Essays on the Economics of Electricity

by

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DEDICATION

To my family

ACKNOWLEDGMENT

To my committee members, thank you for your time, effort and advice over the past few years. To my parents, thank you for your support and encouragement over the past few decades.

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ABSTRACT

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This dissertation analyzes issues relating to the economics of electricity in Texas: implications of wind generation intermittency, valuation of transmission lines and regulatory policies surrounding retail electricity deregulation. Extensive government involvement in the electricity market implies that an improved understanding of the economics of electricity can lead to improved public policies in this area.

Chapter 1 analyzes the effect of wind power intermittency on generation costs and emissions. Electricity generation and load must be close to equal at all times. However the ability of wind turbines to generate electricity varies with wind conditions. This chapter finds evidence that, while overall, wind generation reduces generation costs and CO_2 emissions by offsetting fossil fuel generation, wind generation intermittency is associated with a shift in the fossil fuel generation mix from cheaper coal to more expensive, cleaner and more flexible natural gas, with the associated impacts on emissions and costs.

Chapter 2 analyzes the recent expansion of transmission lines in the western part of Texas to better access areas with high wind generation potential. While greater access to

wind resources in western Texas will ultimately allow for reduced use of fossil fuel generation and corresponding reductions in generation costs and pollution, the transmission grid expansion cost approximately $7 billion. This chapter compares the costs and benefits of this transmission project and finds that the costs of this transmission expansion will consume a non-trivial amount of the value of the additional wind generated.

Chapter 3 analyzes deregulation policies for retail electricity markets. In states where consumers can select between retail electricity providers, consumers exhibit strong inertia to stay with their current provider, leading to imperfect competition. Texas employed an unusual approach to regulating the incumbent firm during the transition to a deregulated market, forcing the incumbent to set a relatively high price to allow entrant firms to be more competitive. This chapter models the retail electricity industry and finds that it is possible, but not guaranteed, for a Texas-style approach with high temporary regulated prices on the incumbent to result in superior outcome to an alternative transitional policy with lower prices.

CHAPTER I

The Effects of Wind Power Intermittency on Generation and Emissions

1.1 Introduction

Electricity generation is a major source of air pollution in the United States, responsible for 32% of greenhouse gas emissions in 2012. Because wind power does not generate any emissions, it has been promoted as a clean way to generate electricity, with a variety of government policies encouraging its use. However, wind power differs from fossil fuel generation in another way: its dependence on wind conditions which vary over time and are imperfectly forecastable. In the absence of storage technology, electricity generation must be continuously matched with consumption, so this wind power intermittency can affect the operation of the electricity grid.[1]

Wind generation reduces the required amount of generation from other sources so if wind generation capacity is relatively small compared to the overall electric load, any expected or unexpected variation in wind generation may not be substantial relative to the short-run vari-

[1] Large scale storage of electricity is not currently feasible apart from hydropower. This chapter examines the Texas market where hydropower is a very small part of the mix of generators.

ation in electricity load. However if wind generation capacity is relatively large and changes in wind generation are compensated for by changing fossil fuel generation levels, greater wind intermittency could increase the optimal desired flexibility of fossil fuel generation.[2]

Thus because of its intermittency, wind power is imposing an externality on the rest of the electricity grid: other generators, and potentially the demand-side, must respond to changes in wind generation. Paying for reserve power and otherwise operating the grid in a less cost-minimizing manner imposes a financial cost. Beyond financial costs, wind power intermittency may have environmental externalities that should be accounted for as well.

Wind power intermittency could affect the emissions produced by electricity generation. Fossil fuel generators differ with respect to their marginal costs, their ability to quickly adjust output levels, as well as the pollution they produce. Compared to coal, natural gas generation tends to be more expensive, less polluting and able to change output levels more rapidly. If wind power intermittency shifts the mix of fossil fuel generation toward cleaner and more flexible natural gas and away from coal, then this channel would reduce the pollution from fossil fuel generation. However, efficiency of individual generation units varies with output, generally with higher efficiency at higher output levels. If wind intermittency causes some fossil fuel generators to be operated at lower output levels than would otherwise be the case, this channel could increase their emissions rate (Bushnell and Wolfram [2005]). Furthermore, when generator units are changing output levels, as would be the case when compensating for wind power changes, they again lose efficiency and increase their emissions rate (Novan [Forthcoming]).

[2] A 2008 report commissioned by ERCOT found that, for their model, when wind generation capacity in Texas was at 5000 MW, the wind generation would have "a limited impact on the system...[its] variability barely rising above the inherent variability caused by system loads". But when wind generation capacity increased to 10,000 MW, "the impacts become more noticeable" and by 15,000 MW, "the operational issues posed by wind generation will become a significant focus of ERCOT operations" (General Electric [2008]).

Various government programs, such as the lapsed federal Production Tax Credit and state-level renewable energy credits, have sought to increase the amount of wind generation.[3,4] California, for example, has a goal of generating 33% of its electricity from renewable sources by 2020. Historically, the value of these wind generation subsidies have at best only been linked to the quantity of power generated by turbines. If the purpose of subsidizing wind power is to reduce emissions, this subsidy policy would optimally instead connect the value of the externalities imposed by wind generation to the value of the subsidy.[5,6] Varying subsidy levels across wind turbines based on their effect on emissions could lead to improved siting decisions (Novan [Forthcoming]). If wind intermittency affects the operation of the grid, subsidization policy would ideally incorporate wind generation intermittency and the value of its corresponding externalities. This includes environmental externalities in addition to imposed financial costs.

Other papers have looked at the integration of large quantities of intermittent generation resources such as wind and solar into the electric grid (van Kooten [2010], DeCarolis and Keith [2004], Gowrisankaran et al. [2014]).[7] This set of papers uses 'engineering' approaches and models the dispatch of generation units. This approach is valuable for out-of-sample prediction but in practice the results from engineering models of electric grids can often deviate from what is ultimately observed (Callaway and Fowlie [2009]).[8]

[3]While wind generation does not pollute in the conventional sense, nearby residents can complain about noise and unsightly turbines.

[4]Hitaj [2013] and Carley [2009] examine the effectiveness of programs at encouraging wind generation.

[5]Alternative polices such as cap-and-trade or a carbon tax could also be preferable to a subsidy for wind generation, however this is beyond the scope of this chapter.

[6]The creation of "green jobs" has also been suggested as a rationale for subsidizing wind power (Obama [2012]).

[7]Green and Vasilakos [2010] model how increased wind generation could affect market prices and output with profit maximizing bidding.

[8]In a different context, Allcott and Greenstone [2012] discuss how engineering models of energy efficiency often understate costs of improved energy efficiency.

Instead of using a detailed dispatch model of the electricity grid, I use a regression approach to estimate the impact of wind generation intermittency on the operation of the electric grid and the resulting emissions. I use recent data from Texas, the state with the most installed capacity for wind generation in the United States, from approximately 2011 to 2013

In Texas, wind was the source of approximately 10% of electricity in 2013 and the share of total generation coming from wind power at a specific moment has reached as high as 36%. I obtain hourly data regarding emissions, fossil fuel generation and and both potential and actual wind generation. I find that wind power does have an effect on electricity generation beyond reducing the necessary amount of generation from other sources. After flexibly controlling for the level of fossil fuel generation, increased wind generation is associated with shifting the fossil fuel generation mix away from coal and towards more flexible natural gas generation. There is a corresponding increase in fuel costs and a decrease in CO_2 emissions, indicating that the environmental effect from shifting the generation mix towards cleaner natural gas dominates any increase in emissions due to increased ramping of fossil fuel generators or operating at less efficient output levels.

This intermittency effect of wind generation on emissions is greater when natural gas would otherwise comprise a smaller part of the generation mix, namely when total generation is at lower levels and baseload coal generation is a larger part of the fossil fuel mix. While the analysis in this chapter only uses Texas data, this does suggest that wind power intermittency may have a larger impact on generation and emissions in regions where coal generation plays a larger role. This result is similar to Holland and Mansur [2008], who find that reducing daily electricity load variation has different effects on emissions depending on the generation mix in the region.

Examining the average impact of wind power intermittency effect does not distinguish between the different forms that wind power intermittency can take. Wind generation levels can vary in expected ways. Additionally, potential wind power could change in an unexpected manner if the forecasts are incorrect. These forecasts can have varying degrees of confidence. When examining the effect of more specific measures of wind intermittency, I find that variation in expected wind generation over a five-hour window (expected wind power variation) is associated with a shift in fossil fuel generation towards natural gas. I find a similar effect with increased uncertainty in wind power forecasts.

The estimates in this chapter are short-run effects that do not incorporate any long-run adjustments to the set of generators available in Texas as a response to increased wind generation capacity. Also, while total wind generation capacity did increase during the three year period examined, a clear majority of the capacity was already installed in Texas at the beginning of that three year period. Most of the observed variation in wind generation levels is a result of changing wind conditions. The impact of installing additional wind turbines on wind generation intermittency depends on how the new wind generation is correlated with the previously installed capacity.

Thus while wind intermittency increases financial costs of generation, it also results in reduced emissions by shifting fossil fuel generation towards cleaner natural gas generators. When measuring the social cost wind intermittency imposes, the value of these environmental benefits should be included. Using the estimates from Texas in this chapter and the U.S. social cost of carbon estimates of $39/ton, the environmental benefit from increased wind intermittency from a 1 MWh increase in wind generation is associated with a reduction in CO_2 emissions valued at $0.92.[9] This value is smaller than the increase in fuel costs

[9] This does not include the value of any emissions reductions besides CO_2.

of \$1.38, but nevertheless indicates a substantial fraction of those costs would be offset by environmental benefits.

1.2 Modeling Effects of Uncertain Wind Generation

To illustrate two channels of the effect of wind generation on the electrical grid and emissions, I use a simplified model of electricity generation. The planner must select a combination of generation sources to minimize costs with the constraint that the total generation must equal the load. The quantity of electricity that needs to be supplied is imperfectly forecast and the value of the load is distributed uniformly $L \sim U\left[(1-\gamma)\bar{L},\ (1+\gamma)\bar{L}\right]$. Wind power is also imperfectly forecast and its value is also distributed uniformly $W \sim U\left[(1-\nu)\bar{W},\ (1+\nu)\bar{W}\right]$.[10,11] Uniform distributions are chosen for tractability. Wind generation has a per-MWh cost of zero.

Assume there are two other sources of power generation: coal and natural gas. Coal and natural gas generation have per-MWh costs of c_{Coal} and c_{NG} respectively. Assume $c_{NG} > c_{Coal}$. Additionally, let coal power have an inflexible output level that must be chosen before the actual load and wind generation levels are determined. Natural gas generation is adjustable and its output level can be selected after the load and wind generation levels are known.

The lowest cost solution where $W + q_{Coal} + q_{NG} = L$ is to set q_{Coal} equal to the minimum possible required generation, with the lowest realization of load and the highest realization of wind generation. This is

[10] Assume that ν and γ are between zero and one.

[11] I abstract away from wind curtailment, or using less wind power than could be generated. In the context of this model, however, wind curtailment would never be beneficial.

$$q_{Coal} = (1-\gamma)\bar{L} - (1+\nu)\bar{W}$$

The amount of natural gas generation will be the quantity that is required to set total generation equal to total load, taking q_{Coal} as given:

$$q_{NG} = L - W - (1-\gamma)\bar{L} + (1+\nu)\bar{W}$$

Increasing wind generation lowers the amount of natural gas generation.[12] However, increased forecast uncertainty (higher ν or γ) will lead to increased levels of natural gas generation and lower amounts of coal. Because natural gas generation is more expensive and cleaner than coal generation, this increased uncertainty will also lead to increased costs and lower emissions levels. The relative value of these effects is unknown. This motivates the empirical work in this chapter, which estimates the effect of wind generation intermittency on the use of coal and natural gas generation, along with the corresponding effect on emissions and generation costs.

1.3 Background

The Electric Reliability Council of Texas (ERCOT) organizes the operation of the electricity grid for about 75% of Texas, including 85% of the state's electric load. ERCOT's boundaries are shown in Figure 1.1. Electricity generation can come from a variety of sources. Wind, coal, nuclear and natural gas power are the dominant sources for ERCOT, comprising 99.2%

[12] In this simplified model, when wind generation reduces the total fossil fuel generation, only coal generation is lowered. In practice, this effect can reduce generation from both coal and natural gas power.

of total generation in 2013.[13] With wind power accounting for 9.9% of generation in 2013, ERCOT has the highest wind generation capacity of any U.S. state.

Wind generation capacity in Texas has grown quickly from near-zero levels in 2000, though installation of additional wind generation capacity has slowed since 2009, as seen in Figure 1.2.[14] The actual quantity of wind power generated in ERCOT, dependent on installed capacity, wind conditions and the ability of grid operators to dispatch the wind power, has also grown over time, though less so since 2011, as seen in Figure 3. Wind generation curtailment, where potential wind generation is not actually used, can occur and is mostly due to transmission constraints between the western region of Texas containing most of the wind generation capacity and the more populated regions. However, a long term project to increase transmission capacity between these areas has substantially reduced curtailment of wind power in recent years.[15]

Additionally, while the electrical grid in the rest of the continental U.S. is more interconnected, ERCOT is relatively isolated with only a small number of connections to other regions, as seen in Figure 1.4.[16] This isolation allows electricity dispatch operations within Texas to largely be conducted independently of the surrounding regions.

Under the current nodal system, instituted on November 1, 2010, ERCOT runs both day-ahead and real-time markets for electricity. Because electricity cannot be economically stored

[13] The remaining electricity is generated mainly by hydropower, solar and biomass.

[14] Little wind generation capacity became active in 2013; this was likely due to the lapsing of the federal Production Tax Credit (PTC) at the end of 2012. In order to qualify for that subsidy, wind turbines needed to be operational by the end of that year. Later legislation extended the PTC so that any turbine that had begun construction by the end of 2013 would also qualify and additional turbines are expected to be completed throughout 2014 and 2015.

[15] Chapter 2 examines the costs and benefits of this additional transmission expansion.

[16] There are two DC connections to the Southwest Power Pool (SPP) with a combined capacity of 820 MW and three DC connections to Mexico with a combined capacity of 286 MW. The DC connections allow control over the flow of power. Additionally two power plants can generate electricity simultaneously for both ERCOT and an outside grid.

in large quantities, ERCOT identifies the most cost-effective way to generate electricity to match the expected load while respecting the system constraints, such as those imposed by the transmission lines.[17] ERCOT also obtains reserve power so generation capacity is available to either increase or decrease generation quickly in response to unexpected changes.

Wind generation units participate with the other generator types in the wholesale electricity markets run by ERCOT. Because wind power does not consume any fuel and is very inexpensive to operate once built, these wind units generally, though not always, submit very low bids and are dispatched whenever possible, given constraints on the electric grid.[18] There are differences in their treatment because of the intermittent nature of wind power. Penalties for deviating from the requested output are relaxed for wind generation units so that wind generation can "follow the wind". Additionally, wind forecasts are critical in determining maximum potential generation in future periods. When operators of wind generation units report their maximum potential output level for each upcoming hour in the day-ahead and reliability unit commitment markets, this value cannot exceed ERCOT's forecast of their potential wind generation. In the real-time market when dispatching wind turbines, ERCOT uses a telemetered value based on current conditions at that generation site for the

[17]For the day-ahead market, bids for both supply and demand of electricity for each hour of the next day at specific locations may be submitted to ERCOT by 10 AM. Unit characteristics such as minimum and maximum output levels must also be submitted. ERCOT releases the results of this auction by 1:30 PM. This stage of the market does not take ERCOT's forecasted load into account and allows firms to reduce the price risk of transacting power in the real-time market. The next stage, day-ahead reliability unit commitment, occurs at 2:30 PM and does take forecasted load into account. ERCOT modifies expected generator output for all hours of the next day so that planned generation will meet expected load at least cost while respecting constraints placed by the transmissions grid. This reliability unit commitment process is repeated hourly with updated ERCOT forecasts and operating plans on the part of the generation units. Under normal circumstances, the real-time market runs every five minutes. In the real-time market ERCOT adjusts the requested output from all generators based on changing conditions and does so to maintain system reliability while minimizing cost. As part of minimizing generation cost, ERCOT attempts to have the outcome of the real time market minimize the use of regulation service, where ERCOT can request changes in output within three to five seconds to maintain appropriate frequency.

[18]Because of subsidies, wind generation units often submit bids with negative values.

maximum possible output for each wind generator instead of a value reported by the wind unit operator.

An extensive discussion of the ERCOT market arrangements with respect to wind generation can be found in Sioshansi and Hurlbut [2010].

1.4 Data

The data used in the analysis in this chapter comes from ERCOT, the EPA, Weather Underground and the U.S. Census. The analysis uses data from February 22, 2011 to December 31, 2013.[19,20] Focusing on this period avoids ERCOT's institutional shift from a zonal to a nodal market, which occurred on November 1, 2010 as well as large changes in the price of natural gas.[21]

Generator output data comes from ERCOT. Generator output data from ERCOT's real-time (SCED) market is available at 15 minute intervals and includes the quantity of electricity generated by and the maximum potential output of each generation unit.[22] The maximum potential output levels for wind generation units at the time the generation units are dispatched depend on wind conditions and are telemetered data instead of being submitted by the wind unit operators. Quantity of electricity generated only includes power added to the

[19] I am missing data for some variables for a small number of days during this time period.

[20] This data is very similar to the data used in Chapter 2, which uses data through 2014. 2014 data is not used in this chapter because I do not have 2014 data for some variables which are used here but not in the second chapter.

[21] As seen in Figure 1.2, during the time period examined in this chapter there is little growth in installed wind turbine capacity so observed changes in potential wind generation will be mainly due to changing weather conditions. Note that over longer time horizons, changes in wind generation could be due to the installation of additional wind turbines.

[22] The value for a generation unit's High Sustainable Limit assumes unlimited time to reach that speed. The amount of power that can be generated on short notice can be less than this maximum level and is called the High Dispatchable Limit.

grid and does not count any electricity consumed by the generator itself. This generation data is aggregated to the ERCOT-level for analysis.

Forecasted levels of potential wind generation for upcoming hours are also available at hourly frequency from ERCOT. ERCOT's forecasts of potential wind generation include a distribution of potential outcomes. The data includes values for potential wind generation that, according to the forecast, have a 80% and 50% chance of being exceeded.

Data on hourly CO_2 emissions from power generation units are obtained through the EPA's Continuous Emissions Monitoring System (CEMS). CEMS allows the EPA to track compliance with emissions-related regulations.[23] I use hourly emissions data for generation units within ERCOT and assume that all generation units that are affected by wind generation in ERCOT are included.

A small number of natural gas units are missing CO_2 data. I fill in these missing values using predicted values based on the heat rate, which is also available from CEMS.[24] If valid readings are not available, EPA requires that high emissions levels be recorded as a penalty. The Sandy Creek coal facility recorded very high and unchanging emissions rates for an extended period of time that were clearly due to CEMS recording issues. The generation and emissions from this unit have been dropped from the analysis.

I create a single hourly temperature measure for Texas using a population-weighted average of the 10 largest cities in ERCOT. Historical temperature data for these cities was obtained from the Weather Underground website.[25,26] The city populations were taken from

[23]Generation units with a capacity less than 25 MW are not required to participate in CEMS and so this analysis omits emissions from those units.

[24]The R^2 for the regression used in the prediction is about 0.95. Novan [Forthcoming] also uses the heat rate to approximate CO_2 emissions for units with missing data.

[25]The airport associated with the city was the location of the data. Some cities share an airport and in those cases the weight for that airport's temperature was the sum of the population of both cities.

[26]Some cities did not have historical temperature data for some hours. In these cases, the statewide weighted temperature measure was calculated without those cities.

the 2000 Census.

Pricing data for coal is at the monthly level and is the average cost of coal delivered for electricity generation in Texas. Coal pricing data comes from the EIA's Electric Power Monthly. Pricing data for natural gas at the daily level and is the spot price for delivery at the Henry Hub as reported by the EIA. Fuel costs are calculated using measures of the heat content of fuel consumed (from CEMS) and the cost of that fuel.[27]

1.5 Wind Intermittency

Potential wind generation is dependent on actual wind conditions which changes over time. Intermittency can come from both expected and unexpected changes in wind generation. As an example, Figure 1.5 plots both the predicted and actual potential hourly wind generation for January 1, 2012, where the prediction for potential wind generation was made one hour earlier. The predicted potential wind generation changes over the day, ranging from over 6000 MWh to less than 2000 MWh. Additionally, the actual maximum amount of wind generation was consistently different than the predicted value.

ERCOT's forecast of future potential wind generation is used to help ensure the stability of the electric grid by anticipating future changes in fossil fuel generation requirements and to allow ERCOT to obtain those generation requirements in a low-cost manner. Furthermore, as noted by an ERCOT representative, "with the increased percentage of the system load served by wind, it becomes critical to have not only a good forecast of how wind will generate during the day, but also an assessment of the level of uncertainty in that forecast." ERCOT

[27] These costs are approximations to the actual price paid by the generators, which will vary across generators. For example, natural gas prices vary geographically. Furthermore, coal prices can vary depending on the type of coal used by specific generators.

[2010]. The short run wind forecasts used by ERCOT have improved substantially in recent years. Figure 1.6 shows the distribution of one-hour-ahead potential wind generation forecast errors. In all years from 2011-2013, the mean forecast error is near zero (-11.6 MWh in 2011, -8.5 MWh in 2012 and 4.9 MWh in 2013). However, the average magnitude of the forecast error has declined even as additional wind turbines have been installed and overall wind generation levels increased, falling from 471.97 MWh in 2011 to 305.06 MWh in 2012 and 312.80 MWh in 2013.[28]

Because the generation must match total load, this wind intermittency will affect the operations of the electric grid. An decrease in wind generation must be balanced by either a decrease in electric load or an increase of electricity into the grid from another sources; either some form of storage or through increased generation from fossil fuel generators. Large scale battery storage is not financially feasible and Texas obtains a very small proportion of its electricity come from hydropower, another form of electricity storage that Texas lacks the necessary geography to effectively exploit.[29] Demand response to maintain grid stability is an alternative means of adjusting for changes in wind generation. While ERCOT has worked to incorporate some load to be capable of quickly reducing their power consumption in response to a signal, demand response has historically been used only several times per year.[30] Increased use of real-time pricing may also help, though having demand quickly adjust to unforeseen changes in wind generation may not be as straightforward as adjusting fossil fuel generation levels.

Adjusting the amount of fossil fuel generation in response to changes in wind generation

[28]Six hour ahead potential wind forecasts have not noticeably improved in terms of average magnitude of forecast error over these three years.

[29]In January 2013, a 36-MW battery project was completed, however this is not a substantial size given that the average hourly wind generation in Texas for 2013 was 3704 MWh.

[30]There were 21 uses of demand response between April 2006 and October 2011.

is an alternative. However, fossil fuel generators have different abilities to adjust output levels; natural gas is much more flexible, with the ramping rate of combined cycle natural gas units generally about four times that of coal units (Tremath et al. [2013]). If it becomes more optimal from either a cost minimization or grid stability perspective to have a more flexible mix of fossil fuel generation sources, then this could result in a shift towards using more natural gas to meet the same level of necessary fossil fuel generation.

Figure 1.7 shows the observed mix of hourly natural gas and coal generation at different levels of fossil fuel generation from Texas during the sample period. At any given level of fossil fuel generation, there is a range of observed mixes of coal and natural gas generation. Determining which mix to use in any given hour can be based on a number of factors. Dynamic considerations are one; if a given fossil fuel generation level occurs in the middle of the night, that would likely result in a different generation mix than if it occurred in late afternoon because the latter would likely use more peaking generation. Plant maintenance is another; if a coal facility is being repaired then this will likely result in increased natural gas generation to compensate. If additional flexibility in fossil fuel output levels is preferred, this may also result in shifting generation mix towards natural gas, as suggested in the stylized model from Section 1.2.

While the wind power intermittency may result in a preference for more flexible fossil fuel output levels to better adjust to future changes in potential wind generation, wind power also directly offsets fossil fuel generation requirements, as also seen in the model from Section 1.2. Figure 1.8 illustrates these different effects: as the level of wind generation increases, the level of fossil fuel falls, decreasing natural gas generation. If the desire for fossil fuel output flexibility increases, however, the quantity of natural gas generation for a given level of total fossil fuel generation increases.

