Gone with the Wind: Consumer Surplus from Renewable Generation*

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Abstract

I show horizontally-integrated electricity generators competing in wholesale electricity markets can internalize the benefits of low-cost renewable generation by strategically withholding output from conventional resources when their own wind turbines are generating electricity. This strategic response attenuates the impact of low-cost renewable generation on the price of electricity, reducing consumer benefit from renewable generation. Using data on one of the largest wholesale electricity markets in the US, I show renewable generation is associated with physical withholding, implying 20% of wind generation replaces withheld units, decreasing potential consumer surplus by $1.5 billion from 2014 to 2016.

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1 Introduction

Whoever benefits from a new, low-cost resource depends largely on how firms compete in a market. This basic notion of economic pass-through under imperfect competition states that a firm with market power has a greater ability to internalize the benefits of a low-cost resource by adjusting their competitive strategies (Weyl and Fabinger, 2013). As a result, consumer surplus derived from the low-cost resources can be attenuated in markets where incumbent firms exert market power. Understanding how market power determines the incidence of benefits from low-cost technologies is important for policy makers – a program designed to deploy low-cost resources as a means to improve consumer surplus might not achieve it's goal if the issue of market power is not given appropriate attention.

In this paper, I demonstrate this principle in the context of wholesale electricity markets. In recent years, wholesale electricity markets have experienced a rapid deployment of a low-cost resource, namely renewable generation in the form of utility scale wind turbines. This technology, coupled with solar generation, accounts for over half of new electricity generation capacity in the US since 2008 (EIA, 2017) and has created immense short-run cost savings because it doesn't require fuel to generate electricity.[1] In these wholesale electricity markets, constructed as multi-unit uniform price auctions, inelastic demand and capacity constraints allows market participants some degree of market power, making it a great setting to understand how market power can influence the incidence of low-cost technologies. Without explicitly taking into account the competitive conduct of existing electricity generators, our understanding of how renewable generation impacts the price of electricity in wholesale electricity markets is incomplete.

To this end, I evaluate the competitive effects of more renewable generation in wholesale electricity markets, and quantify the consumer surplus associated with the lower operating cost of renewable generation taking into account how market participants will strategically respond to renewable generation. I first use an equilibrium framework to derive a quantity pass-through equa-

[1] The value associated with the low-marginal-cost attribute of renewable generation can be just as large if not larger than the public benefit of avoided pollution externalities (Callaway, Fowlie, and McCormick, 2018; Ovaere and Gillingham, 2019).

tion, showing how more renewable generation should impact the price of electricity taking into account firm conduct. Then, modifying Klemperer and Meyer's (1989) Supply Function Equilibrium framework, I show that integrated market participants, those that own wind turbines and conventional electricity generators, have an incentive to withhold their other assets when their own wind turbines are generating electricity.[2] Doing so increases the revenue for all infra-marginal electricity generating units, including wind turbines. This physical withholding[3] attenuates the consumer benefit associated with renewable generation, and showcases how firms can exert market power to internalize the benefits of a low-cost technology.

Leveraging hourly data on ex-ante generator-specific strategies from one of the largest wholesale electricity market in the United States, I show direct evidence of strategic withholding by integrated market participants. I do so by using variation in the cleared quantity offered by a market participant, to the wholesale market operator, at a given price within a year-month-hour (e.g. June, 2016, 4pm). While my empirical strategy is most similar to Fabra and Reguant's (2014) analysis of emission cost pass-through, the use of within offer price variation is novel. I find the market participants that own more wind capacity withhold their output more in response to renewable generation. And these market participants withhold their output more in response to their own wind generation relative to wind generation from wind turbines they do not own. With the detailed data on supply and demand for every hour, I am able to make credible claims regarding consumer surplus from renewable generation by re-constructing the market equilibrium and calculating an expression for the price reduction from renewable generation taking into account the strategic response by traditional electricity generators. My results are robust to concerns regarding transmission congestion, endogenous sample selection, and the existence of related markets.

I find that the potential consumer surplus from the low-cost of renewable generation is large. In the Midcontinent Independent System Operator's wholesale electricity market from 2014 to 2016,

[2]Throughout, I use the term *integrated* to define horizontally integrated market participants that own wind turbines and conventional electricity generators word *conventional* to describe electricity generators that are not wind turbines or solar panels.

