Essays on Wind Energy Integration and the Costs of Intermittency

A Dissertation Submitted to the Faculty of the Graduate School of the University of Minnesota By

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Abstract

This paper consists of three chapters. In chapter 1, I analyze the costs of intermittency in European wholesale power markets. Intermittent dispatch is a barrier to the widespread adoption of renewables. I revisit this issue from a sufficient statistic perspective by observing that in a very general environment, the cost of intermittency can be summarized in the degree of covariance between production and marginal value of power. If spot prices are market-determined, this covariance can be measured using daily price and production data. I document that the covariance becomes increasing negative as wind penetration increases within European bidding zones, which does not occur for dispatchable forms of power. I then show in a simple framework that the equilibrium level of wind penetration can be summarized with the elasticity of demand, the cost differential between wind and other forms of power, and the variance of wind supply. Applying this to wind generation data across bidding zones, I demonstrate that integration among regions allows for substantial increases in potential wind penetration by reducing the variance of supply.

In chapter 2, I analyze the relationship between wind energy and transmission congestion in the Midwest wholesale power market. Transmission constraints and congestion costs are a significant barrier to variable renewable penetration. I use state-level wind speed observations to analyze the relationship between wind generation and the congestion and energy components of wholesale energy prices in the midwest. In states with high wind penetration such as Minnesota and Iowa, negative congestion charges during periods of high wind generation are on average 40% and 50% respectively of the marginal energy charge, which is a significant effect on wholesale prices and the revenues of wind producers. In states without high wind penetration, congestion charges are on average much lower in magnitude and have no relation to wind speed. Because state level production is not published in the wholesale market, this is a novel approach for looking at the relationship between generation and prices at the state level. I additionally look at the frequency of negative prices across hourly observations at the nodal level within each MISO state, finding that Iowa and Minnesota see not infrequent cases of negative prices, particularly in the real-time market (12% and 9%, respectively). Isolating for just the hours when wind speeds are in the top quartile, the frequencies rise to 21% and 13%. Finally, I show that the frequency with which negative price observations exceeds tax credits and therefore generation would be unprofitable for wind producers is uncommon.

In chapter 3, I introduce a simple theoretical framework for modeling wind energy as a random variable and analyze how intermittent supply is balanced with dispatchable sources of power like natural gas to meet demand. I extend the model to the application of transmission between two countries and show that as transmission increases in the long run, the amount of wind farms increases as well. In the short run, when the number of wind farms is fixed, increased transmission may boost natural gas usage under certain conditions.

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1 Estimating Costs of Wind Energy Intermittency in European Wholesale Power Markets

1.1 Introduction

Decarbonizing the electricity sector will depend on the widespread deployment of wind and solar energy. While both forms of power have seen dramatic reductions in their costs, neither can reliably provide electricity to meet demand due to intermittency and the high costs of storage technology without support from dispatchable sources of power. Intermittency likewise hurts the revenues of wind and solar producers as they cannot choose to produce during periods of high demand if generation is simply unavailable.

This paper introduces the covariance of energy generation and the wholesale price as a sufficient statistic to capture the costs of intermittency for wind and illustrate difficulties of integrating variable power relative to dispatchable forms like natural gas, nuclear, and hydro. Using data from European bidding zones, I find that as wind penetration increases, the covariance becomes increasingly negative, while other forms of power see no relationship or have a positive one. I then show in a theoretical setting that the possible penetration of wind energy can be summarized in the degree of the cost advantage of wind, the variability of wind power, and the elasticity of demand with respect to prices. Finally, using this measure for penetration, I use production data across bidding zones to illustrate that regional integration can allow for substantially higher wind penetration by reducing wind supply variance by approximately 100% for less volatile regions and 200% for regions with more volatile supply, as a very rough calculation.

Joskow's (2011) seminal paper demonstrated that levelized cost of energy (LCOE), the traditional metric for comparing costs across forms of power, is not suitable for comparisons of dispatchable and intermittent forms of energy. This metric, which divides a generator's (plant, wind farm, etc.) lifetime output by its total fixed and variable costs, is shown to dramatically overvalue intermittent forms of energy. Joskow also posits that the approach may overvalue wind relative to solar, a result discussed later in both Chapters 1 and 2. Hirth, Ueckerdt, and Edenhofer (2016) introduced a ”system LCOE” to compare generation technologies and found through a literature review that as wind market share approaches 30-40%, the value of a megawatt hour of electricity from wind can be 20-50% lower than the that demanded by consumers. In that vein, this paper's simple measure provides a pedagogical way to illustrate the costs of intermittency and compare dispatachable and variable forms of power, in addition to reinforcing the results discussed here. I leave a more detailed discussion of the empirical and theoretical literature on intermittency and regional integration to chapters 2 and 3.

1.2 Data

All electricity price and generation data is taken from the Entsoe Transparency Platform, which collects and publishes electricity generation, consumption, and transmission data from the pan-European market. In the following section, the Day-Ahead price is used rather than the Real-Time price. In most regions, renewable producers are required to offer on the day-ahead rather than real time markets, which are more volatile and often used for balancing differences in forecast and realized supply and load. Data was gathered for all bidding zones, but due to errors in data not all are included in the section. Appendix 1 provides a list of excluded bidding zones and the explanation.

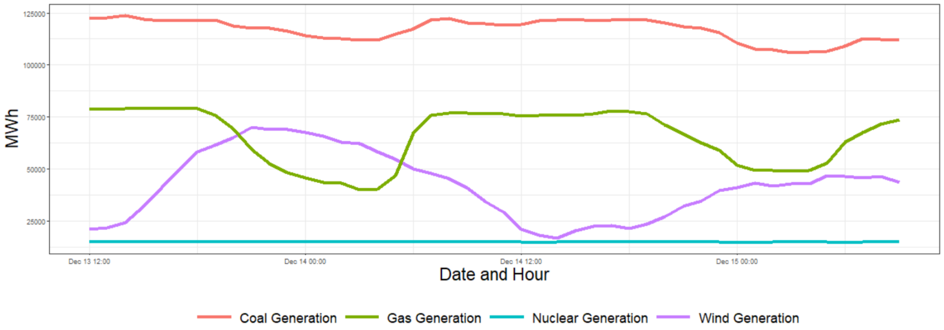
1.3 The Energy Merit Order and Winter Intermittency

I provide a brief overview of how variable sources of power like wind are balanced with dispatchable sources. While the examples here are from European bidding zones, the same concepts apply to the U.S. states discussed in Chapter 2 and they additionally serve as a real-world example of the framework developed in Chapter 3.

The production of electricity follows a merit order with sources of power which have the lowest marginal cost and sometimes fewest emissions forming the bottom of the supply curve. Wind farms and solar farms, which have a marginal cost of zero, are the first sources of power used to meet demand, but unlike other forms of power, wind and solar are variable and cannot be dispatched. Hydro and nuclear are also on the low end of the merit order, while coal and natural gas form are ranked higher, The marginal cost of natural gas plants can fluctuate considerably given the price of gas, which may affect its usage relative to coal. Increased deployment of wind and solar has results in a decrease in wholesale energy prices, which is known as the merit order effect (see literature discussion in Chapter 2).

Since wind and solar cannot be dispatched on command, their usage must be balanced with faster reacting sources of power, notably gas and hydro, in order to meet demand. In figure 1.1, I plot a snapshot of electricity generation in Germany in 2022 to show how the usage of the other primary sources of power fluctuates in response to changes in wind supply. Notably, gas generation is the most responsive, because gas plants are fast-reacting and can be quickly adjusted or dispatched to meet sudden shifts in wind generation. Coal and nuclear provide baseload power, and as such are less responsive to wind than gas usage. I also note that, in this period of time coal usage is particularly high in Germany due to the energy crisis and high natural gas prices seen then. Nuclear power, which has no emissions and a low marginal cost compared to coal, is extremely stable.

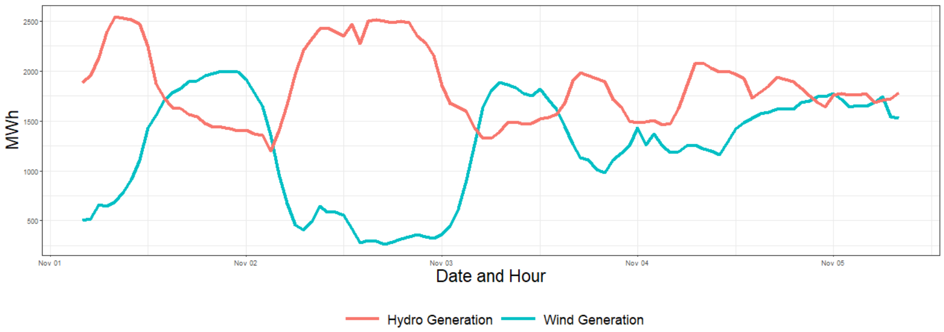
Figure 1.1: Electricity Generation by Source (Germany, December 2022)



In figure 1.2, I plot a snapshot of electricity generation in Norway's third bidding zone, this time demonstrating that hydro power can also be used to balance variable supply. Over this time frame, this bidding zone in Norway was not generating any other form of power, though it may have been importing power from elsewhere. Clearly, when wind generation dips, hydro generation increases, and vice versa. Thus, hydro generation can function much like a fast reacting natural plant, and is generally faster at ramping up, but of course there are geographical constraints.

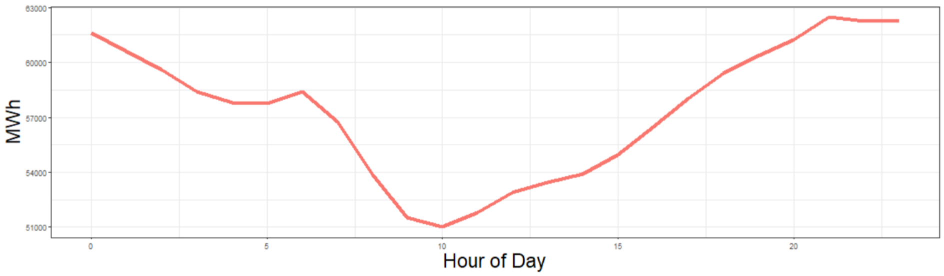
Generally, wind generation is also more likely to occur in off-peak periods, when electricity demand is lowest on average, but this can fluctuate somewhat depending on the area. In figure 1.3, I plot the average wind generation in Germany for each hour of the day over the course of the year. Because demand is lower in off peak periods, prices are lower as well, which affects the revenue that wind producers will receive,

Figure 1.2: Electricity Generation by Source (Norway 3, November 2022)



as discussed in the next section. Finally, consider that figure 1.3 coupled with 1.1 demonstrates that gas production is balancing wind on average more often when prices are higher.

Figure 1.3: Average Wind Generation by Hour of the Day (Germany, 2022)



1.4 Empirical Evidence on Production-Price Covariance and Wind Penetration

The costs of intermittency of wind energy can be captured via the covariance of the wholesale price for electricity and the supply of wind generation. The definition of the covariance between price P and energy Y is given by:

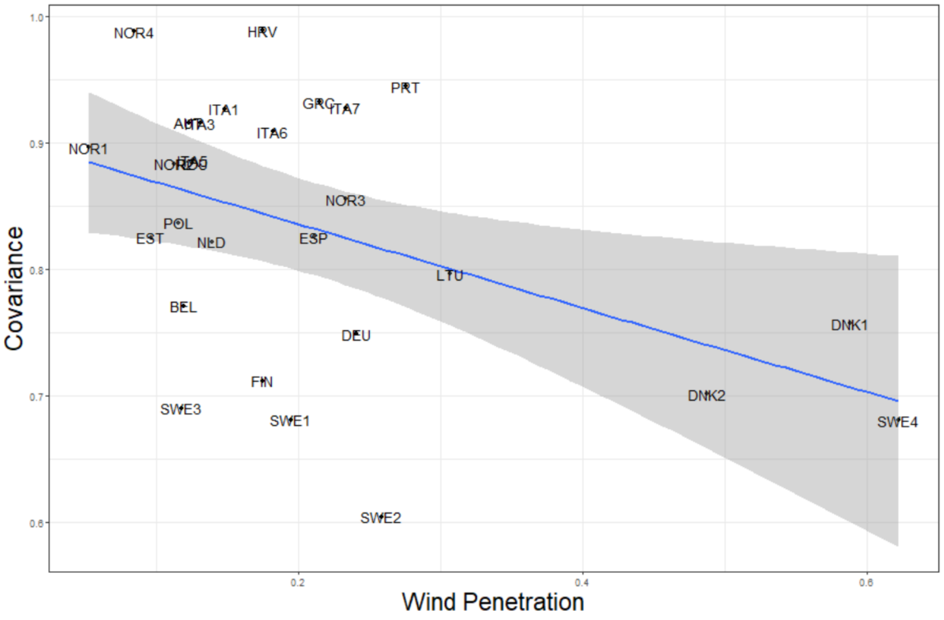
$$\mathrm{cov}(P, Y) = E[P \times Y] - E[P]E[Y]$$

I normalize the covariance as:

$$\frac{E[P \times Y]}{E[P]E[Y]} = 1 - \frac{\mathrm{cov}(P,Y)}{E[P]E[Y]}$$

The left-hand side (LHS) then is the expected revenue divided by the expected price and expected wind supply (or other form power), which in essence is how much average revenue deviates from that predicted by average production and average prices in the market. In the following graphs, the statistic on the LHS is plotted on the Y-axis with the share of electricity coming from wind supply on the X-axis. In the figures with other sources of power, that generation type replaces wind in the statistic. In each figure, regions with less than 2% of that form of power are not included. Figure 1.4 shows this relationship for European bidding zones in 2022.

Figure 1.4: Wind Production-Price Covariance



With the normalization, a covariance below one illustrates a negative relationship between prices and quantity. As wind penetration increases in bidding zones, the relationship between price and quantity becomes increasingly negative on average. The above relationship is due entirely to the intermittency of wind- if there was a cost-free storage technology available to producers, the trend would be an approximately flat line at 0. As it is, wind farms are most productive on average when demand is low (see figure 1.3), causing them to sell for lower prices or in some cases negative prices if supply exceeds demand.

Local policies, such as the magnitude of feed-in tariffs, the availability of transmission to other regions or hydro-storage, can affect the degree to which any given bidding zone's falls below 1 in its covariance, and as such the relationship is not perfectly linear. For example, in the cases of the two Danish bidding zones, the extremely high wind penetration is in part supported by the capacity to trade with Norway's abundant hydro power, which due to is fast dispatch time can compliment intermittent power, and the option to import abundant nuclear power from Sweden during periods of low wind supply. Even so, Danish wind producers are earning 25-30% less than that predicted by their average generation and average prices in the market and are often reliant on feed-in tariffs. Wind producers will sell for negative prices due to feed-in tariffs if the value of the subsidy exceeds the magnitude of the loss and would alternatively shut down when prices fell below their marginal cost sans the subsidy.