1.5.1 Electricity Generation and Emissions

Electricity generation was responsible for 32% of greenhouse gas emissions in the United States in 2012. While generation sources such as wind, solar, geothermal or nuclear power do not produce emissions, coal and natural gas do. Any effect of wind power on emissions will depend on how it affects the operation of the grid. If the intermittent nature of wind power causes a shift in the fossil fuel mix towards more flexible natural gas generation, then this could reduce emissions because natural gas generating units are generally cleaner than coal units. Additionally, when total fossil fuel generation is reduced in response to increased wind generation, the resulting reduction in emissions will depend on what type of generation unit was offset.[31] Table 1.1 shows the average emissions rates for coal and natural gas generation units in the dataset. Electricity generated from coal, on average, emits over twice as much CO_2 pollution as electricity generated from natural gas. However the cost of the fuel consumed in natural gas generation tends to be more expensive than coal generation.

If wind intermittency changes the fossil fuel generation mix, then this would likely impact emissions and fuel costs. For a given level of fossil fuel generation, emissions would be expected to be higher when coal makes up a larger share of the fossil fuel generation. Additionally, generators are less efficient when they are changing output levels. When fossil fuel generators must ramp their production levels up or down to compensate for changes in wind generation, this can reduce the efficiency of these generators and lead to increased emissions.The magnitude of this impact as compared to shifting fossil fuel generation mix is

[31]Novan [Forthcoming] finds that increased wind generation results in larger emissions reductions when total generation levels are lower and coal is more likely to be the marginal unit.

an empirical question.

In addition to impacting emissions through intermittency, wind generation affects emissions by reducing the total amount of fossil fuel generation. This effect results in a corresponding decrease in emissions. Kaffine et al. [2010] and Novan [Forthcoming] find that the effect of additional wind generation on emissions is related to the type of generation units whose output is reduced by the wind power. Thus on average, if wind power reduces coal power instead of non-peaker natural gas power, the effect of that increase of wind power on emissions will on average differ substantially.[32]

The marginal generator can in turn depend on what the overall load is. Figure 1.7 shows how on average the use of coal versus natural gas generation changes as the total fossil fuel generation increases in Texas. Initially at low fossil fuel generation levels, additional generation on average comes from both natural gas and coal generation. Once fossil fuel generation is at about 30,000 MWh, further generation primarily comes from natural gas plants, as can be seen by the essentially flat slope of the coal generation-net generation relationship when net generation is high. Thus when total fossil fuel generation is high, the effect of wind power on reducing total fossil fuel generation is likely to reduce natural gas power.

1.6 Empirical Analysis

Using ERCOT-wide time series data, I examine how wind power intermittency affects the fossil fuel generation mix, CO_2 emissions and fuel costs. I initially test if wind generation has an effect on electricity generation apart from simply reducing the amount of necessary

[32]Fell and Kaffine [2014] find that increased wind generation generally reduces coal generation capacity factors and this effect is stronger when natural gas prices are lower.

fossil fuel generation and find this is the case. I then test if this additional effect changes in different situations, across electric load levels and across years, before testing the effect of explicit wind intermittency variables. I then test the impact of wind power intermittency on CO_2 emissions and fuel costs.

1.6.1 Baseline Model

To observe the effect of wind intermittency, my baseline model estimates the average effect of additional wind generation on the fossil fuel generation mix while controlling for the effect of wind generation on reducing total fossil fuel generation using the following specification:

$$\begin{aligned} NatGasGeneration_t =& \beta_1 W_t + f(FossilFuel_t) + \\ & \alpha_0 + \alpha_1 Temp_t + \alpha_2 Temp_t^2 + \gamma_m HourMonth_t + \epsilon_t \qquad (1.1) \end{aligned}$$

$NatGasGeneration_t$ is the amount of natural gas generation in hour t.[33] The fossil fuel generation mix will be affected by the total amount of fossil fuel generation as seen in Figure 1.7. This is captured through the $f(FossilFuel_t)$ term, a fifth-degree orthogonalized polynomial.[34] The amount of required fossil fuel generation is total required electricity generation net of generation from other fuel sources. The amount of total electricity demand is assumed to be exogenous. Power must then be generated to meet this inflexible load. For the state of

[33] Note that because I control for the total level of fossil fuel generation, increasing the amount of natural gas generation is increasing the share of natural gas generation in the fossil fuel generation mix. These results are robust to directly using the share of natural gas in fossil fuel generation as the dependent variable, as shown in Appendix A.

[34] Results are robust to using alternative degrees.

Texas, this mainly comes from nuclear, fossil fuel and wind power.[35] Nuclear power reduces the amount of fossil fuel generation, but these generation levels do not substantially change in the short term and are also taken to be exogenous. Wind power also reduces the required amount of fossil fuel generation, as illustrated in Figure 1.8.[36]

The amount of wind power generated in hour t, W_t, reduces the amount of fossil fuel generation, as illustrated in Figure 1.8 and this effect is captured in $f(FossilFuel_t)$. Wind generation is allowed to have an additional effect, captured by β_1. Identifying these effects separately comes from variation in the total electric load as the wind power effect on total fossil fuel generation is set to have the opposite effect as total electric load. If β_1 is not equal to zero, then wind generation has an additional effect on the dependent variables apart from simply reducing the quantity of generation required from other sources. Considering that, unlike conventional generation sources, wind power is not perfectly dispatchable and depends on wind conditions, I will initially attribute this effect to wind intermittency. Later specifications will include specific intermittency related variables.[37]

Temperature affects the efficiency of generators, with high temperatures reducing efficiency. Heterogeneous effects of temperature on efficiency across generator types could affect the fossil fuel generation mix.

[35]Other power sources such as biomass, solar and hydroelectric comprise less than 1% of the generation.

[36]I assume that wind conditions do not affect the total load. Novan [Forthcoming] notes that most wind generation resources are located in a different area of Texas as most electricity demand. Novan [Forthcoming] further notes that the windspeed conditions on the ground are not highly correlated with windspeed conditions at the height of the wind turbine blades.

[37]If β_1 does represent the effect of wind power intermittency, then nuclear power (which does not produce emissions and whose production is not dependent on weather conditions) should not have an additional effect on the dependent variables apart from its role in reducing reducing fossil fuel generation. I separately run this test and, as expected, find no significant effect for nuclear power apart from reducing fossil fuel generation. However, the standard errors for the additional effect of nuclear power are several times larger than the standard errors for the equivalent wind parameter. This is likely because of limited variation in total nuclear generation levels, mainly driven by large jumps several times per year as opposed to substantial within-day variation as with wind.

$HourMonth_t$ is an hourly dummy variable that varies by year-month combination m, included to address dynamic issues. Figure 1.9 plots the average total generation and wind generation for each hour. The top panel shows that the average need for fossil fuel generation can change across the hours of the day.[38] For the same level of total fossil fuel generation, baseload generators (those with lower marginal costs and less flexibility) should be a larger share of the fossil fuel generation when the total required fossil fuel generation is near a local minimum as compared to when it is near a local maximum; hourly controls are included to address this. Because both average total generation and average wind generation are related to the hour and this relationship can differ across months, as seen in Figure 1.9, I also allow the hourly fixed effects to vary across months. This specification will also control for movement in relative fuel prices across months.

The amount of wind generation may not be exogenous. While wind speed likely is exogenous, actual wind generation can be less than the maximum level allowed if grid operators choose. This curtailment could happen for a number of reasons, most prominently transmission constraints. To address potential endogeneity issues with wind curtailment, I instrument for ERCOT-wide wind generation using the maximum possible generation (high sustainable limit) given current conditions for all wind generation units. This is the expected maximum potential output of wind power used by ERCOT when dispatching wind generation resources.[39,40] Note that actual wind generation is on average quite close to the high sustainable limit and wind curtailment drops substantially from 2011 to 2013. Appendix B tests the importance of using an instrument for the wind generation variable and finds only minor

[38]Total generation in Figure 1.9 includes nuclear power, however this does not vary substantially across hours.

[39]The maximum possible wind generation values in the real-time market are set by ERCOT based on telemetered values, not on reported values from the operator of the wind generation resource. However, maintenance decisions for wind turbines could be endogenous.

[40]This differs from Novan [Forthcoming] who uses a measure of wind speed as an instrument.

differences.

To correct standard errors for heteroskedasticity and serial correlation, Newey-West standard errors with 69 lags are used. The lag order was determined through the automatic bandwidth selection procedure of Newey and West [1994].[41]

Table 1.2 shows selected results for this specification. After accounting for its effect in reducing fossil fuel generation, a 1 MWh increase in wind generation is associated with a 0.034 MWh shift in the fossil fuel generation mix away from coal and toward natural gas.

1.6.2 Changes in Effect Across Load and Time

While additional wind power shifts the fossil fuel generation mix towards natural gas, this effect may be less prominent when natural gas is already a larger portion of the generation mix. To test if this intermittency effect falls as load gets larger, I use the following specification which allows for a different impact depending on if total generation net of nuclear power is relatively high or low:

$$\begin{aligned} NatGasGeneration_t = & \beta_1 W_t * 1[High\ Load_t] + \\ & \beta_2 W_t * 1[Low\ Load_t] + \\ & \beta_3 1[High\ Load_t] + \\ & f(FossilFuel_t) + \\ & \alpha_0 + \alpha_1 Temp_t + \alpha_2 Temp_t^2 + \gamma_m HourMonth_t + \epsilon_t \end{aligned} \quad (1.2)$$

[41] This is also close to the 3 days worth of lags used in Kaffine et al. [2010] when studying CO_2 emissions in ERCOT.

where the cutoff for the high or low load indicator function is having total generation net of nuclear power above or below 30,000 MWh, approximately its mean. When generation net of nuclear power is this high, generally there is already a larger share of natural gas generation, as seen in Figure 1.7. Table 1.3 shows the point estimate of the wind intermittency effect on shifting fossil fuel generation from coal to natural gas is weaker when total generation net of nuclear power is greater than 30,000 MWh, falling from 0.048 MWh to 0.028 MWh.[42]

To test if the intermittency effect changes over time, potentially as experience is gained with relatively high levels of wind penetration and wind forecast precision increases, I allow it to differ across years as follows:

$$\begin{aligned} NatGasGeneration_t = & \beta_1 W_t * 1[year = 2011]_t + \\ & \beta_2 W_t * 1[year = 2012]_t + \\ & \beta_3 W_t * 1[year = 2013]_t + \\ & f(FossilFuel_t) + \\ & \alpha_0 + \alpha_1 Temp_t + \alpha_2 Temp_t^2 + \gamma_m HourMonth_t + \epsilon_t \end{aligned} \tag{1.3}$$

Coefficient estimates can be found in Table 1.4. The wind intermittency effect on shifting fossil fuel generation from coal to natural gas is strongest in 2011. A 1 MWh increase in wind generation is associated with a shift in fossil fuel generation from coal to natural gas of 0.075 MWh. By 2013, the same 1 MWh increase in wind generation was responsible for a shift in fossil fuel generation from coal to natural gas of 0.021 MWh.[43] To the extent that

[42] The difference in impact is statistically significant at the 10% level.

[43] The difference in the effect on natural gas generation between 2011 and 2012 is significant at the 10% level while testing that the effect is the same in 2011 and 2013 has a p-value of 0.11.

wind forecast precision has improved from 2011, as seen in Figure 1.6, any given level of wind generation may be associated with lower risk of unexpected change in wind generation in the later years, potentially contributing to the intermittency effect in 2011, β_1, being substantially larger than the other β parameters. Additional experience with higher levels of wind generation could also be a contributing factor.

1.6.3 Explicit Intermittency Variables

In previous specifications, the effect of additional wind beyond reducing fossil fuel generation has been interpreted as the effect of wind intermittency without indicating what feature or features of wind generation was causing such effects, such as forecasted or unforecasted change in wind generation. Identifying the specific features of wind intermittency responsible for effects on fossil fuel generation mix will be important if the value of wind intermittency is to be incorporated into policy decisions. I add a set of explicit wind intermittency variables to do so:

$$\begin{aligned} NatGasGeneration_t = &\beta_1 W_t + \\ &\psi[IntermittencyVars_t] + \\ &f(FossilFuel_t) + \\ &\alpha_0 + \alpha_1 Temp_t + \alpha_2 Temp_t^2 + \gamma_m HourMonth_t + \epsilon_t \end{aligned} \tag{1.4}$$

where *IntermittencyVars* are a vector of intermittency related variables that vary across specifications.

To capture the effect of expected changes in wind generation over time, I calculate the standard deviation of wind generation over a five hour window spanning two hours before and after hour t (for the upcoming two hours I use forecasted potential wind generation for those hours in hour t to distinguish between expected and unexpected change.) To capture the effect of uncertainty in wind power forecasts, I use the difference between the 20th and 50th percentiles of ERCOT's potential wind generation forecast for the upcoming hour.

Four specifications are used with differing vectors of intermittency variables as follows:

1. No intermittency variables; reproduces results from equation 1.1 for ease of comparison

2. Standard deviation of expected wind generation (expected variation)

3. Uncertainty of wind forecast for upcoming hour (unexpected variation)

4. Standard deviation of expected wind generation (expected variation); uncertainty of wind forecast for upcoming hour (unexpected variation)

Table 1.5 shows the coefficient estimates for these specifications. Column 1 reproduces the results from Table 1.2. When the measure of expected variation, the standard deviation of expected wind generation over a five hour window, is included, it shifts fossil fuel generation from coal to natural gas, as seen in Column 2. Similarly, Column 3 shows additional uncertainty in potential wind power forecasts also shifts fossil fuel generation from coal to natural gas. Column 4 includes both types of intermittency (the standard deviation of expected wind generation over a five hour window and the measure of wind forecast uncertainty). The effects of both intermittency variables remain qualitatively the same, shifting natural gas generation from coal to natural gas, although the effect of each individual variable is not as strong as it was when the other was not included.

1.6.4 Effect of Intermittency on Emissions and Fuel Costs

Because natural gas generation is generally both more expensive and less polluting than coal generation, the effect of wind power intermittency on shifting fossil fuel generation from coal to natural gas should also affect total emissions and fuel costs. Any increase in fuel costs or decrease in emissions as a result of wind generation intermittency are costs and benefits imposed by wind generation but the resulting value of these impacts are not borne by the owners of wind generation units.

I directly test the effect of wind intermittency on measures of aggregate CO_2 emissions and fuel costs instead of using the fossil fuel generation mix results combined with measures of average emissions and fuel costs across the generator types. This is because, as noted by Kaffine et al. [2013] and Novan [Forthcoming], emissions for a given unit or type of unit is not always at its average level and directly estimating the effect of wind generation intermittency on emissions can account for these varying emissions levels. The same is true for the efficiency of generation units. See Kaffine et al. [2013] or Novan [Forthcoming] for a more complete discussion.

Initially, to estimate the effect of wind generation intermittency on fuel costs and CO_2 emissions, I use the same approach as in Equation 1.1, reproduced here:

$$\begin{aligned} DependentVar_t = & \beta_1 W_t + f(FossilFuel_t) + \\ & \alpha_0 + \alpha_1 Temp_t + \alpha_2 Temp_t^2 + \gamma_m HourMonth_t + \epsilon_t \end{aligned} \tag{1.5}$$

$DependentVar_t$ is either CO_2 emissions or fuel cost. Coefficient estimates for β_1 for both specifications are found in Table 1.6. After controlling for the effect of wind generation on lowering total fossil fuel generation requirements, the additional effect of wind generation intermittency is associated with reduced overall CO_2 emissions, assuming any additional effect of wind generation is due to intermittency, though the effect on the cost of consumed fuel is close to zero and not statistically significant.[44] Considering that wind intermittency was found to shift fossil fuel generation from coal to natural gas, an increase in fuel generation cost may have been expected as the average fuel cost per MWh of every natural gas generator in the sample is higher than the average fuel cost per MWh of every coal generator.

The prior analysis only looks at the same-hour effects of wind generation intermittency on CO_2 emissions and fuel costs. If wind intermittency has a dynamic impact, affecting emissions and costs in neighboring periods, then the prior CO_2 and fuel cost estimates will be mismeasured. This could be especially true if wind generation affects the outcomes and timing of generator startup decisions as this process consumes fuel inefficiently. I incorporate effects across hours by allowing wind intermittency two hours before and after the current hour to affect the current hour fuel costs and emissions:

$$\begin{aligned} DependentVar_t = \sum_{i=-2}^{2} [\beta_i WindGen_{t+i} + f(FossilFuel_{t+i})] + \\ \alpha_0 + \alpha_1 Temp_t + \alpha_2 Temp_t^2 + \gamma_j MonthHour_t + \epsilon_t \end{aligned} \tag{1.6}$$

The dynamic effect of wind intermittency is the sum of the β_i coefficients. The coefficient results are found in Table 1.7. Wind intermittency increases cost and decreases CO_2 emis-

[44]Measurement error in the dependent variable arises from assuming all coal generators are paying the statewide monthly average rate for coal and that natural gas generators are paying the daily closing price at Henry Hub. This does not incorporate individual long term contracts, individualized transportation costs or differences in coal price due to different coal types. This measurement error will result in less precise estimates of the effect of wind intermittency on fuel costs.

sions. The intermittency associated with a 1 MWh increase in wind generation is associated with a fall of CO_2 emissions of 0.0236 tons, with a value of \$0.92 when using a social cost of carbon of \$39/ton. The associated increase in fuel costs is \$1.38. With average wind generation over the approximate 2011-2013 period covered by the dataset of 3464 MW per hour, the annual increase in fuel generation costs as a result of wind intermittency is about \$42 million. However there is also an average hourly reduction of 81.75 tons of CO_2 with an annual value of about \$28 million, which substantially offsets the increase in fuel generation costs.

Cullen [2013],Kaffine et al. [2013] and Novan [Forthcoming] estimate the impact of an additional MWh of wind generation on overall CO_2 emissions in Texas. While their approaches to this estimation do vary in their specifics, in their base specifications they each find that additional MWh of wind generation lowers CO_2 by an average of 0.523 tons (Kaffine et al. [2013]), 0.4735 tons (Cullen [2013]) and 0.63 tons (Novan [Forthcoming]). These effects are aggregate effects that include both any intermittency related effect as well as the more direct effect of offsetting fossil fuel generation. Averaging the estimates from these three papers results in an average decrease of 0.542 tons of CO_2 per additional MWh of wind generation.[45] This can be compared to the effect of wind intermittency on CO_2 from Table 1.7, where the wind intermittency associated with an increase in wind generation of one MWh results in a fall of CO_2 emissions of 0.0236 tons. This indicates that the effect of wind power offsetting fossil fuel generation is substantially larger than effects resulting from wind intermittency, at least at the levels of wind generation observed in Texas over this time period; the intermittency effect is about 4.4% of the aggregated overall effect from the earlier three papers.[46]

[45] Results from Chapter 2 of this document indicate that an additional MWh of wind generation is associated with a decrease in CO_2 emissions of 0.640 tons in 2011, which is very close to the results found in Novan [Forthcoming].

[46] Note that this chapter uses data from 2011-2013, while the earlier papers use data from varying time

Results from Chapter 2 showing that increased wind generation of 1 MWh on average reduces generation costs by \$26.01 in 2011, indicating that offsetting fossil fuel generation does dominate wind intermittency effects on generation cost as well.

In addition to testing the overall effect of wind intermittency on CO_2 emissions and fuel costs, I examine the effect of the explicit wind intermittency variables that measure expected and unexpected wind power variation. Following the approach from equation 1.4, I allow the intermittency variables from up to two hours before and after hour t to affect the current dependent variable in order to capture effects outside the current hour such as changing generator start-up decisions. The specification is as follows:

$$\begin{aligned} DependentVar_t = & \sum_{i=-2}^{2} [\beta_i WindGen_{t+i} + f(FossilFuel_{t+i})] + \\ & \sum_{i=-2}^{2} [\alpha_i StdDevOfExpectedWindGen_{t+i}] + \\ & \sum_{i=-2}^{2} [\gamma_i UpcomingForecastUncertainty_{t+i}] + \\ & \alpha_0 + \alpha_1 Temp_t + \alpha_2 Temp_t^2 + \gamma_j MonthHour_t + \epsilon_t \end{aligned} \tag{1.7}$$

where $DependentVar_t$ is either CO_2 emissions or fuel costs. Coefficient estimates for the sum of β_i, α_i and γ_i can be found in Table 1.8. For fuel costs, the additional explicit intermittency variables are not statistically significant and the coefficient on the 'additional wind generation effect' after controlling for reduced fossil fuel requirements is largely unchanged from when the explicit intermittency variables were not included in Table 1.7. The CO_2 results, however, are different. The 'additional wind generation effect' is no longer statistically

periods spanning 2005 to 2011.

significant though the coefficient estimate is only slightly changed from Table 1.7. However the measure of expected wind generation variation (the standard deviation of expected wind generation over a five hour window) is statistically significant and reduces CO_2 emissions as would be expected from a shift from coal to natural gas generation. The measure of wind forecast uncertainty is also not statistically significant.

The estimated effect of wind generation intermittency on CO_2 emissions and fuel costs should not be seen as a comprehensive measure of positive and negative externalities imposed by wind generation intermittency. The financial costs of electricity generation come from a number of sources beyond the cost of consumed fuel. Capital costs of constructing the generation units, including interest paid on any initial loan, are also costly. Usage patterns of generators also affect maintenance costs. Newly constructed generation facilities may also require investment in costly additional transmission capacity. Furthermore, natural gas generation is cleaner than coal generation in more ways than just reduced CO_2 emissions. Natural gas generation also generally results in less NO_x, SO_2 and particulate matter pollution. The estimated value of CO_2 emissions reduction and increased fuel costs are lower bounds of both costs and benefits of wind intermittency. For example, engineering estimates suggest that wind generation intermittency will have a financial cost of around \$2 to \$6 per MWh of wind generation (Albadi and El-Saadany [2010]).

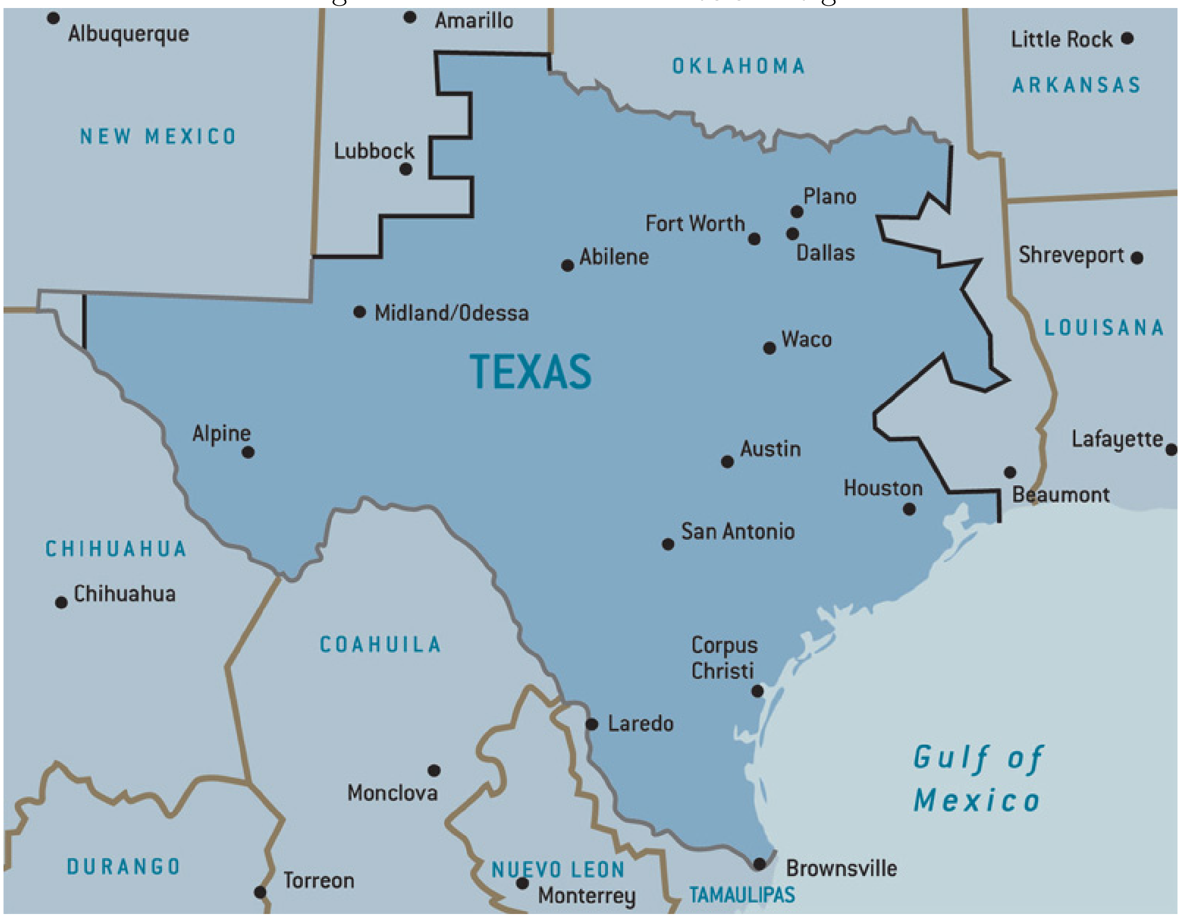
1.7 Conclusion

Wind power intermittency imposes a financial cost on electricity generation. However this intermittency also provides an environmental benefit which should also be accounted for when determining the social impacts of wind generation. On average, wind generation intermittency is associated with increased natural gas generation and reduced coal power. Because natural gas generation is cleaner but more expensive than coal generation, this intermittency-induced shift reduces the emissions resulting from electricity generation but increases fuel costs. The fall in CO_2 emissions suggests this shifting effect dominates any generator-level increased inefficiency due to ramping production levels to accommodate wind intermittency.

