
	(116.3)	(83.93)	(29.76)
wdGWw	18.45	-43.40**	-63.42***
	(16.75)	(19.73)	(9.983)
c.wdGWw#c.wdGWw	0.532	-15.39***	5.837***
	(4.034)	(4.024)	(1.790)
c.wdGWw#c.wdGWw#c.wdGWw	-0.0413	0.499*	-0.299***
	(0.306)	(0.262)	(0.112)
wdGWs	34.25	15.01	26.22
	(53.33)	(52.52)	(18.92)
c.wdGWs#c.wdGWs	-36.58	-56.23	-8.738
	(33.13)	(35.93)	(12.32)
c.wdGWs#c.wdGWs#c.wdGWs	4.927	8.366	0.291
	(6.432)	(7.232)	(2.127)
wdGWn	174.5**	33.17	-14.81
	(70.29)	(58.34)	(19.37)
c.percent#c.wdGWw	-32.38***	92.67***	24.00***
	(10.28)	(14.46)	(6.615)
solarGW	-57.59	112.7	54.77
	(122.2)	(94.96)	(61.02)
NUC_S	-0.0413	-0.0112	-0.00149
	(0.0466)	(0.0264)	(0.00949)
NUC_N	0.0296	-0.0421	-0.0170
	(0.0442)	(0.0307)	(0.0120)
COAST	-0.0389**	0.00492	0.0134**
	(0.0194)	(0.0127)	(0.00622)
EAST	0.127	0.364***	-0.0830
	(0.152)	(0.105)	(0.0509)
FAR_WEST	-0.176	-0.0973	0.143***
	(0.127)	(0.0943)	(0.0240)
NORTH	-0.0912	0.491**	0.336***
	(0.330)	(0.216)	(0.0852)
NORTH_C	0.00882	0.0139	0.00553
	(0.0157)	(0.0128)	(0.00653)
SOUTHERN	0.128***	0.0154	0.0214
	(0.0448)	(0.0279)	(0.0248)
SOUTH_C	0.0242	0.0452**	0.0102
	(0.0331)	(0.0223)	(0.0150)
WEST	-0.0677	0.219	-0.160**
	(0.231)	(0.149)	(0.0703)
Coal_NG_P_ratio	651.3	-466.9	-319.1
	(965.1)	(614.5)	(200.6)
Observations	58,176	58,176	58,176
R-squared	0.388	0.552	0.348

Note: Standard errors (in parentheses) are clustered by sample year by month. Significance: *** p<0.01, ** p<0.05, * p<0.1.