Figure 1.5: Gas Production-Price Covariance

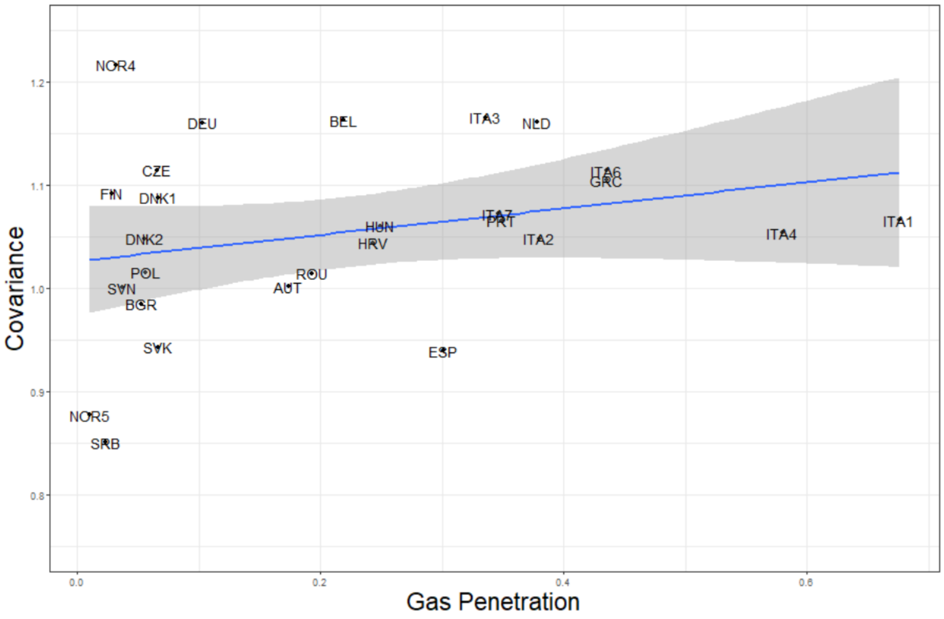


Figure 1.5 plots the normalized covariance for gas production and the day-ahead price. In contrast to the wind relationship in figure 1.4, the trend here is slightly positive and above 1 for a positive covariance. In both the day-ahead and real-time markets, gas plants are used to balance renewable droughts, which allow them to sell for higher prices on average. When wholesale prices are extremely low and/or negative due to large wind generation, gas plants will shut off, contributing to their positive covariance. A comparison

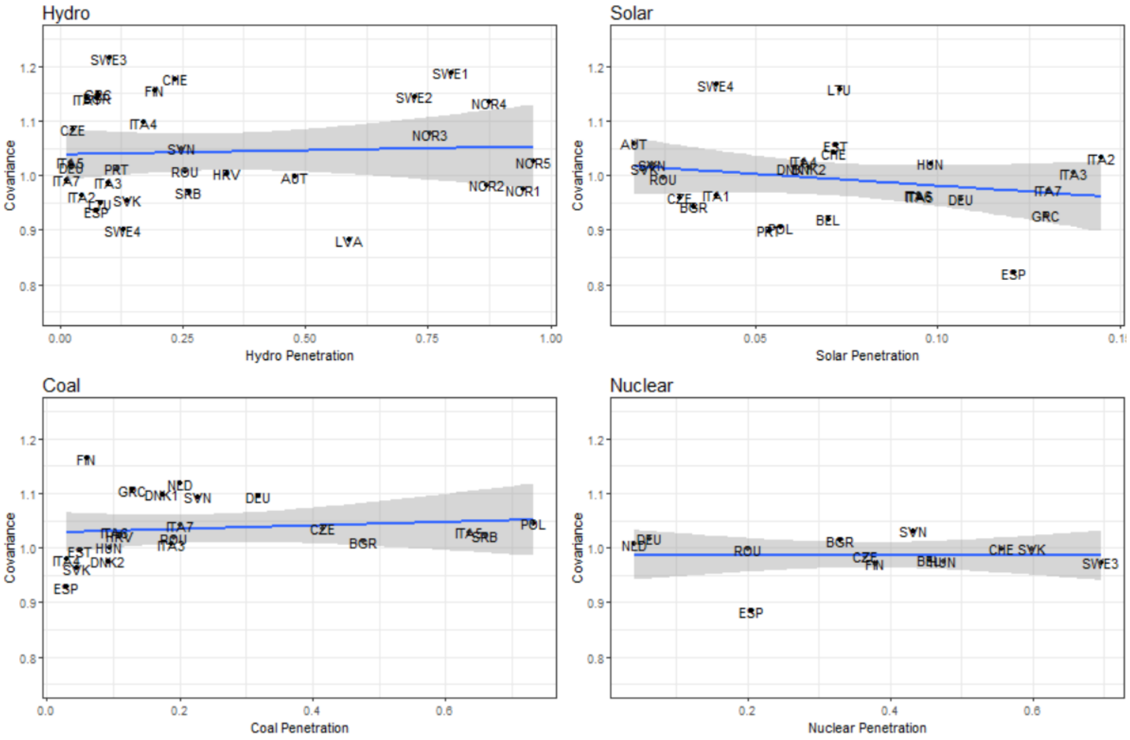
of figures 1.4 and 1.5 further shows the complementarity of the two forms of power, as explained in the previous section. In countries like Denmark and Germany, with high wind penetration, gas producers earn nearly 10% more than that predicted by average prices and average generation in the market.

The covariance-penetration relationship for other forms of power is shown in figure 1.6. Hydro power is the most quickly dispatchable form of power and is low in the merit order, giving it a slightly positive covariance. As explained above, hydro generation parallels natural gas in its ability to balance intermittent power and as such the similarity between the hydro graph and figure 1.5 is to be expected. For solar power, in the top right, penetration levels remain too low to provide a good sense of the relationship here as its share of an energy portfolio increases. However, even though it will likely look more similar to figure 1.6 as solar installations ramp up and deployment of affordable storage technology lags, solar benefits from a larger overlap with peak demand than wind does, making it unlikely to have as large a negative covariance as high levels of wind penetration. Joskow (2011) speculated that this would be the case in his paper, because wind energy is more heavily concentrated in off-peak periods.

Coal and nuclear, both much less flexible forms of power, are shown in the bottom quadrants. Both types provide baseload power and therefore would be expected to have a normalized covariance here of approximately 1 regardless of penetration level, which is a price-generation covariance of 0. In the case of coal, it has much higher marginal costs than nuclear and is near the top of the merit order, giving it a sufficient statistic of slightly higher than 1 across most bidding zones as coal plants are relatively more likely to be used in periods of higher demand and shut off in off-peak hours. However, the inflexibility of coal plants does at times contribute to periods of negative prices, as suddenly high wind penetration may be coupled with inflexible coal plants that are cheaper to keep operating at negative prices than power down. For nuclear, which due to its extremely low marginal costs and reliability is used constantly in many areas, the sufficient statistic captures the expected relationship of 1 regardless of penetration. That is, nuclear plants earn the amount of revenue that would be predicted given their average output and prices in the market.

Taken together, the results here illustrate the obstacle that intermittency poses to high levels of wind penetration and potentially solar penetration, as variable producers must sell their output for much less

Figure 1.6: Production-Price Covariance for Other Forms of Power



on average dispatchable producers. Simply using LCOE to compare sources of power may suggest that much higher levels of variable penetration should exist than are possible given intermittent dispatch, which can be illustrated here using the price-output covariance statistic. To build upon the empirical analysis of intermittency, the next section provides a theoretical framework for determining the equilibrium level of penetration possible for variable power without widespread, affordable storage technology.

1.5 Equilibrium Wind Penetration in Theoretical Setting

Consider an environment where electricity is produced with two technologies, wind and other, that have marginal costs c_{wind} and c_{other}. Each wind farm M has stochastic production with mean 1, while Other has a deterministic production of 1. Let demand be given by $D(p)$, where the price p is a random variable determined by:

$$D[p; \text{other}, M] = \text{Other} + M * \text{Wind} \tag{1}$$

Free entry for wind and other energy production implies:

$$E[p_{\text{Wind}}] = c_{\text{Wind}}$$

$$E[p] = c_{\text{other}}$$

Define $\bar{p}$ as the price that that prevails when there are no shocks to wind production, that is $D(\bar{p}; \text{other}, M) = \text{Other} + M$. Then using a first order approximation of the market clearing condition (1), I can obtain:

$$\frac{\partial \log(p)}{\partial \log(\text{Wind})} = \frac{-s_{\text{wind}}}{\epsilon_d}$$

where $s_{\text{wind}} \equiv \frac{M}{\text{other}+M}$ is the share of wind with the expected shock of 1 and $\epsilon_d \equiv \frac{D'(\bar{p})\bar{p}}{D(\bar{p})}$ is the elasticity of demand with respect to prices. A longer derivation is included in appendix 2. Then, I have that:

$$E[p_{\text{wind}}] = E[p] + \text{cov}(p, \text{Wind})$$

Using the marginal costs gives:

$$c_{\text{wind}} - c_{\text{other}} = \text{cov}(p, \text{Wind})$$

I can then obtain that:

$$\frac{c_{\text{wind}} - c_{\text{other}}}{\bar{p}} = \text{cov}(\text{Wind}, \text{Wind}^{\frac{-s_{\text{wind}}}{\epsilon_d}}) \tag{2}$$

Using a first-order Taylor approximation of the LHS we have:

$$\frac{c_{\text{wind}} - c_{\text{other}}}{\bar{p}} = \frac{-s_{\text{wind}}}{\epsilon_d} \text{var}(\text{Wind})$$

Then the equilibrium share of wind can be solved as:

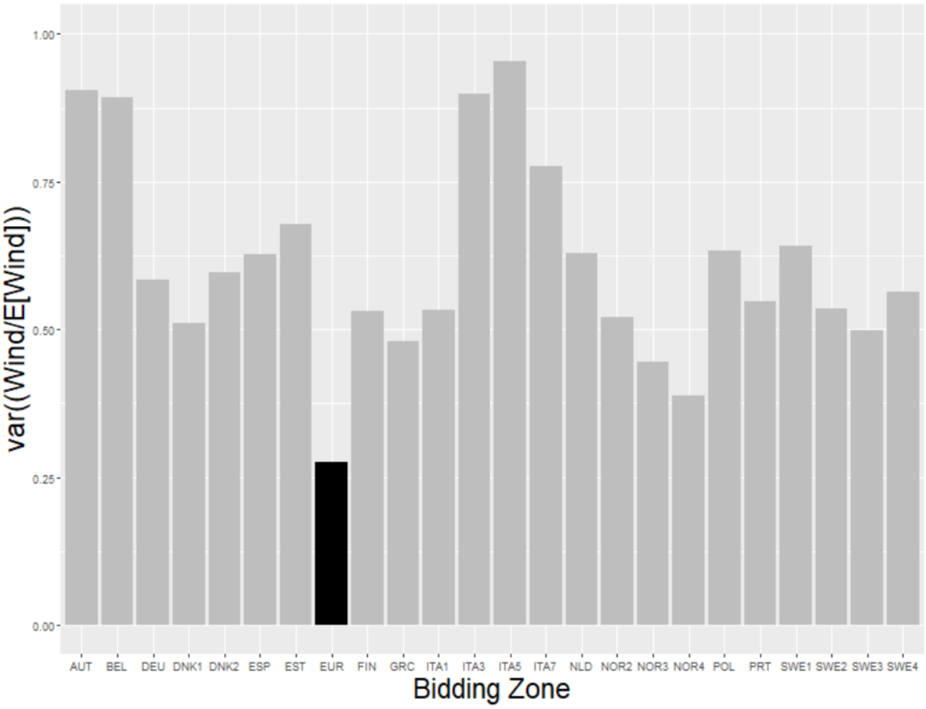
$$s_{\text{wind}} \approx \epsilon_d \frac{c_{\text{oother}ther} - c_{\text{wind}}}{\bar{p}} \times \frac{1}{\text{var}(\text{Wind})} \tag{3}$$

Thus, the share of wind in this simplified environment can be summarized in the elasticity of demand, the cost advantage of wind relative to other sources of power, and the inverse of the variance of wind supply. As wind becomes cheaper relative to other sources of power, penetration will increase, but higher variability in wind supply will decrease this potential share. At a high level, this captures what is observed in Figure 1.4 in the previous section- that intermittency has a significant effect on revenues and thus possible penetration.

1.6 Integration and Potential Wind Penetration

By utilizing equation 3, I can roughly estimate the increases in potential wind penetration that can occur from regional integration and the corresponding decrease in volatility of wind supply. By assuming that both the elasticity of demand and price differentials are constant across regions, the potential increase in

Figure 1.7: Wind Supply Variance by Region



wind possible from integrating is given by the ratio of the variances. I claim that this assumption is somewhat reasonable for a back of the envelope calculation in that the elasticity of demand for electricity should be comparable across developed countries, and the price differential should be fairly similar in the absence of government subsidies. In figure 1.7, the variance of each bidding zone's wind supply divided by the mean of production is graphed. While equation 3 is simply the variance without the mean, the normalization is necessary to capture the relative variance of a region without being skewed by the actual wind supply, which would otherwise vary enormously based on the actual constructed amount of farms.

The sum of wind production across the regions is the black bar for Europe, which captures a dramatic reduction in wind supply variance from the potential integration across regions without frictions from lack of transmission or line losses. In comparison to nearly every other region, except Norway 4, complete integration allows for at least 2x higher potential wind supply, assuming constant price differentials and cost differentials. Of course, even with unconstrained transmission between regions, which would require a significant investment, line losses of 5-10% would mitigate some of the gains. However, in the absence of affordable and widely available storage technology, this example demonstrates that regional integration is a key component of increasing variable renewable penetration and ultimately decarbonization of the electricity sector. Even as storage becomes more widely available, increased transmission capacity can lead to better utilization of it and reduce the amount needed.

1.7 Conclusion

This paper introduces a simply measure for capturing the costs of intermittency to wind production using the covariance between production and wholesale prices. I show that as wind penetration increases, the covariance becomes increasingly negatively, which is not a relationship observed for other forms of power. At high levels of expected wind penetration ($>$ 40% of supply), expected revenues for wind producers are 30% less than that predicted by average price and generation. The sufficient statistic also captures the relative role of each form of power in meeting demand, with the flat covariances in the coal and nuclear graphs highlighting their role as baseload power, while the upward sloping hydro and gas lines illustrate their ability to quickly balance supply with demand. Future research could apply this metric to wholesale prices in US states and additional examine the relationship between solar and wholesale prices at higher level of solar penetration, which cannot yet be observed in Europe.

In the second half of the paper, I introduce a simple framework to show in a general environment that the potential wind supply possible in a region can be summarized via the elasticity of demand, the price differential between wind and other forms of power, and the variance of wind supply, which lowers potential penetration. Extending this framework to production data for European bidding zones, I find that complete integration across Europe could increase potential wind supply by approximately 100% from bidding zones with the next highest potential, as a back of the envelope calculation and pedagogical exercise. While this number is not meant to be taken literally, it demonstrates that significant gains are possible from reducing intermittency of supply by integrating between regions. In future work, I intend to augment this framework to account for multiple periods, as equation 3 would suggest that the effect of intermittency is the same on the potential ceiling for wind and solar, which cannot be the case. Future research could also construct more sophisticated models for determining the true gains in potential renewable penetration that can occur from complete and partial integration of bidding zones.

References

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[2] Hirth, Lion, Falko Ueckerdt, and Ottmar Edenhofer. ”Why Wind Is Not Coal: On the Economics of Electricity Generation”, *The Energy Journal* V37 (3)/ (July 2016): 1-27. http://www.jstor.org/stable/44075648.

1.8 Appendix 1 - Observations removed for data issues

While Entsoe lists all European bidding zones for both price and generation, not all entries contain data for 2022, and in other cases have clear errors in their data.

- Albania – No production data in 2022
- Bosnia and Herzegovina – Missing most of the data for 2022
- Bulgaria has frequent
- Cyprus has no day ahead price data.
- France has no day ahead price data.
- Georgia has no day ahead price data.
- Italy Brindisi has no production data.
- Italy Priolo has no production data.
- Italy Rossano has no production data.
- Macedonia has no day ahead price data.
- Maltahas no day ahead price data.
- Montenegro has no day ahead price data.
- Moldova has no production data
- Ukraine has no production data
- Note that Ireland and UK are one bidding zone. It is removed because of frequent missing production data

1.9 Appendix 2 - Toy Model Derviation

A first order approximation of the market clearing condition obtains:

$$\frac{D'(\bar{p})\bar{p}}{D(\bar{p})} d \log p = \frac{M}{\text{Other} + M} d \log \text{wind}$$

This implies a relationship

$$\frac{d \log(p)}{d \log \text{wind}} = -\frac{s_{\text{wind}}}{\epsilon_d}$$

where

$$s_{wind} = \frac{M}{\text{Other} + M}$$

is the share of wind with the expected shock and

$$\epsilon_d \equiv \frac{D'(\bar{p})\bar{p}}{D(\bar{p})}$$

is the elasticity of demand with respect to prices. Furthermore, we have

$$E[p_{\text{wind}}] = E[p] + \text{cov}(p, \text{wind})$$

which means that we get

$$c_{\text{wind}} - c_{\text{other}} = \text{cov}(p, \text{wind}]$$

Furthermore, since

$$p = \bar{p}[\text{wind}]^{-\frac{s_w}{\epsilon_d}}]$$

we obtain

$$\frac{c_{\text{wind}} - c_{\text{other}}}{\bar{p}} = \text{cov}(\text{wind}, \text{wind}^{\frac{-s_w}{\epsilon}})$$

We approximate the LHS using $E[f(x)] \approx f(\mu_x) + \frac{f''(\mu)x}{2}\sigma_x^2$. Define

$$f(\text{Wind}) \equiv (\text{Wind} - E[\text{Wind}])(\text{Wind}^{\frac{-s}{\epsilon}} - E[\text{Wind}^{\frac{-s}{\epsilon}}])$$

Then

$$f'(\text{Wind}) = (\text{Wind}^{\frac{-s}{\epsilon}} - E[X^{\frac{-s}{\epsilon}}]) - \frac{s}{\epsilon}\text{Wind}^{\frac{-s+\epsilon}{\epsilon}}(\text{Wind} - E[\text{Wind}]$$

$$= \text{Wind}^{\frac{-s}{\epsilon}} - E[\text{Wind}^{\frac{-s}{\epsilon}}] - \frac{s}{\epsilon}\text{Wind}^{\frac{-s}{\epsilon}} + \frac{s}{\epsilon}\text{Wind}^{\frac{-s+\epsilon}{\epsilon}}$$