Using the U.S. social cost of carbon of $39/ton, the average effect of wind intermittency from a 1 MWh increase in wind generation is associated with a reduction in CO_2 emissions valued at $0.92, not including the value of any emissions reductions apart from CO_2. This value is smaller than the estimated increase in fuel costs of $1.38 as well as engineering estimates of the overall financial costs of wind intermittency of around $2 to $6 per MWh of wind generation but nevertheless indicates a substantial fraction of those financial costs would be offset by environmental benefits. If the social cost of carbon is underestimated due to unmeasurable effects, as suggested by the Intergovernmental Panel on Climate Change report (IPCC [2007]), then these environmental benefits from wind intermittency will be further understated as well.

The impact of intermittency on emissions reduction is relevant for subsidy policy. While subsidizing each MWh of wind power based on its associated emissions reduction would be ideal, this is not a practical solution. However, connecting the subsidy payments for each wind turbine in part to its expected or actual contribution to total wind power intermittency could be feasible; an additional wind turbine will contribute to the overall variation in wind generation based on how its output is correlated with other wind turbines. Incorporating this when setting subsidy levels would encourage any effect on variation in wind generation to be incorporated into siting decisions for new wind turbines and more accurately align the impact of additional wind turbines on emissions with the subsidy payment. Similarly, any subsidy payment related to wind intermittency could reflect the fossil fuel generation mix in the region. While it may be beneficial to lock in a methodology to calculate subsidy payments before turbine is built to simplify financing concerns (compared to other generation sources, the cost of wind generation is effectively all up-front when building the turbine), changes in the social cost of wind generation intermittency over time would ideally be incorporated as well. Most significantly, when determining the social costs of wind intermittency, the impact of intermittency on both generation costs and emissions reduction should be considered.

Figure 1.1: Boundaries of ERCOT Region



Source: ERCOT

Figure 1.2: Wind Generation Capacity in ERCOT

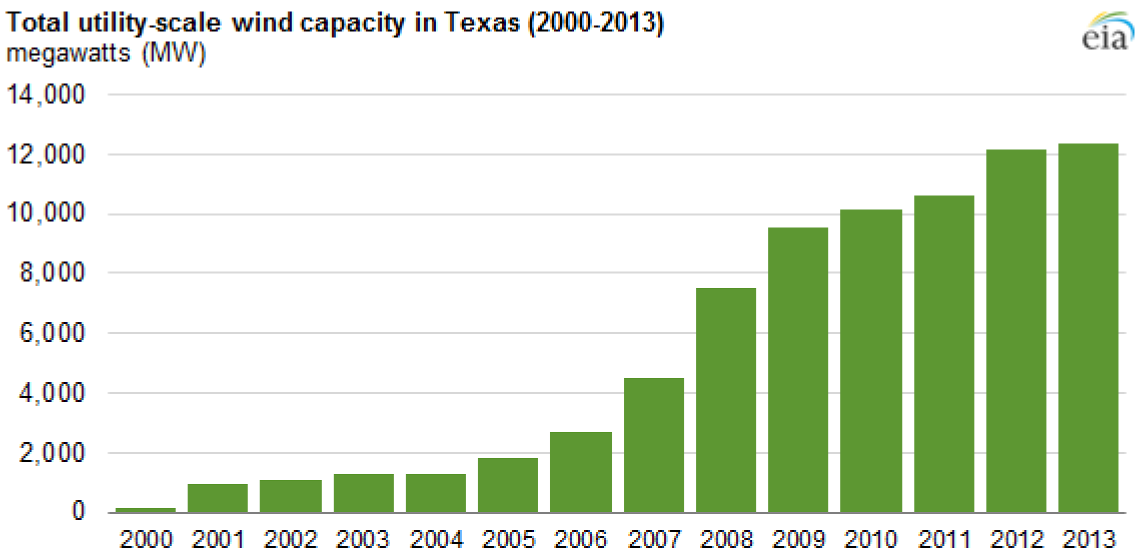


Figure 1.3: Monthly Average Hourly Wind Generation in ERCOT

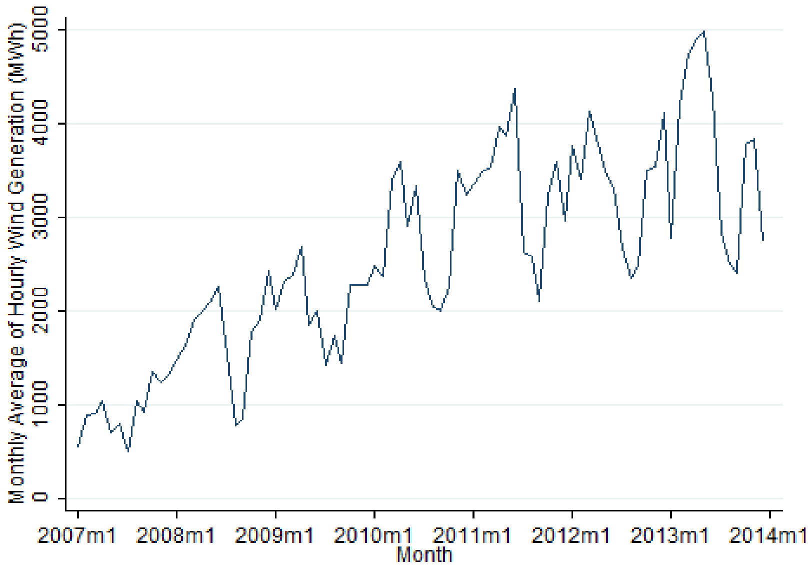
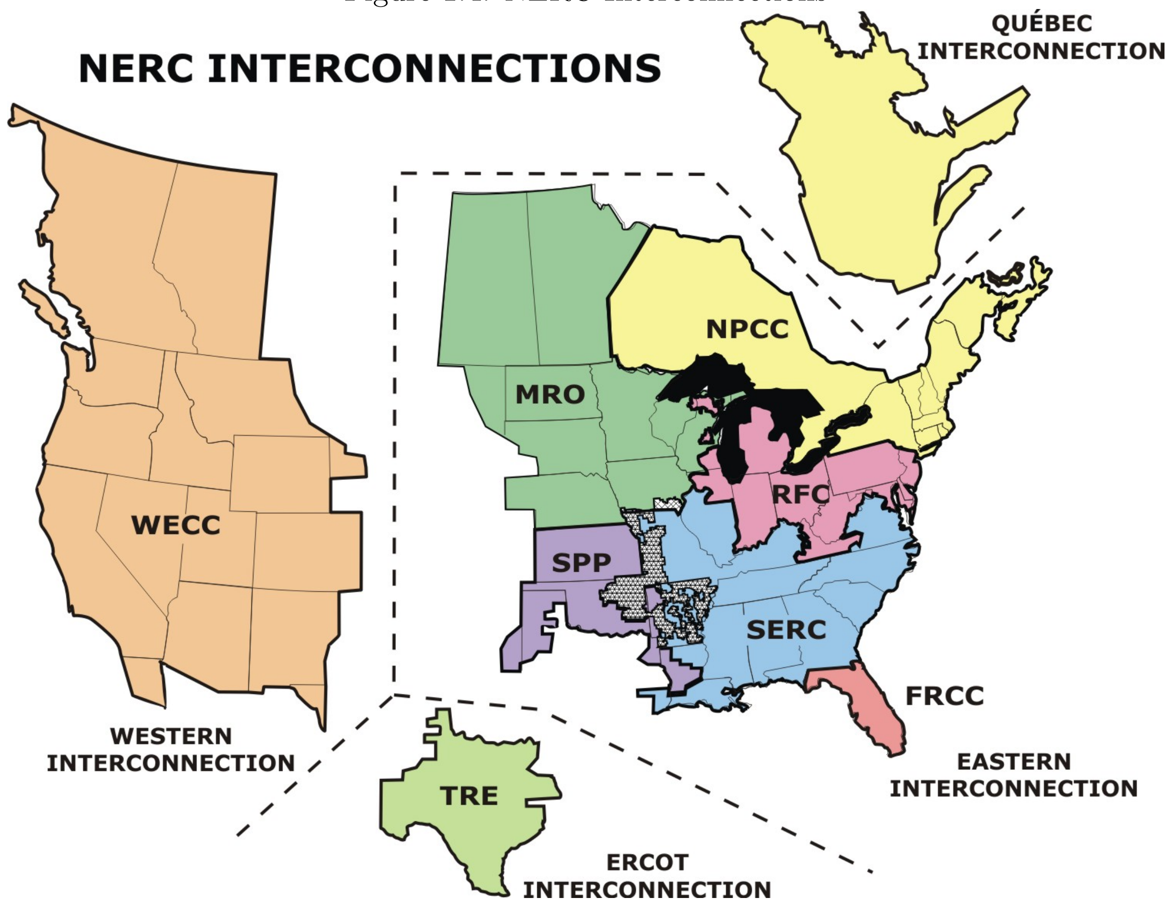


Figure 1.4: NERC Interconnections



Source: NERC

Figure 1.5: Predicted vs. Actual Wind Generation in ERCOT

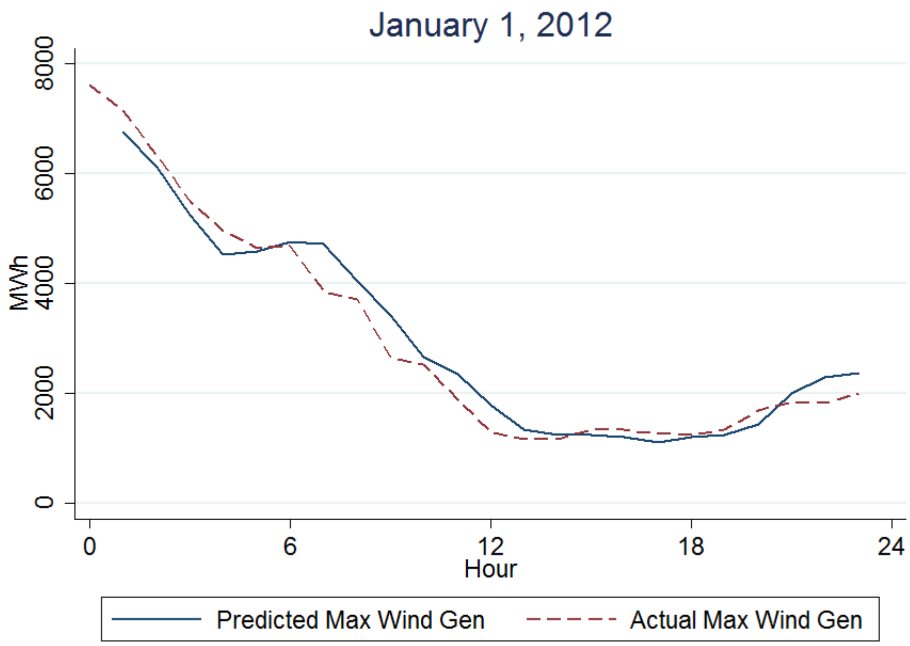


Figure 1.6: Distribution of Wind Forecast Error By Year

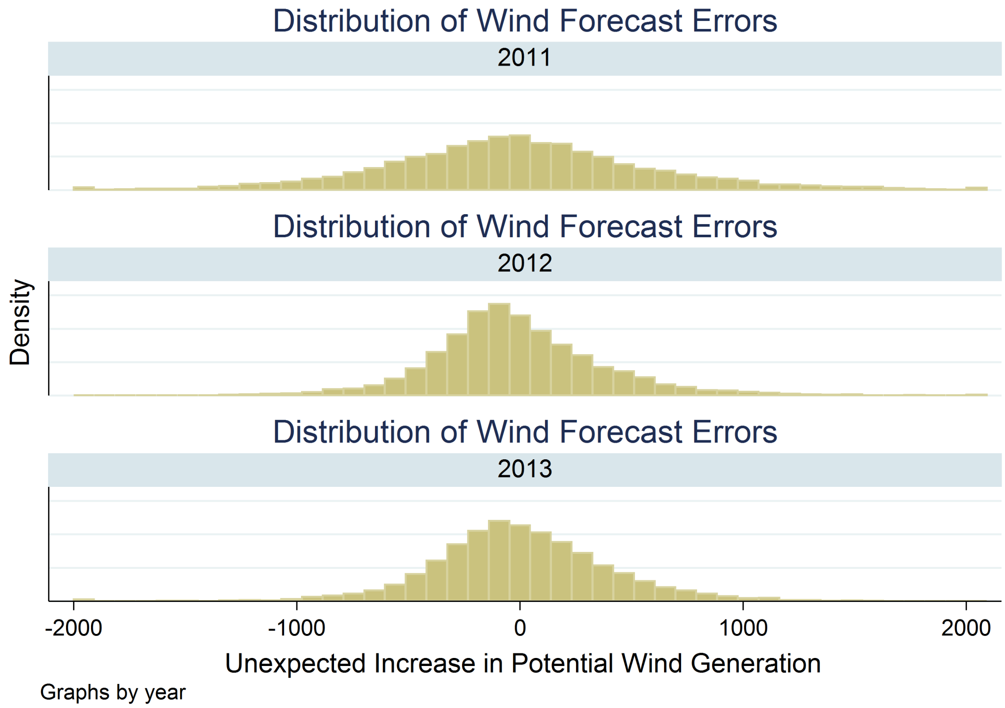


Figure 1.7: Generation By Type vs. Non-Nuclear, Non-Wind Generation

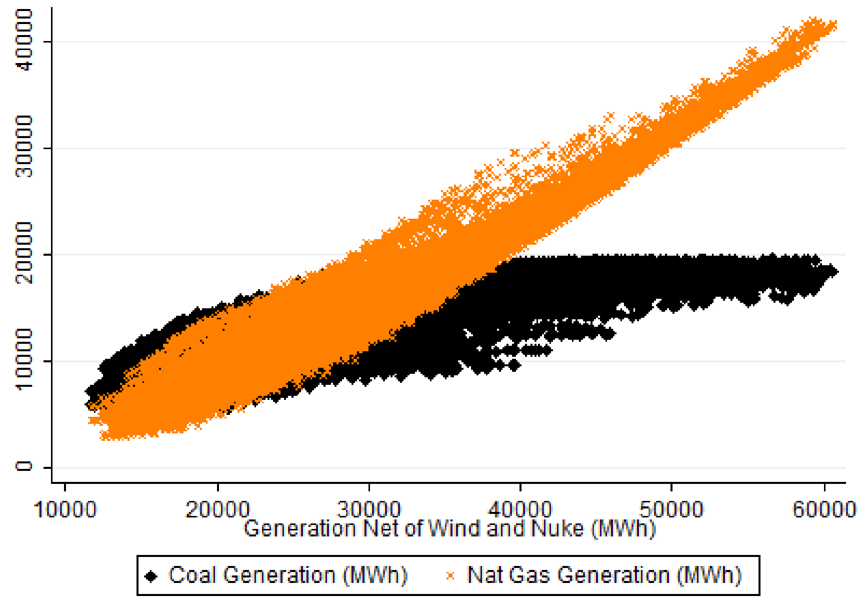


Figure 1.8: Illustration of Potential Effects of Increasing Wind Power on Natural Gas Generation

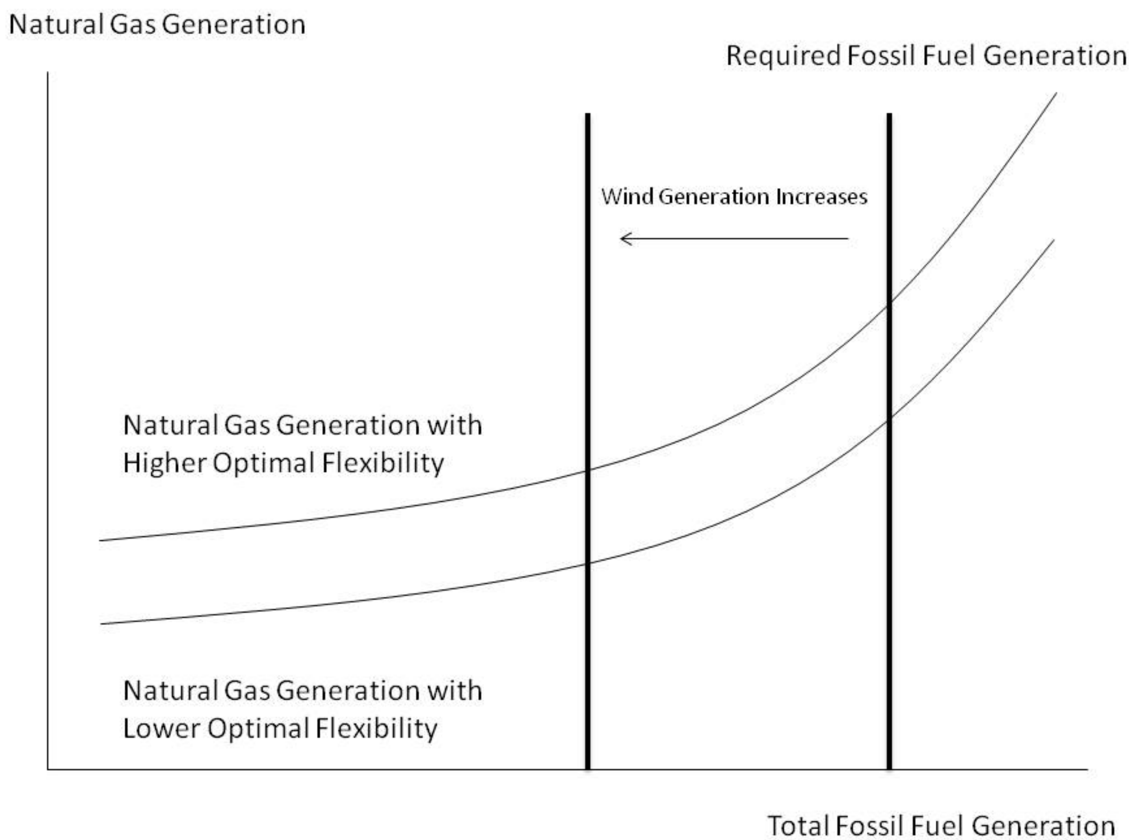


Figure 1.9: Generation By Hour

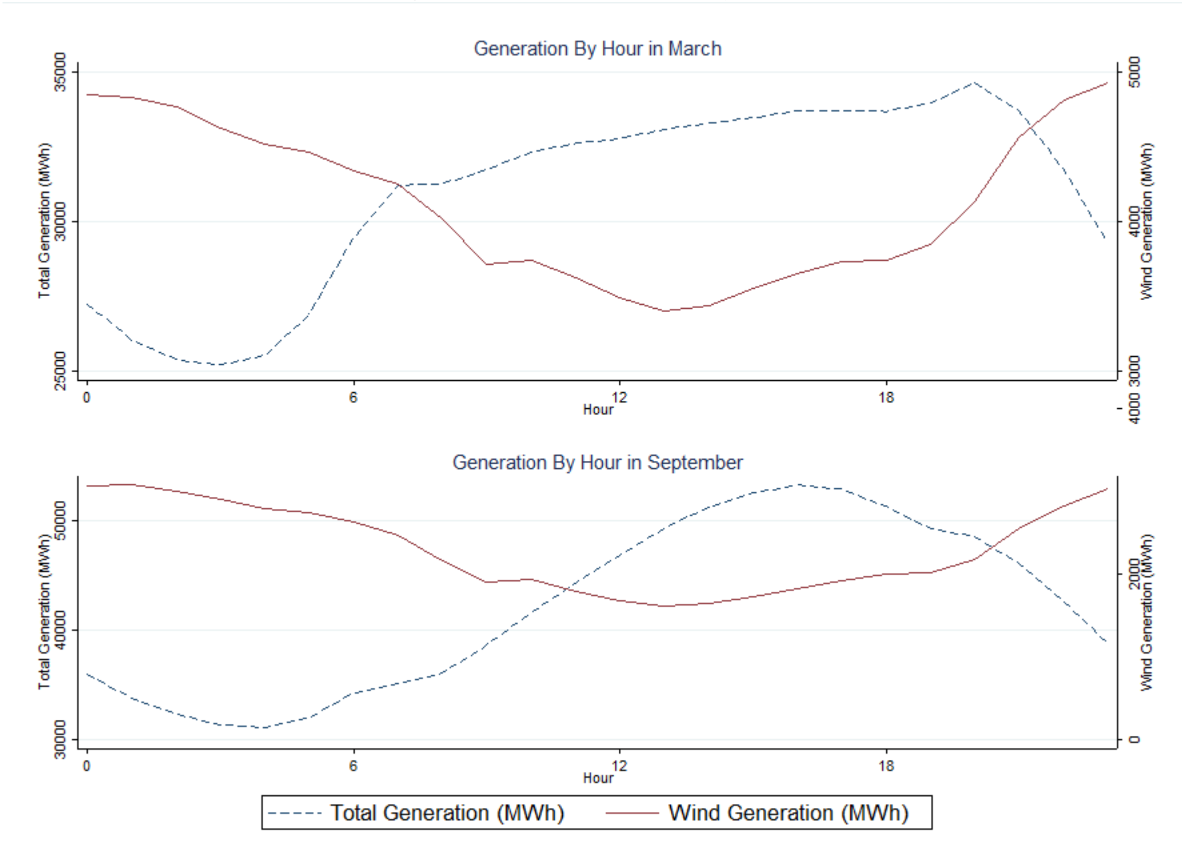


Table 1.1: Emissions and Generation Cost By Fuel Source

	Coal	Natural Gas
Average CO_2 Emissions (tons/MWh)	1.19	0.53
Average Fuel Cost ($/MWh)	21.42	30.75
Average Max Generation (MW)	632	201

Average maximum generation is the average of the highest observed output for each generation unit. Average fuel cost and CO_2 emissions is the ratio of total CO_2 and total fuel cost to total generation by fuel type.