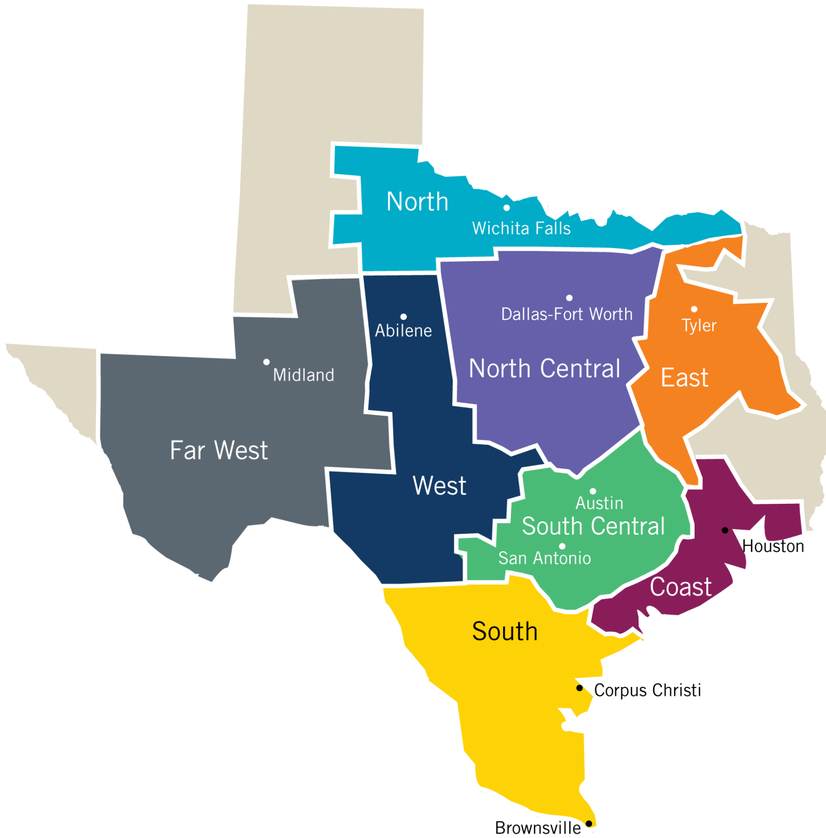


Figure S1: ERCOT Weather Zone

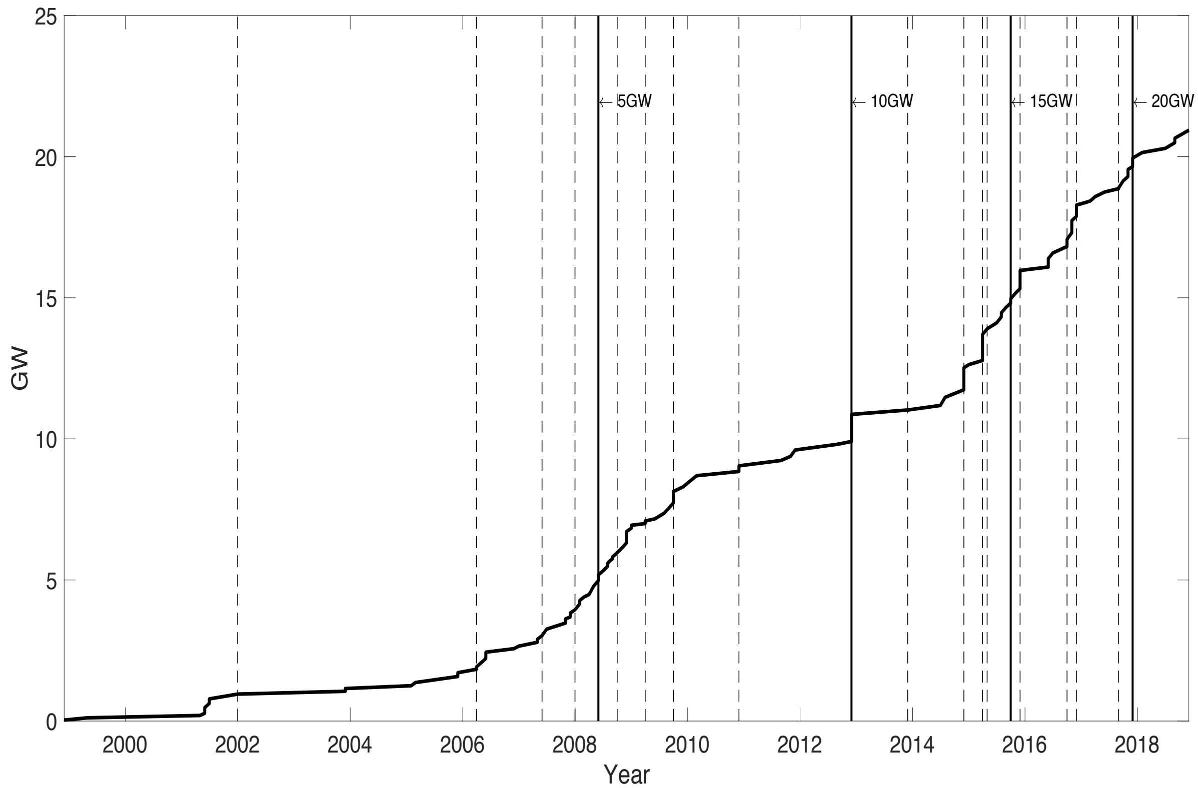


Figure S2: Installed Wind Capacity in ERCOT

Note: This figure was constructed by the authors using data on an ERCOT report of "Wind Patterns for Existing Sites from 1980 to 2017". This figure plots the total capacity of wind turbines installed in ERCOT. Each dotted vertical line indicates every 1 GW increase and thick solid vertical line shows an increase in 5 GW from 5 GW to 20 GW.