Then $f'(E[\text{Wind}]) = f'(1) = 0$. Next,

$$f''(\text{Wind}) = \frac{-s}{\epsilon}\text{Wind}^{\frac{-s+\epsilon}{\epsilon}} + \frac{s^2}{\epsilon^2}\text{Wind}^{\frac{-s+\epsilon}{\epsilon}} - \frac{s(s+\epsilon)}{2}\text{Wind}^{\frac{-s+2\epsilon}{\epsilon}}E[\text{Wind}]$$

$$f''(E[\text{Wind}]) = f''(1) = \frac{-s}{\epsilon} + \frac{s^2}{\epsilon^2} - \frac{s(s+\epsilon)}{\epsilon^2} = \frac{1}{\epsilon^2}(-s\epsilon + s^2 - s^2 - s\epsilon) = \frac{-2s\epsilon}{\epsilon^2} = \frac{-2s}{\epsilon}$$

Putting these pieces together for the approximation -

$$E[f(\text{Wind}] \approx f(1) + \frac{f''(E[\text{Wind}]}{2}\text{Var}(\text{wind})$$

$$\implies 0 + \frac{-2\frac{s}{\epsilon}}{2}Var(\text{Wind}) = \frac{-s}{\epsilon}\text{Var}(\text{Wind})$$

Now returning to where we started for the approximation,

$$\frac{c_{wind} - c_{other}}{\bar{p}} = \frac{-s}{\epsilon}\text{Var}(\text{Wind})$$

We solve for the wind share as:

$$s = \epsilon\frac{c_{other} - c_{wind}}{\bar{p}\text{Var}(\text{Wind})}$$

2 Wind Energy Generation and Transmission Congestion in the Midwest Wholesale Power Market

2.1 Introduction

Transmission constraints pose a significant barrier to the decarbonization of the U.S. electrical sector and have a large impact on wholesale electricity prices. Wind producers frequently have production that exceeds local demand for electricity and have limited transmission capacity to supply power elsewhere, which limits profitability and hence potential wind penetration. More, when the power cannot be transported elsewhere it will likely substituted in other regions by dispatchable and carbon-intensive sources like natural gas and coal. The issue is exacerbated by the lack of low-cost storage technology, which also contributes to the growing queue for interconnection to the grid, as the excess power cannot be stored affordably for use at a later time. The combination of lack of transmission, lack of storage, and high wind production can frequently cause negative prices, meaning the producer is paying the buyer to take power. It can also cause curtailment, in which wind producers stop turbine generation and in essence throw away additional power that has a marginal cost of zero to generate. Discourse on climate change more frequently focuses on the need for improved storage to address renewable intermittency, but large increases in transmission capacity are required as well and will mitigate the need to deploy storage technology. This paper analyzes congestion charges and wholesale prices in the Midwest wholesale market during periods of high wind generation and shows that congestion charges significantly affect the price of power and revenues of wind producers in states with high wind penetration.

I use wholesale prices for the Midwest Independent System Operator (MISO) market in 2022 and isolate them by the three components used in their calculation (energy charge, congestion charge, line loss charge) to study how they each vary with wind speeds to instrument for wind generation. Hourly production data is also not available at the state level and would be an equilibrium object with prices. I find that as wind speeds increase in the states with the highest wind penetration, Minnesota and Iowa, the congestion charges become increasingly negative and eliminate on average over 40% of the value of the energy production in the wholesale price in Minnesota and over 50% in Iowa. In Arkansas and Wisconsin, states with low to zero wind penetration, there is no relationship between the wholesale price components and wind speeds. Finally, I show that at the regional level, congestion charges have a strong negative correlation with wind generation and a positive correlation with gas generation. This paper contributes to a growing literature analyzing the costs of transmission constraints in the U.S., provides a clear illustration of how and why negative electricity prices occur in U.S. electricity markets, and motivates the theoretical framework used in chapter 3. More, due to the lack of state-level production data, this paper also introduces an approach for studying the relationship between wind production and state prices by using wind speed data. I first discuss related literature and introduce a simple model to explain the components of wholesale prices before discussion of the empirical strategy and results.

2.2 Related Literature

There is a rich applied economic literature analyzing the relationship between renewable penetration, negative prices, and transmission constraints in the U.S. and Europe. I list some related examples here, but this is by no means exhaustive. Quint and Dahlke (2019) analyze the impact of wind generation on MISO prices and show that each additional 100 MW of wind generation lowers wholesale prices by \$.014 to \$.34 per MWh on average. Woo, Horowitz, and Pacheco (2011) analyze the impact of wind generation on prices in the Texas ERCOT market and find a decrease of \$0.32 per MWh to \$1.53 for a 100 MWh increase in wind generation depending on the ERCOT zone. Mills, Wiser, Millstein, Carvallo, Gorman, Seel, and Jeong (2021) find that from 2009 to 2017, the expansion of wind and solar reduced average annual wholesale electricity prices by less than \$3 per MWh, while the decline in natural gas prices over than period reduced wholesale prices by \$7-53 per MWh depending on the region. There is also a large empirical literature discussing best methods for the prediction of wholesale energy prices, including how forecast errors can explain the price spread between the Day-Ahead and Real-time market, but this paper does not touch on predictions.

There is a relatively larger empirical literature analyzing the effect of renewable penetration on wholesale prices in Europe. For example, Würzburg, Abandeira, and Linares (2013) provide a comprehensive review of renewable electricity production on wholesale prices and conduct an empirical investigation of Germany and Austria and find a similar effect in magnitude to Quint and Dahlke. Kallabis, Pape, and Weber (2016) analyze the decline in Germany electricity prices from 2007 to 2014 and find a decline of more than 40%. They show further that the changes in the use of renewables is as important as changes in demand and installed capacities for explaining the decrease in operation margins of conventional plants. Gulli and Balbo (2015) look at photovoltaic (PV) solar penetration in Italy and find that when firms can exert market power, the average wholesale spot price does not necessarily decrease following higher renewable penetration, particularly when the increase is attributable to solar instead of wind. De Vos (2015) researches negative price frequency and finds that renewable support mechanisms can exacerbate the frequency of negative prices, such as Germany's feed-in-tariffs and stringent curtailment policy.

There are also various papers which measure the costs of congestion and transmission value in U.S. wholesale markets. Millstein, Wiser, Gorman, Jeong, Kim, and Ancell (2022) use LMP differentials to estimate the value of congestion relief for potential regional and interregional linkages and find that extreme conditions on the grid account for an outsized portion of the value of congestion relief, with 50% of congestion value coming from 5% of hours. The MISO independent market monitor, Potomac Economics, publishes annual and quarterly reports which include analysis of the costs of transmission congestion in the market. In their most recent annual report, covering 2021, they found that the value of congestion increased to $2.8 billion in the real-time market and $1.8 billion in the day-ahead market due to higher wind production and increased natural gas prices (Potomac Economics, 2022). Gorman, Mills, and Wiser (2019) estimate transmission capital costs for wind and solar projects and find that the average range for the Levelized Cost of Transmission is $1 - $10 per MWh and can can increase plant-level levelized cost of energy by 3% to 33%. Lamy, Jaramillo, Azevedo, and Wiser (2022) find it is more economical to construct wind farms in remote, windier areas like North/South Dakota versus closer to higher load in Illinois, which is also less windy. They also find that it is likely more economical to construct wind farms in Iowa and Minnesota instead of other MISO states, given the combination of wind speeds and load proximity.

This paper contributes to the strands of literature analyzing the frequency of negative prices and the costs of transmission congestion. I take a different approach than the papers above by first introducing a way to proxy for state level wind production in MISO states using wind speed data, and then studying the relationship between transmission charges and wind congestion rather than an actual estimation of the cost of congestion, an approach not yet used to my knowledge. I additionally study the relative frequency of negative prices and show this frequency increases on windier days in Minnesota and Iowa, which have high levels of wind penetration.

2.3 Wholesale Electricity Markets

This paper focuses on wind energy and wholesale prices in the Midwest Independent System Operator (MISO) market, which uses a pricing system that is standard across most regional wholesale markets in the U.S., and is the second largest wholesale power market in the U.S. Unlike in Europe, prices are calculated at specific locations, called nodes, and there is not one market clearing price for a region or bidding zone. These Locational Marginal Prices (LMPs) capture the costs of buying and selling power at specific locations within the regional market, and the LMP at each node incorporates local transmission and line loss costs. Electricity can be traded in the day-ahead market, which clears the day before generation occurs, and in real time, but the pricing structure is the same in each. Renewable producers frequently offer in the day-ahead market using forecasts and then balance their commitments in the real-time market.

2.3.1 Locational Marginal Prices

LMPs are made up of three components:

- Marginal Energy Charge (MEC) - the cost of generation
- Marginal Loss Charge (MLC) - the cost of line losses
- Marginal Congestion Charge (MCC) - the cost of transmission

The LMP is then calculated as the sum of the three:

$$\text{LMP} = \text{MEC} + \text{MLC} + \text{MCC}$$

The MEC will always be positive as the costs of generation are non-negative. For the MLC, the value is less intuitive. Line losses are always a cost of transmission and distribution in that 5% of power is lost in power lines on average; however, the MLC can be positive or negative. The loss charge at a node is calculated relative to line losses in the system. If increased generation from a node would decrease system line losses, then the MLC may be negative at that location.

The primary focus of this paper is on the marginal congestion charge, MCC, which can be positive or negative as well. When a power source is dispatched out of the merit order due to transmission congestion, that is being used when cheaper generation is available elsewhere, the MCC will be positive and be calculated using the difference in the costs of generation. Alternatively, when generation at a node exceeds local demand and there is not adequate transmission to other locations, this ”trapped power” will cause a negative charge. As will be discussed throughout the paper, this is a frequent occurrence with wind power and can often cause the entire LMP to be negative, amounting in sellers paying buyers to take power. Last, when producers can sell power at other nodes, the price received is the price at the generation node, not the node of sale.

2.3.2 Simplified Framework of LMPs

I provide a simple example to explain LMP calculation in more detail before proceeding to the empirical results. Consider two nodes A and B with localized demand and generation of wind at A and gas at B. Wind production is a random variable Y_w with a marginal cost of p_w while gas is dispatchable with production Y_g and constant marginal cost p_g where $p_g > p_w$. Assume demand D is fixed and identical in each node and that there is fixed transmission available between the two of T. For simplicity, I assume there are no line losses, and because the MLC is computed as relative component to the system, it would always be positive in the two node example here.

The equilibrium allocations for the two producers will depend on the magnitude of the wind shock relative to local demand in A.

Case 1) $Y_w > D_A$ and $Y_w - D_A \leq T$. In this case, wind production at A exceeds local demand, but the difference is less than the transmission constraint. Then the producer at node A will sell the excess at node B and $Y_g = D_B - (1-\delta) \times (Y_w - D_A)$. The LMP at node A is p_w, the MEC of wind, with MCC and MLC =0. At node B, the price is set by the MEC of the gas used p_g. Notably, the wind producer at A receives p_w for all power sold at B.

Case 2) $Y_w > D_A$ and $Y_w - D_A > T$. Like in case 1, wind production at A exceeds local demand, but now the excess is also larger than the transmission capacity. There is now trapped power, which will cause negative MCCs. If we assume that D_A actually has some elasticity and can increase if prices fall enough, then MCC < 0 and the LMP at A will fall below p_w. At B, all demand is met using natural gas production, and the LMP is calculated the same as in Case 1.

Case 3) $Y_w = D_A$. In the case that the wind shock at A is equivalent to local demand, there is no transmission between the two nodes. The LMPs are p_w at A and p_g at B. Again at B, all demand is met using natural gas production.

Case 4) $Y_w < D_A$. For simplicity, assume the shocks are always large enough such that B can meet residual demand in A without exceeding the transmission constraint. Then in this case the LMP at both A and B is p_g. Again, as in case 1, the LMP is set by cost of the marginal fuel used.

In these examples, the MCC was either zero or negative. To obtain a positive MCC, there would need to be a dispatchable generator in A instead of wind with a cheaper marginal cost than that in B, and the positive MCC would arise when the generator intentionally produced less due to transmission constraints instead of sending additional power to B. Then the LMP in B would additionally have a positive MCC added to the energy and loss charges as generation in B was dispatched out of merit order. In reality, wind farms also can curtail power, and negative congestion charges are a signal to potentially begin curtailment.

As was mentioned, producers in LMP markets receive the price at the generation node, not at the node of sale. That is, even if the wind producer is selling at B, they continue to receive the LMP at A for the amount of power sold at B. This may seem odd, but the producer is generally not responsible for construction of the transmission lines, just the interconnection to them, and as such not necessarily entitled to the revenue that may occur from usage of the line. The difference in prices is given to the holder of the financial transmission rights (FTRs) for the transmission connecting the nodes, which are auctioned off. Renewable producers can then hedge against congestion by bidding for the relevant FTRs. A detailed discussion of this is outside of the scope of this paper.

Midwest Independent System Operator

2.4 Data

Wholesale price data was obtained by node from the MISO website. The isolation of nodes at the state level was then done manually based on utilities operating in each state, which means that the mapping is not completely accurate as some utilities straddle state boundaries, like Otter Tail Power in Minnesota and North Dakota. MISO publishes regional prices at hub levels that correspond to areas within specific states, but not all states in the market, and as such the hub series were not used. Wind speed data for the states is taken from Weather Underground's historical weather database and daily airport wind speed observations near a state's primary area of wind generation are used. For the production data used in the last section of the paper, MISO only publishes hourly generation at the regional level. For wind penetration numbers by state, the Energy Information Administration state profiles are used.

2.5 Empirical Results

2.5.1 Wind Speed and LMP Components

As discussed previously, wind energy producers in the MISO region and elsewhere often face transmission constraints during periods of high wind speeds and may encounter highly negative congestion charges in local generation nodes. Because the prices and generation are both equilibrium objects, I use wind speed observations to proxy for wind generation and show how the components of the LMPs vary on average by state during low to high wind speeds, which are exogenous. Daily MISO production data is also unavailable at the state level, which makes this a novel approach for analyzing wind generation on a state-by-state basis. I note that while in the simple example above wind producers simply sold the amount of the shock, in reality wind producers can curtail production based on forecasts and local prices, and negative charges can be a signal to begin curtailment.

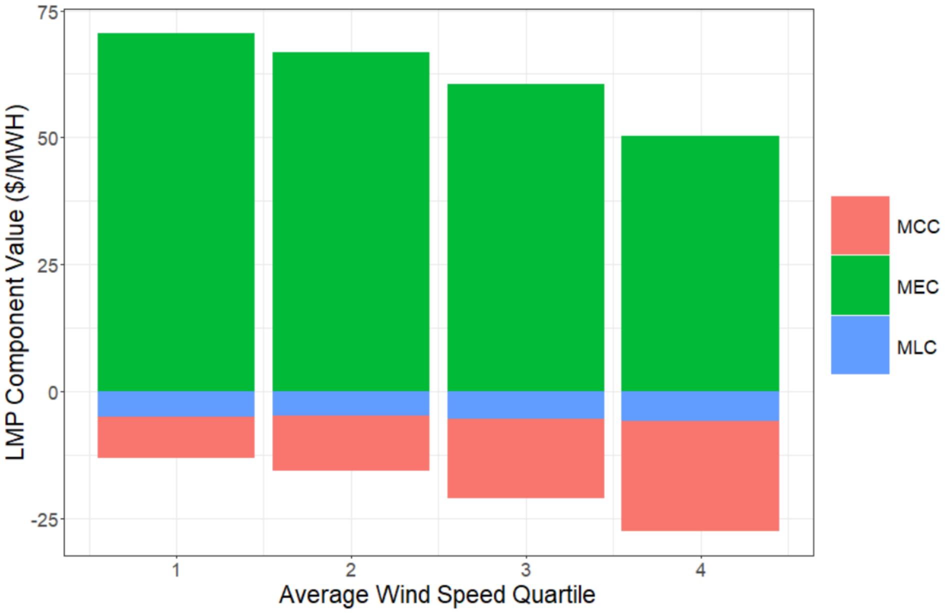
I construct the graphs as follows: The 24 hourly LMP compoment (MEC, MLC, MEC) observations for each node are are sorted into quartiles by the correspondingly daily average wind speed for the relevant state and then used to compute the average LMP component for the quartiles. For example, if February 10th was one of the top 25% windiest days of the year in Minnesota, the 24 hourly observations for each LMP component at all Minnesota nodes would be part of the average MEC, MLC, and MCC for the highest wind quartile with the other 90 days in that grouping. I am restricted in that I cannot access hourly wind speed observations in historical data for the states, which requires me to approximate with the daily average.