Table 1.2: Effect of Wind Intermittency on Fossil Fuel Generation Mix

VARIABLES	(1) Nat Gas Generation
Wind Gen	0.0336*
	(0.0176)
f(Fossil Fuel Gen)	X
Observations	23,665

Observations are hourly and aggregated to ERCOT-level. Data is from approximately 2011-2013. Newey-West standard errors with 69 lags used to correct for heteroskedasticity and serial correlation. Potential wind generation is used to instrument for actual wind generation. Coefficients for temperature, hour-month indicator variables and nonlinear controls for generation net of nuclear and wind power are omitted. *** p<0.01, ** p<0.05, * p<0.1

Table 1.3: Effect of Wind Intermittency on Fossil Fuel Generation Mix - By Load Level

VARIABLES	(1) Nat Gas Generation
Wind Gen (High Load)	0.0282
	(0.0178)
Wind Gen (Low Load)	0.0483**
	(0.0189)
High Load Indicator	29.94
	(58.67)
f(Fossil Fuel Gen)	X
Observations	23,665

Observations are hourly and aggregated to ERCOT-level. Data is from approximately 2011-2013. Newey-West standard errors with 69 lags used to correct for heteroskedasticity and serial correlation. Potential wind generation is used to instrument for actual wind generation. Coefficients for temperature, hour-month indicator variables and nonlinear controls for generation net of nuclear and wind power are omitted. *** p<0.01, ** p<0.05, * p<0.1

Table 1.4: Effect of Wind Intermittency on Fossil Fuel Generation Mix - By Year

VARIABLES	(1) Nat Gas Generation
Wind Gen (2011)	0.0751***
	(0.0235)
Wind Gen (2012)	0.0215
	(0.0238)
Wind Gen (2013)	0.0209
	(0.0286)
f(Fossil Fuel Gen)	X
Observations	23,665

Observations are hourly and aggregated to ERCOT-level. Data is from approximately 2011-2013. Newey-West standard errors with 69 lags used to correct for heteroskedasticity and serial correlation. Potential wind generation is used to instrument for actual wind generation. Coefficients for temperature, hour-month indicator variables and nonlinear controls for generation net of nuclear and wind power are omitted. *** $p<0.01$, ** $p<0.05$, * $p<0.1$

Table 1.5: Effect of Detailed Wind Intermittency Variables on Fossil Fuel Generation Mix

VARIABLES	(1) Nat Gas Gen	(2) Nat Gas Generation	(3) Nat Gas Gen	(4) Nat Gas Gen
Wind Gen	0.0336*	0.0300*	0.0200	0.0200
	(0.0176)	(0.0177)	(0.0192)	(0.0191)
Forecast Uncertainty			0.355**	0.273*
			(0.160)	(0.161)
Std Dev of Expected Wind Gen (5 Hr Window)		0.155***		0.131**
		(0.053)		(0.053)
f(Fossil Fuel Gen)	X	X	X	X
Observations	23,665	23,665	23,665	23,665

Observations are hourly and aggregated to ERCOT-level. Data is from approximately 2011-2013. Newey-West standard errors with 69 lags used to correct for heteroskedasticity and serial correlation. Potential wind generation is used to instrument for actual wind generation. ”Std Dev of Expected Wind Gen (5 Hr Window)” measures expected variance in wind generation. ”Forecast Uncertainty” is the difference between the 20th and 50th percentile of predicted potential wind generation outcomes in the following hour. Coefficients for temperature, hour-month indicator variables and nonlinear controls for generation net of nuclear and wind power are omitted. *** $p<0.01$, ** $p<0.05$, * $p<0.1$

Table 1.6: Static Effect of Wind Intermittency on Generation Costs and Emissions

VARIABLES	(1) CO_2	(2) Generation Cost
Wind Gen	-0.0551***	-0.00501
	(0.0118)	(0.575)
f(Fossil Fuel Gen)	X	X
Observations	23,665	23,665

Observations are hourly and aggregated to ERCOT-level. Data is from approximately 2011-2013. Newey-West standard errors with 69 lags used to correct for heteroskedasticity and serial correlation. Potential wind generation is used to instrument for actual wind generation. Coefficients for temperature, hour-month indicator variables and nonlinear controls for generation net of nuclear and wind power are omitted. NG and Coal results do not sum to ”total” results due to a small number of other generation units. *** p<0.01, ** p<0.05, * p<0.1

Table 1.7: Dynamic Effect of Wind Intermittency on Generation Costs and Emissions

VARIABLES	(1) CO_2	(2) Generation Cost
Dynamic Wind Gen	-0.0236*	1.38**
	[0.070]	[0.0301]
f(Fossil Fuel Gen)	X	X
Observations	23,665	23,665

Observations are hourly and aggregated to ERCOT-level. Dynamic effects include impacts over a five hour window. Data is from approximately 2011-2013. Newey-West standard errors with 69 lags used to correct for heteroskedasticity and serial correlation. Potential wind generation is used to instrument for actual wind generation. Coefficients for temperature, hour-month indicator variables and nonlinear controls for generation net of nuclear and wind power are omitted. NG and Coal results do not sum to "total" results due to a small number of other generation units. P-value for F-test of summed effect in brackets. *** p<0.01, ** p<0.05, * p<0.1

Table 1.8: Dynamic Effect of Detailed Wind Intermittency Variables on Generation Cost and Emissions

VARIABLES	(1) Generation Cost	(2) CO_2
Dynamic Wind Gen	1.44*	-0.021
	[0.054]	[0.162]
Dynamic Std Dev of Expected Wind Gen (5 Hr Window)	0.179	-0.215***
	[0.846]	[0.002]
Dynamic Forecast Uncertainty	-1.63	0.0685
	[0.951]	[0.652]
f(Fossil Fuel Gen)	X	X
Observations	23,665	23,665

Observations are hourly and aggregated to ERCOT-level. Dynamic effects include impacts over a five hour window. Data is from approximately 2011-2013. Newey-West standard errors with 69 lags used to correct for heteroskedasticity and serial correlation. "Std Dev of Expected Wind Gen (5 Hr Window)" measures expected variance in wind generation. "Forecast Uncertainty" is the difference between the 20th and 50th percentile of predicted potential wind generation outcomes in the following hour. Coefficients for temperature, hour-month indicator variables and nonlinear controls for generation net of nuclear and wind power are omitted. P-value for F-test of summed effect in brackets. *** $p<0.01$, ** $p<0.05$, * $p<0.1$

CHAPTER II

Valuing Transmission and Curtailment of Wind Generation

2.1 Introduction

Wind generation has expanded dramatically in Texas over the past 15 years. Much of this generation capacity was installed in remote areas in the western part of the state because of more favorable wind conditions. As the number of turbines in this area increased, the amount of wind power curtailment – not generating wind power that could have been generated based on weather conditions – increased as well because of the inability of the transmission grid to move all of the potential wind power to the more populated areas of the state where most of the electricity demand was. This wind power curtailment meant that the forfeited electricity must instead be generated from a source with higher marginal cost such as coal or natural gas. In 2011, Texas curtailed over 5% of its potential wind generation with wind curtailment potentially becoming an increasingly large issue as the number of wind turbines continued to grow.

Recognizing early on that the locations with this highest quality wind conditions for wind power generation were in remote areas, the Public Utilities Commission of Texas (PUCT) initiated a project in 2008 to increase transmission capacity to take greater advantage of the wind generation potential. The resulting expansion of transmission capacity substantially reduced the amount of wind generation curtailment; by 2013 curtailment was down to well under 0.5% of potential wind generation even as the number of wind turbines and the amount of the resulting wind generation continued to increase. However after running over the initial forecasted budget, the final cost of this transmission expansion was around $7 billion, essentially a large fixed cost that was paid in order to better access the selected wind resources.

This chapter compares estimates of the financial and environmental benefits of this transmission expansion to its costs. While accessing additional wind power, with its absence of fuel costs and air pollution, has clear benefits, how much of the value of the recent Texas expansion was consumed by the cost of transmission? To do so I estimate the impact of additional wind generation on generation cost and CO_2 emissions from before the transmission expansion. I then use data from after the expansion to obtain a counterfactual level of wind generation. I find this additional generation falls far short of the amount of wind generation necessary to generate enough value to justify the transmission expansion, which is unsurprising given that allowing for more effective use of additional wind turbines was the main purpose of the transmission expansion. I then estimate the amount of additional wind generation that would be necessary to justify the cost of expanded transmission.

Ultimately if the expanded transmission capacity is fully used by wind generation, under some conservative assumptions, I find that between about 2.5-11.2% of the additional value will be consumed by the cost of the transmission expansion. As transmission expansion was not immediately fully used (the current record for peak wind generation is around 60% of the capacity of the transmission expansion) the true cost of transmission is non-trivially higher.

While the low-marginal cost nature of wind generation is attractive, the fixed costs of installation can be large. Additionally, the costs of transmission capacity to move the electricity to the areas where it is needed can be nontrivial and should be considered part of the overall costs of generation. This can be a larger issue for wind generation as opposed to other power sources that do not depend on weather conditions and can be located closer to the areas where it is demanded, lowering the necessary transmission costs. While wind generation can be constructed anywhere, the financial viability of any specific wind turbine project depends on the average weather conditions allowing sufficient generation to pay for the turbine. Incorporating any necessary transmission cost into this benefit-cost analysis may result in regions with less ideal wind conditions but lesser transmission requirements being preferable to remote regions with excellent weather conditions for wind generation. Incorporating the cost of transmission into the financial incentives for the entity making the siting decisions for wind turbines could improve overall welfare.

2.2 Background

2.2.1 Wind Generation in Texas and CREZ Construction

The amount of electricity that can be generated by wind depends on the wind conditions. As the cost of wind generation is essentially the construction and installation of the turbine, with little operating costs later, from the perspective of the turbine owners, it is most cost effective to place these turbines in areas with high average wind speed. Often these places are geographically remote; across the United States as a whole, the middle region of the country stands out as being a particularly fruitful place for wind generation (2.1). In Texas, the best locations for wind turbine construction, in terms of their potential wind energy generation, are in the western part of the state. However this area is not close to the major urban areas of the state and initially there was limited transmission capacity to move electricity out of this area.

In the mid-2000s, as wind generation capacity was dramatically increasing with increasing numbers of wind turbines being installed (Figure 1.2), the Texas government began to look at ways to upgrade the transmission grid to best take advantage of the natural wind resources in the western part of the state. Texas Senate Bill 20, in 2005, required the Public Utilities Commission of Texas (PUCT) to identify Competitive Renewable Energy Zones (CREZ) where wind generation potential was high and where transmission capacity would be upgraded. In 2008, the PUCT declared five regions as CREZ (Figure 2.2). Initial construction on the transmission expansion began around 2010 and was essentially completed by the end of 2013 at a cost of $6.9 billion (Figure 2.3).[47,48]

Over 3,589 miles of new 345 kV transmission lines were part of this project, with a capacity of about 18,500 MW. To reach this level of wind generation would require substantial additional wind turbines; the current instantaneous wind production record in Texas is 10,957 MW and was set on December 25, 2014.

Interested readers should refer to the final CREZ progress report for additional details (RS&H [2014]).

During the period between when the CREZ project was started and when sections of additional transmission began coming online, wind generation capacity continued to grow

[47]One project (out of 169) is expected to be completed by December 2015.

[48]The initial predicted cost was $5.0 billion for 2,963 miles of transmission. For simplicity, this early estimate assumed that the transmission lines would be straight, however in practice this did not turn out to be the case, leading to increases in required transmission lines and cost.

(Figure 1.2). Wind curtailment, due to transmission constraints, became more common.[49] Additionally spot prices for electricity in the western part of the state were often negative when this transmission congestion occurred. This was because the federal Production Tax Credit paid wind turbine owners based on their output and so wind turbine operators could profitably submit negative bids. During periods of transmission congestion, the marginal generator in the western part of the state could be wind.

The top panel in Figure 2.4 shows that in 2011, wind generation curtailment was substantial at higher levels of potential wind generation. Once the CREZ projects began to be completed, transmission constraints were reduced and occurrences of wind curtailment and negative spot prices in the western part of the state became more infrequent (Figure 2.6). In 2014, after the completion of the CREZ expansion, wind generation curtailment became trivial, even at the highest observed levels of potential wind generation, as seen in the bottom panel of Figure 2.4.[50]

2.2.2 Related Literature

Other researchers have studied the importance of transmission. The closest paper is Davis and Hausman [2014], who look empirically at the impact of the unexpected closure of the SONGS nuclear generating facility in California that was located between Los Angeles and San Diego. In addition to needing to replace the missing nuclear generation with higher marginal cost sources, transmission constraints imposed an additional cost because higher marginal cost generation in the southern part of the state needed to be used in place of lower-marginal cost generation in the north. This out-of-merit-order generation due to transmission

[49] Appendix C discusses some evidence of minor wind power curtailment due to the exercise of market power.

[50] The total transmission capacity of the CREZ lines is approximately 18,500 MW, substantially higher than the potential wind generation in any hour in 2014.

constraints raised the cost of energy by an average of $4,500 per hour.[51] Other papers have studied electricity transmission from a theoretical perspective, such as Joskow and Tirole [2000], Bushnell [1999], Ryan [2013], Borenstein et al. [2000] and Wolak [2012]

In the specific case of the CREZ transmission expansion in Texas, the stated purpose was to allow for greater access to areas with high wind generation potential. Thus much of the value of the CREZ project would be expected to come from greater access to this low-marginal cost resource. In addition to being less expensive with regards to marginal cost than fossil fuel generation, wind generation also does not create air pollution such as CO_2. Other papers that have empirically studied the value of wind generation on reducing emissions include Callaway and Fowlie [2009], Cullen [2013], Novan [Forthcoming], Kaffine et al. [2013] (as well as the working paper version that looks at MISO and CAISO in addition to Texas, Kaffine et al. [2010]), in addition to Chapter 1 of this text.

2.3 Model of Optimal Transmission Capacity

To illustrate the value of additional transmission capacity and optimal decisions regarding transmission installation, I use a stylized model of the electric grid. This model is intended to capture a feature of the Texas electricity situation, where a remote area has excellent wind generation but little demand or other sources of power.

Assume there are two regions, A and B. Region A has the ability to generate an exogenously determined amount of wind power in any hour, W_t^A, but does not have any other generation capacity or electricity load. The amount of potential wind generation in any hour is given by $f(W^A)$, which is bounded from above by the maximum capacity of all installed

[51] This was about 7% of the total increase in generation cost from shutting the SONGS facility down.

wind turbines in the region, $MaxWind$. Region B has an inelastic demand for electricity, L^B and fossil fuel generation capacity $G^{B,Capacity}$. $G^{B,Capacity}$ is assumed to be equal to or larger than L^B so the demand for electricity can be met without any wind generation. For simplicity, region B does not have any wind generation capacity. Assume that L^B is larger than the maximum potential wind generation in region A.

The marginal cost of generating electricity through fossil fuels is increasing with the level of fossil fuel generation: $c'(G_t^B) > 0$, where G_t^B is the amount of electricity generated through fossil fuels in time period t. Assume that this cost function incorporates both financial cost and the impact of any resulting environmental pollution. Generating electricity through wind generation has zero marginal cost.

Assume that there are transmission constraints between regions A and B, so that the most electricity that can be sent from region A to region B is T. The cost minimizing solution to have total generation equal to total load is to use as much (zero marginal cost) wind generation as possible and generate the rest with fossil fuels. This leads to a fossil fuel generation decision of $G_t^B = L^B - min\left(W_t^A, T\right)$.

Increasing the transmission capacity T decreases the amount of required fossil fuel generation if the transmission constraint is binding and does nothing otherwise. This expansion changes the generation and environmental costs by $\frac{\partial c(L^B - min\left(W_t^A, T\right))}{\partial T}$, which is either negative if the transmission constraints bind and zero otherwise. The expected cost savings in a single period of expanding transmission capacity would then be
$\int_0^{MaxWind}\left(\frac{\partial c(L^B - min\left(W_t^A, T\right))}{\partial T}\right) f(W_t^A)dW_t^A$. Over an infinite number of periods with discount value δ, and assuming that the value of transmission in each period is the expected value, the present value of an additional unit of transmission capacity would be
$\frac{\int_0^{MaxWind}\left(\frac{\partial c(L^B - min\left(W_t^A, T\right))}{\partial T}\right) f(W_t^A)dW_t^A}{\delta}$.

When deciding whether to construction additional transmission capacity, it will be optimal to expand transmission as long as the marginal cost of additional transmission, assumed here to be an infinitely lived resource, is less than the present discounted value of the financial and environmental cost savings. This cutoff could easily be reached before the transmission capacity is equal to the maximum wind generation, so that the optimal level of wind curtailment could be positive.

2.4 Data

The data used in this chapter is very similar to that of Chapter 1, with the key addition being data from 2014.[52] The analysis uses data for Texas from February 22, 2011 to December 31, 2014.[53] Data for this project comes from ERCOT, the EPA, Weather Underground and the U.S. Census.

Generator output data comes from ERCOT. Generator output data from ERCOT's real-time market is available at 15 minute intervals and includes the quantity of electricity generated by and the maximum potential output of each generation unit given its current output and ability to change output levels within a short amount of time.[54] The maximum potential output levels for wind generation units at the time the generation units are dispatched depend on wind conditions and are telemetered data instead of being submitted by the wind unit operators. Quantity of electricity generated only includes power added to the grid and does not count any electricity consumed by the generator itself.

Data on hourly CO_2 emissions from power generation units within ERCOT are obtained

[52]I do not have 2014 data for some variables used in Chapter 1 (all of the wind forecast error variables) so that year is omitted from the Chapter 1 analysis.

[53]I am missing data for a small number of days during this time period.

[54]This is called the High Dispatchable Limit.

through the EPA's Continuous Emissions Monitoring System (CEMS). CEMS allows the EPA to track compliance with emissions-related regulations.[55] See Section 1.4 for details.

I create a single hourly temperature measure for Texas using a population-weighted average of the 10 largest cities in ERCOT. Again, see Section 1.4 for details.

Pricing data for coal is at the monthly level and is the average cost of coal delivered for electricity generation in Texas. Coal pricing data comes from the EIA's Electric Power Monthly. Pricing data for natural gas at the daily level and is the spot price for delivery at the Henry Hub as reported by the EIA. Fuel costs are calculated using measures of the heat content of fuel consumed (from CEMS) and the cost of that fuel. These costs are approximations to the actual price paid by the generators, which will vary across generators. For example, natural gas prices vary geographically and coal prices can vary depending on the type of coal used by specific generators.

2.5 Costs of Additional Transmission

While the construction of the CREZ transmission lines allowed for a reduction in generation costs, the expense involved could represent a non-trivial amount of those savings. After cost overruns of about $2 billion, the final cost of the CREZ transmission lines was $6.9 billion. In addition to the construction costs, these power lines must be maintained. KEMA [2012] notes that operations and maintenance costs account for about 1% of the costs of a typical 345 kV transmission line. Applying this approximation to the initial cost results in a lifetime cost of approximately $6.969 billion.

The annual savings that would justify such an expense in present value terms can be found

[55] Generation units with a capacity less than 25 MW are not required to participate in CEMS and so this analysis omits emissions from those units.

by solving for V in $6,969,000,000 = \sum_{y=1}^{T} \frac{V}{(1+\delta)^y}$, where T is the lifespan of the transmission lines and assuming the value of the payments were received at the end of each year. I use two discount values in this calculation: 3% and 7%. These values were chosen because they are the values used by the U.S. government in benefit-cost analyses as required in the Office of Management and Budget's Circular A-4 (OMB [2003]).[56] Following KEMA [2012], I set a lifespan for the transmission lines of 40 years. With a discount rate of 3%, the amount of annual benefits needed to justify the CREZ construction is \$301,495,511; with a discount rate of 7% this value is \$522,738,688.

2.6 Estimating Benefits of Additional Transmission

To estimate the financial and environmental value of additional transmission that reduces wind power curtailment, I construct a counterfactual level of 2011 wind generation and curtailment as if the CREZ transmission lines had been completed. I measure the impact of additional wind generation on both generation costs and CO_2 emissions to place a dollar value on the counterfactual additional wind permitted by the new transmission lines. I then estimate how much additional wind generation beyond the curtailment reduction will be necessary on average to justify the large costs of the CREZ transmission lines.

[56] OMB selected 7% as an historical average pre-tax rate of return on private investment. Alternatively, 3% is their value for consumption discounting.

2.6.1 Estimating Counterfactual Wind Generation With Transmission Expansion

The CREZ expansion of transmission lines to allow for additional wind generation from the western part of Texas was essentially completed in 2013. Compared to 2011 wind generation, after the completion of the new transmission lines, wind generation curtailment was sharply reduced, though not eliminated entirely as seen in the lower panel of Figure 2.4. To obtain a counterfactual estimate of the amount of hourly wind generation in 2011 that would have occurred with the expanded transmission grid, I estimate the relationship between potential wind generation and actual wind generation in 2014, when the expansion of the transmission grid was complete. Potential wind generation is allowed to affect wind generation in a quadratic manner because curtailment is more likely to occur at higher levels of potential wind generation due to transmission constraints or other reasons.

$$WindGen_t = \beta_0 + \beta_1 PotentialWindGen_t + \beta_2 PotentialWindGen_t^2 + \epsilon_t \qquad (2.8)$$

Both potential wind generation coefficients are statistically significant at the 1% level. The estimated relationship between potential and actual wind generation in 2014 is illustrated in the top panel of Figure 2.7 while the lower panel shows the 2014 relationship between potential wind generation and wind generation curtailment. Wind generation curtailment does increase as potential wind generation rises, however even at the highest observed levels of wind generation in 2014, the expected wind curtailment is around 1%.[57] The 95% confi-

[57] Note that this estimated relationship only uses 2014 data and caution should be used if applying this relationship to predict wind generation when potential wind generation is substantially outside the observed sample.

dence interval for the predicted wind generation is sufficiently tight as to not be observable in the upper panel of the figure.

Figure 2.5 shows the monthly average actual and counterfactual ("with completed CREZ lines") wind generation. Potential wind generation is not included on the figure; were it to be included it would essentially overlap the "counterfactual wind generation" line. The counterfactual wind generation in 2011 is notably larger than the actual wind generation; as the date gets closer to 2014 and CREZ transmission lines become active, these lines converge.

2.6.2 Value of Reduction In Wind Curtailment From Additional Transmission

To determine the value of of the reduced wind power curtailment caused by the addition of the CREZ transmission lines, I estimate the value of additional wind power on reducing generation costs and CO_2 pollution. I then determine the value of counterfactual reduced wind curtailment in 2011.

Average Value of Wind Generation and Impact of Curtailments

To calculate the value of additional wind generation and the effect of wind curtailment on the costs of generating a given quantity of fossil fuels, I estimate the following specification using data from 2011:

$$\begin{aligned} CO2_t \ or \ GenCost_t = & \beta_1 WindGen_t + f(TotalGen_t - Nuclear_t) + \\ & + \beta_6 Temp_t + \beta_7 Temp_t^2 + HrMonthYear_t + \epsilon_t \end{aligned} \tag{2.9}$$

where the dependent variable is either hourly fossil fuel generation cost or CO_2 emissions.[58] The coefficient on the $WindGen_t$ parameter captures the average effect of an additional MWh of wind generation on the dependent variable and is expected to lower both CO_2 and generation costs by replacing fossil fuel generation with zero marginal cost, zero emissions wind generation. The total generation net of nuclear generation (both of which are assumed to be exogenous) is included as a fifth-degree orthogonalized polynomial in order to flexibly capture increasing cost and CO_2 emissions as the amount of non-nuclear generation increases. This measure is net of nuclear generation because nuclear generators have high output capacity, very low marginal cost and generally do not adjust output levels with generation levels, instead running at high output levels unless they are shut down for maintenance. Thus not adjusting total generation in the specification for the amount of nuclear generation would model periods with the same overall load that do and do not have a substantial amount of nuclear generation as having the same cost and CO_2 emissions.[59]

Higher temperatures are associated with reduced generator efficiency which would be expected to lead to increased generation cost and emissions and are also correlated with wind generation. The temperature variables are included to flexibly capture this effect.

Dummy variables for each hour-month-year combination are included to address dynamic issues. Figure 1.9 plots the average total generation and wind generation for each hour in both September and March for 2011-2013. These show that the average need for fossil fuel generation can change across the hours of the day. For the same level of total generation,

[58]Note that increasing wind generation and offsetting fossil fuel generation will result in the reduction of more pollutants than just CO_2, such as NO_x, SO_2 and particulate matter pollution. The analysis in this chapter does not incorporate the value of reducing these emissions. Incorporating their value would, if reduction in pollutants are valued by policymakers, make the the costs of the CREZ transmission expansion a smaller part of the overall value of the permitted wind generation and would reduce the amount of additional wind generation necessary to create enough value to cover the costs of construction.

[59]Nuclear power represents about 10% of the electricity generation in Texas.

baseload generators should be a larger share of the generation when the total generation is near a local minimum as compared to when it is near a local maximum with corresponding effects on generation cost and CO_2 emissions; hourly controls are included to address this. Because both average total generation and average wind generation are related to the hour and this relationship can differ across months, I also allow the hourly fixed effects to vary across months. Newey-West standard errors are robust to heteroskedasticity and serial correlation and include 53 lags.[60]

When wind generation is being heavily curtailed, this is likely due to transmission constraints.[61] This constraint implies that it will be necessary to operate the grid in a manner that is less cost-minimizing than would otherwise be the case, such as by substituting more expensive fossil fuel generation for wind generation. Results indicating that non-wind generation out-of-merit order effects due to transmission constraints are generally not statistically significant and are of small magnitude are available upon request.