[3]Physical withholding is a reduction in the quantity offered to the market, at a given price, with the intent to influence the market price. This is in comparison to economic withholding, which involves bidding a generator's quantity at a higher price. Although related, these two concepts are distinct and treated differently by market monitors.

I find a potential consumer benefit of \$69 per person, per year associated with the low operating cost of renewable generation. However, this number depends crucially on the competitive conduct of integrated market participants. If these electricity generators were to act as profit maximizers in a supply function equilibrium, the realized consumer surplus would have been only \$19 per person per year. Conversely, estimated parameters of firm level withholding, that do not place any structure on the firm's incentives, suggest \$58 per person per year of consumer benefit is realized. During the entire sample period, this suggests physical withholding associated with renewable generation reduced consumer surplus by over 1.5 billion US dollars during the sample period.

With this paper I am making three contributions. First, I show that understanding firm incentives is essential to calculating the consumer benefit of low-cost, renewable, electricity generation. Many papers have evaluated the integration of renewable generation in electricity markets, uncovering a "merit order effect" where renewable generation displaces high cost generation and lowers the market price, idealized in Figure 1.[4] The results are location specific, often determined by the fuel mix and fuel prices, and are large.[5] Overwhelmingly, these empirical papers do not consider how the increase in renewable generation might change the strategies of electricity generators, but instead assume a perfectly competitive market or an economic dispatch of resources based on the marginal cost of production. This is despite theoretical importance of competitive conduct in how renewable generation can impact the price, as shown by Ben-Moshe and Rubin (2015) and Acemoglu, Kakhbod, and Ozdaglar (2017).

In this paper I focus on the consumer surplus component of total welfare for three reasons.[6] For one, the impact renewable generation on the price of electricity is frequently cited as one of the

[4]These papers either consider a simulation model (Sensfuß, Ragwitz, and Genoese 2008; McConnell et al. 2013), or estimate the reduced form change in price due to renewable generation (Woo et al. 2011; Cludius et al. 2014; Clò, Cataldi, and Zoppoli 2015; Woo et al. 2015, 2016).

[5]For example, Woo et al. (2016) find that a one gigawatt hour (GWh) increase of wind generation in California lowers the wholesale market price by \$1.5 to \$11.4 per megawatt hour. This implies average hourly wind generation can lower total market revenue by millions of dollars per day assuming the average hourly wind generation in California during 2017 was around 1.5 GWh and the average hourly load is 24 GWh. If 1.5 GWh of wind generation reduces the price by 9.75 \$/MWh, for 24 GWh in a hour, for twenty-four hours, total market revenue declines by 5.6 million USD that day.

[6]The consumer in a wholesale electricity market is not always the end consumer of electricity. Often it is a regulated distribution utility. However, consumer surplus in wholesale markets can broadly represent consumer surplus as long as the wholesale price is passed onto the retail, commercial, or industrial price of electricity.

reasons to enact policies supporting renewable generation.[7] For example, a report from the American Wind Energy Association identifying the merits of wind energy in the Mid-Western United States points to a simulation that finds "wind has been shown to reduce overall energy costs for consumers saving ratepayers $63 to $147 per year (assuming a 20 GW scenario in 2020)" (AWEA, 2014). I show these "consumer savings" depend materially on the strategies of market participants in wholesale electricity markets; public policies with the intent of providing consumers this benefit will under-deliver if they ignore the incentives of existing electricity generators. Second, increasing consumer surplus is one of the historical reasons for forming wholesale electricity markets.[8] Finally, I am unable to observe the fuel type, fuel and operating costs, or ownership identity of electricity generators in my sample, at least one of which is necessary to do a complete welfare analysis.

My second contribution it to provide direct evidence of strategic bidding in multi-unit auctions using exogenous variation in wind production. Wholesale electricity markets are multi-unit auctions where the uniform price is set by the marginal unit. In such markets there is a known incentive for market participants to withhold output to increase their own revenue (Ausubel et al., 2014). This incentive increases in proportion to the infra-marginal market share of the electricity generator (Wolfram, 1998). For the firms that own renewable resources, increased renewable generation is a large short-run increase in their infra-marginal market share, intensifying their incentive to withhold their generation. Because wind generation is determined predominately by weather patterns, this variation in the incentives to exercise market power is as good as random.