In areas with high wind energy penetration, I expect that marginal congestion charges will become increasingly negative as wind speeds increase, while areas with low wind penetration should have little to no relationship. Minnesota and Iowa, which have wind penetration of 22% and 58% respectively, are compared with Arkansas and Wisconsin, which have wind penetration levels of 0% and 2% respectively (EIA 2021 data profiles). The 2022 day-ahead LMPs are used in this section, but the real-time results are the same and are included in Appendix 1. The LMP graphs for the other MISO states are included in Appendix 2.

Figure 2.1 shows the 3 components of Minnesota's average Day-Ahead LMPs for 2022 sorted by the average wind speed quartile. While the largest component of the LMP is the energy charge, as average wind speeds increase, the average marginal congestion charges (red) increase significantly, from $-\$8.2$ per MWh in the first quartile to $-\$21.7$ per MWh in the fourth. This increase is particularly significant relative to the total LMP value, as it is over 40% of the average marginal energy charge in the highest quartile, meaning that wind producers must often sell at a significant discount due to lack of adequate transmission. The energy charges also decline, which is to be expected as (1) the marginal cost of wind is much lower than most other forms of power and (2) the periods of highest wind generation are more likely to occur when demand is lower. These factors combined will lower the clearing price in the market. While on average the magnitude of the negative congestion charge does not exceed the energy charge, the figure makes clear how LMPs can fall below zero during periods of high generation if congestion charges begin to exceed energy charges in magnitude. Negative LMPs are a regular occurrence in Western Minnesota, where much of the state's wind production is located, because there is inadequate transmission to bring the power during high periods of generation to ares with higher demand, like the Twin Cities metro in the eastern side of the state.

Figure 2.2 similarly plots the average LMP components across nodes in Iowa for 2022 by quartile of average wind generation. Iowa has significantly higher wind penetration than Minnesota (60% vs 21%) and the highest in the MISO region, and as such the results are more dramatic. The average MCC increases from $-\$4.51$ per MWh in the first quartile to $-\$23.61$ in the fourth. The MEC declines from \$75.88 per MWh in

Figure 2.1: Minnesota - Daily Average Wind Speed and Day-Ahead LMP Components



quartile 1 to $44.38 in quartile 4. That is, when wind generation is in the highest quartile, the magnitude of the average marginal congestion charge is over 50% of the energy charge, again indicating how negative LMPs can occur as a result of inadequate transmission and high wind generation.

Both figures share some other similarities, such as negative congestion charges even in the lowest quartile of wind generation. These charges are near zero, but show that congestion poses a mild problem on the grind even when wind production is lower. Both also show that the average loss charges (MLCs) are negative in these states. As explained previously, MLCs can be positive or negative even though line losses always occur. There is no clear relationship between wind generation and the magnitude of average line losses, even though wind generation often occurs in remote areas away from demand centers. It is striking though that line losses are negative on average in both Minnesota and Iowa, regardless of wind conditions.

Figures 2.3 and 2.4 show the same average LMP component and wind speed quartiles for Arkansas and Wisconsin, which have zero (Arkansas) to insignificant levels of wind penetration (Wisconsin), for purposes of comparison with the other figures. I wish to establish that it is unlikely the trend in 2.1 and 2.2 can be explained by something correlated with wind speeds that is not wind production that is related to trans-

Figure 2.2: Iowa - Daily Average Wind Speed and Day-Ahead LMP Components

mission in Minnesota and Iowa. In both cases, as expected, there is no relationship between wind speeds and any of the LMP components. As such, there is not a factor related to wind speeds that is explaining the changes in the congestion and energy charges in figures 2,1 and 2.2 beyond higher wind generation.

The marginal congestion charges are often positive in these states, as seen in the fourth quartiles of each. In the case of Wisconsin, which has low wind penetration but still a few wind farms, the results might suggest that congestion is an issue that is less likely to affect the first wind farms in a region, as their production alone is less likely to overwhelm transmission capacity. To some extent, this is seen in chapter 1, figure 1.1. As wind generation capacity increases in a region though, they will receive similar shocks (wind speeds) to generation and thus have simultaneous high production, often exceeding local demand and transmission.

Figure 2.3: Arkansas - Daily Average Wind Speed and Day-Ahead LMP Components

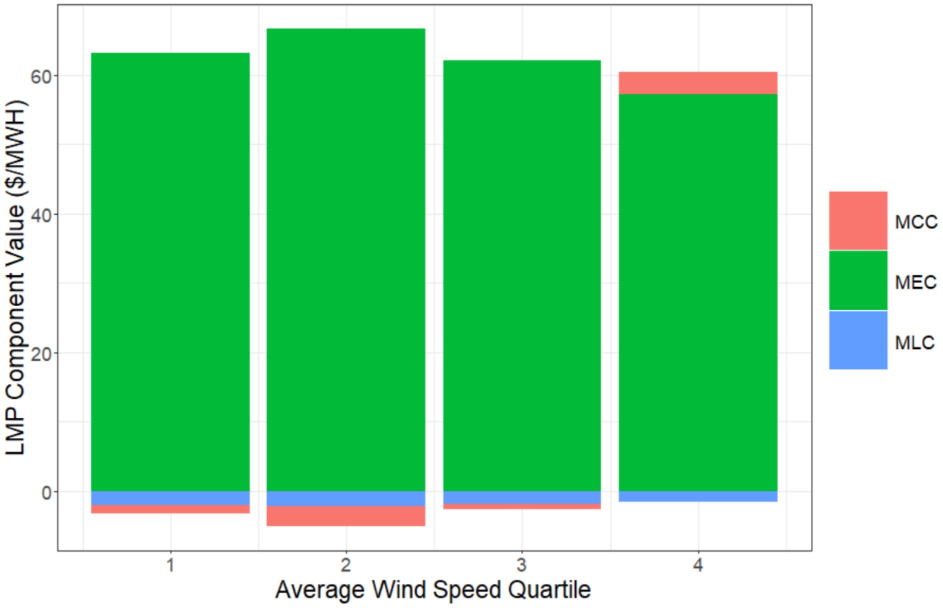
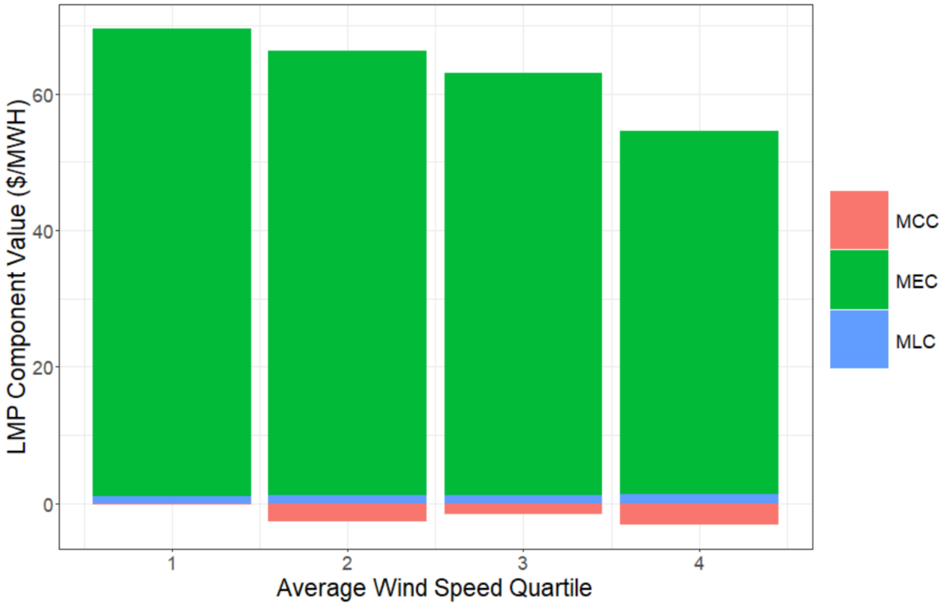


Figure 2.4: Wisconsin - Daily Average Wind Speed and Day-Ahead LMP Components



2.5.2 Generation and Marginal Congestion Charges

In order to compare the trends in the previous section to dispatachable forms of power and as an additional robustness check of the trends identified, I next show the relationship between actual generation and marginal congestion charges for wind and gas in 2022. In this case, these are both equilibrium objects and as such there are no implicit claims to causality here. The average charges are computed in the same manner as the previous section, except the nodal values are divided into quartiles by the corresponding penetration of wind and gas. Because hourly generation data is only available at the regional and system wide level for MISO, the MISO North Region is used, which has the highest wind share of the MISO regions. Last, the real-time market is analyzed in this section.

Figure 2.5 illustrates that as wind energy becomes a higher share of the generation mix, the congestion charges also become increasingly negative, as was shown in figures 2.1 and 2.2 with wind speed in Minnesota and Iowa. The relationship between gas and congestion charges in Figure 2.6 is striking for being the exact opposite and when viewed together, these figures capture the complementarity between wind and gas! When wind production is low relative to the total fuel mix, fast reacting fossil fuels like peaker gas plants or more efficient combined cycle plants are used to balance supply and meet demand. Furthermore, gas generation does not suffer from the same congestion penalty as wind because its output is unlikely to exceed local demand because it could quickly be adjusted. It also typically benefits from a proximity advantage relative to wind. The areas with the highest potential for utility-scale wind are unlikely to correlate to high population areas, while for gas the plant need not be situated remotely. In figure 2.6, when gas generation is at its highest relative to total supply, the average congestion penalty is approximately zero, while for wind it is over -$20 per MWh. In appendix 3, I reproduce the below analysis for solar, nuclear, and coal.

2.6 Frequency of Negative Prices

A natural question that follows the above analysis is how frequently negative prices occur. As seen in Figures 2.1 and 2.2, when wind speeds are high, the magnitude of the negative LMP can be substantial relative to the overall LMP. When it exceeds the sum of the energy and line loss charges, then the price of

Figure 2.5: MISO North - Real-Time Congestion Charges and Wind Penetration

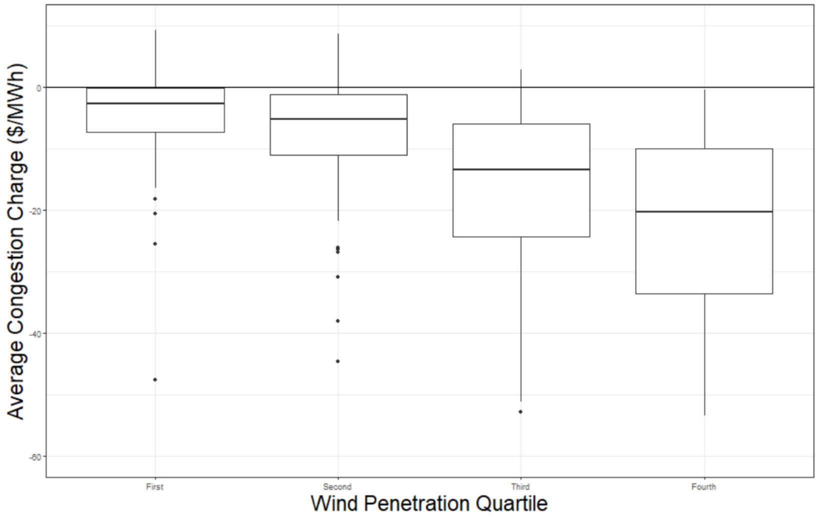
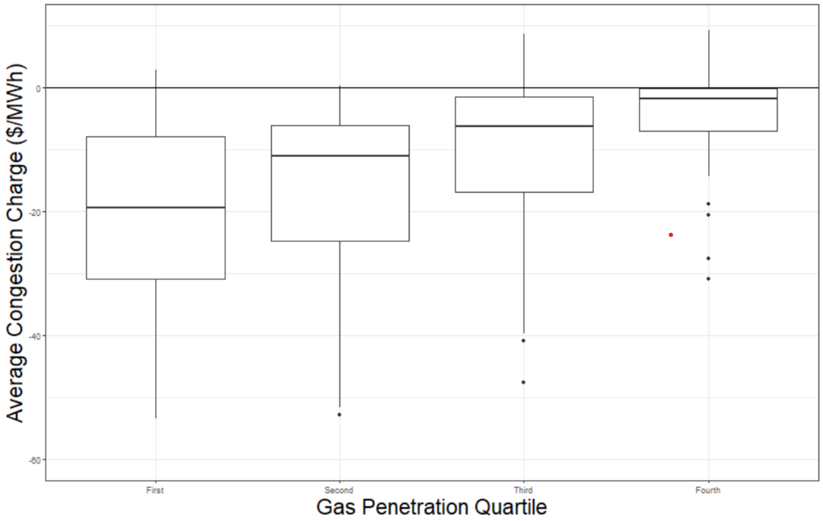


Figure 2.6: MISO North - Real-Time Congestion Charges and Gas Penetrationn



electricity at a node is negative. In Table 2.1, I next look at the frequency of negative prices in the Day-Ahead market, measured as the share of hourly observations that are negative across all price nodes in a state, and the share of observations that are negative in the highest quartile of wind speeds.With the exceptions of Minnesota and Iowa, the frequency with which nodes has a negative price is extremely low and often approximately 0%. In Minnesota and Iowa, though, the frequency is not insignificant. Across all days, the share of hourly nodal observations that have a price below zero is 5% and 8% for Minnesota and Iowa, respectively, and on the windiest share of days, these increase to 13% and 21%. Because these are sorted by days that are in the top quartile of average wind speed and not the hours, again due to data limitations, this is more like a lower bound on the share of nodes that have a negative price when wind generation is high. In the windiest hours, it should be even higher.

Table 2.1: Negative Day-Ahead LMP Frequency by State

State	All Observations	Highest Wind Quartile Observations
Arkansas	$< .1\%$	$< .1\%$
Illinois	.3%	.8%
Indiana	.2%	.4%
Iowa	8%	21%
Louisiana	$< .1\%$	$< .1\%$
Michigan	$< .1\%$	$< .1\%$
Minnesota	5%	13%
Mississippi	$< .1\%$	$< .1\%$
Wisconsin	.1%	.2%

In Table 2.2 I take the same approach but look at the Real-Time market. The frequency of negative prices is noticeably higher in the Real-Time market than the Day-Ahead. The Real-Time market, as stated before, is used to balance the Day-Ahead when there are deviations from the predicted supply and demand, such as an error in the weather forecast. These unexpected deviations then might partially explain the higher frequency, as there is inherently higher volatility in real-time prices. In Minnesota and Iowa, the share of all 2022 observations that are below zero is 9% and 12%, respectively, and for the windiest quarter of days, it increases to 19% and 26%, which are both substantial. While still extremely small, the shares in other states are higher as well, with several of the states that do have limited wind penetration, including Illinois, Indiana, and Wisconsin, getting above 1% in the highest quartile.

Table 2.2: Negative Real-Time LMP Frequency by State

State	All Observations	Highest Wind Quartile Observations
Arkansas	< .1%	< .1%
Illinois	1%	2%
Indiana	.5%	1%
Iowa	12%	26%
Louisiana	< .1%	< .1%
Michigan	.1%	< .1%
Minnesota	9%	19%
Mississippi	.1%	< .1%
Wisconsin	.7%	2%

Wind projects are eligible for a Production Tax Credit (PTC) for the first ten years of their operation that can make it profitable to keep producing when the price is below zero. For 2022, the full value of the credit was $26. If the marginal cost of wind is assumed to be 0, then a producer might be willing to sell up to -$26. In Table 2.3, I display the portion of negative price observations that exceed this lower bound in Minnesota and Iowa. In contrast to the previous analyses, in this case I only use the price nodes for generation points, which is the price received by the producer if they do not own the financial transmission rights.

Table 2.3: Share of Negative Prices That Exceeds PTC

State	Day-Ahead Share	Real-Time Share
Minnesota	12.1%	20.2%
Iowa	7.6%	18.1%

Somewhat surprisingly, the share is quite high. Wind farms can curtail or stop production when prices begin to go negative, but in this case a significant share of negative observations exceeds the lower bound of the PTC. To the extent that any producer keeps producing, though, is not going to be apparent from this, and as stated previously, state level production data is unavailable. These percentages dispute the notion that when prices are negative it is always profitable for wind farms constructed within the past 10 years to keep producing, particularly if selling in the Real-Time market. That said, this would suggest when couple with Table 2.2, that real time prices are only too low for wind producers to make a profit in about 2% of observations across time and location.