Coefficient estimates are found in Tables 2.9 and 2.10, for the dependent variables of generation cost and CO_2 emissions, respectively. As expected, because wind generation offsets fossil fuel generation, additional wind generation reduces both the overall costs of generation and CO_2 emissions. On average, a 1 MWh increase in wind generation is associated with a decrease in generation costs of \$26.01 and a decrease in CO_2 emissions of 0.640 tons. Based on a social cost of carbon of \$39/ton, this decrease in CO_2 emissions has a value of \$24.96.

[60]This number of lags was selected using an automatic bandwidth selector. This result is about 75% of the 72 lags used in a similar regression in Kaffine et al. [2010].

[61]See Appendix C for a brief discussion of evidence of market power based wind curtailment.

Valuation of 2011 Counterfactual Reduced Wind Curtailment Due To Transmission Expansion

I calculate a counterfactual wind generation for 2011 using the potential wind generation from 2011 with the relationship between potential and actual wind generation in 2014, after the completion of the CREZ transmission lines, as estimated in Specification 2.8. I can then estimate counterfactual generation cost and CO_2 emissions that would have occurred in 2011 if the CREZ transmission lines had been in place using the results from the prior section.

Column 1 of Table 2.11 shows the actual fossil fuel generation costs and CO_2 emissions in 2011. Column 2 shows the generation cost and CO_2 emissions when using the counterfactual 2011 wind generation as if the CREZ project was already complete. Column 3 shows a separate counterfactual generation cost and CO_2 emissions when there is no wind power curtailment at all.

Comparing Columns 1 and 2 of Table 2.11 shows that having completed the CREZ transmission expansion would have reduced hourly generation costs in 2011 by an average of $5577 and CO_2 emissions by 137 tons. Using a social cost of carbon of $39/ton, this CO_2 savings would be valued at $5343. The differences in value between Columns 2 and 3 – the additional savings in generation cost and CO_2 emissions if wind curtailment was brought to zero – are not large, about $300/hour in value each. Arranging the electric grid to prevent any wind curtailment at all would almost surely not be cost effective, as noted in the model in Section 2.3.

2.7 Comparing Costs and Benefits of CREZ Transmission in Texas

From Section 2.5, the annual benefits needed to justify the CREZ construction is \$301,495,511 using a discount rate of 3%; with a discount rate of 7% this value is \$522,738,688. This additional transmission capacity allowed for a reduction in transmission constraints and essentially ended wind power curtailment at the current levels of wind generation, with a corresponding reduction in generation costs and emissions.

Table 2.12 notes that had the CREZ expansion been in place, 2011 generation costs would be reduced by \$48,854,520 annually based on the reduced curtailment of wind generation (at an average rate of \$5577/hour). Similarly, using a social cost of carbon of \$39/ton, the reduced CO_2 from the transmission expansion has an annual value of \$46,892,280 (\$5353/hour); if CO_2 savings are counted then the total annual value from reduced curtailment is \$95,746,800.[62] However, considering that Texas bears all of cost of the transmission lines and gets only a fraction of the (global) benefit from CO_2 reduction, policymakers may wish to value the CREZ transmission lines simply in terms of the financial savings and not count any pollution reduction. Assuming this value of reduced curtailment in 2011 is constant over time, regardless of which discount factor is chosen or whether reductions in CO_2 emissions are valued at \$39/ton or zero, the reduction in curtailment produces far too little value to justify the construction of the CREZ transmission lines. This is not unexpected, as the capacity of the CREZ transmission lines substantially exceeds the current levels of wind generation.

Assuming that the value of additional uncurtailed wind generation is the same in the future as in 2011, for every increase in wind generation of 1 MWh in every hour, the annual

[62] Note that the minor difference in hourly savings from CO_2 emissions reduction between here and the prior section is due to rounding differences.

value of this additional wind generation is \$446,497 if CO_2 is valued at \$39/ton and \$227,847 if CO_2 impacts are not valued. Thus the additional wind generation each hour necessary to provide enough annual value to offset the construction of the CREZ transmission lines ranges from 461 to 2080 MWh, depending on the chosen discount rate and if CO_2 savings are counted. See Table 2.12 for details.[63] Note that until this additional wind generation is achieved, all of the value from the additional wind generation can be thought of as going towards paying for the additional transmission lines and not reducing generation costs, covering the cost of wind subsidies such as the Production Tax Credit or the construction of the turbines themselves. Also note average potential wind generation has increased from 2011 to 2014, rising from 3509 MWh to 3954 MWh.[64] However it is not clear what the counterfactual increase in potential wind generation over this time period would have been had the CREZ project not been undertaken; determining how much of this increase in wind generation is due to the CREZ transmission project is beyond the scope of this chapter.

The additional capacity of the CREZ transmission lines is 18,500 MW. Assuming this capacity was immediately fully used (note that this was not the case; average hourly wind generation in 2014 was 655MWh higher than in 2011) then about 2.5 to 11.2% of the value of the additional wind generation would be consumed by the construction costs of the transmission lines. Delays in obtaining the additional wind generation would reduce the overall benefit of this investment in transmission in an environment with a non-zero discount value.

Additionally, not fully using the capacity of the CREZ lines will also lead to the fixed costs of transmission installation capturing a greater portion of the value of the additional wind generation. Because of the variability of wind generation, substantial underuse of the

[63]This calculation, based on the present value calculation in Section 2.5, assumes that the additional wind generation begins immediately and is not phased in over time.

[64]Examining increases in potential wind generation avoids incorporating reductions in wind curtailment.

CREZ transmission lines at some points of the day are very likely as wind turbines that will face substantial production curtailment are not likely to be financially viable.

Generation cost savings do depend on the cost of the fossil fuels that are no longer consumed; the above analysis uses the cost of coal and natural gas for 2011. Should input costs change, then the benefits resulting from CREZ transmission expansion will change as well. Figure 2.8 shows historical natural gas spot prices at Henry Hub; 2011 is after the large fall in natural gas prices; overall the prices in that year do not appear to be abnormal, even if only compared to more recent years after the spread of fracking. Additionally, this analysis assumes that mix of fossil fuel generators will not change in the future; low natural gas prices or government policies that disproportionately increase the price of coal generation could cause power that is now generated from coal could switch to natural gas, with impacts on generation costs and CO_2 emissions. Linn et al. [2015] does find that changes in natural gas prices did not have a statistically significant impact on the short run use of natural gas generation in Texas.

2.8 Conclusion

While wind generation does not create air pollution and does not consume costly fossil fuel to operate, areas particularly suited for wind generation are often in remote regions. In order to move the electricity to more populated areas, expensive transmission must be constructed. The cost of this transmission can consume a non-trivial amount of the value created by the wind turbines, essentially adding to the fixed costs of wind generation. While transmission costs are idiosyncratic to the particular projects being examined, this chapter examines the cost effectiveness of the CREZ transmission project in Texas and finds if the additional

CREZ capacity was immediately fully used (which it was not), transmission construction costs would have consumed around 2.5-11.2% of the value of wind generation. Delayed installation of additional wind turbines and less than full use of the capacity will increase the proportion of value consumed by transmission costs, likely by substantial amounts.

When projecting costs and benefits of transmission and wind generation projects in the planning stage, more realistic projections for transmission costs would allow a more credible cost-benefit analysis. For example, either not using "straight-line" transmission line assumptions or factoring in a generous cost penalty for doing so would reduce the likelihood of actual transmission construction costs being about 40% over initial estimates. Including accurate estimates of the required transmission costs may make remote but windy areas less attractive than regions with inferior wind characteristics that are closer to areas with high demand and with a lower transmission cost. As transmission lines are not free, more generally, when determining the cost-competitiveness of a given generation project, required transmission costs should be incorporated for a more complete measure. This could make wind projects relatively less attractive as compared to other generation sources that have more flexibility regarding siting locations.

Figure 2.1: Wind Speed Across The U.S.

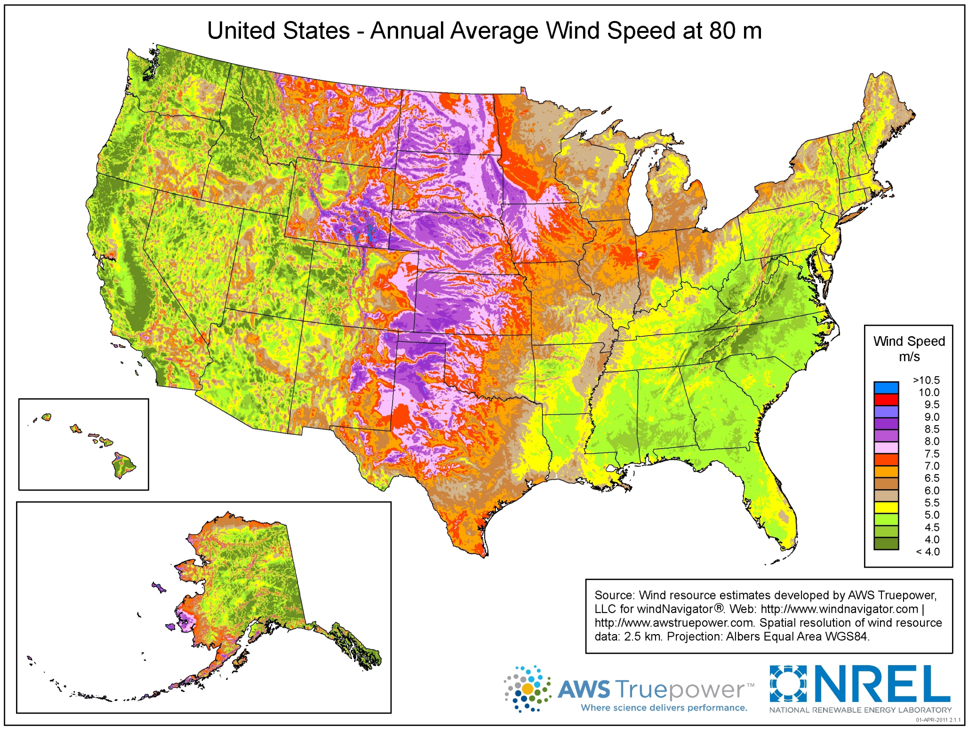


Figure 2.2: CREZ Zones

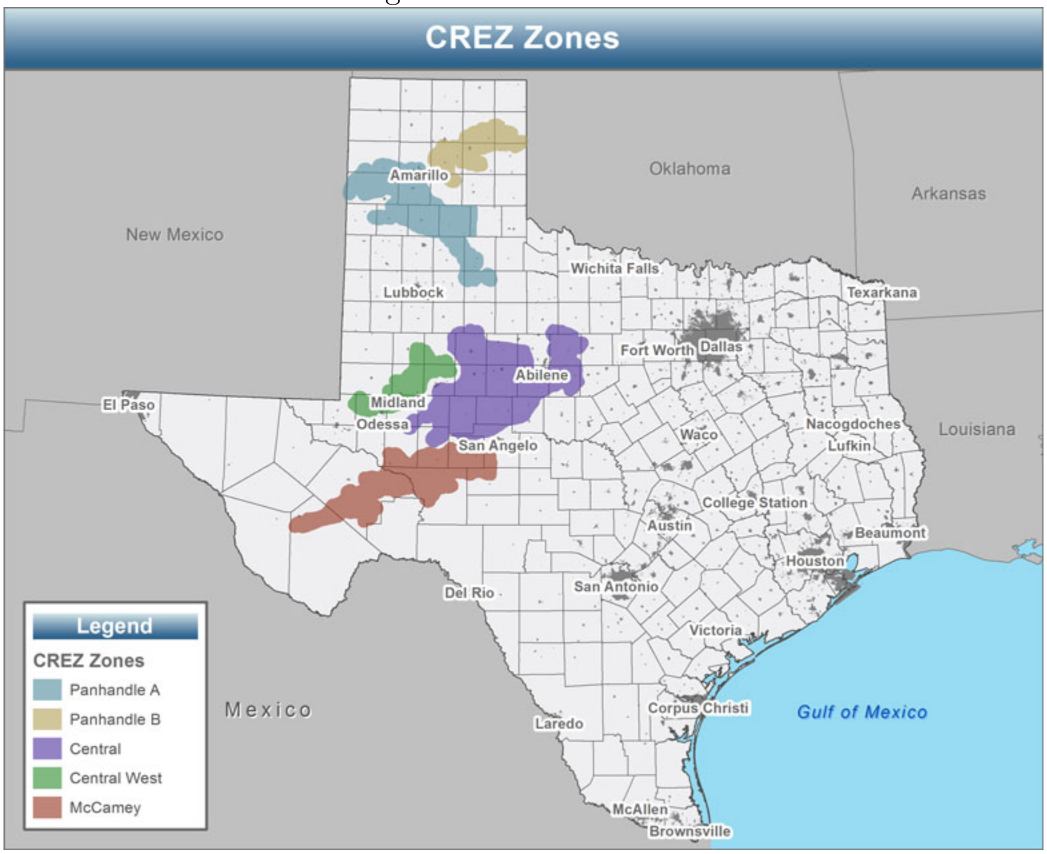
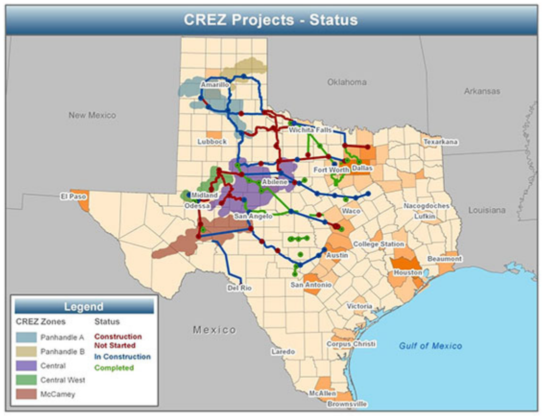
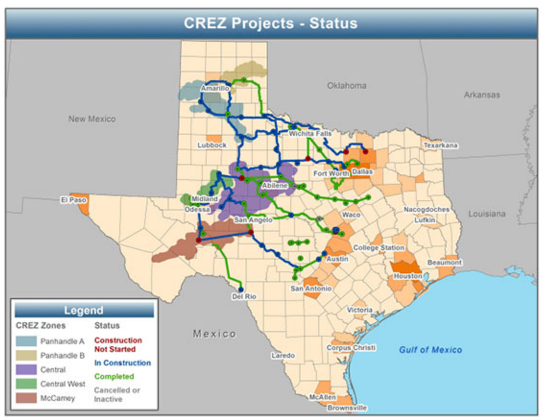


Figure 2.3: Installation of CREZ Transmission Lines

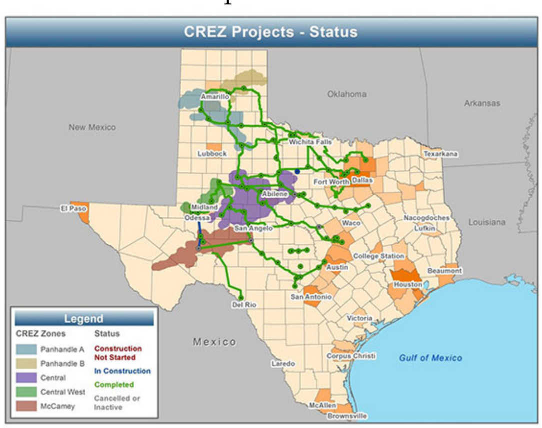
October 2012



April 2013



April 2014



Source: PUCT

Figure 2.4: Hourly Potential Wind Generation vs. Curtailment in 2011 and 2014

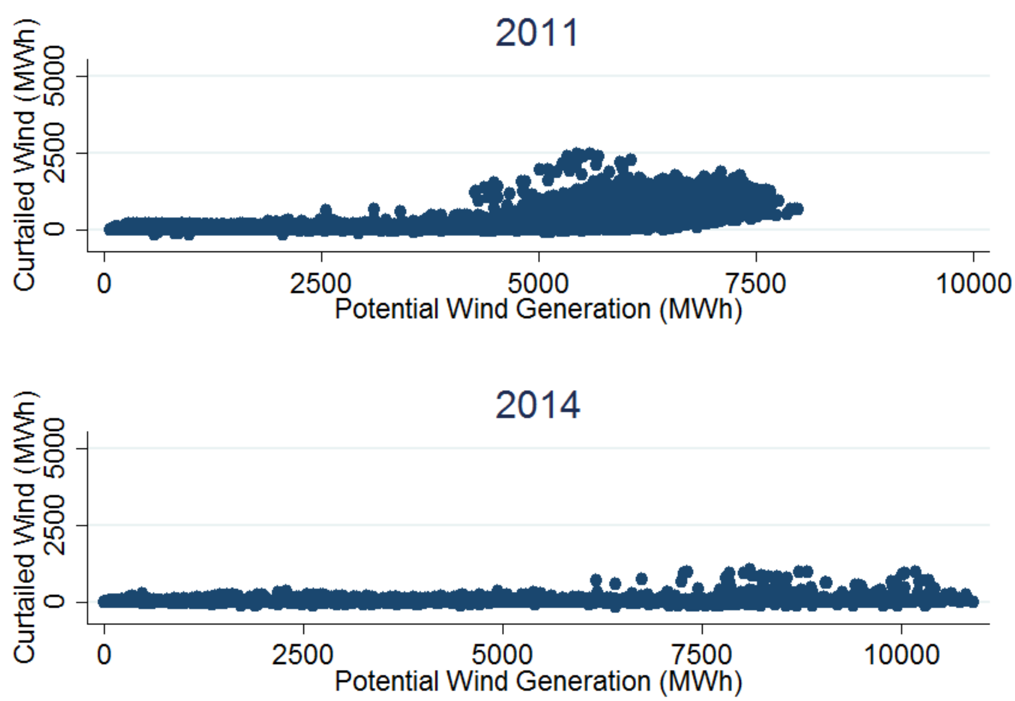
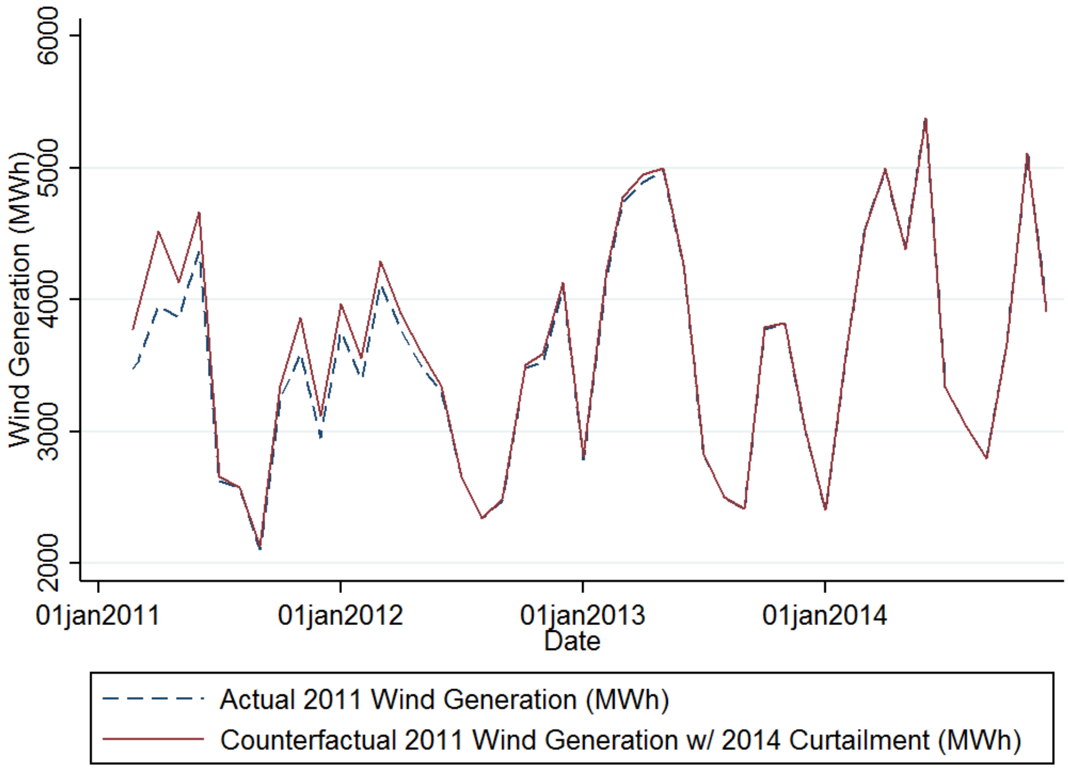


Figure 2.5: Actual vs Counterfactual Wind Generation By Month



Counterfactual wind generation is based on the relationship between potential and actual wind generation from 2014

Figure 2.6: Wind Curtailments and Occurrences of Negative Spot Prices in ERCOT Over Time

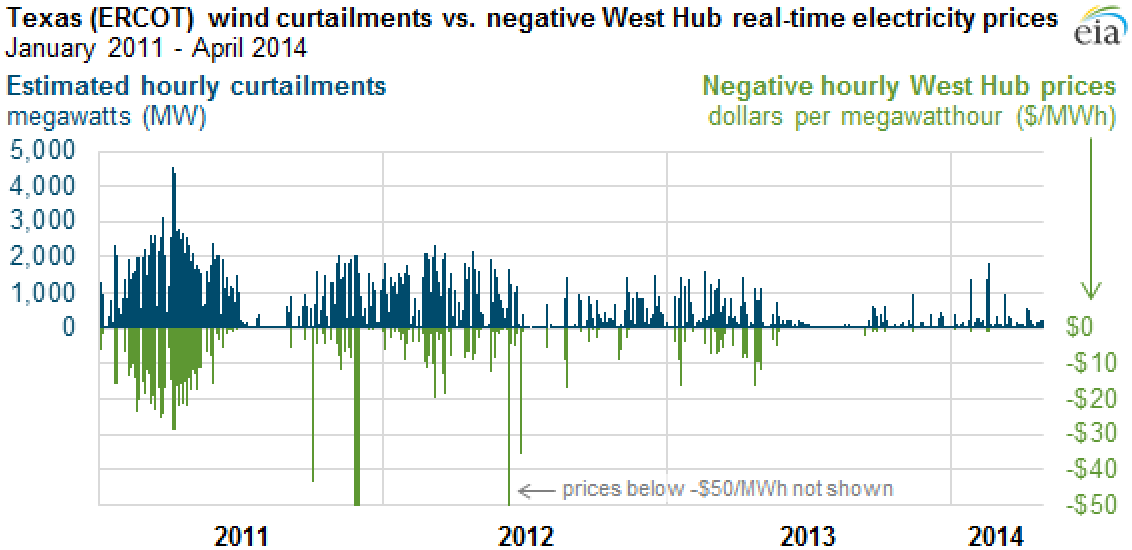


Figure 2.7: Estimated Relationship Between Potential and Actual Wind Generation in 2014