While a number of papers have looked at strategic bidding in multi-unit auctions (Hortaçsu, Kastl, and Zhang, 2018; Doraszelski et al., 2017; List and Lucking-Reiley, 2002), and even in wholesale electricity markets (Hortaçsu and Puller, 2008; Wolfram, 1998; Borenstein, Bushnell,

[7]The primary reason for policies supporting renewable energy is the public benefits of avoided pollution. Despite this, the cost component is often brought up in public policy debates.

[8]See, for example, Federal Energy Regulatory Commission (FERC) Order 2000 advancing the formation of Regional Transmission Organizations: "The Commission's goal is to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service." See also Borenstein and Bushnell (2015) for the historical, political, and economic rationale for wholesale electricity markets and an assessment of whether wholesale electricity markets did indeed provide consumer benefits.

and Wolak, 2002; Reguant, 2014; Ito and Reguant, 2016), they typically rely on structural models trying to uncover price-cost margins or underlying valuations. The exogenous nature of wind generation, in combination with the rich data on generator-specific strategies, allows me to substitute structural assumptions on firm conduct with parsimonious estimating equations that identify parameters of a firm's underlying strategy. With these parameters, and the quantity pass-through equation, it is straight forward to make claims regarding consumer surplus in the spirit of Chetty (2009).

Finally, this paper provides an status update on competition in wholesale electricity markets. Ever since the California electricity crisis in the early 2000s, regulators and market monitors have worked to ensure that wholesale electricity markets approximate the competitive outcome. As a result of these efforts, wholesale electricity markets in the US are currently perceived as competitive by economic researchers (Bushnell, Mansur, and Novan, 2017), regulators (FERC, 2011), and independent market monitors (Potomac Economics, 2018). This is partly because of long term forward contracts, a forward wholesale market, and vertical commitments between producers and consumers of wholesale electricity. Despite this, there is mounting evidence that the market participants in wholesale electricity markets still have the ability and incentive to exercise market power in certain settings(Woerman, 2019; McDermott, 2019; McRae and Wolak, 2019). As the electricity grid transitions towards more renewable generation, it is important to consider the ways in which a firm's ability and incentive to exert market power might change, and to develop tools to characterize and diagnose imperfectly competitive behavior.[9] An immediate policy implication of this paper is better market monitoring for physical withholding of capacity. This can be accomplished using the methods I outline in this paper.

The paper proceeds as follows, section 2 outlines a general framework for understanding how renewable generation, in particular wind, impacts the price of electricity in wholesale markets. Section 3 applies to model to real data from the Mid-continent Independent System Operator,

[9] Overall, Independent Market Monitors do a good job identifying and mitigating blatant exertion of market power in wholesale electricity markets. In Appendix B I outline exactly how this is done for the market I study, as well as characterize the market in terms of forward contracts and vertical commitments.

quantifying the price effects of renewable generation, showing how this depends on market participants strategies, and provides direct evidence consistent with the theory. Section 4 summarizes the implications of withholding for consumer surplus in wholesale markets and briefly discusses the emissions implications of physical withholding, section 5 concludes with a discussion.

2 Wind Generation in Wholesale Electricity Markets

The high fixed costs of electricity generation, transmission, and distribution lends itself to a model of natural monopoly and has historically been served by vertically integrated investor, or municipality, owned utilities operating under cost-of-service regulation. Since the 1980s the electricity industry has undergone deregulation and restructuring at the state and federal level largely motivated by the success seen in other industries (such as rail and natural gas), and analysis showing the potential for increased efficiency (for example Joskow and Schmalensee (1983)).[10] Restructured wholesale electricity markets emerged, where competitive supply and demand bids are submitted to a centralized and impartial Independent System Operator, who then decides which units to dispatch and the price they receive. As of 2012, these markets cover 60% of generation capacity within the US and they are effective in reducing production cost by reallocating output within and between power control areas (Cicala, 2017).