2.7 Conclusion

This paper introduces a simple method for illustrating the cost of congestion related to wind energy at the state level by using wind speed to approximate wind generation and shows that as wind speeds increase, the average marginal congestion costs become increasingly negative in Minnesota and Iowa. In Wisconsin and Arkansas, states with little to no wind energy, there is no relationship between wind speeds and marginal congestion costs. The magnitude of the negative charges is significant in Minnesota and Iowa and pose a substantial penalty relative to the market value of the energy produced, exceeding 50% in Iowa and 40% in Minnesota on average. More, this paper demonstrates how negative LMPs can occur by capturing that the magnitude of a negative congestion charge may exceed the energy charge during periods of significant trapped power. I also show at the MISO North Regional level, wind and gas generation have opposite relationships with congestion charges, as high periods of gas production have little to no congestion charges on average. Last, I find the frequency with with which negative prices occur across MISO states for both the daily average and the average when wind generation is highest, showing that in Minnesota and Iowa a not insignificant share of price nodes have negative LMPs when it is windiest. I additionally show that the frequency of negative prices is higher in the Real-Time market than the Day-Ahead market. These results reinforce a growing literature studying the costs of congestion and how transmission constraints pose an obstacle to the decarbonization of the grid.

Future research can conduct a similar analysis for other U.S. states and wholesale markets and potentially study to what degree transmission constraints limit potential variable renewable energy penetration. One limitation of the MISO market is that there are only two states that have significant shares of wind penetration, but other wholesale markets like the Southwest Power Pool (SPP), also have states with high wind shares, and using the approach there could provide more clarity on the relationship between wind energy generation and congestion charges. Additional research could also compare the degree of negative LMPs and curtailment across generation nodes for wind and solar projects that are still actively receiving the production tax credit, which makes selling for a negative price worthwhile, versus projects that are no longer eligible.

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2.8 Appendix 1- Real-Time Graphs

The real time results for Iowa, Minnesota, Wisconsin, and Arkansas are included here. The trends are the same as those highlighted in the Day-Ahead graphs in the body of the paper. As wind speeds increase, and by extension wind energy becomes a higher portion of the energy portfolio, the congestion charges become increasingly negative in Minnesota and Iowa, which have higher shares of wind energy. In Wisconsin and Arkanas, there is no such relationship, to help establish the lack of a spurious correlation here.

Figure 2.7: Minnesota - Daily Average Wind Speed and Real-Time LMP Components

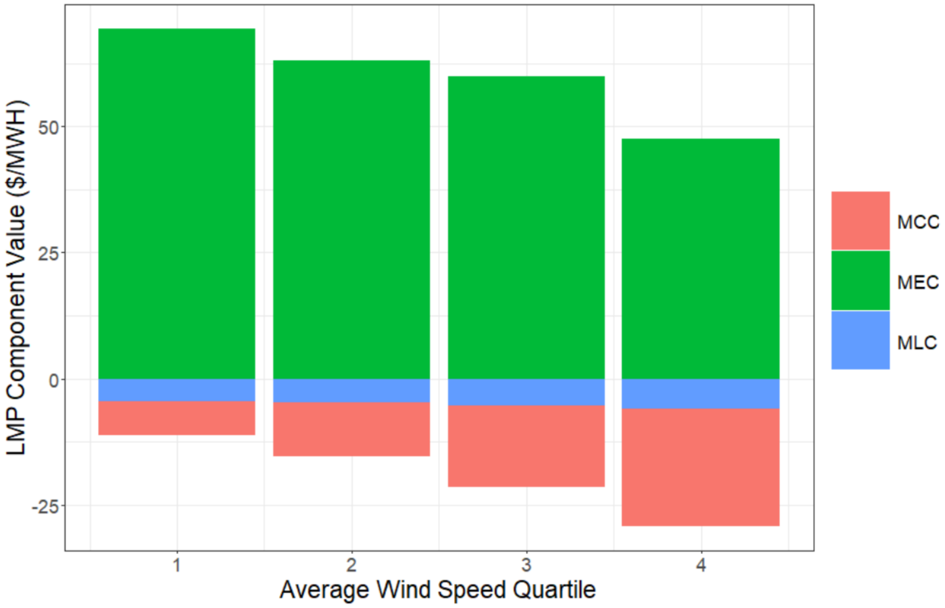


Figure 2.8: Iowa - Daily Average Wind Speed and Real-Time LMP Components

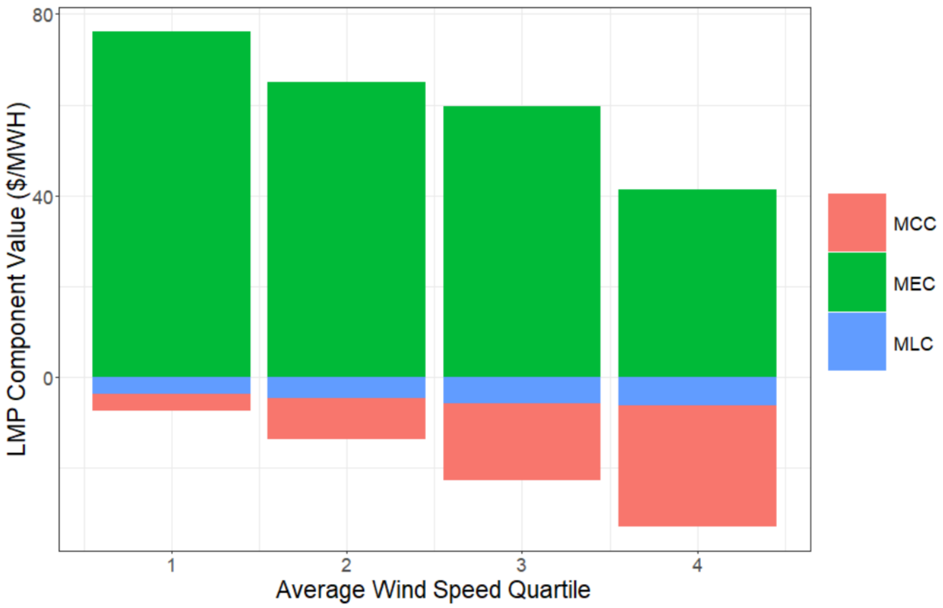


Figure 2.9: Arkansas - Daily Average Wind Speed and Real-Time LMP Components

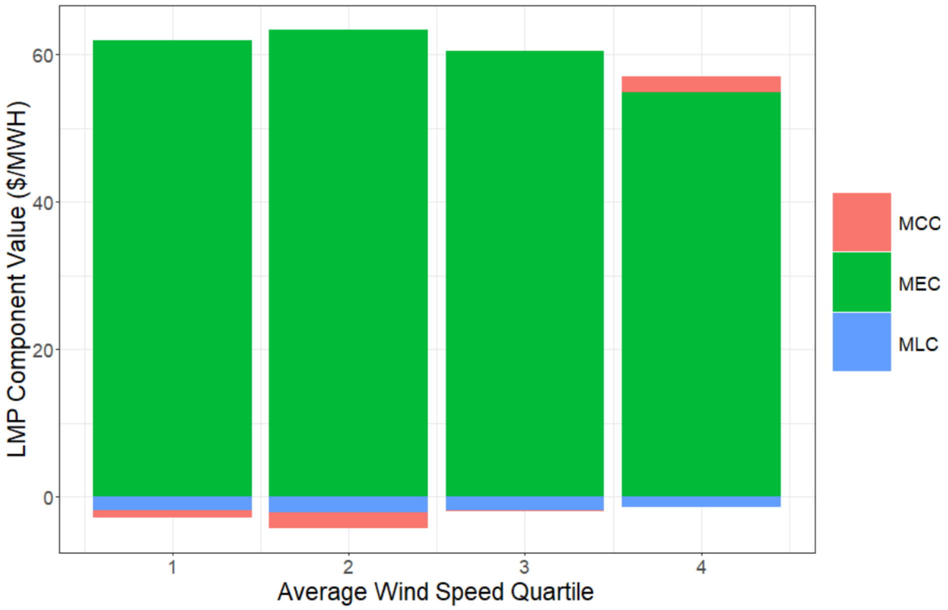
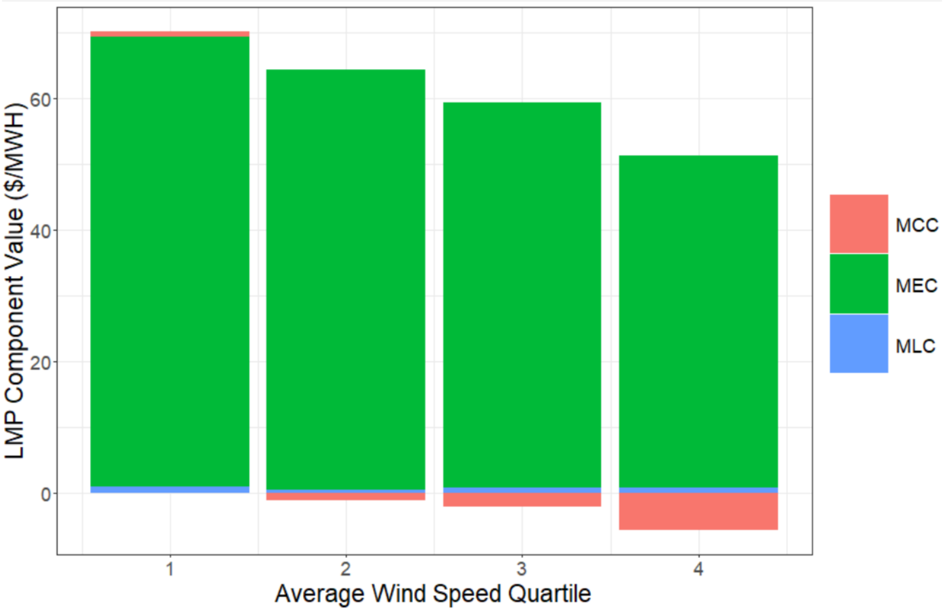


Figure 2.10: Wisconsin - Daily Average Wind Speed and Real-Time LMP Components



2.9 Appendix 2 - Other MISO States

I also conducted nodal mappings to compute average 2022 real-time LMPs for the other MISO states: Illinois (10% wind penetration), Indiana (8%), Michigan (8%), Louisiana (0%), and Mississippi (0%). Texas is excluded because MISO coverage of the state is limited, and it predominantly trades electricity in ERCOT. The graphs for Illinois, Indiana, and Michigan are interesting in that while wind energy is not nonexistent in these states, it is not causing negative congestion charges on average in the real-time market. In Illinois, the average MCC decreases by wind quartile, but remains positive. In Indiana, it actually slightly increases. In Michigan it does decrease, but is just very slightly below zero (-$.54 per MWh) in the fourth quartile. These results together suggest that perhaps the level of wind penetration in a region needs to be higher than 10%, potentially approaching Minnesota at about 20%, and/or otherwise these states have built out transmission (possible combined with curtailment) to limit the occurrence of trapped power. It will become clearer as wind and solar comprise a larger share of their energy portfolios.

Figure 2.11: Illinois - Daily Average Wind Speed and Real-Time LMP Components

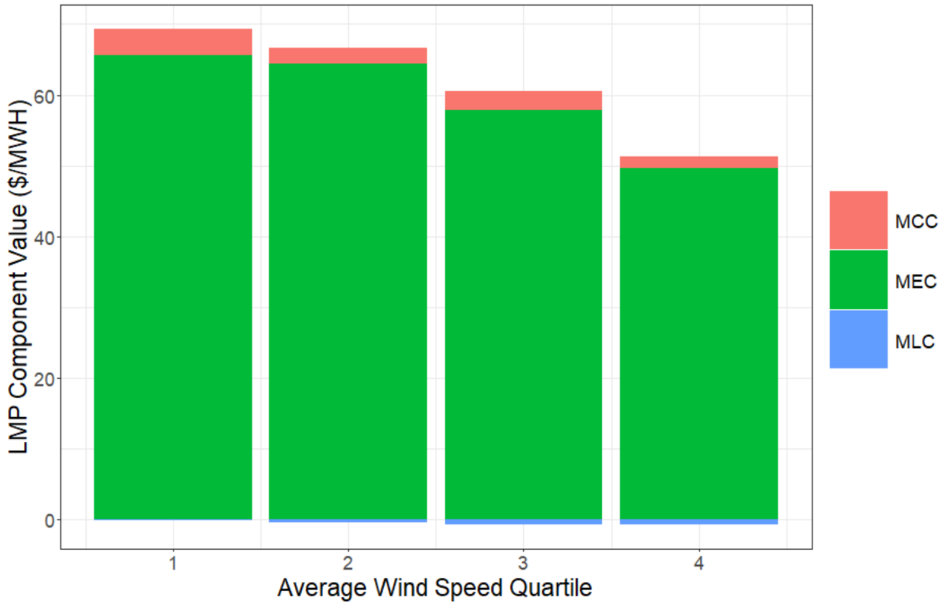


Figure 2.12: Indiana - Daily Average Wind Speed and Real-Time LMP Components

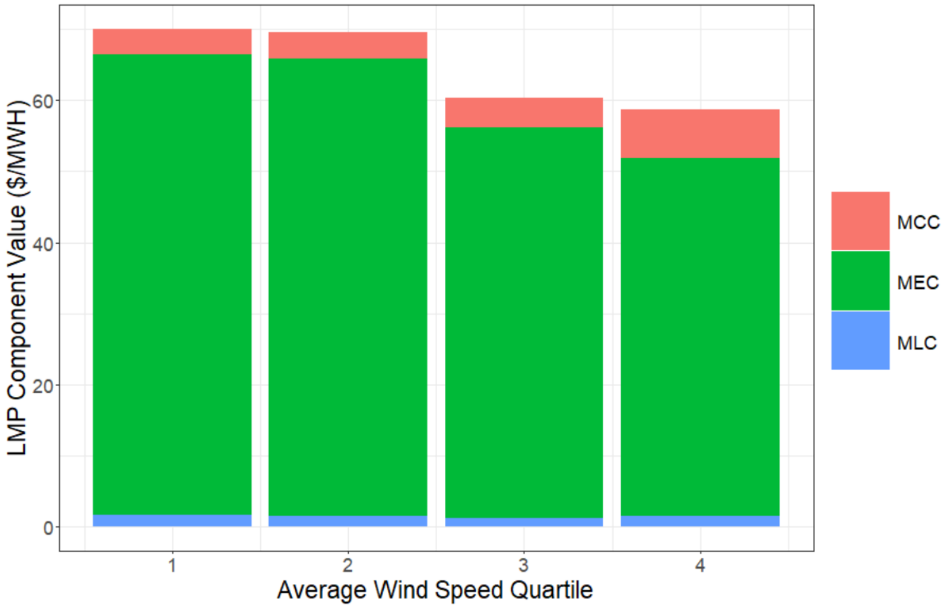
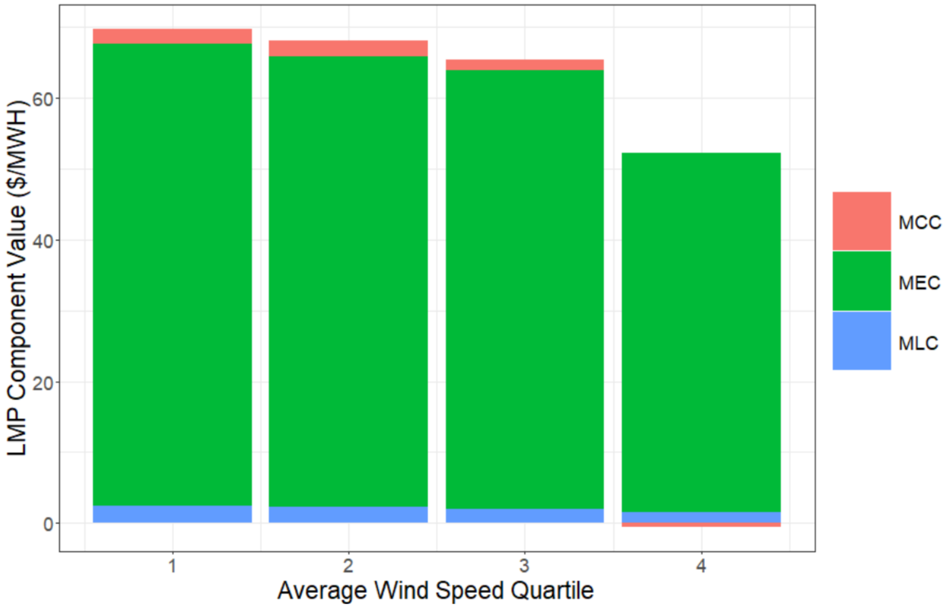


Figure 2.13: Michigan - Daily Average Wind Speed and Real-Time LMP Components



Louisiana and Missippi are included for completition of the MISO region, but they have no expected relationship between LMP component and wind speed given their complete lack of wind energy installation. These graphs do reinforce that there is not a spurious correlation driving the Iowa and Minnesota results, like the results for of Arkansas and Wisconsin.