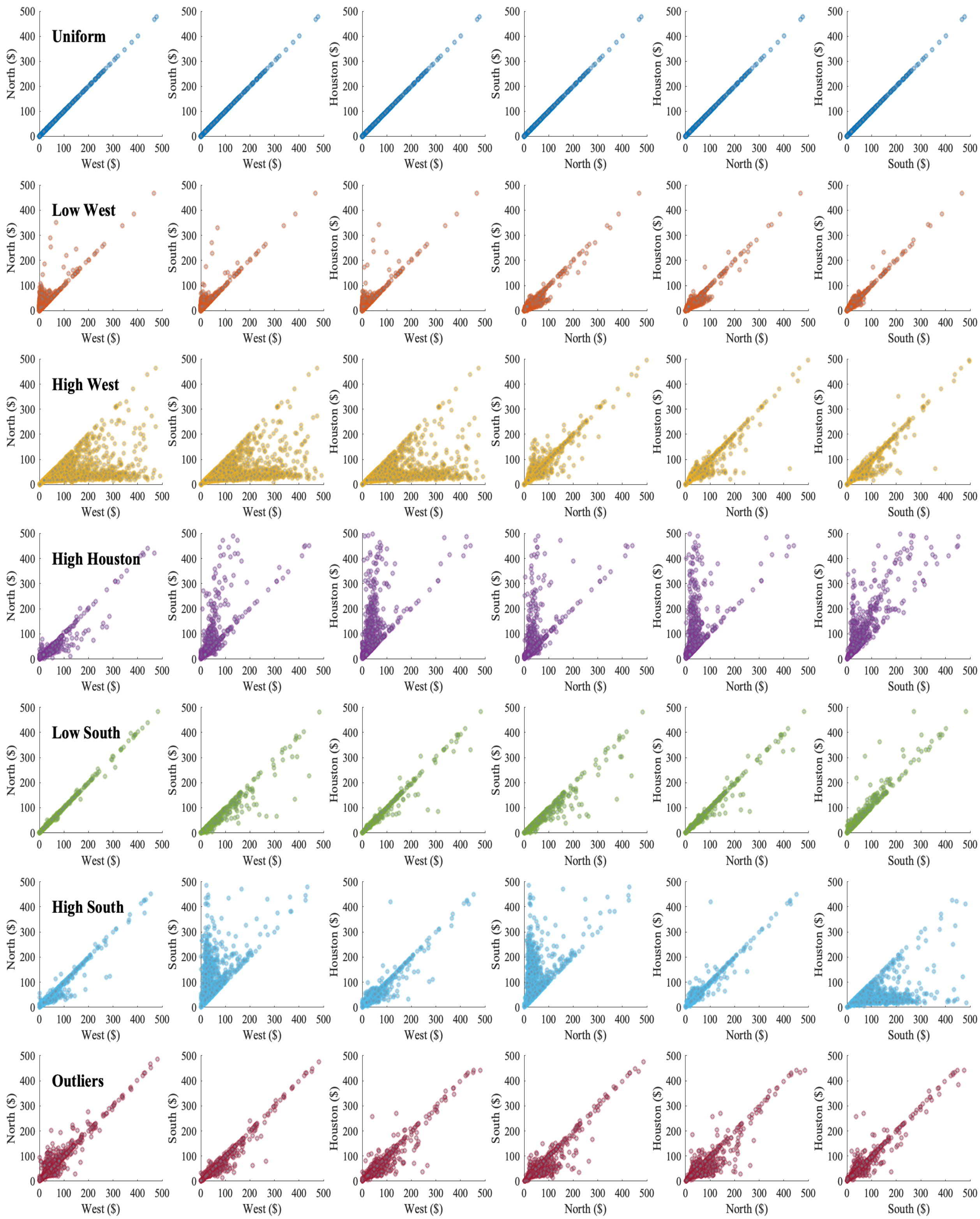
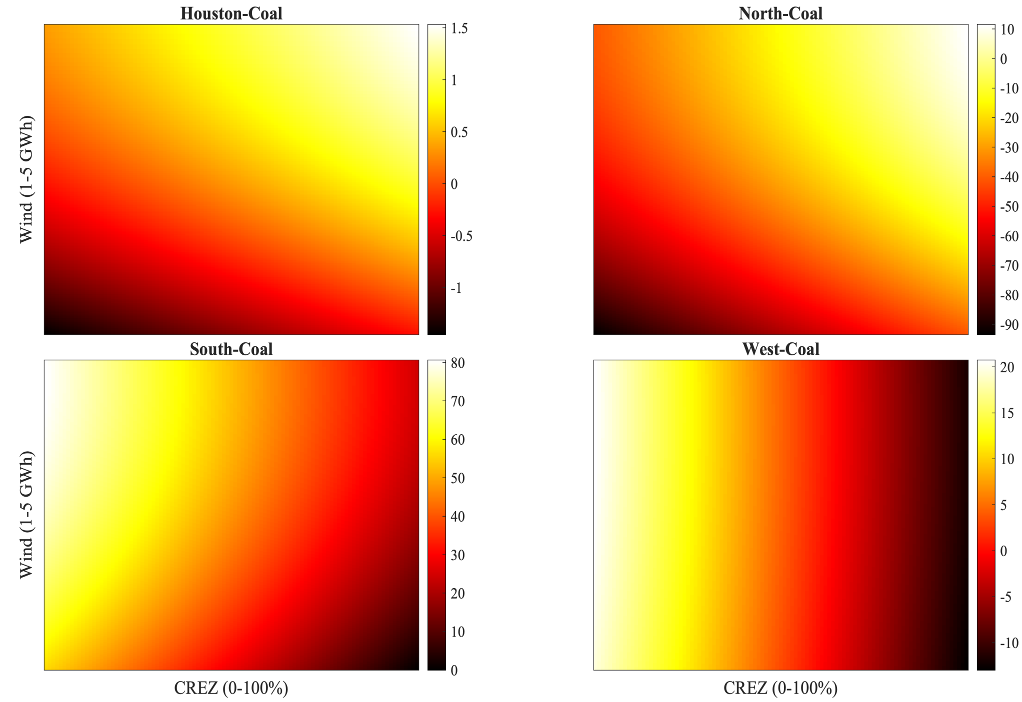
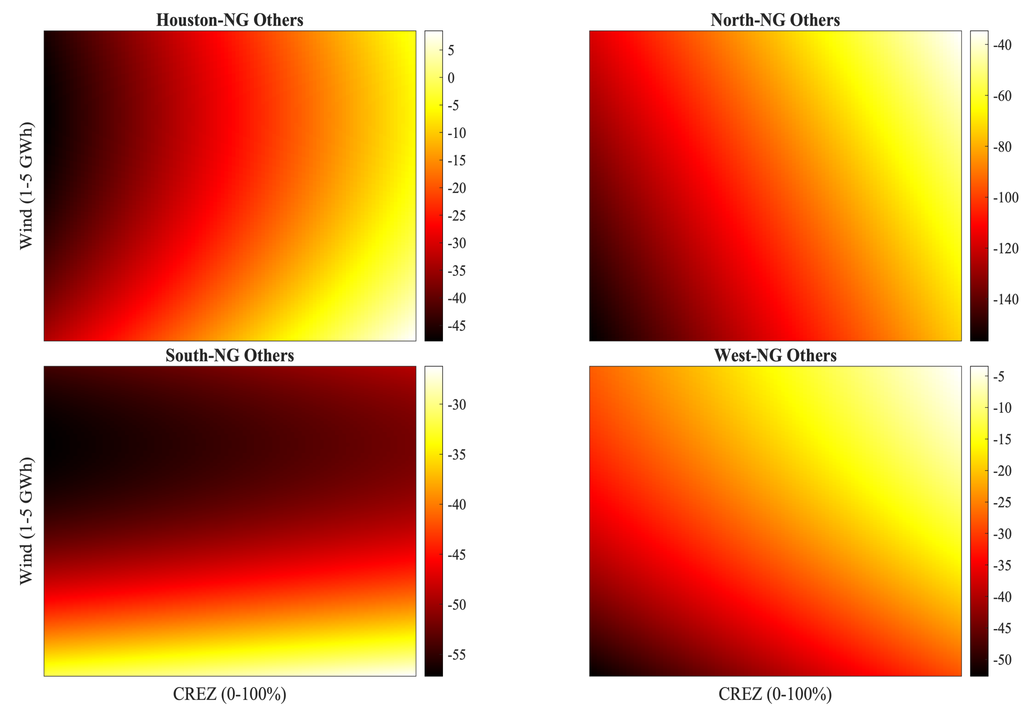


Figure S3: Price Comparisons in DBSCAN Clusters

Note: Figures in each row show zonal price comparisons between two zones for each type of six different market conditions found by DBSCAN.



(a) Coal



(b) Other Natural Gas Units

Figure S4: Average Marginal Impacts of West Wind Generation on Capacity in Operation
Note: Figures in Panel (a) plot the impacts of West wind on coal capacity in operation. Figures in Panel (b) show the impacts of West wind on other natural gas capacity in operation. The effects are estimated at grid points, each of which denotes different levels of West wind generation and CREZ values. Wind value escalates in 10 MWh increments from 1GWh to 5 GWh in the y-axis and CREZ increases by 1% from 0 to 100% in the x-axis. The impacts are painted by different colors. Darker red color denotes more negative impacts and lighter yellow denotes less impacts. The scaliling of the colorbars denoting the magnitudes of the impacts differs across load zones.