The following is intended to model a wholesale electricity market operating as a multi-unit uniform price auction that allows for integrated market participants and a degree of low variable cost renewable generation. This illustrative model is based off Klemperer and Meyer (1989) and motivated by the "supply function" nature of the data, however the testable predictions I present can be derived from a general model of imperfect competition under Cournot competition as done in Acemoglu, Kakhbod, and Ozdaglar (2017). Demand for electricity is determined by Load Serving

[10]Public Utilities Regulatory Policy Act (PURPA) of 1978 encouraged alternative fuels and introduced independent power producers (IPPs). Federal Energy Regulatory Commission (FERC) orders 888 and 889 in 1996 laid the ground work for competitive wholesale electricity markets. FERC order 2000, promulgated in 1999, encouraged the formation of Regional Transmission Organizations to serve as planning bodies over a larger geographic area. State policies have introduced retail competition and forced divestiture of vertically integrated assets.

Entities, predominately utilities, that charge customers a rate for electricity in the retail market.[11] These Load Serving Entities submit demand bids for each hour that can be price sensitive, but are overwhelmingly inelastic with respect to price. I model demand in the wholesale market at time t as $D_t(p) = d_t(p) + \varepsilon_t$ where $d_t(p)$ is the deterministic component of demand as a function of price that can be forecasted and ε_t is a random variable representing fluctuations in the quantity demanded. I model ε_t to be an $i.i.d.$ random variable with expectation equal to zero.

Supply in the wholesale electricity market is provided by market participants, which I denote by the subscript o, who own multiple electricity generating assets including coal, gas, oil, nuclear, or hydrological based resources. Each conventional unit owned by market participant o, denoted by the subscripts $k \in K_o$, submits a unit-specific supply curve as a function of price and the wind forecast, $s_{kt}(p, W_t)$ where W_t denotes the quantity of electricity generated by all wind turbines at time t. This offer curve represents the quantity the market participant o is willing to produce from unit k at time t for price p and wind forecast W_t. I consider the market participant's aggregate supply sans wind generation as $S_{ot}(p, W_t) = \sum_{k \in K_o} s_{kt}(p, W_t)$. When the uniform market clearing price is $\hat{p}$, the market participant will produce $S_{ot}(\hat{p}, W_t)$ with costs $C_{ot}(S_{ot}(\hat{p}, W_t))$ and revenue $\hat{p} S_{ot}(\hat{p}, W_t)$. In what follows I assume that costs are weakly increasing and convex, $C''_{ot}(S_{ot}(\hat{p}, W_t)) \geq 0, C'_{ot}(S_{ot}(\hat{p}, W_t)) \geq 0$.

I assume that each unit's supply curve is linear and separable in the wind forecast implying each market participant's aggregate supply sans wind generation can be represented as $S_{ot}(p, W_t) = \xi_{ot}(p) + \delta_o W_t$.[12] Here $\xi_{ot}(p)$ is market participant o's supply curve as a function of price across all K_o conventional units, and δ_o is the change in aggregate output from market participant o in response to more wind generation. This implies that market participants will change the quantity offered in response to wind generation equally at all prices. This assumption greatly increases the tractability of the model, as I discuss in Appendix B.3. It is possible market participants not only

[11] Load Serving Entities in wholesale markets can also be generators of electricity if they are vertically integrated. The commercial and retail rate of electricity is typically a time-invariant rate or increasing block pricing. Industrial consumers typically have peak demand charges.

[12] This assumption is similar the "additive separability" assumption for forward contracts common in the empirical supply function equilibrium literature (Hortaçsu and Puller, 2008; Mercadal, 2015; Hortaçsu et al., 2017).

change the quantity offered at all prices, but also the slope of their supply function in response to more wind generation. I abstract away from this for two reasons. First, the slope is of second-order importance relative to the change in the total quantity offered at, or near, the equilibrium price. Second, information on reduction in aggregate supply at, or near, the equilibrium with information on the slope of aggregate supply is sufficient for the consumer surplus calculations I do in section 4.