Figure 2.14: Louisiana - Daily Average Wind Speed and Real-Time LMP Components

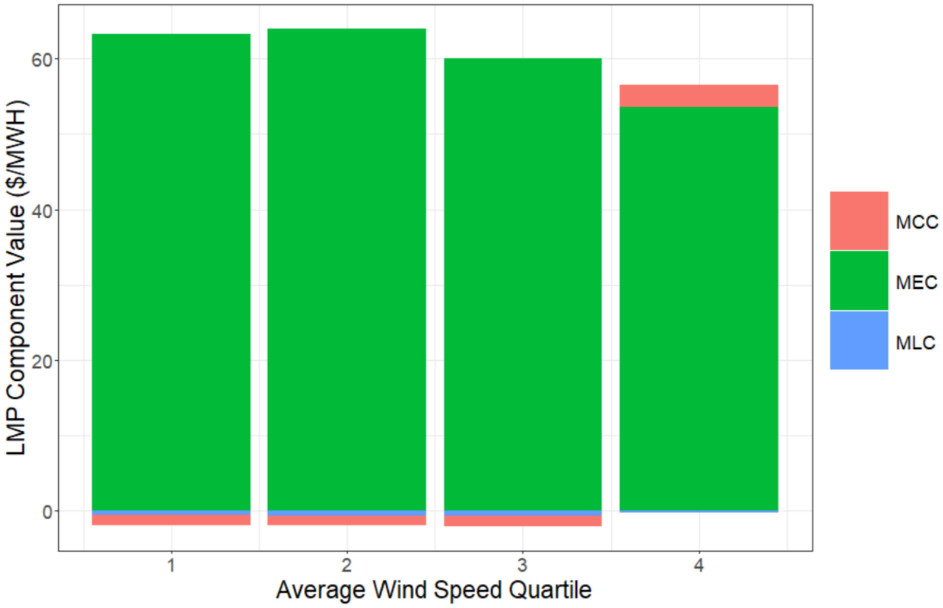
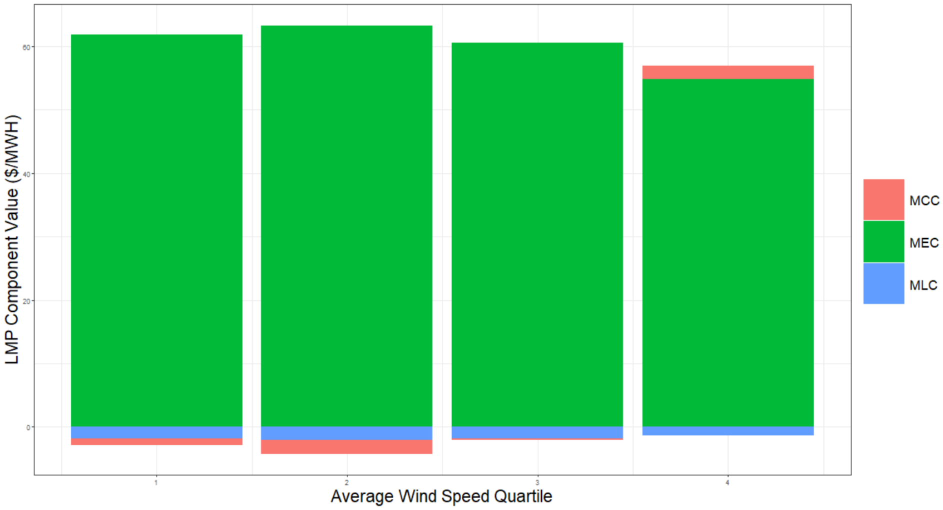


Figure 2.15: Mississippi - Daily Average Wind Speed and Real-Time LMP Components



2.10 Appendix 3 - MISO Generation and MCCs for Coal, Nuclear, and Solar

To expand on the analysis of the correlations between actual generation and congestion charges, I have reproduced the same charts for Coal, Nuclear, and Solar. At first glance, the coal and nuclear relationships are similar to gas, which suggests that to some extent they also balance the usage of wind. However, both function as base load power, and neither has a median average charge as close to 0 as gas does in the fourth quartile. This is clearer with Nuclear, which given its lower marginal cost and lack of emissions, is lower in the merit order than coal, which would be used to balance a renewable drought or when demand is peaking. In that sense, the degree to which the progression through the quartiles correlates with an average MCC approaching 0 is not unexpected- the coal progression is much more dramatic than nuclear. When coal use is at its lowest, it is highly likely that wind generation would be extremely high, giving it the most negative MCC in that quartile of any of the forms of power. In the case of solar power, the penetration is so low that no clear relationship is to be expected, and the marginal congestion charges are low in comparison to the other power sources.

Figure 2.16: MISO North - Real-Time Congestion Charges and Coal Penetration

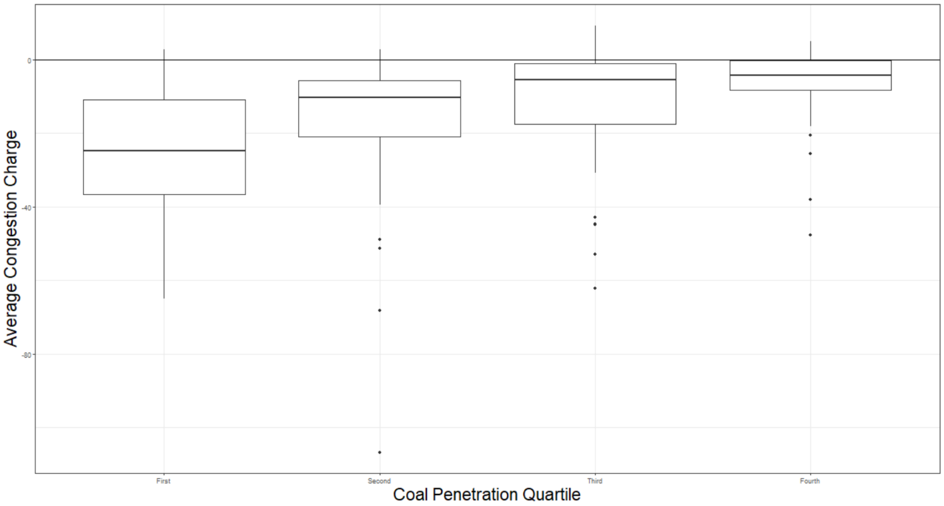


Figure 2.17: MISO North - Real-Time Congestion Charges and Nuclear Penetration

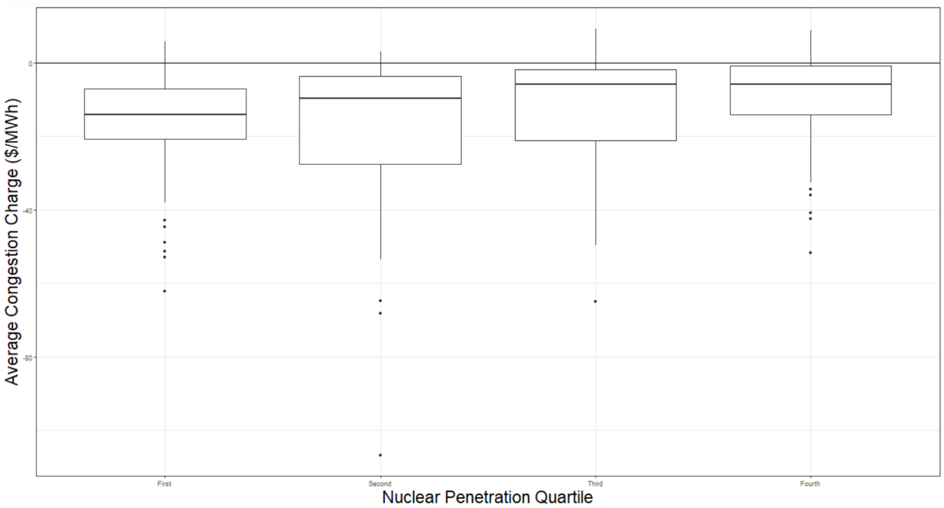
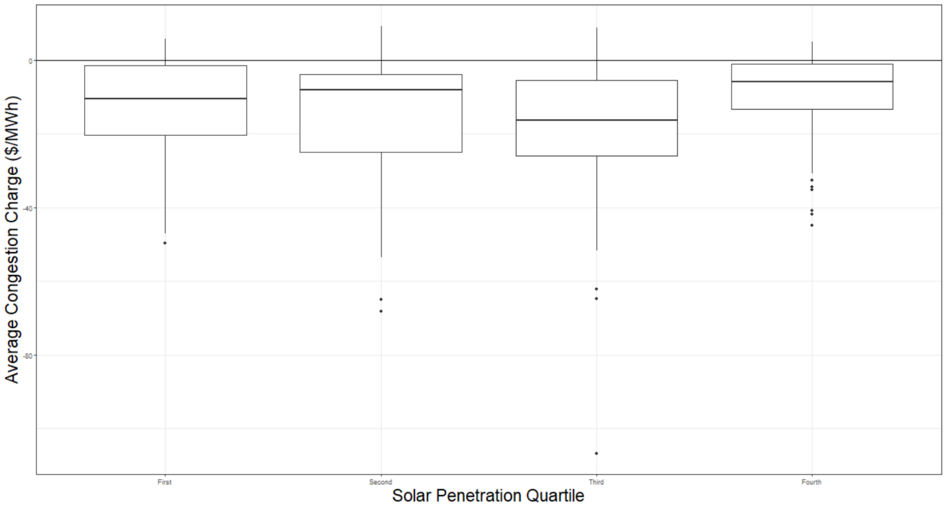


Figure 2.18: MISO North - Real-Time Congestion Charges and Solar Penetration



3 A Theoretical Model of Intermittent Power and Regional Integration

3.1 Introduction

To mitigate climate change, the decarbonization of the electricity sector is essential. In recent years, the costs of wind and solar power have fallen dramatically, such that each is cheaper than the traditional fossil fuels used. However, intermittent generation poses a massive barrier to their capacity of these sources to replace fossil fuels. Much discussion in the economics literature and public policy sphere has focused on policies to support wind and solar and the potential of storage technology to address the intermittency problem, yet much less of the discourse has focused on the crucial role of transmission to support high levels of renewable penetration. In conjunction with chapter 2, this paper studies the role of transmission constraints in limiting the penetration of renewables and shows in a theoretical setting that as transmission capacity increases, wind penetration in the energy portfolio mix increases as well.

3.2 Intermittency and Renewable Deployment

The energy produced from wind turbines and photovoltaic (PV) panels varies based on the time of day, year, and the weather. In the case of solar production, there is some overlap with peak production and when demand for electricity is highest, yet for onshore wind the highest periods of production are generally overnight and in the early morning. Therefore, while wind can deliver power for a marginal cost of near zero, it cannot reliably meet peak demand without dispatchable sources being used as well. When generation is particularly high during off peak periods it can exceed local demand, which combined with the lack of affordable storage technology, can result in negative electricity prices on the wholesale market, a phenomenon occurring in both U.S. and European regional markets. For wind producers, the problem is often constrained by a lack of transmission to other areas, which may have additional demand, as was discussed in chapter 2. Building additional transmission can mitigate ”trapped power,” and increase the profitability of wind farms, which will boost overall penetration.

3.3 Related Literature

A limited number of macro papers have attempted to model clean power as intermittent. As discussed in chapter two, there is a large empirical literature studying intermittency and the costs of congestion. Particularly relevant to this paper, Verdolini, Vona, and Popp (2016) document that wind penetration is higher in regions with higher deployment of mid-merit fossil fuel technologies, which is a result that is not necessarily reconcilable with how clean energy is modeled in multiple seminal papers in the field. Acemoglu, Aghion, Bursztyn, and Hemous (2012) and Fischer and Newell (2008) examine public policies without accounting for variablity in production. When intermittency is not accounted for, macro models will generally predict when the cost of clean power is low enough (or the subsidy high enough), the dirty sources of power will disappear. In reality, wind and solar are reliant on quickly dispatchable sources of power like natural gas for backup.

In a similar vein to this paper, Ambec and Crampes (2012) analyze the optimal mix of electricity when one source of power in intermittent and abstract from environmental externalities, as this paper does. In their paper, there are only two states of the world, either with and without power, and only one region, though it may have multiple sources of intermittent power. An additional difference from their model to this one is that the planner in theirs knows the state of the world when choosing how much power to dispatch. In a later paper (2020), Ambec and Crampes use a model with intermittency to analyze storage technology and public policy.

Helm and Mier (2016, 2018) also study the effects of intermittency on the penetration and profitability of renewable sources. In the first (2016), they show that diffusion of renewables may follow an S-shaped pattern with a rapid initial deployment followed by a slower phase, and then a rapid final phase of penetration. In the latter (2018), the authors use a model with intermittent power and fossil fuels to analyze the implications of storage technology on renewable penetration.

This paper also contributes to a related strand of literature on carbon leakage, which is the phenomenon where a unilateral policy to address emissions in one area causes emissions to rise elsewhere. However, theoretical papers in this area also ignore intermittency, which does influence the channels by which emissions may ”leak” across borders. The following is a brief but nonexhaustive overview of papers in this area.

Copeland and Taylor (2005) show in their model that leakage is typically positive but negative leakage can occur through endogenous policy changes. In this case, an emissions cut in one regions leads to income gains in the other and ultimately cause them to choose higher environmental quality with an increase in their own tax. Di Maria and Van der Wef (2008) illustrate in a two region model that endogenous technical change can mitigate carbon leakage when the climate policy incentivizes technological advances. Fullerton, Karney, and Baylis (2011) show in a simple two-sector general equilibrium model that the mobility of capital can also cause negative leakage if the taxed sector absorbs capital and shrinks the other sector. Tan, Lio, Cui, and Su (2018) use a computable general equilibrium model to analyze different channels of leakage and find that relocation of energy-intensive production from taxed regions to untaxed is the primary source of positive carbon leakage. Yu, Zhao, and Wei (2021) conduct a literature review of this subject and conclude that carbon leakage predominantly arises through the international trade for fossil fuels and through the trade in non-energy products, but it does not appear that the trade of electricity itself was analyzed, a channel that appears to be neglected in the research on the subject broadly.

To my knowledge, this is the first such macro-theoretical model to consider intermittency across multiple regions and the implications of transmission capacity on renewable investment. This paper contributes to an area with a large amount of research in the empirical side and the as yet limited work modeling intermittent power on the theoretical side.

3.4 Model

3.4.1 Environment

There are two countries which receive independent wind shocks $y_{wi}(z_i)$ that draw from a log normal distribution (the firm cannot receive negative wind power). Let $\mathbf{z} = (z_i, z_j)$. Each country has a representative consumer and an aggregate firm. Firm i produces electricity $E_i(\mathbf{z})$ with wind, natural gas, and nuclear energy.

While the model includes the decision to construct wind farms, the static setup is meant to mimic an hour in the day-ahead wholesale market, where variable power supply is balanced with relatively fixed amounts of nuclear/coal and fast-reacting dispatchable sources such as hydro and natural gas. A longer discussion of wholesale electricity markets is included in Chapters 1 and 2. The model here more closely resembles an energy balancing market than the typical regional U.S. wholesale markets in that producers receive the price of energy of where it was consumed, not produced. To consider the model in terms of the MISO environment evaluated in chapter 2, the energy producer would own the financial transmission rights when they are exporting power.

3.4.2 Consumption

The representative consumer $i \in \{i, j\}$ has quasi-linear utility over electricity and an outside good. The consumer is endowed with income I and receives profits from local firm ownership. Each consumer is also endowed with natural gas, which is sold on a global market, and receives disutility from its usage. Given income I, the local price of electricity $p_{ei}(\mathbf{z})$, and the price of gas $p_g(\mathbf{z})$, consumer i solves the following:

$$\max_{c_{ei}(\mathbf{z}),c_{oi}(\mathbf{z}),Y_{gi,s}(\mathbf{z})} a_e c_{ei}(\mathbf{z}) - b_e c_{ei}^2(\mathbf{z}) + c_{oi}(\mathbf{z}) - Y_g^{\gamma}(\mathbf{z}) \text{ s.t.}$$

$$p_{ei}(\mathbf{z})c_{ei}(\mathbf{z}) + c_{oi}(\mathbf{z}) \leq I + \pi_i + Y_{gi,s}(\mathbf{z})p_g(\mathbf{z})$$

$$c_{ei}(\mathbf{z}), c_{oi}(\mathbf{z}), Y_{gi}(\mathbf{z}) \geq 0$$

$$Y_g(\mathbf{z}) = Y_{gi}(\mathbf{z}) + Y_{gj}(\mathbf{z})$$

First, the disutility of natural gas is assumed in order to give an upward sloping supply curve, and this assumption can also capture rising extraction costs of natural gas. It is not meant to be a negative externality. Second, I have chosen to use quasi-linear utility because it can allow for negative prices, a frequent occurrence in wholesale markets, and allows for an easily derivable demand curve which can be set to be relatively inelastic with a_e and b_e. Third, the consumer here should be thought of as a utility on the wholesale market, not a household buying power in the retail market. Last, profits, both positive and negative, can arise from ownership of the energy producing firm and its investments in wind and nuclear.