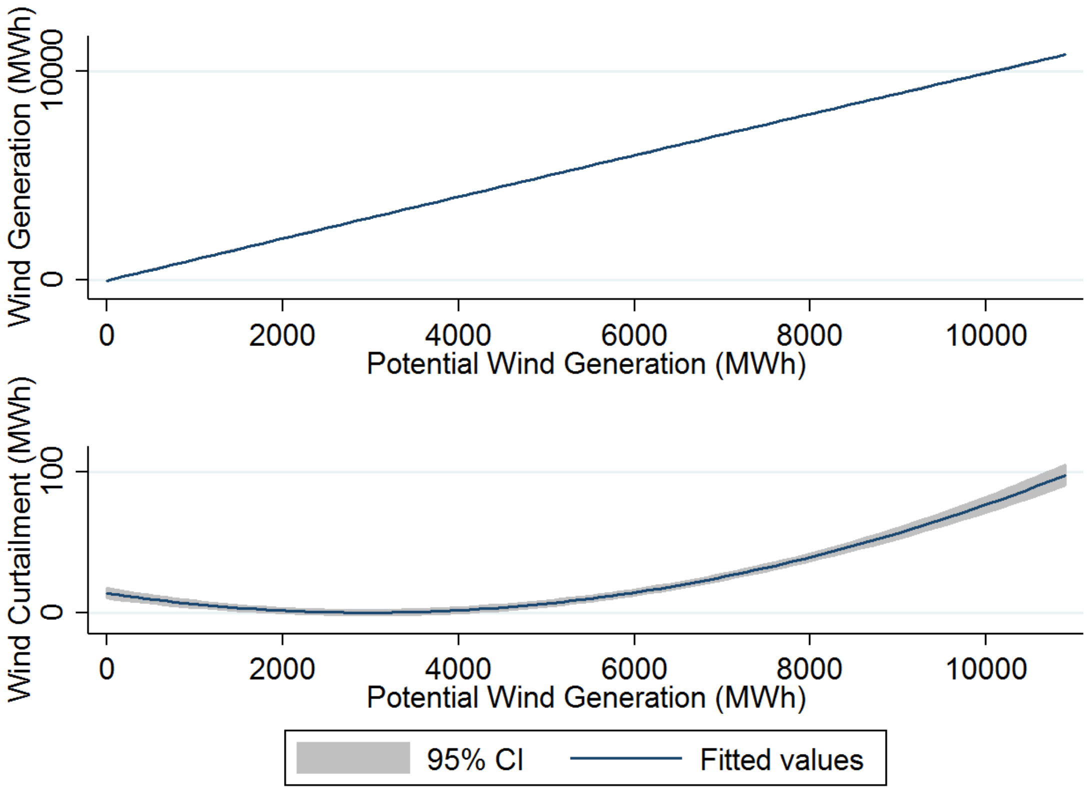


Figure 2.8: Historical Natural Gas Prices

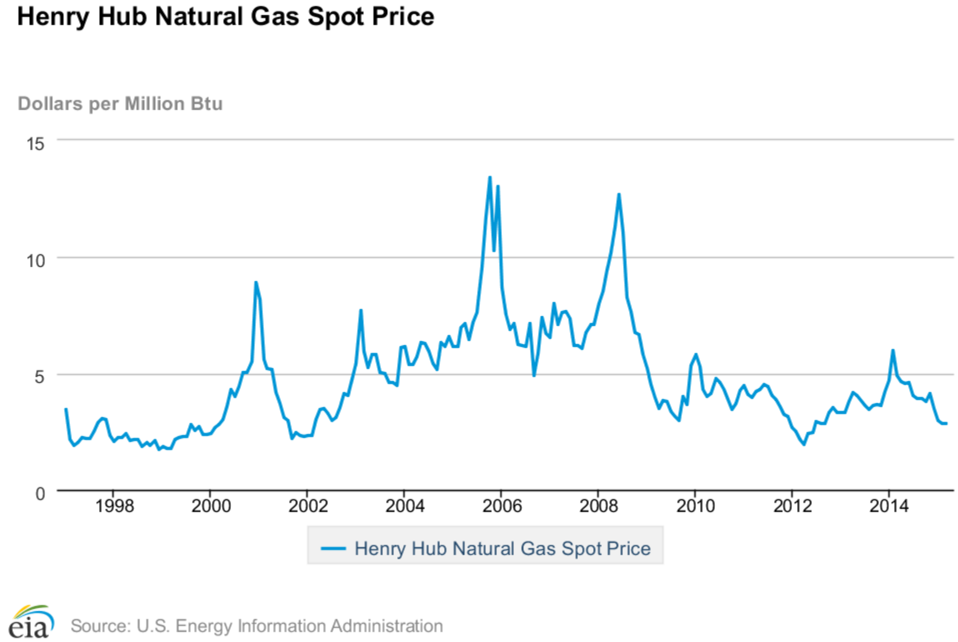


Table 2.9: Average Effect of Wind Generation on Generation Cost in 2011

VARIABLES	(1) Generation Cost
Wind Generation	-26.01***
	(0.990)
f(Generation-Nuclear)	X
Observations	7,509

Observations are hourly and aggregated to ERCOT-level. Data is from 2011. Newey-West standard errors with 53 lags used to correct for heteroskedasticity and serial correlation. Coefficients for temperature, hour-month indicator variables and nonlinear controls for generation net of nuclear power are omitted. *** p<0.01, ** p<0.05, * p<0.1

Table 2.10: Average Effect of Wind Generation on CO_2 Emissions in 2011

	(1)
VARIABLES	CO_2 Emissions
Wind Generation	-0.640***
	(0.0168)
f(Generation-Nuclear)	X
Observations	7,509

Observations are hourly and aggregated to ERCOT-level. Data is from 2011. Newey-West standard errors with 53 lags used to correct for heteroskedasticity and serial correlation. Coefficients for temperature, hour-month indicator variables and nonlinear controls for generation net of nuclear power are omitted. *** p<0.01, ** p<0.05, * p<0.1

Table 2.11: Actual and Counterfactual Values for 2011

	(1)	(2)	(3)
	Actual 2011 Wind	Counterfactual 2011 Wind (Completed CREZ Transmission)	Counterfactual 2011 Wind (Zero Curtailment)
Generation Cost ($/hr)	885,816	880,239	879,929
CO_2Emissions (tons/hr)	26,380	26,243	26,235
Hourly CO_2 value at $39/ton	1,028,838	1,023,485	1,023,187

Counterfactual wind generation uses 2014 (post CREZ completion) relationship between potential and actual wind generation.

Table 2.12: Comparison of Costs vs. Benefits from Additional Wind Generation

	3% Discount Value	7% Discount Value	3% Discount Value	7% Discount Value
	Gen Cost + CO_2	Gen Cost + CO_2	Gen Cost Only	Gen Cost Only
2011 Gen Cost Savings	$48,854,520	$48,854,520	$48,854,520	$48,854,520
2011 CO_2 Savings	$46,892,280	$46,892,280	–	–
Total Savings	$95,746,800	$95,746,800	$48,854,520	$48,854,520
Break-even Annual Value for CREZ	$301,495,511	$522,738,688	$301,495,511	$522,738,688
Annual Value of Additional 1 MWh Wind Per Hour	$446,497	$446,497	$227,847	$227,847
Necessary Additional Wind MWh (Per Hour) to Break Even	461	956	1109	2080

CHAPTER III

Transitional Policy in Retail Electricity Deregulation

3.1 Introduction

The retail electricity market for residential consumers has been deregulated in several regions of the United States during recent years. Instead of residential consumers obtaining electricity through a price-regulated monopolist, retail electricity providers obtain electricity from wholesale markets, set their own retail prices and compete over residential customers. However, when moving to a deregulated market policymakers do not completely deregulate prices immediately. In practice, when given a choice of retail electricity providers (REPs) many consumers do not actively pick and must be served by a default provider until they do. Because of customers' inertia in selecting a provider, temporary price regulation on the default provider could help in the transition to a fully price-deregulated market.

Deregulated states have taken different approaches to managing this transition, usually forcing the default provider to charge what regulators believe is a low price. However, when Texas deregulated retail electricity prices in 2002, unlike in other states, their default electricity providers were directed to charge their consumers a relatively high price for several years. This was intended to promote firm entry by allowing new firms to profitably undercut the incumbent and to motivate consumers to switch to those new entrants. Texas has in fact seen more consumers switch away from the default provider than any other deregulated state. Could the Texas approach to transitional policy be preferable, given that consumers have inertia when choosing a provider? If prices fall with market concentration and the default provider's market share, then transition polices that encourage the transition to a low concentration environment, such as mandating a higher price for the default provider, could be beneficial in the long run. However, as consumers historically appear to mostly remain with their current provider in any given period, overcoming this inertia by imposing higher prices on those consumers would likely have short-run costs, most notably the higher costs imposed on consumers who did not switch.

Consumer inattention to the retail electricity market complicates the transition from a regulated monopolist provider to a market where multiple firms can set their own prices and compete; they likely make retail electricity deregulation less attractive. Initially most consumers will be served by a default provider who could set a relatively high price to "harvest" profits from these customers if allowed to set their own price, though optimally they would not want to set price too high and cause suboptimal levels of switching away.[65] Given this, policymakers may prefer to continue to intervene in the market, at least temporarily, to improve the transition to a deregulated market.[66]

[65]This is a kind of "investment" in retaining a large number of customers for the following periods.

[66]Policymakers could also have different objectives – Joskow [2008] notes that some policymakers in US states have also, among other possible objectives, seemingly prioritized an immediate price cut to consumers at the start of regulation, or neglected to adequately increase regulated retail prices as wholesale prices rose. Note these policies can and have resulted the default provider's regulated retail price being below its wholesale costs. Additionally, the main purpose of deregulating retail electricity markets is to have a competitive market with low prices; while low market concentration is generally associated with competitive markets, reduced market concentration in and of itself should not be the final objective.

More broadly, the question of whether retail electricity deregulation should be undertaken has been discussed in the literature (such as Brennan [2007], Defeuilley [2009], and Joskow [2000]). Paul Joskow writes that "there is no shortage of ideological views" regarding this larger question (Joskow [2008]) Perhaps the most prominent potential benefits to deregulation would be lower retail electricity prices and a greater variety of products to choose from. Lower prices to consumers would be the result if competition between firms drove prices lower than what would be obtained through cost-based price regulation. Swadley and Yucel [2011] find that deregulation lowered residential retail prices in some states but not others.It is possible that regions with greater scope for price improvements may be more inclined to deregulate. While the actual electricity is a homogeneous good, retailers could distinguish their products by offering varying levels of "green power", different lengths of locked-in retail prices and improved customer service. J.D. Power has begun to publish ratings of Texas REPs in several categories.

A more desirable outcome than what would have been obtained under regulation is not guaranteed with regards to pricing when deregulating the retail electricity market for residential consumers. Consumer inertia appears to be present with most consumers rarely comparing retail electricity providers and simply continuing to use their current provider rather than the cheapest one. Not paying close attention to the choice of electricity retailer could even be a rational choice given the financial stakes involved (Sallee [2014]). Some consumers may not even be aware that they are allowed to choose electricity retailers. Furthermore, consumers may incorrectly believe that the choice of retailer affects the reliability of their electricity supply which would increase the risk of switching away from the default provider.[67] Depending on the institutional arrangements, there may be a financial cost to

[67] Supplying electricity to residences occurs in a number of stages: generation, transmission and distribution, and retailing. Generation, transmission and distribution are where the power is actually generated and

switching providers. Finally, choosing a new firm and executing the move simply takes time and mental effort.

This general reluctance to switch providers even when lower priced options are available will affect the average price paid in a deregulated retail electricity market. Recent literature suggests that large switching costs can result in higher equilibrium prices though there are situations where switching costs can lower equilibrium price (Dube et al. [2009]). Additionally, large switching costs could deter potential entrants from entering the market, which could further affect the degree of market power participating retailing firms have.

In this chapter, I examine the impact of alternative transitional policies and any resulting tradeoffs between the short and long run to determine if Texas' approach to transitional policy - with relatively high price floors - could be an improvement. To do so, I solve a dynamic model of the residential retail electricity industry under various transitional policies and examine the simulated market outcomes. In the model, deregulated firms set price each period in order to maximize discounted profits, noting the market share they end the period with will affect their profitability in the next period. One firm – the default provider – may be price regulated for a certain number of periods and must set their price as directed, while the entrant firms are always free to select their own price. Consumers face a two-stage problem each period. In the first stage they decide whether to search for a potentially different REP or to remain with their current provider without learning of alternate prices. In the second stage, consumers that chose to search select an electricity provider.

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moved to its destination over the power grid. While spot prices in the wholesale market are very volatile, residential consumers pay infrequently and historically pay the same rate for all electricity consumed over the billing period though the increasing use of 'smart meters', which can record the time when electricity was consumed in addition to the total amount, is changing this. REPs obtain power in the wholesale market for their consumers and then charge the consumers a retail price. They thus serve as a financial middleman between residential consumers and the wholesale electricity market. Depending on the institutional details of the deregulation, they may become responsible for the actual billing as well.

I find that, with the selected parameters for consumer demand, that it could be possible for the "Texas approach" of higher transitional price controls to be superior to setting selected lower prices for the incumbent firm. Furthermore, the simulated market outcome under alternate parameters suggests that if consumers are less inattentive and are more likely to shop for retail electricity, the resulting pricing outcomes are improved.

3.2 Background

3.2.1 Retail Electricity Under Regulation

Deregulating the retail electricity market replaces imperfect regulation with what would likely be imperfect competition (Puller and West [2013]). Traditionally the price of retail electricity has been regulated, potentially at different rates for different customer classes through rate cases, for a set period of time with the objective of allowing the electricity provider to recoup their reasonable and prudent costs. If the wholesale electricity market is competitive, then some of the cost that would need to be recouped is the cost of acquiring electricity in the wholesale market.[68] If retailers must purchase all of their electricity at the spot market price, then the regulators should have an good understanding of what the "reasonable costs" of that wholesale power should be. However if much of the wholesale power is purchased under private negotiated bilateral contracts – as can be the case – then

[68] A competitive deregulated wholesale electricity market is crucial to the functioning of a deregulated retail electricity market so that the entering REPs can obtain competitively priced wholesale electricity. Several papers have looked at the competitiveness of these wholesale markets. Hortacsu and Puller [2008] find that the Texas wholesale market is reasonably competitive. Mansur [2008] finds that when the rate at which power generating units can shift output levels is taken into account the Pennsylvania/New Jersey/Maryland market appears reasonably competitive as well.

what the price "should" be is less clear.[69] What "reasonable" costs are for other expenses such as billing or customer service on the part of the retail electricity provider may also be unclear. Uncertainty as to what the "correct" price should be could lead regulators to err on the side of caution and set a higher price than could be obtained in the competitive market. Additional choices for consumers is another potential benefit of deregulation.

3.2.2 Different Transition Policies and Outcomes in Deregulation

Deregulation of retail electricity for residential consumers has previously been undertaken in a number of jurisdictions, both within the United States and internationally, such as Connecticut, Massachusetts, New York, Ohio, Pennsylvania, Texas, the United Kingdom and New Zealand. News reports show that policymakers in areas such as Arizona, Indiana, Michigan and Japan have been considering either deregulating retail electricity or further expanding their current levels of deregulation in recent years.[70,71]Deregulated markets do not share the same outcomes, however. A common approach in the industry to measure the effectiveness of retail electricity deregulation policy is to examine the switching rate of consumers: how many of them remain with the default provider? Table 3.13 shows that the switching rate as of 2010 varied widely between states that have deregulated residential retail electricity markets, suggesting large differences in the success of deregulation when using this measure. However, while this measure does have the advantage of being easy to observe,

[69]In a slightly different context, Cicala [Forthcoming] finds that after deregulation, fuel procurement costs for coal power plants – generally purchased through bilateral contracts but unlike electricity, a heterogeneous good – fell by 12%. He also found that fuel procurement costs for natural gas plants, a homogeneous good that is not generally traded with bilateral contracts, did not appear to be affected by deregulation. Similarly, Jha [2015] finds that regulated coal power plants pay about 3% more per month for coal purchases and storage than coal power plants that face market prices.

[70]Arizona: Randazzo [2013]. Indiana and Michigan: Malcolm [2013]. Japan: Reuters [2013]

[71]Note that Arizona ultimately decided not to further pursue deregulation, though this decision was driven by their expectation that it would be found to violate the state constitution rather than a judgment on the merits of the policy itself.

it should not be mistaken for a direct observation of the competitiveness of the market (as implied by the title of Alfred Kahn's paper "Bribing Customers To Leave And Calling It Competition"; Kahn [1999]).

These differences in switching rate outcomes can be attributed in part to different transitional policies between the states. Different approaches with respect to setting temporary price controls on the default provider were used. When the temporary price controls ended, Swadley and Yucel [2011] find that in some states, retail electricity prices rose while in others electricity prices fell. Thus several years into the transitions, some states restricted the prices of the default provider to be higher than what would have been seen in the market, while other states restrict the default provider to price under the market price.[72]

Perhaps the simplest deregulation process would be to simply leave all the customers with a default REP, allow entry of new competitors and immediately end price regulation. However, given that customers are often slow to switch providers – initially they may not even know that there is a market for retail electricity – the exercise of market power is a potential concern. Temporary price regulation on the default provider is one solution to this issue. Policymakers could face tradeoffs here.

On one hand, policies that discourage switching may detract from the development of a competitive market. For example, having the default provider set a relatively low price for electricity has obvious short-run benefits to consumers but a drawback is that it limits the ability of other firms to obtain market share while making positive profits. Furthermore, potential entrants may be discouraged from entering the market at all. If the expectation when deregulating the market was a competitive market outcome would be preferable, this competitive market outcome could be delayed or prevented by discouraging customer switch-

[72]Like Swadley and Yucel [2011], Kang and Zarnikau [2009] find that in Texas the retail prices of the entrant firms fell after the end of price regulation.

ing.

On the other hand, forcing the default provider to have a relatively high price – perhaps even above what an unregulated monopolist would prefer to set – could induce higher rates of switching early in the transition and could lower the market concentration in a more rapid manner. However, this would come at the cost of higher retail prices for consumers who are slower to switch during the period that they do remain with their default provider[73]. The idea that allowing – or even requiring – high prices in the short term to lead to a better outcome later is related to Fershtman and Pakes [2000], which finds that permitting collusion between firms could be socially beneficial in the long run because it can induce entry, in contrast to static models which would suggest that collusion is not socially optimal.

3.2.3 Retail Electricity Deregulation in Texas

Texas has five regions where retail price deregulation occurred beginning in 2002 (Figure 3.1).[74] During the first five years of the deregulated market, the default provider in each of the five regions was required to offer a regulated "price-to-beat" while other entrant REPs could offer any price they chose.[75] The price-to-beat was adjusted over time to account for changing input costs and was different across the regions. Importantly, when setting the "price to beat", regulators included an additional markup which was intended to allow other firms to profitably undercut the default provider. Thus, the regulated price of the default provider was set in a manner that was intended to facilitate both entry into the market and consumer switching, though this caused the consumers that did not switch away to pay

[73]I assume setting an extraordinarily high price to induce widespread quick switching or canceling electricity service to those consumers who do not pick a provider would not be politically viable.

[74]Interested readers should review Kiesling and Kleit [2009] for a more detailed description of the Texas deregulation process.

[75]If the market share of the default provider had dropped below 60% in those first five years, the temporary regulation would have ended early.

higher prices than they "should have".

Entrant firms generally priced lower than the price-to-beat during the transitional period. Figure 3.2 shows the prices of selected major firms in one of the five regions in Texas over time, as well as the wholesale price of electricity.[76] Should consumers have switched away from the default provider, they could have lowered their electricity bill. Even with this financial incentive, consumers tend to remain with their current provider; even about a decade after the start of deregulation, the default electricity providers still serve a substantial portion of residential consumers (Figure 3.3). Again, consumer inertia appears to be a major issue in this market.

3.3 Model of Retail Electricity Industry

In order to study transitional policies, I model the retail electricity industry and solve for the optimal pricing decisions of firms under various conditions. I model both the consumer's optimization problem and that of the retail electricity providers.

At the start of every period, each firm begins with all the customers they had at the end of the prior period and sets a price for that period. Consumers who were already in the market and thus purchased electricity from one of the firms in the prior period observe their firm's price and decide whether or not to search for a (potentially) new retail electricity provider. Consumers who moved into the market in the current period must search and choose an electricity provider. Consumers who decide to search then observe the current price of all of the firms in the market and choose to purchase their electricity from one of them. At the end of the period, consumers purchase and consume a constant amount of

[76] Green Mountain Energy only sells "green" power which allows it to charge a higher price.

electricity from their chosen firm.

To model retail electricity deregulation, the default electricity provider starts with the entire market share. For a specified number of periods, that provider must set a price determined by the regulator. A competing firm starts with zero market share but can always set whatever price they wish.[77] When the temporary price regulation on the incumbent has expired, the incumbent can also price freely, just like the entrant firm. Any firm that is not price-regulated maximizes expected discounted profits.

3.3.1 Model of Consumer Behavior

Consumer Inertia

In each period, consumers are assumed to make their decisions concerning their choice of retail choice providers in two steps. In the first stage, the consumers decide whether to simply remain with their current provider or whether to examine their options and potentially switch to another provider. In the second stage, those consumers that do decide to search learn the prices of all providers and select one, which may or may not be their current provider. Consumers then consume electricity and pay their provider. All consumers must select a provider and it is assumed that the quantity of electricity consumed does not depend on the price.[78] Consumers are myopic and in all situations only incorporate current prices into their decisions.[79]

For consumers who were in the market in the prior period, the search decision is modeled

[77] I abstract away from firm entry and instead assume that at the beginning of the market there is one other firm.

[78] Allowing consumption to depend in part of the price is not expected to substantially change the results due to the relative inelasticity of electricity demand.

[79] In the context of gasoline price forecasts, Anderson et al. [2013] find that consumers' gasoline price forecasts are generally not distinguishable from a no-change forecast.

as

$$SearchProbability_{it} = \Phi(\alpha_0 + \alpha_1 P_{ft}) \tag{3.10}$$

where $SearchProbability_{it}$ indicates the probability of whether consumer i searches in period t, P_{ift} is the price of firm f in period t, where firm f is the initial provider at the start of the period. Consumers are more likely to search if their current provider has set a high price in the current period. The normal distribution is used to keep the probability of search between zero and one. The price of the other firm does not affect the search decision. When aggregated over a large number of customers, the search probability is also the fraction of consumers that do search. Price is assumed to have the same effect on all consumers' decisions, both when deciding to search and later when choosing a provider.[80]

Consumers who have moved into the market at the start of the current period must search for an electricity provider. I assume that no consumers leave the market.[81]

Selecting a Provider

When choosing between providers, consumers are assumed to have logit demand, so when purchasing electricity from firm i in period t, consumer c receives utility:

$$U_{ift} = \beta_1 P_{ft} + \varepsilon_{ift}$$

[80]Hortacsu et al. [2015] does find heterogeneous demand across demographic groups, however modeling additional heterogeneity for the consumers would substantially increase the size of the state space in the dynamic model of firm pricing behavior

[81]An alternative assumption that would not affect the model is that consumers who move out of the market come from all of the firms in proportion to their size and that the measure of the quantity of move-ins is instead a measure of net move-ins which is assumed to be non-negative.

where P_{ft} is the retail price charged by firm f and ε_{ift} is an iid extreme value error term. The probability that a searching consumer will select firm f is then

$$P(Firm_f) = \frac{exp\left(\beta_1 P_{ft}\right)}{\sum_{j=1}^{N} exp\left(\beta_1 P_{jt}\right)}$$

where N is the total number of firms in the market (two). Aggregating again over a large number of searchers, this probability is also the fraction of searchers that will choose firm *f*. This specification assumes that consumers do not systematically view the retail providers differently on any dimension apart from price.[82]

An alternative way to incorporate consumer inertia into the model of the retail electricity industry, apart from adding a first stage where consumers decide if they wish to search, would be to incorporate switching costs into the provider choice decision. A key difference between these two approaches is that unlike with switching costs, using a separate 'decision to search' stage as specified above excludes other firm pricing from the inertia. If a firm keeps its price sufficiently low, then it can keep the number of its consumers who choose to search arbitrarily low, regardless of the prices of the other firms. On the other hand, using switching costs as the source of consumer inertia implies that the inertia from consumers of a given firm can be overcome by other firms if they set their prices sufficiently low. Given that in the data the incumbent firms were able to maintain large market shares for many year even with other firms offering lower prices, this model uses the 'decision to search' stage as the source of inertia in order to allow the incumbent firm to more effectively defend its market share.

[82]Hortacsu et al. [2015] finds that in Texas, consumers do initially view the incumbent firm more favorably, though this effect falls by about 75% after just two years. This may be due to a mistaken belief that the incumbent firm offers more reliable service.

3.3.2 Deregulated Firms' Problem

Firm Profit and Value Function

In period t, the profit for firm f conditional on having market share s_{ft} after the consumers have selected their retail electricity provider for the period is

$$\pi_{it} = (p_{it} - c)(s_{ft} M_t)$$

where c is the marginal cost of serving a customer and M_t is the total number of customers in the market. The marginal cost is assumed to be constant over time and equal across firms; all firms are assumed to have equal access to the competitive wholesale market for electricity and I assume away any price-hedging issues. The size of the market grows with the number of customers who move in during each period:

$$M_t = M_0 \prod_{j=1}^{t} (1 + \eta_j)$$

where η_t is the percentage of the market that is comprised of consumers who have moved into the market in period t and must search for a provider.