3.4.3 Production

In each country, an aggregate firm produces electricity to be sold locally and/or in the other region. Electricity sold by the exporting firm to the other region depreciates at rate δ, to capture typical transmission line losses.

Before the period begins, each firms chooses how many wind farms M_i to construct at cost p_w. Each wind farm in country i receives expected shock $E[y_{wi}]$. Free entry implies that:

$$E[p_{ei}(\mathbf{z})y_{wii}(\mathbf{z}) + (1-\delta)p_{ej}(\mathbf{z})y_{wij}(\mathbf{z})] = p_w \tag{4}$$

where y_{wii} is wind energy produced and sold in country i, and y_{wij} is energy produced in country i and sold in j, where $y_{wii} + y_{wij} = M_i y_{wi}(z_i)$ Equation (4) tells us that firm i will choose M_i such that the expected revenue of a wind farm is equal to its cost.

Before the period begins and after choosing the number of wind farms to construct , each energy firm chooses the amount of nuclear power Y_{ni} to produce at cost p_n such that:

$$E[p_{ei}(\mathbf{z})Y_{nii}(z_i) + (1-\delta)p_{ej}(\mathbf{z})y_{wij)(z_i)}] = p_n \tag{5}$$

with the same notation as in (4). When the period begins, the energy firm i in each country receives the wind shock and then decides the amount of natural gas power to use, $Y_{gi}(\mathbf{z})$. Each firm faces an identical gas cap G and export cap C, which limit the amount of natural gas electricity and exported electricity, respectively. Given prices, the exporting firm i solves:

$$\max_{Y_{gi}(\mathbf{z}),E_{ii}(\mathbf{z}),E_{ij}(\mathbf{z})} \quad p_{ei}(\mathbf{z})E_{i,i}(\mathbf{z}) + (1-\delta)p_{ej}(\mathbf{z})E_{i,j}(\mathbf{z}) - p_w M_i - p_n Y_{ni} - p_g(\mathbf{z})Y_{gi}(\mathbf{z}) \quad \text{s.t}$$

$$M_i y_{wi}(\mathbf{z}) + Y_{gi}(\mathbf{z}) + Y_{ni} = E_{ii}(\mathbf{z}) + E_{ij}(\mathbf{z})$$

$$0 \leq Y_{gi}(\mathbf{z}) \leq G$$

$$0 \leq E_{eij}(\mathbf{z}) \leq C$$

where again $E_{ii}(\mathbf{z})$ is electricity produced and consumed in country i, and E_{ij} is electricity exported to country j. The exporting country is determined in equilibrium by the relative sizes of the wind shocks and the amount of nuclear power chosen, which together are an amount of power fixed before the choice to use gas or export. Given prices, the importing firm solves:

$$\max_{Y_{gi}(\mathbf{z})} \; p_{ej}E_{ii}(\mathbf{z}) - p_g(\mathbf{z})Y_{gi}(\mathbf{z}) - p_w M_i - p_n Y_{ni} \quad \text{s.t}$$

$$M_i y_{wi}(z) + Y_{gi}(\mathbf{z}) + Y_{ni} = E_{i,i}(\mathbf{z})$$

$$0 \leq Y_{gi}(\mathbf{z}) \leq G$$

In some cases, such as if the wind shocks to each region were very small, neither country may export power, and each simply sells to the local consumer.

3.4.4 Market Clearing and Equilibrium

The following set of equations governs market clearing in equilibrium:

$$c_{ei}(\mathbf{z}) = E_{ii}(\mathbf{z}) \tag{6}$$

$$c_{ej} = (1-\delta)E_{ij}(\mathbf{z}) + E_{jj}(\mathbf{z}) \tag{7}$$

$$Y_{gis}(\mathbf{z}) + Y_{gjs}(\mathbf{z}) = Y_{gi}(\mathbf{z}) + Y_{gj}(\mathbf{z}) \tag{8}$$

Equations (6) and (7) govern electricity clearing in each region, while equation (8) is global gas clearing.

Define an **equilibrium** as an allocation for households $\{c_{ei}(\mathbf{z}), c_{oi}(\mathbf{z}), Y_{gi,s}(\mathbf{z})\}_{i\in\{i,j\}}$, firm allocations $\{M_i, Y_{ni}, Y_{gi}(\mathbf{z}), E_{ii}(\mathbf{z}), E_{ij}(\mathbf{z}), Y_{gi,d}(\mathbf{z})\}_{i\in\{i,j\}}$ and prices $\{p_{ei}(\mathbf{z}), p_{ej}(\mathbf{z}), p_g(\mathbf{z})\}$ such that

1) Consumer $i \in \{i, j\}$'s problem is solved;

2) Firm $i \in \{i, j\}$'s problem is solved;

3) Markets clear as defined in equations 6-8.

3.4.5 Characterizing Equilibrium Production and Prices

Consider first a case with only one country. Then there exists a level of wind generation Y_w^* such that equilibrium gas production is given by:

$$Y_g(z) = \begin{cases} Y_w^* - Y_w(z), & \text{if } Y_w(z) < Y_w^* \\ 0, & \text{if } Y_w(z) \geq Y_w^* \end{cases}$$

That is, if the wind shock is large enough given the deterministic power choice, the country will not need to use natural gas. Energy supply is then given by:

$$E(z) = \begin{cases} Y_w^* + Y_d, & \text{if } Y_w(z) \leq Y_w^* \\ Y_w(z) + Y_d, & \text{if } Y_w(z) > Y_w^* \end{cases}$$

The local fixed point Y_{wi}^* is determined by:

$$u'(Y_{di} + Y_{wi}^*) = a_{ei} - 2b_e * (Y_{di} + Y_{wi}^*) = 0$$

That is, the country receives a wind shock such that the marginal utility is equal to 0. Now, consider the two region case, in which a country may elect to use natural gas even if given a high wind shock depending on the magnitude of the other country's shock, the constraint on gas G, and the export cap C. There exists a fixed point of wind production Y_{wi}^* as defined above in each country $\{i, j\}$ such that equilibrium local gas production $Y_{gi}(\mathbf{z})$ for $i \in \{i, j\}$ is given by:

$$Y_{gi}(\mathbf{z}) = \begin{cases} Y_{wi}^* - Y_{wi}(z_i), & \text{if } Y_{wi}(z_i) < Y_{wi}^*, Y_{wj}(z_j) + Y_{gj}(\mathbf{z}) \geq Y_{wj}^* \\ 0, & \text{if } Y_{wi}(z_i) \geq Y_{w}^*,\ Y_{wj}(z_j) + Y_{gj}(\mathbf{z}) \geq Y_{wj}^* \\ Y_{wj}^* - (Y_{wj}(z_j) + G) - Y_{wij}(\mathbf{z}), & \text{if } Y_{wi}(z_i) \geq Y_{wi}^*, Y_{wj}(z_j) + G + Y_{wij}(\mathbf{z}) < Y_{wj}^* \\ Y_{wi}^* - Y_{wi}(z_i) + Y_{wj}^* - Y_{wj}(z_j) - G, & \text{if } Y_{wi}(z_i) < Y_{wi}^*, Y_{wj}(\mathbf{z}) + G < Y_{wj^*} \end{cases}$$

The first, second, and third cases all assume that G is nonbinding, and the last two cases assume C is nonbinding as well. Considering each case in turn, the local gas plant will meet the difference in the received shock and the fixed point if that amount is less than the gas cap and if the other country does not need additional gas production as well. The local production will be 0 if the local shock is larger than the fixed point and if the other country has a wind and gas mix that also meets the fixed point. In case 3, the local gas plant will export if the local wind shock is large enough to meet local demand but the other country is simultaneously gas constrained and below the fixed point even with potential wind exports from the local country. Here, the gas plant will either export the full difference or up to the gas cap or export cap, whichever binds first. Last, the local gas plant will meet the difference between fixed points in both countries if neither country's wind shock has met the fixed point and the other country is gas constrained. In any case, if G or C does bind, the plant will produce up until the constraint. The amount of energy supplied is not reproduced for the two region case, but it would follow the cases outlined above given deterministic power Y_{di} and Y_{dj}.

The fixed points of wind production provide a characterization of trade as well. If both countries receive a wind shock that with their given gas cap allows them to reach the fixed point without trading power, then no trade occurs in equilibrium and prices are equivalent. That is, if $Y_{wi}(z_i) + Y_{gi}(\mathbf{z}) = Y_{wi}^*\ \forall i \in \{i, j\}$, then $p_{ei}(\mathbf{z}) = p_{ej}(\mathbf{z}) = p_g(\mathbf{z})$ and $E_{ij}(\mathbf{z}) = E_{ji}(\mathbf{z}) = 0$. When trade occurs in equilibrium, and the gas and export constraints are not binding, prices are given by:

$$p_{ei}(\mathbf{z}) = (1 - \delta) p_{ej}(\mathbf{z})$$

That is, when G and C are not binding, the the price ratio is equal to the non-depreciated rate of power. Appendix 2 includes a more detailed discussion of the constraints that cause price deviations and under what situations of gas usage and trade does an equilibrium exist. Intuitively, a country will not choose to export wind energy and use gas solely for consumption locally- it would consume wind energy at home with its 0 marginal cost. Likewise, a country would not import electricity generated from gas when its own gas constraint is not binding because of depreciation in trade.

3.4.6 Transmission Capacity and Optimal Energy Mix

Proposition 1: *Assume each region receives an independent wind shock from the same distribution. The number of wind farms M_i and M_j constructed in each region is increasing in C.*

Proposition 1 establishes that as the export cap increases, the energy firm in each country will choose to build more wind farms. The proof, included in appendix 1, is just for two countries, but the result can be generalizable to more regions. As regions become connected, the "portfolio" of wind production is diversified and allows for the firms to invest in more power. The risks of having trapped power, as discussed in chapter 2, decrease, which increases the profitability of potential wind shocks. In essence, the likelihood that an energy firm will have to sell wind power for low or negative prices is decreased as the capacity to export that power to other regions increases. Likewise, the revenue of dispatachable sources diminishes as additional wind supply comes to market. The assumption that the shocks are independent and from the same distribution is important as it could be the case if one area is much more suitable to wind production (has a higher expected shock) than the other, that integration may decrease local wind development in the less suitable area on the margin.

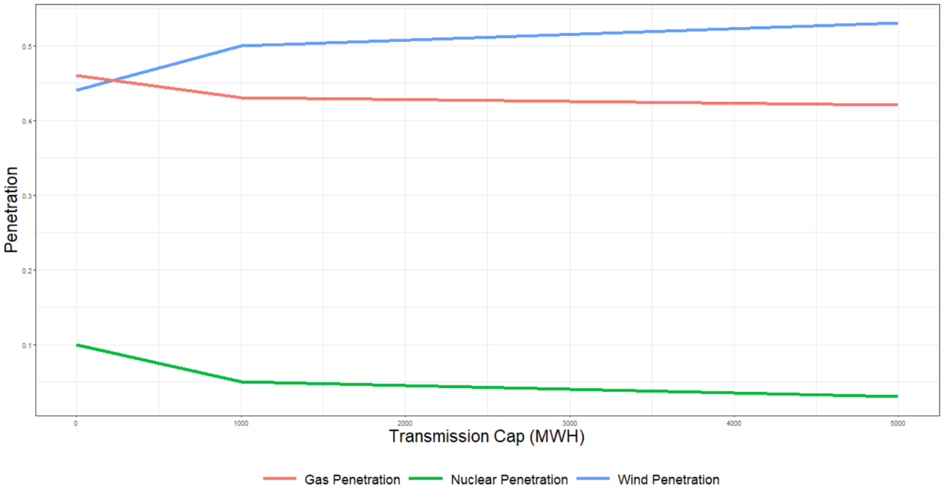
Proposition 2: *Assume M_i, M_j are fixed, G_j is binding, and $E_{ii}(z) > 0$. Then global gas usage $Y_{gi}(z) + Y_{gj}(z)$ and global energy usage $E_i(z) + E_j(z)$ are nondecreasing in C.*

That is, short run integration (no additional wind farm construction) can cause global natural gas and energy usage to increase if one region has constrained gas production, such as due to a low wind shock, and the other region does not, such as due to a higher wind shock. This result is entirely dependent on there being a limit on gas production G. Without a limit, integration in the short run would have no effect on total energy usage and gas usage. Proposition 2 illustrates that under certain situations, the effect of integration on renewable penetration is not always positive, though in the long run it will decrease the usage of natural gas. This result is captured in the third and fourth cases of equilibrium gas production, which show that opportunities for trade will increase gas output depending on G and C. The proof is in appendix 2.

3.4.7 Simulations of Expanded Transmission Capacity

For illustrative purposes, comparative statics of proposition 1 and proposition 2 are included. The values in each figure and parameters chosen should be given no weight; the purpose is to demonstrate the relative changes of variables from changes in transmission. Figure 3.1 shows the change in penetration of each energy source as the cap C between countries increases along the x-axis.

Figure 3.1: Changes in Energy Usage from Increases in Transmission in the Long Run



As the cap increases, the energy firm in each country chooses to invest more in wind farms and as a result uses less natural gas and nuclear power, which is the result from Proposition 1. Once again, this captures that additional transmission between regions allows additional power sharing, which boosts renewable sources as it allows droughts to be more easily balanced with imports and excess supply to be exported. In

Figure 3.2: Changes in Energy Usage from Increases in Transmission in the Short Run

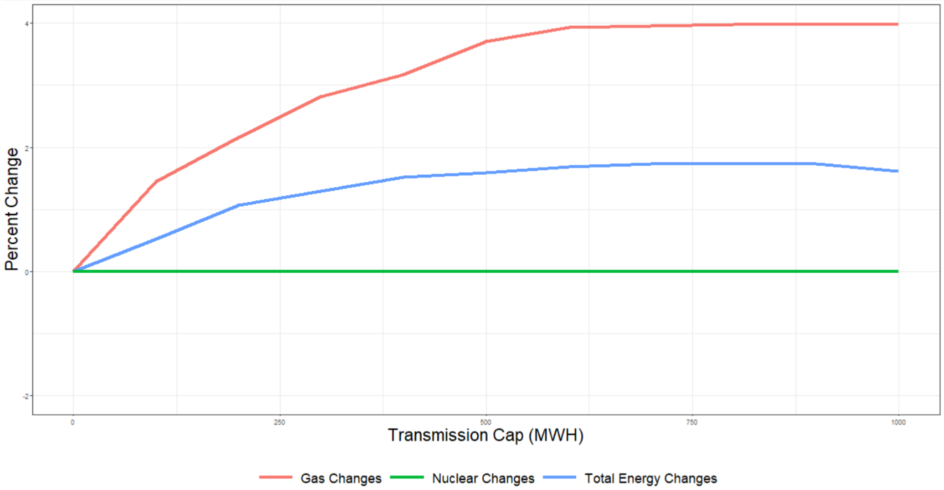


figure 3.2, the primary result from proposition 2 is shown. The y-axis displays the percent change in the global use of energy sources where the number of wind farms is fixed but integration increase. Again, this effect is entirely due to there being a constraint on the amount of natural gas production. If one region has a large wind shock and excess gas usage it could export to a region with a lower wind shock and constrained gas, then integration could cause gas usage and total energy usage to increase as power sharing increases. Nuclear has no cap in the model, and as a result there is not an effect from short run integration. In the case that there is no cap in gas, given that the price of gas is global, then integration would have no effect as a country would consume the optimal amount of gas without imports.

3.5 Carbon Leakage

As discussed in the related literature section, there is a niche area of the macro environmental field analyzing how public policies may influence the migration of emissions across borders. By introducing intermittency and the actual trading of electricity, this paper shows there is an additional channel by which policies may cause emissions to ”leak” than is discussed in this literature. Typically, positive carbon leakage (where emissions elsewhere increase) may occur via three channels (Tan, Li, Cui, and Su):

1) Energy channel: A decrease in demand for fossil fuels in one country lowers global prices, leading to

increased quantity demanded elsewhere

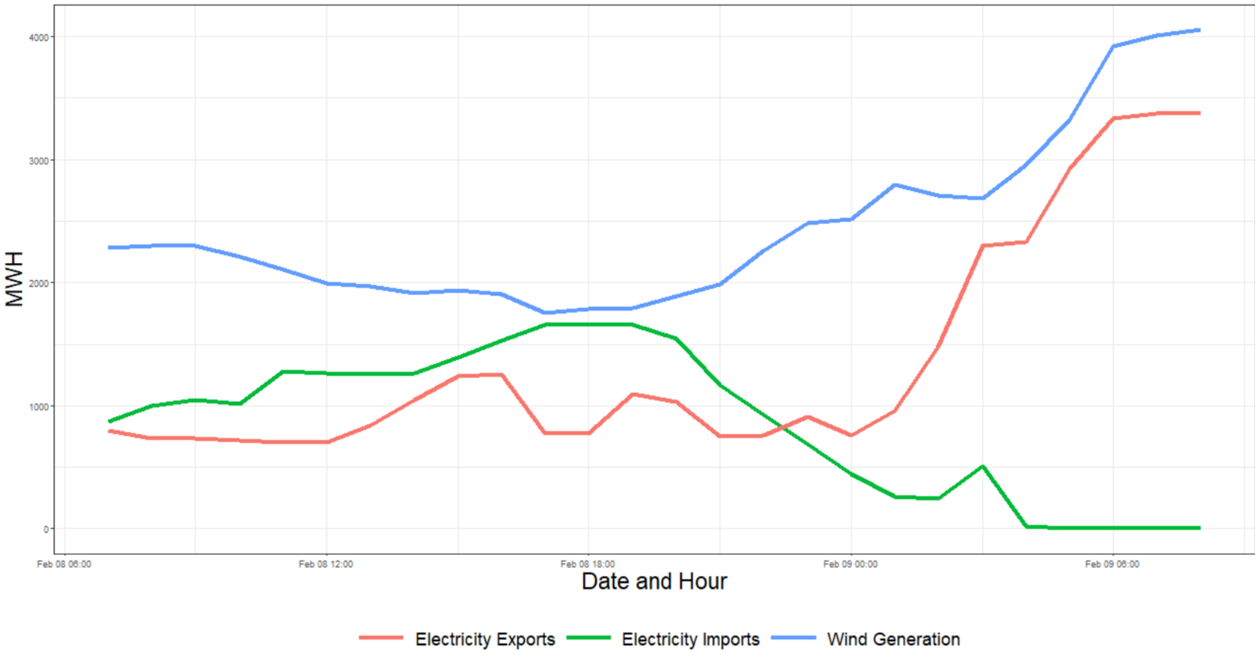
2) Terms of trade: Consumers import substitutable goods from countries without a climate policy
3) Capital Re-allocation: Capital could move from constrained to unconstrained regions

As noted previously, other papers posit that negative leakage may also occur, such as through endogenous technical change with spillovers or endogenous policy changes causing renewable deployment in another region to increase.

The trading of electricity is a channel through which positive or negative leakage may occur. This result does not arise in the other papers in this area because without introducing intermittency, the trading of electricity on wholesale markets is not typically a relevant part of analyzing a climate policy. In reality, electricity is frequently traded between bidding zones and countries and with it come effects on emissions of the trading countries. The second channel above does discuss trade, yet this does not capture the carbon leakage channel of trading electricity. Implementing a carbon tax may cause renewable deployment to increase, but it may also drive wholesale electricity prices to increase in the taxed country if the usage of fossil fuels falls significantly and is not replaced by renewables. The second channel suggests the taxed country may import goods which are produced more cheaply with untaxed fossil fuels abroad, but alternatively there would be periods on the wholesale market where this country actually exports electricity to other bidding zones if renewable deployment and a wind shock are sufficiently high, as discussed in the previous section. This type of export is wholly unrelated to the ”terms of trade” effect. The taxed country would also not necessarily import increased electricity from fossil fuels from abroad if the tax applied to its usage, which it likely would, as the trading of electricity may be distinct from a carbon tariff.

Figures 3.3 shows a day of electricity exports and imports in Denmark with varying levels of wind production. When the wind production dips, electricity imports rise, while when wind production increases, exports mirror the increase. As such, this rather clearly shows how any policy that would affect variable power generation, would in turn affect the emissions leaked from the trading of electricity. Denmark’s ambitious Feed-in-tariffs for wind might cause there to be negative leakage in many instances as it exports excess wind power to other countries, perhaps inducing them to use less natural gas or coal, but it also makes the country susceptible to renewable drought and can cause positive leakage of emissions if it imports electricity derived from dispatchable fossil fuels from abroad.

Figure 3.3: Wind Generation and Electricity Trading in Denmark (Bidding Zone 1)



3.5.1 Intermittency and Carbon Leakage in the Model

Consider the same model as before, but one country implements a carbon tax on natural gas usage where revenue is distributed lump sum to the consumer. For ease of notation, refer to the taxing country as i. Given prices, the wind shock, and the tax $\tau \in (0, 1)$, the energy firm in A solves:

$$\max_{Y_{gi}(\mathbf{z}),E_{i,i}(\mathbf{z}),E_{i,j}(\mathbf{z})} \quad p_{ei}(\mathbf{z})E_{i,i}(\mathbf{z}) + (1-\delta)p_{ej}(\mathbf{z})E_{i,j}(\mathbf{z}) - p_w M_i - p_n Y_{ni} - (1+\tau)p_g(\mathbf{z})Y_{gi}(\mathbf{z}) \quad \text{s.t}$$

$$M_i y_{wi}(\mathbf{z}) + Y_{gi}(\mathbf{z}) + Y_{ni} = E_{i,i}(\mathbf{z}) + E_{i,j}(\mathbf{z})$$

$$0 \leq Y_{gi}(\mathbf{z}) \leq G$$

$$0 \leq E_{i,j}(\mathbf{z}) \leq C$$

In this case, the problem is written as if country i may be exporting, but it may also be the case that $E_{i,j}(\mathbf{z}) = 0$. Intuitively, the electricity price in country i $p_{ei}(\mathbf{z})$ is now higher due to lower natural gas usage, which in turn will increase wind penetration and generation as higher prices will make wind farms more profitable. In turn, this may cause higher wind shocks that increase wind energy exports and negative carbon leakage to country j. However, the decrease in demand for gas in country i will lower the global price and may increase usage in j, which is the normal positive carbon leakage via the energy channel. Likewise, if wind generation in i is low and local gas generation is constrained by the tax, there may be electricity generated from wind or gas sent from j to i. Therefore, the trading of electricity could introduce positive or negative channels of leakage.

Table 3.1 shows an illustrative example of a tax with arbitrary parameter values to demonstrate that the trading of electricity itself is a corridor for carbon leakage:

Table 3.1: Carbon Leakage Simulation Averages

Variable	No Tax	Tax on A
Wind Penetration A	.66	.72
Wind Penetration B	.67	.68
Gas Generation A	1596	1395
Gas Generation B	1562	1506
Wind Exports A to B	64	114
Gas Exports B to A	44	57

In this case, the tax on average increased wind penetration in both A and B due to increased exported wind generation from A to B. The energy channel suggests that due to the lower price of gas $p_g(\mathbf{z})$, the demand for gas should increase in country B. However, just in this example, gas generation declined in both countries, but country B's gas exports to A did increase. The gas generation in B declines by roughly the amount of the inrease in exports of clean power from A to B. If electricity trading was not featured as part of this, and indeed it would likely not be necessary to model in most circumstance unless a source of power is intermittent, then the outcome of the tax would typically be that gas generation rises due to the energy channel. Therefore, ignoring the trading of intermittent power and how it may substitute for dirty forms of power can mischaracterize the results of a unilateral climate policy. I make no claim that this accurately represents the outcome of a tax when electricity is traded, but rather include it to show that electricity trading could cause negative leakage in addition to the standard endogenous technical change channel. Last, the terms of trade effect is not captured here, despite the trading of electricity. To model that case, electricity would need to be used as an input in other goods, and this channel would capture to what extent the tax affected trade of a carbon-intensive good.

This simple example captures that the degree of carbon leakage from a policy can depend significantly on the extent to which that country trades electricity with countries around it, such as in the EU. The example could also be considered in the context of unilateral climate policies at the U.S. state level, which will also have implications for leakage via regional wholesale markets. I find that in standard data sets on electricity generation, such as those in chapters 1 and 2, the source of the power being traded is not typically identified, which may create difficulties in obtaining an empirical estimation of leakage from electricity trading.

3.6 Conclusion

In this paper I introduce a simple model for analyzing intermittent power and apply it to the example of transmission to show implications of transmission capacity on renewable penetration. This paper contributes to the macrotheoretical literature by being one of the few to introduce variable power as a random variable and discuss how this affects integration and additionally introduces a new channel by which carbon leakage occurs. The primary results, that increased transmission will boost renewable integration in the long run but may have varied effects in the short run, are two which have received significant attention in the applied energy field but have not yet in the macrotheory papers on the environment and decarbonization. I additionally apply the model to the topic of carbon leakage and discuss how the trading of electricity and the effects of intermittency are not captured in the typical channels of carbon leakage. The frequency with which countries trade electricity across borders affect the degree to which emissions leak, yet the trading of electricity has not generally been modeled in macrotheory papers on carbon leakage.

The framework developed here is not meant to accurately model a region's power production or demand for power but rather highlight the importance of modeling renewable power as intermittent in order to develop a better understanding of best policies for decarbonizing the electricity sector. Further exploration within this framework could introduce a second form of renewable power, solar, and multiple periods, to better understand the slight complementarity of these sources and analyze implications of investing in a portfolio of variable sources and storage technology. On the topic of carbon leakage, applied work could analyze to what extent emissions leak via the trading of electricity to compare that to other empirical estimates.

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3.7 Appendix 1

3.7.1 Proof for Proposition 1

Suppose that $C_1 > C_2$ and there is wind production in both countries. We want to show that $M_{i1} > M_{i2}$ for all i. Note that since the countries are symmetrical, we just need to show this for one country. The zero profit condition for the wind firm in each country is given by:

$$\int_z [E_{ii}(\mathbf{z}, M_i, M_j, C)p_{e,i}(\mathbf{z}, M_i, M_j, C) + (1-\delta)Y_{i,j}p_{e,j}(\mathbf{z}, M_i, M_j, C)]\partial z = p_w$$

Taking the total derivative we get:

$$[\int_z \partial E_{ii}p_{e,i} + E_{i,i}\partial p_{e,i} + (1-\delta)\partial E_{i,j}p_{e,j} + (1-\delta)E_{i,j}\partial p_{e,j}]dz = 0$$

Regrouping terms here:

$$\int_z (\partial E_{ii}p_{ei} + (1-\delta)\partial E_{ij}p_{ej}dz + \int_z E_{ii}\partial p_{ei} + (1-\delta)E_{ij}\partial p_{ej}]dz = 0$$

The firm term then is the change in revenue from energy exported and energy consumed locally. Looking at term one-

$$\int_z p_{ei}(\frac{\partial E_{ii}}{\partial M_i}\frac{\partial M_i}{\partial C} + \frac{\partial E_{ii}}{\partial C}) + (1-\delta)p_{ej}(\frac{\partial E_{ij}}{\partial M_i}\frac{\partial M_i}{\partial C} + \frac{\partial E_{ij}}{\partial C})$$

This must be positive, which follows from the exporting resource constraint:

$$E_{ii}(\mathbf{z}) + E_{ij}(\mathbf{z}) = MY_{wi}(z) + Y_g\mathbf{z} + Y_d$$

and in particular when the cap is binding,

$$E_{ii}(\mathbf{z}) + C = MY_{wi}(z) + Y_g\mathbf{z} + Y_d$$

That either the effect of a change in C is either 0 or positive in each state of the world, and as such term 1 is positive. Term 2 then is the change in prices due to the change in interconnection-

$$\int_z E_{ii}(\frac{\partial p_{ei}}{\partial M_i}\frac{\partial M_i}{\partial C}+\frac{\partial p_{ei}}{\partial C})+(1-\delta)E_{ij}(\frac{\partial p_{ej}}{\partial M_i}\frac{\partial M_i}{\partial C}+\frac{\partial p_{ej}}{\partial C})dz$$

Considering the terms, we see that

- $\frac{\partial p_{ei}}{\partial M_i} < 0$ from $a_e - 2b_e[E_i - Eij] = p_{ei}$
- $\frac{\partial p_{ei}}{\partial C} > 0$ from same condition as above, when C is binding
- $\frac{\partial p_{ej}}{\partial M_i} < 0$ from $a_e - 2b_e[E_i - Eij] = (1-\delta)p_{ej}$
- $\frac{\partial p_{ej}}{\partial C} > 0$ from same condition as above, when C is binding

In order for the sum of the terms to be equal to zero, term 2 must be less than 0. Then given the signs of the above conditions, it must be the case that $\frac{\partial M_i}{\partial C} > 0$. That is, as the transmission increases between the two countries, they will choose to invest more in wind farms.

3.7.2 Proposition 2 and Trading with Gas Usage

Assume M_i, M_j, Y_{ni}, Y_{nj} are fixed, $Y_{gi}(\mathbf{z}) = G$, and $E_{ij}(\mathbf{z}) = C$. In the context of this proof, i is the exporting country and j importing. First, I establish that if $E_{ij}(\mathbf{z}) > 0$ and $Y_{gj}(\mathbf{z}) < G$, then $Y_{gii}(\mathbf{z}) = 0$. Suppose not, that is $Y_{gii}(\mathbf{z}) > 0$ (it cannot be negative). From the FOCs of firm i's problem, I have that:

$$(Y_{gii}(\mathbf{z})) : p_i(\mathbf{z}) = p_g(\mathbf{z})$$

$$(Y_{wii}(\mathbf{z})) : p_i(\mathbf{z}) = \lambda$$

$$(Y_{wij}(\mathbf{z})) : (1-\delta)p_j(\mathbf{z}) = \lambda$$

From the FOC of firm j's problem,

$$p_j(\mathbf{z} = p_g(\mathbf{z}$$

because its gas usage is unconstrained. Combining, yields that

$$p_j(\mathbf{z}) = p_g(\mathbf{z}) = p_i(\mathbf{z}) = (1-\delta)p_j(\mathbf{z})$$

$$\implies p_j(\mathbf{z}) = (1-\delta)p_j(\mathbf{z})$$

Therefore, it cannot be that $Y_{gii}(\mathbf{z}) > 0$. That is, the equilibrium does not exist where a country chooses to consume gas at home while exporting a cheaper fuel with depreciation costs. By the same approach, $Y_{gij}(\mathbf{z}) = 0$ under these assumptions, as with depreciation, country j would consume more fuel at home when $Y_{gj}(\mathbf{z} < G$. Now, I show that in the case that $Y_{gj} = G$, prices do exist where $Y_{gij}(\mathbf{z}) > 0$. Consider the FOCs from firm i's problem with the assumption of $E_{ij}(\mathbf{z}) = C$:

$$(Y_{gij}(\mathbf{z})) : (1-\delta)p_j(\mathbf{z}) - p_g(\mathbf{z}) = \gamma$$

$$(Y_{wii}(\mathbf{z})) : p_i(\mathbf{z}) - \lambda = 0$$

$$(Y_{wij}(\mathbf{z})) : (1-\delta)p_j(\mathbf{z}) - \lambda = \gamma$$

where γ is the constraint on exports. And from firm j I have that $p_j(\mathbf{z}) - p_g(\mathbf{z}) = \mu$. Then, combining gives $\mu - \gamma = \delta p_j(\mathbf{z})$ and that

$$p_j(\mathbf{z})(1-\delta) - p_i(\mathbf{z}) = \gamma$$

which are compatible. Then, relaxing C will cause exports to rise until the price ratio equals $1-\delta$ and as such $\Delta Y_{gij}(\mathbf{z}) \geq 0$. Next consider the components of global energy usage. In country j,

$$E_{jj}(\mathbf{z}) = Y_{wj}(z_j) + G$$

$$E_{ji}(\mathbf{z}) = 0$$

The amount consumed locally is unchanged due to any increase in C because the wind shock is fixed and gas usage is at the constraint. The exports from j to i are 0 because both countries cannot export power in the same state. In country i,

$$E_{ij}(\mathbf{z}) = Y_{wij}(\mathbf{z}) + Y_{gij}(\mathbf{z}) \leq C$$

$$E_{ii}(\mathbf{z}) = Y_{wii}(\mathbf{z}) + Y_{gii}(\mathbf{z})$$

The amount exported has now increased due to the relaxation of C, with the exception of the state where the optimum was equivalent to C. In the case of power consumed locally,this may decrease, but not by more than the amount exported, as otherwise they would have chosen to use that much less in gas power in the original state of the world. Then, $\Delta E_i(\mathbf{z}) \geq 0$.