The market share of firm f at the end of period t is then

$$\begin{aligned} s_{ft} \quad = \quad & \left\{ s_{f,t-1} \left[1 - \Phi(\alpha_0 + \alpha_1 P_{ft}) \right] + \sum_{j=1}^{N} \Phi(\alpha_0 + \alpha_1 P_{jt}) \left[\frac{exp\left(\beta_1 P_{ft}\right)}{\sum_{k=1}^{N} exp\left(\beta_1 P_{kt}\right)} \right] \right\} \frac{1}{(1+\eta_t)} + \\ & \left[\frac{exp\left(\beta_1 P_{ft}\right)}{\sum_{k=1}^{N} exp\left(\beta_1 P_{kt}\right)} \right] \frac{\eta_t}{(1+\eta_t)} \end{aligned}$$

If the default provider is price regulated, then it simply sets the price that regulators direct.[83] Firms that are not price regulated select the price to charge consumers in the current period to maximize their expected discounted profits.[84]

Deregulated firm f faces the following Bellman equation:

$$V(s, \bar{s}, T) = sup_p E\left[\pi(s', \bar{s}', p) + \delta V(s', \bar{s}', T'|p)\right]$$

Here, s is the firm's market share level in the prior period (that they begin the period with) and $\bar{s}$ is a vector with the prior-period market share level of each of the deregulated firms.[85] T is the number of remaining periods, including the present period, that the transitional regulation will be in effect. When the transitional regulation ends, T is zero and the default provider becomes a deregulated firm like the entrant. δ is the discount rate.

Firm Pricing Order

I also assume that firms do not price simultaneously. Instead, deregulated firms set their prices in descending order of size. If two deregulated firms have the same size, then they set their price in an order that is randomly assigned at the start of the period. This assumption is made for tractability reasons; consumer inertia (whether in the form of a two stage decision

[83] In the case that regulators choose a sufficiently high or low price, this is equivalent to imposing a binding price floor or ceiling.

[84] In practice, firms can offer multiple plans with varying attributes and prices. I assume in the model that firms offer only one plan each.

[85] In practice, this is a vector with the number of other deregulated firms at each possible market share level. The deregulated firms are identical apart from their initial market share level in each period.

process or if modeled more straightforwardly with switching costs) leads to discontinuities in the firm best response function for pricing decisions which in turn can potentially lead to multiple or no pure strategy equilibria. Using sequential moves eliminates the potential lack of a pure strategy equilibrium because the early firms cannot respond to the pricing choice of later firms, and instead must take the smaller firms' expected pricing choice into account.[86]

Intuitively, this discontinuity arises because as other firms raise their prices and cause more of their customers to choose to search, it can eventually become marginally more profitable to, instead of raising your own price slightly, jump down in price in order to attract a large number of consumers from other firms. This strategy is essentially switching from making profits with high markups to making profits with lower markups but with a larger customer base that is obtained by acquiring many of the other firms' customers.

The order of firm moves is set to be in descending order by size instead of random assignment in order to generate more realistic results.[87] When a relatively small firm goes first, it is generally profit maximizing for them to set a very high price. The larger firms respond by also selecting high prices that are somewhat under the smallest firm's price with the final results that many consumers search but do largely return to the larger firm.

[86]Ordered pricing does not affect the Bellman equation because there is no private information in the model; all firms are able to anticipate pricing choices of all other firms given the initial state.

[87]Another specification that would allow firms with large market share to have an advantage would be to change the consumer logit demand to favor larger firms and eliminate the search decision. If prior period firm market share is added to the logit demand function and there is no first stage (all consumer search each period) then the market share of each firm f in period t would be

$$s_{ft} = \frac{exp(\alpha_1 p_{ft} + \alpha s_{f,t-1})}{\sum_k exp(\alpha_1 p_{kt} + \alpha_2 s_{k,t-1})}$$

This specification has the benefit that the resulting best response functions for firm pricing decisions are not discontinuous. However, this specification has the undesirable property that instead of allowing for consumer inertia it instead makes it difficult for small firms to retain their market share when there is a much larger firm present, assuming α_2 is reasonably large. For example, in a two firm situation, a firm with 25% market share in the prior period would be forced to substantially undercut the firm with 75% market share in the prior period just to maintain their current level of market share.

Intuitively, the small firm can credibly signal (since they cannot change their selected price) that they will not attempt to substantially increase their market size by acquiring the larger firms' customers and instead will try to earn profits through high markups.

The literature on switching costs have discussed a tradeoff that firms face between "investing" in acquiring new customers by setting a low price and "harvesting" profits from current customers who face some inertia when considering moving (Farrell and Klemperer [2007]). While the model in this chapter does not have switching costs, the tradeoff between investing and harvesting when setting price remains the same because of the consumer inattention stage. If small firms go first, they can credibly abandon any serious attempt to invest in new consumers. However if the smaller firms go later, then the larger firms (who, regardless of the order in which they set their price, have less motivation to "invest" in acquiring new consumers because they already have a relatively large market share) must consider the potential for the smaller firm to later set a low price in an attempt to acquire customers from the larger firms.

3.4 Market Simulations

In order to examine the impact of alternative transitional policies, I solve for the value and policy functions and then simulate out the market under alternative policies. Additionally I test for the sensitivity of these results when consumers are less inattentive.

3.4.1 Parameterization

In order to solve for optimal firm pricing decisions and simulate the evolution of the industry under different transitional policies, I need to select demand parameters.

For my baseline parameterization, I set the marginal cost of electricity at 5. The discount value for firms is 0.925. The value of the constant term in the decision to search (α_0) is -7.5, the value of the price coefficient in the decision to search (α_1) is 0.75 and the price parameter in the logit demand model when deciding between firms (β_1) is -4.0. With these parameters, setting price equal to marginal cost results in virtually none of the customers deciding to search for alternate REP options. If the price is raised to 7.5, then 3.0% of consumers search, while if the price is set at 8.5 then 13.0% search. Setting $\beta_1 = -4$ implies that when consumers do choose to search they are quite price sensitive. A firm that has a price 0.25 less than the other will get about 73% of searching customers.

As an alternative specification, I make the consumers more likely to decide to search by setting $\alpha_0 = -7.0$. With this increase, essentially no customers search if the retail price is set at marginal cost, 8.4% search if the price is 7.5 and 26.6% search if the price is 8.5.

In selecting these parameters, a high level of price sensitivity when deciding between firms was chosen due to the largely homogeneous nature of the product. The parameterization of the decision of whether or not to search was selected so that firms could retain most of their customer base if they chose to operate with low price-cost margins; the ability to retain market share over an extended period of time appears to be a key feature of this market.

Additionally, the market expands by 1% each year due to new consumers moving into the area.

Hortacsu et al. [2015] estimate consumer demand parameters using data from the early period of the Texas retail electricity deregulation. However their model variants diverge from the modeling approach described in Section 3.3 and are not directly usable. For example, while they do also use the same general two-step model (decide whether to search; if so, select a firm), they model the first stage "decide to search" decision by having a constant fraction of consumers search.[88] When solving for optimal firm pricing with a two stage "search decision/firm selection" model for consumers, penalizing high prices in the "search decision" stage is critical in order to prevent firms from setting very high prices and gaining very large profits from their old customers (who mostly would not search for other options).

Comparing the parameters used in this chapter to those in Hortacsu et al. [2015], the probability of a consumer deciding to search is much lower in this chapter. This is because, unlike in this chapter, Hortacsu et al. [2015] have switching costs in the firm decision stage. Without those costs in the model and parameters from this chapter, all the consumer inertia is placed into the search decision. Consumer demand elasticities at observed prices are substantially higher in Hortacsu et al. [2015]. In their paper, the demand elasticity for an entrant firm at the average price during the regulated transitional period is -4.51, whereas in this chapter the demand elasticity for the entrant firm during the regulated period is around -0.75, changing to a small degree depending on the transitional regulation that is used. Note that the model in this chapter has one entrant firm, compared to the larger number of entrant firms observed in the Texas data and used in the demand estimation of Hortacsu et al. [2015]. A more direct comparison of the demand elasticity used in this chapter and Hortacsu et al. [2015] could examine the effect of all entrant firms simultaneously changing their price on total entrant market share.

3.4.2 Market Simulations

As a baseline, I solve for pricing and value functions when there is no transitional regulation: both firms can set their prices to maximize discounted profits in all periods. Figure 3.4 shows

[88] In an alternative specification, they also allow for consumers to be more likely to search if their bill increases in recent months. However in my model I would prefer not to track firm pricing in earlier periods as this would dramatically expand the state space.

how prices of both firms evolve over 10 periods. Initially the incumbent firm sets a price of \$7.52 and stays close to this level for several periods before lowering price. The entrant firm starts off at a lower price and price eventually grows to surpass the incumbent firm.

Figure 3.5 shows how the market share of the incumbent firm falls over the 10 periods, plateauing around 75%. Figure 3.6 shows the average price weighted by market share.

Figures 3.5 and 3.6 show the evolution of market share and weighted price across alternative transitional regulations. In each of the alternatives, the incumbent firm must set a price ranging from \$6.50 to \$9.00 in the first period before being able to optimize its price to maximize discounted profits beginning in the second period. This range was chosen to encompass price controls at levels both below and above what the incumbent firm would prefer. As expected, forcing the incumbent firm to set a price higher than it would prefer drives its market share down faster (and vice versa). Forcing a relatively high price in the first period causes the weighted price in the first period to be higher than it otherwise would have been, but the price is lower in subsequent periods The reverse is true when forcing the incumbent firm to price lower than it would have preferred. This indicates a short-run/medium run tradeoff when setting transitional pricing regulations (weighted prices essentially converge by the 10th period).

Table 3.14 shows the cumulative weighted price across the first 10 periods for each of these transitional regulatory policies.[89] Both regulations that set a price below what the incumbent firm would have chosen result in lower cumulative prices paid by customers. The results are mixed when forcing the regulated firm to set a price higher than it would prefer for one period: for two of the studied policies, the cumulative price paid by consumers is higher

[89] Valuing the cumulative weighted price in this manner implicitly sets a discount value of zero. Incorporating a positive discount value would be straightforward and would make "high initial regulated price" regulations worse as these have short run costs for medium run gains.

than if there was no transitional price controls. However one of the policies ($9.00) results in the cumulative average price over the first 10 periods being lower than a no-regulation outcome. Furthermore, the cumulative price paid is even less than one of the price control scenarios where the price was set to be less than the incumbent-preferred quantity ($7.00); it is possible for a higher transitional price to yield a superior average result to a lower transitional price.

Note that the overall market outcomes are sensitive to the demand parameters used. With an alternative demand specification where consumers are more likely to search for a potentially new electricity provider ($\alpha_0 = -7.0$), the market prices are lower than before, as can be seen in Figure 3.8, which shows how prices change an unregulated market over the first 10 periods. This is true even though market concentration is actually higher in the long run, as seen in Figure 3.7

3.5 Conclusion

When deregulating residential retail electricity, consumer inattention will create imperfect markets and can lead to a role for transitional price regulation. While many states chose to price-regulate incumbent firms in a manner that had them set what was thought to be a low price, Texas instead had the incumbent firms deliberately set a price that was thought to be sufficiently high as to allow other firms to enter the market, undercut the incumbent and be profitable. This did cause Texas to quickly have more entry and lower market concentration than other deregulated states, at the cost of higher prices in the short-run. While this chapter does not provide evidence that the Texas approach was superior to other states, the model results do show that it is at least possible for higher incumbent prices in the first period to result in an overall lower average price over the first 10 periods than if specific lower incumbent price had been set. Based on the range of first-period prices examined, increasing the incumbent's first period price could either raise or lower the cumulative average price paid by consumers over the first 10 periods.

The model used in this chapter only had one entrant firm and exogenous entry. In reality, Texas had a large number of entrant firms competing with the incumbent and entry was endogenous. Increasing the number of firms would likely cause the entrant firms to price lower than the current entrant firm does to compete more strongly to attract "searchers" from the incumbent firm. An additional incentive to set a lower price would be to retain customers already attached to the firm since reclaiming them in the future would be more costly. Adding additional firms would not eliminate the process by which the "Texas-style" transitional regulation has the potential to be preferable to some transitional regulations imposing lower prices if long run weighted deregulated prices are lower than the incumbent's initial price.

For retail electricity deregulation to be a success, either the final deregulated markup should feature low markups or regulators must have a difficult time setting the appropriate regulated price. In environments where consumers are attentive, low markups in a long-run deregulated market may be more likely. This could be the case for large commercial customers, where the incentives to search for low energy prices are stronger. For residential retail electricity deregulation, some effort to make switching easier and to educate consumers about the existence of the market (and increasing the attention paid to the market) would likely be beneficial in terms of the market price.

Setting a temporary, high price floor on the incumbent firm imposes short run costs on consumers who do not switch, as their price is higher than it would have been under standard cost-of-service regulation. The potential benefit is if competition can result in lower prices than would have occurred under regulation and if encouraging entry and switching achieves those lower prices more quickly. Given that deregulated retail electricity can only work in areas with deregulated wholesale electricity markets, procurement costs should be reasonably clear to regulators and likely limiting any potential spread between low market prices and higher regulated prices. Thus while the "Texas approach" to retail electricity deregulation policy could potentially be successful, it is a risky strategy.

Figure 3.1: Service Zones of Deregulated Retail Electricity Markets

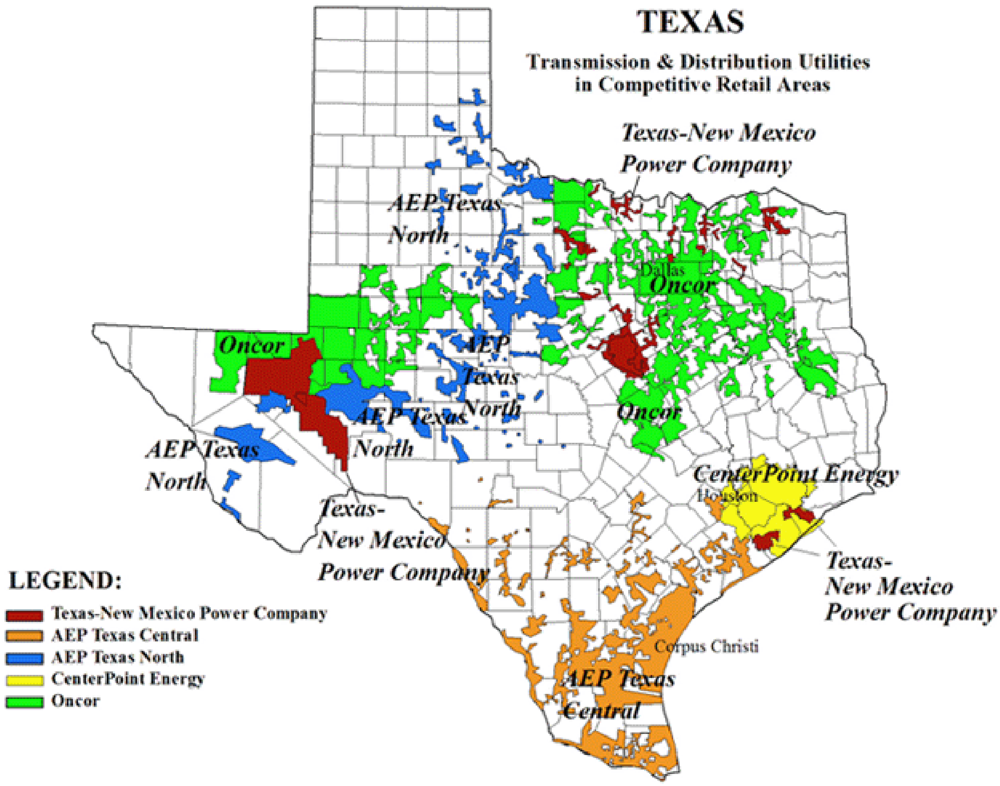

Figure 3.2: Prices of Selected Firms in CenterPoint Region

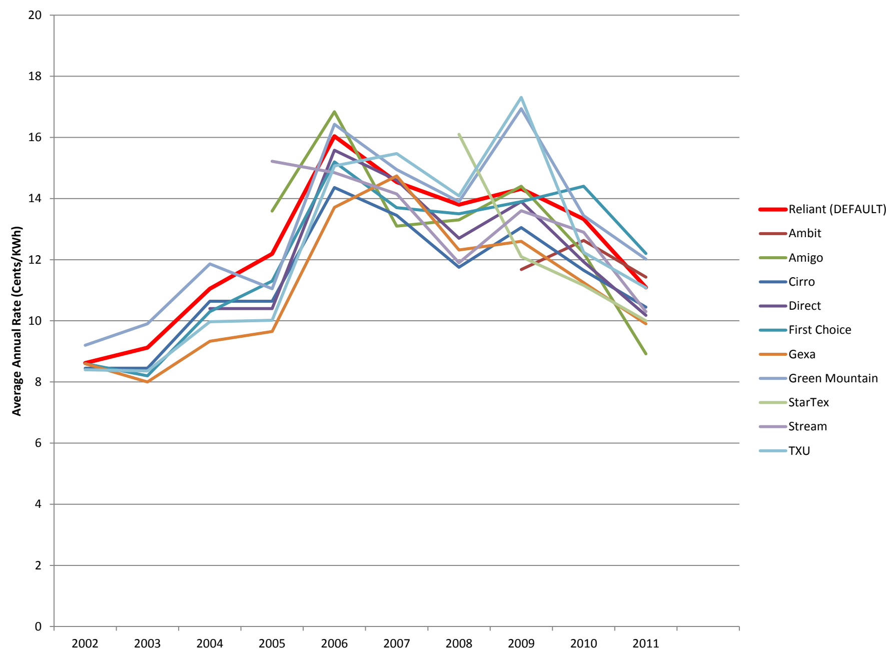

Figure 3.3: Market Share of Default Provider in Five Texas Regions

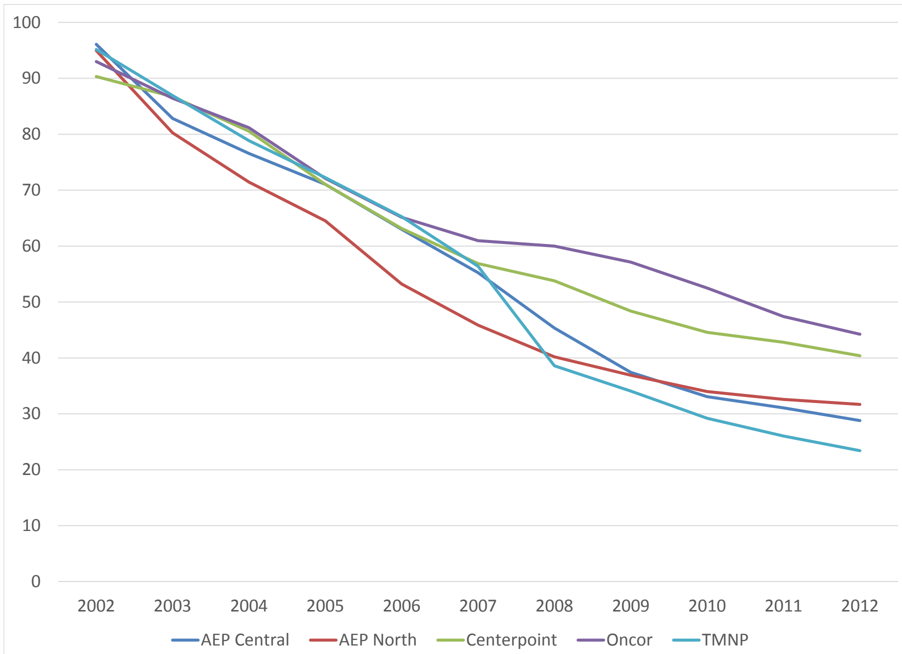

Figure 3.4: Unregulated Prices Over Time

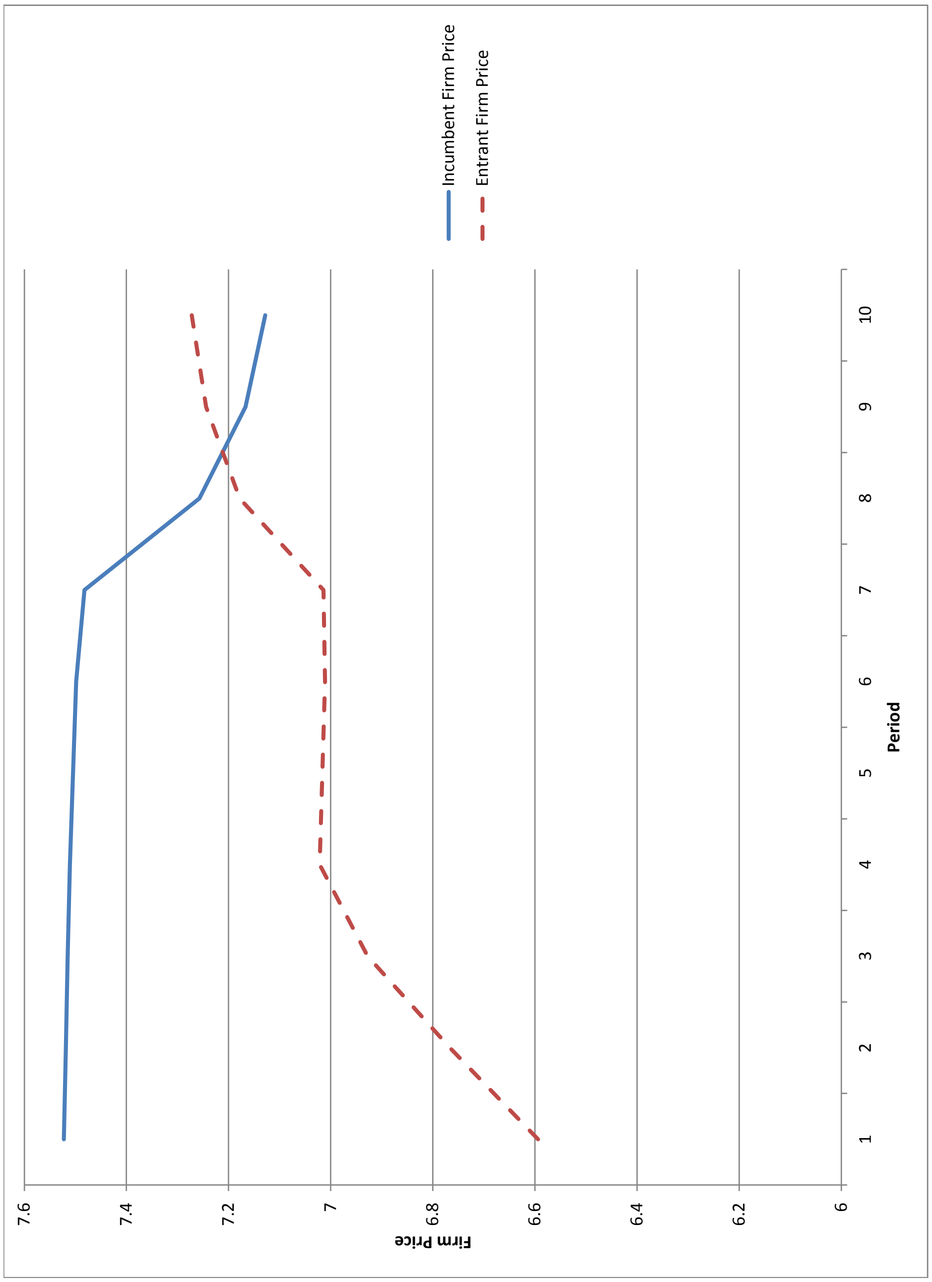

Figure 3.5: Market Share Evolution By Initial Regulated Price

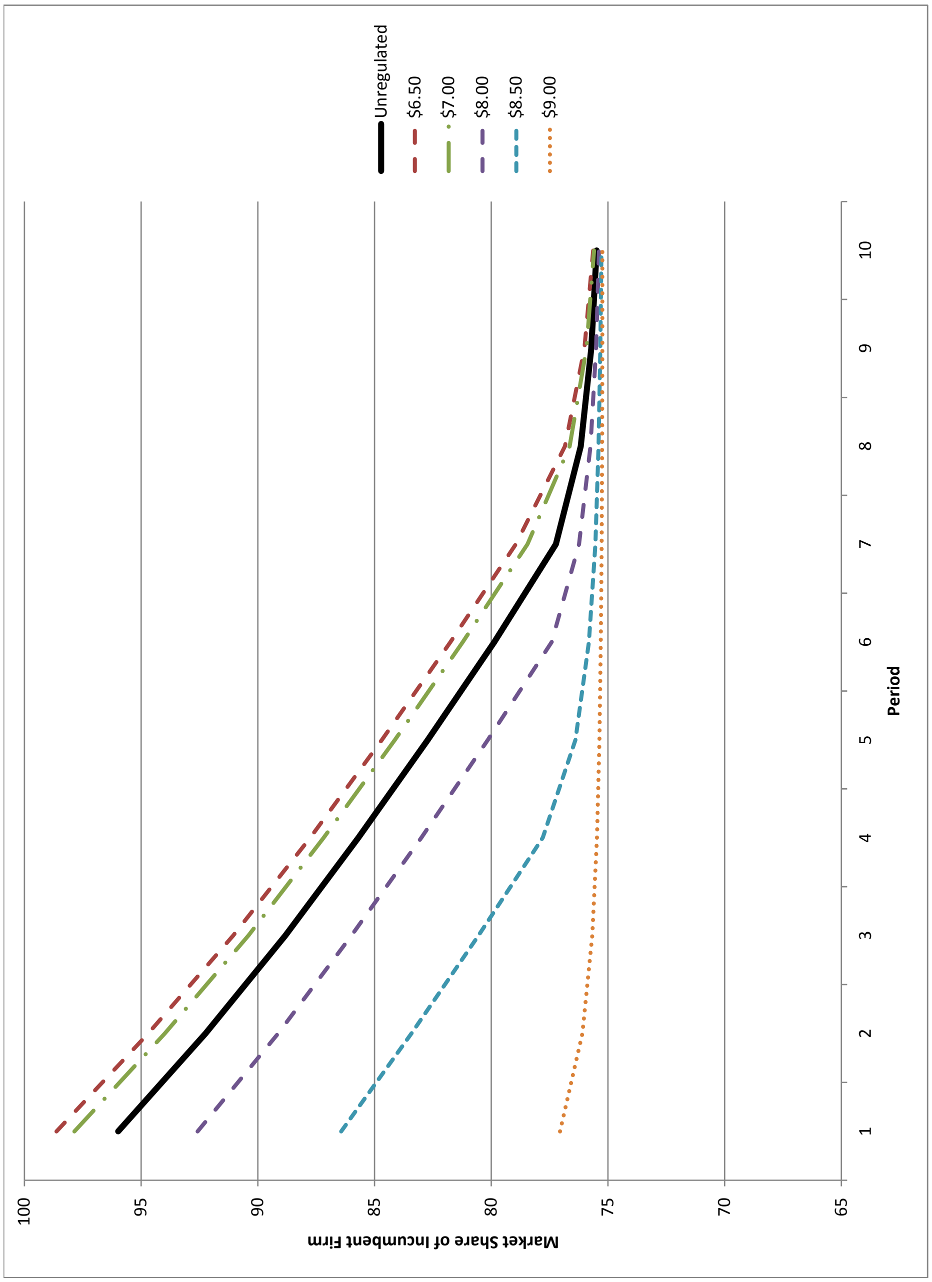

Figure 3.6: Weighted Price Evolution By Initial Regulated Price

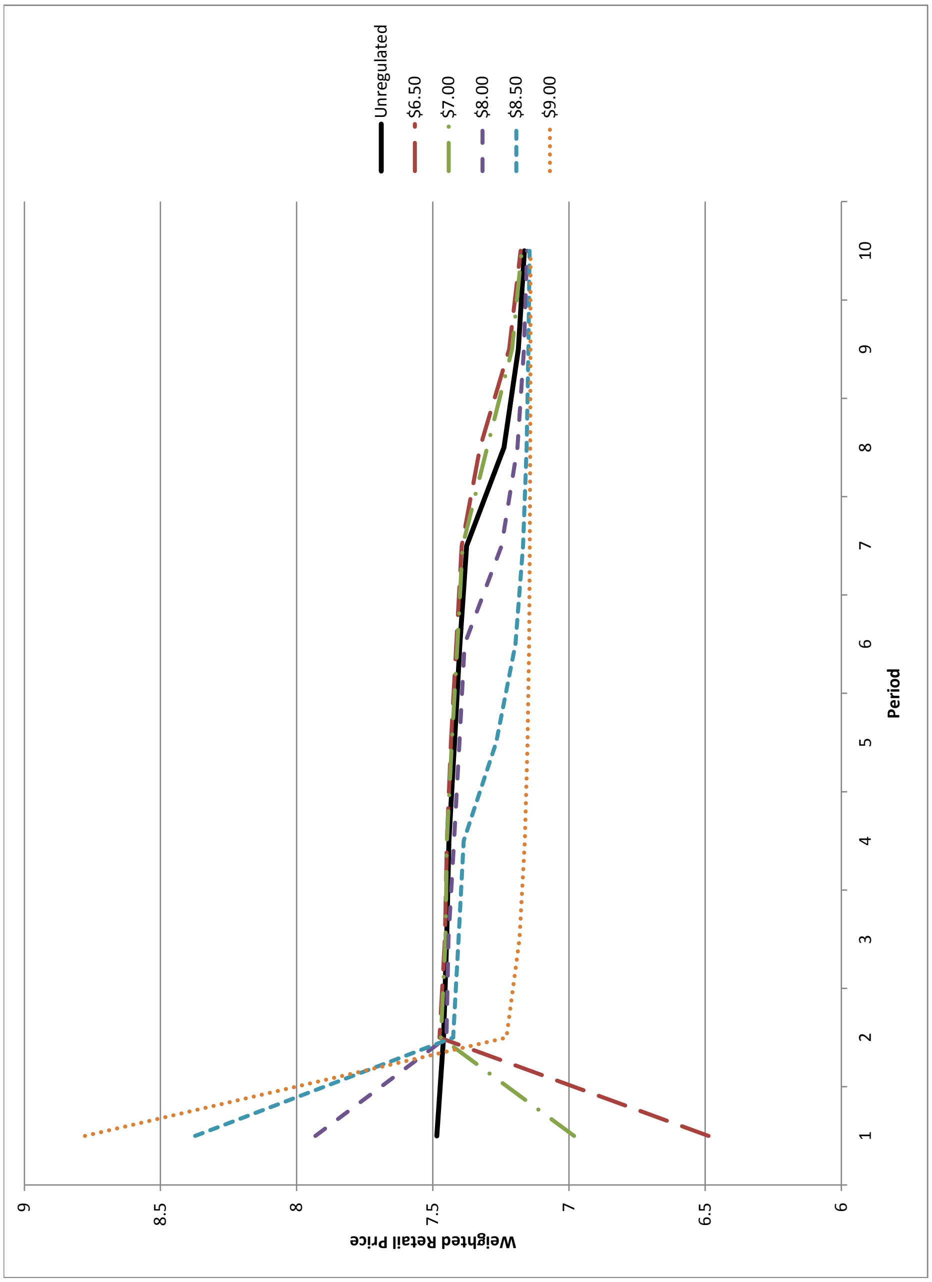

Figure 3.7: Evolution of Incumbent Market Share with Increased Customer Attentiveness

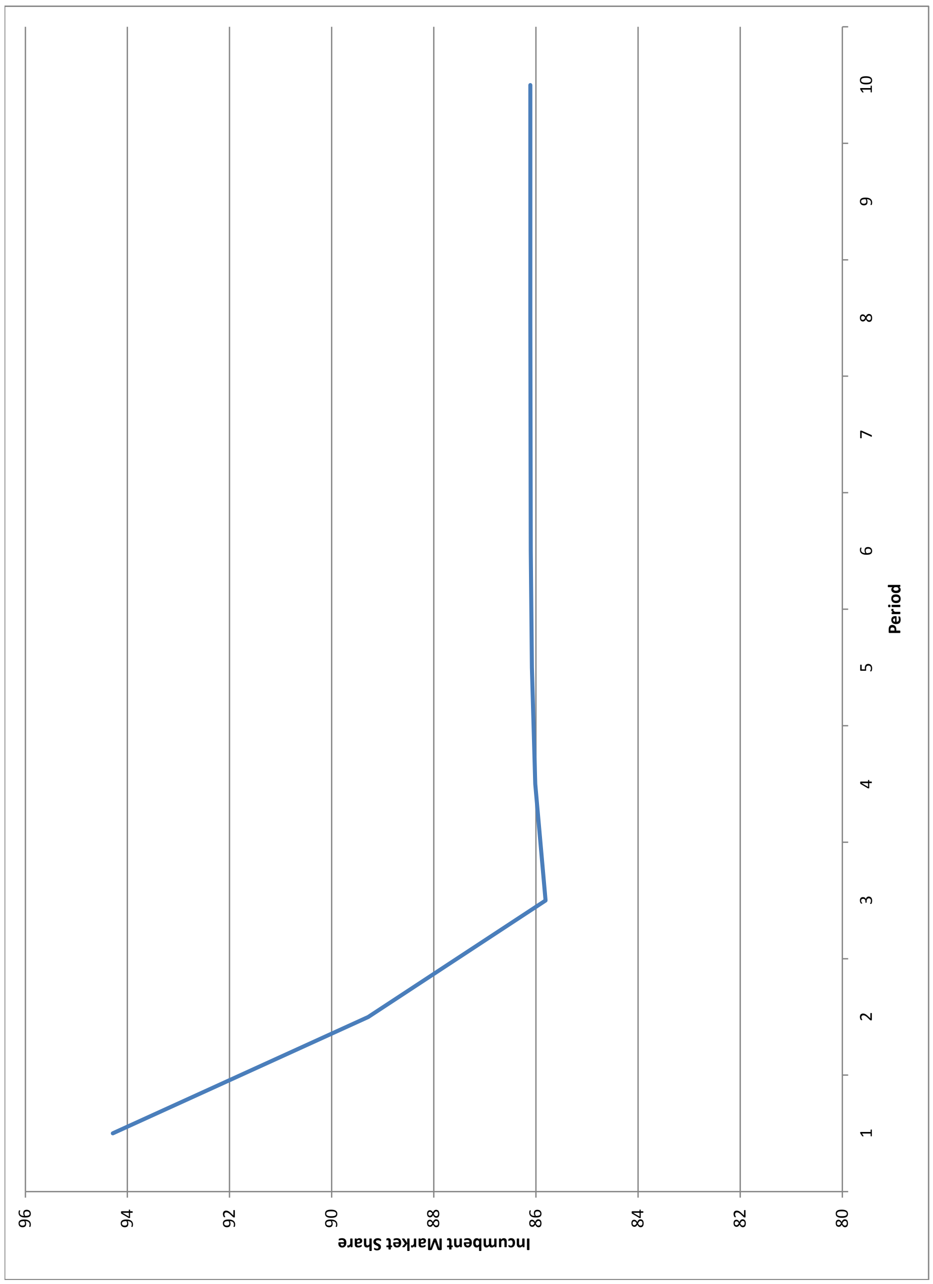

Figure 3.8: Evolution of Prices with Increased Customer Attentiveness

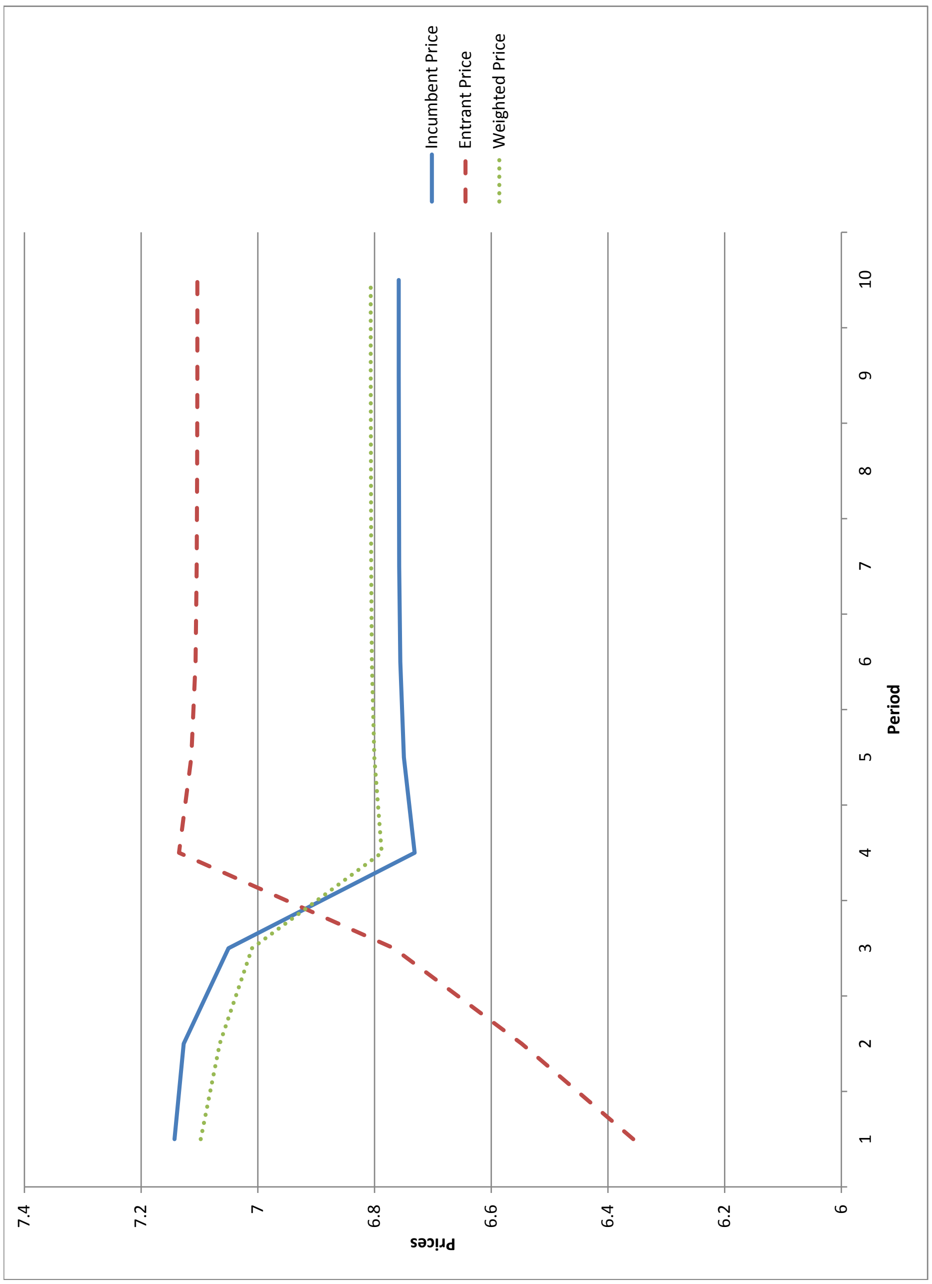

Table 3.13: Switching Rate Across States (2010)

State	% Consumers Who Do Not Have Default Provider
TX	50.6
CT	24.6
OH	22
NY	17.9
MA	12.3
PA	11.3
MD	6.7
DC	3.4
DE	2.6
ME	2.6
NJ	0.5
IL	0.01

Source: Swadley and Yucel [2011]

Table 3.14: Cumulative Prices for First 10 Periods With Alternate Transitional Policies

First Period Regulated Price	Cumulative Weighted Price	Difference vs Unregulated
6.5	72.831	0.788
7.0	73.266	0.354
Unregulated ($7.522 in 1st period)	73.619	–
8.0	73.786	-0.167
8.5	73.669	-0.050
9	73.218	0.401

Cumulative weighted price is the average price charged by firms, weighted by firm market share. Without price regulation, the incumbent firm would set a price of $7.522 in the first period

APPENDICES

APPENDIX A
Impact of Wind Intermittency on Generation Using Ratios Instead of Levels

The main text commonly uses the level of natural gas generation as a dependent variable. In those specifications, I control for the total level of fossil fuel generation, implying that any increase in natural gas generation increases the share of fossil fuel generation coming from natural gas. I rerun the specifications based on equation 1.4 using the ratio of natural gas generation to total fossil fuel generation as the dependent variable. Equation 1.4 is reproduced here with an updated dependent variable:

$$\begin{aligned}\left(\frac{Natural\ Gas\ Generation}{Fossil\ Fuel\ Generation}\right)_t =& \beta_1 W_t + \\ & \psi[IntermittencyVars_t] + \\ & f(FossilFuel_t) + \\ & \alpha_0 + \alpha_1 Temp_t + \alpha_2 Temp_t^2 + \gamma_m HourMonth_t + \epsilon_t\end{aligned}$$

I run four specifications, with different combinations of intermittency variables. These are the same as in Section 1.6.3:

1. No intermittency variables

2. Standard deviation of expected wind generation (expected variation)

3. Uncertainty of wind forecast for upcoming hour (unexpected variation)

4. Standard deviation of expected wind generation (expected variation); Uncertainty of wind forecast for upcoming hour (unexpected variation)

The coefficient estimates can be found in Table 4.15. As compared to the earlier results from Table 1.2 where the dependent variable was natural gas generation levels, all variables except for forecast uncertainty that were statistically significant earlier remain so. No variable that was not statistically significant in Table 1.2 is statistically significant in Table 4.15. Additionally, the signs on all coefficients are the same across Tables 1.2 and 4.15.

Table 4.15: Effect of Wind Intermittency on Nat Gas-Coal Ratio

VARIABLES	(1) NG-Coal Ratio	(2) NG-Coal Ratio	(3) NG-Coal Ratio	(4) NG-Coal Ratio
Wind Gen	1.50e-06**	1.38e-06**	1.16e-06	1.16e-06
	(6.77e-07)	(6.82e-07)	(7.58e-07)	(7.56e-07)
Forecast Uncertainty			8.95e-06	5.82e-06
			(5.83e-06)	(5.41e-06)
Std Dev of Expected Wind Gen (5 Hr Window)		5.50e-06***		4.98e-06**
		(2.05e-06)		(2.05e-06)
f(Fossil Fuel Gen)	X	X	X	X
Observations	23,665	23,665	23,665	23,665

Observations are hourly and aggregated to ERCOT-level. Data is from approximately 2011-2013. Newey-West standard errors with 69 lags used to correct for heteroskedasticity and serial correlation. Potential wind generation is used to instrument for actual wind generation. "Std Dev of Expected Wind Gen (5 Hr Window)" measures expected variance in wind generation. "Forecast Uncertainty" is the difference between the 20th and 50th percentile of predicted potential wind generation outcomes in the following hour. Coefficients for temperature, hour-month indicator variables and nonlinear controls for generation net of nuclear and wind power are omitted. *** p<0.01, ** p<0.05, * p<0.1

APPENDIX B
Impact of Use of Instruments for Wind Generation

While the weather conditions that determine the maximum potential wind generation are exogenously determined, the actual level of wind generation is determined by a combination of windspeed conditions, supply and demand in the wholesale electricity market and transmission constraints. Wind power can be curtailed by grid operators for a variety of reasons; mainly to address congestion issues on transmission lines. The main analysis uses the high sustainable limit of wind generation used by ERCOT in the dispatch process as an instrument for actual wind generation. The actual wind generation is on average close to the high sustainable limit, though this was less earlier in the period studied. Initially in 2011, approximately 5% of potential wind power was curtailed. By 2013, additional transmission capacity was introduced and average wind curtailment fell to under 1%.

To test the importance of using instrumental variables and how this could change over time, I redo specifications 1.1 and 1.3, reproduced here, without instrumentation.

$$\begin{aligned}Natural\ Gas\ Generation_t =& \beta_1 W_t + f(FossilFuel_t) + \alpha_0 + \alpha_1 Temp_t + \alpha_2 Temp_t^2 + \\ &\gamma_m HourMonth_t + \epsilon_t\end{aligned}$$

$$
\begin{aligned}
Natural\ Gas\ Generation_t = & \beta_1 W_t * 1[year = 2011]_t + \beta_2 W_t * 1[year = 2012]_t + \\
& \beta_3 W_t * 1[year = 2013]_t + f(FossilFuel_t) + \\
& \alpha_0 + \alpha_1 Temp_t + \alpha_2 Temp_t^2 + \gamma_m HourMonth_t + \epsilon_t
\end{aligned}
$$

Comparing the parameter estimates from Table 4.16 to Tables 1.2 and 1.4, instrumenting for actual wind generation with potential wind generation does not result in substantial changes, even for the effect of wind intermittency in 2011. As noted by Cullen [2013], if the wind curtailment is simply caused by transmission congestion that itself is caused by high levels of wind generation, this does not introduce endogeneity into the parameter estimates.

Table 4.16: Impact of Wind Intermittency on Generation Mix Without Instrumentation

VARIABLES	(1) Nat Gas Generation	(2) Nat Gas Generation
Wind Gen	0.0346*	
	(0.0178)	
Wind Gen (2011)		0.0760***
		(0.0235)
Wind Gen (2012)		0.0294
		(0.0230)
Wind Gen (2013)		0.0181
		(0.0287)
f(Fossil Fuel Gen)	X	X
Observations	23,665	23,665

Observations are hourly and aggregated to ERCOT-level. Data is from approximately 2011-2013. Newey-West standard errors with 69 lags used to correct for heteroskedasticity and serial correlation. Instrumental variables not used. Coefficients for temperature, hour-month indicator variables and nonlinear controls for generation net of nuclear and wind power are omitted. *** $p<0.01$, ** $p<0.05$, * $p<0.1$

APPENDIX C
Market Power and Wind Generation Curtailment

ERCOT runs a bidding system as part of its procedures to determine which generators will be assigned to generate power at any point in time. Generation resources submit a bidding function stating the prices they they are asking for to provide given quantities of electricity. One potential source of wind generation curtailment is that in the real-time electricity market, the owners of the wind generation units could bid above their effective marginal cost in an exercise of market power with the possible result that some or all of the wind generation capacity does not end up dispatched by ERCOT. It is likely that wind generation sources should have the lowest effective marginal cost of all generation sources in ERCOT: the marginal cost of wind generation is near zero and additionally wind generation is eligible for a federal per-unit subsidy which should push the effective marginal cost of wind generation negative.[90] If a wind unit's production is curtailed because its bid curve into the real-time market is high enough that some of the potential wind generation is not selected for dispatch and is replaced by a higher-cost non-wind unit, this would be an example of curtailment due to market power exercise.

It is relatively straightforward to identify occurrences in the data where attempted market power exercise could be a contributing factor to wind curtailment. When examining the wind unit bids into the real-time electricity market, if a wind unit is curtailed while the

[90]Some wind generators qualified for and took an investment tax credit in place of the production tax credit as a result of the American Recovery and Reinvestment Act of 2009; these turbines should not be willing to submit negative bids, but still face zero fuel costs to generate electricity.

marginal price for additional generation according to its wholesale electricity bid is positive, the generation unit was likely bidding to sell output above marginal cost and that curtailment was potentially related to the exercise of market power. This is not a complete determinant of market power-based curtailment because this does not determine exactly if wind production was curtailed and replaced with other generation sources with a lower bid. Instead this only checks if a wind unit's bids has the marginal price of additional output at their dispatched level clearly above marginal cost and were curtailed.[91]

Examining bidding data from early 2011, 20.58% of curtailed wind generator observations have a bid price greater than zero at the actual quantity produced. Table 4.17 gives summary statistics for the bid price for the curtailed wind units at the actual quantity produced when that number is greater that zero. This clearly shows that while about a fifth of the observations of curtailed wind turbines have a positive marginal bid price, the vast majority of these observations are extremely close to zero. Over 75% of these curtailed observations with positive marginal prices have a marginal price of less than one dollar – far less than the average price of \$35.42/MWh over the Jan-Nov 2010 period. While there are a number of curtailed wind observations where the marginal bid price was very high, indicating a high likelihood of curtailment due to market power exercise – the highest marginal price for observations where this value is positive is \$62.93 – these are rare occurrences.

Table 4.17: Distribution of Positive Marginal Bid Prices for Curtailed Wind Units

Percentile	1st	5th	25th	50th	75th	95th	99th	Max
Price (\$)	0.99	0.99	0.99	0.99	0.99	5	5	62.93

[91]Some other generation types have negative bids as well for some range of output, but presumably this is to maintain a minimum level of production and avoid shutdown costs. Note that this is directly related to the discussion of curtailing wind to avoid shutdown of other units.

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