The aggregate quantity, W_t, is common knowledge to all market participants and perfectly forecast-able.[13] The proportion of wind that is owned by market participant o at time t is denoted by $\theta_{ot} \in [0,1]$, with $\sum_o \theta_{ot} = 1$. This implies the amount of wind generated by market participant o at time t is $\theta_{ot} W_t$. In this model I assume that wind generation always clears at the equilibrium because of its low variable cost.[14]

Wholesale electricity markets typically have an hourly day-ahead forward market in addition to the real-time market. The forward market is a purely financial market that allows electricity generators to commit to production ahead of time. Any shortfall of a market participant's day-ahead commitment must be resolved with electricity purchased in real-time. This forward commitment effectively forces each market participant to act as a Stackelberg leader (Allaz and Vila, 1993). Although this is an important component of wholesale electricity markets, I do not include it in what follows because it will not change the strategic response of electricity generators to more wind generation in the real-time market, as shown by Acemoglu, Kakhbod, and Ozdaglar (2017) and discussed in Appendix B.3.

The price concept most common in U.S. wholesale electricity markets is a Locational Marginal Price (LMP). This price represents the marginal value of increasing energy production at any given moment and at any given location within the market, and therefore varies by location (at different

[13] The comparative statics below do not change in a meaningful way by introducing a random component to total wind generation. Acemoglu, Kakhbod, and Ozdaglar (2017) show the general incentives to withhold output remain when wind generation is a random value, is private information, and correlated across wind turbines.

[14] I assume the variable cost of production for wind turbines is zero as it does not require fuel. There are other variable operation and management cost associated with wind turbines, but the Federal Renewable Energy Production Tax Credit is larger than these costs. It is possible that wind generation can be curtailed manually, however the market I study, MISO, has incorporated wind generation as part of the economic dispatch since 2011, resulting in a manual-curtailment rate less that 1% (Bird, Cochran, and Wang, 2014).

pricing nodes) and by time (typically at 5 minute intervals). The LMP can be decomposed into three distinct components: the Marginal Energy Component (MEC) determined as the price where supply equals demand at a load-weighted reference node, marginal congestion cost associated with the shadow price of system transmission constraints and out of merit dispatch, and marginal losses associated with transmitting the electricity over long distances. At any given moment, the MEC is the same at every location within the market while the losses and congestion components vary by node.[15] Analytically, I consider the price p to represent the MEC of the LMP, as I do not explicitly model congestion. In application I largely consider the MEC as the market price, however I make use of the congestion component of the LMP in supplemental analysis.

2.1 Market Equilibrium and the Analytical Merit Order Effect

Moving forward, I suppress the time subscript. The market operator takes the supply offers as given, observes the realized demand shock, ε, to solve for the dispatch quantity for each firm and the price received in accordance with a dispatch algorithm. Outside of security constraints and reliability concerns, we can think of the market clearing as follows:

$$\underbrace{d(p)+\varepsilon}_{\text{demand } D(p)} = \underbrace{\sum_o S_o(p,W)}_{\text{conventional supply}} + \underbrace{W}_{\text{wind}} \tag{1}$$

Implicitly differentiating the market clearing condition with respect to total wind generation, W, gives the equilibrium effect of increased renewable generation on wholesale market price.[16]

$$\frac{dp}{dW} = -\frac{1+\sum_o \delta_o}{\sum S_o'(p,W) - d'(p)} \tag{2}$$

[15] The LMP can be very high, or negative, at times. Typically, this is because of the congestion and loss components of the LMP.

[16] I assume that the quantity of electricity demanded in the wholesale market by load serving entities does not depend on the quantity of electricity generated by wind turbines at a given moment in time, that is $\frac{\partial D(p)}{\partial W} = 0$. If this assumption is violated Equation 2 becomes $\frac{dp}{dW} = -\frac{1+\sum_o \delta_o - \frac{\partial D(p)}{\partial W}}{\sum S_o'(p,W) - d'(p)}$.

Where $'$ denotes the partial derivative with respect to first argument, in this case price. Equation 2 is the rate at which an increase in renewable generation impacts the equilibrium price, what I am calling the analytical merit order effect. This value depends on the supply function slope, demand slope, and the strategic response by market participants. The intuition of Equation 2, when the slope of demand and δ_o are equal to zero, $\forall o$, is shown in fig. 1 where the change in the price of electricity is determined by the difference in price submitted for the marginal unit, $-\frac{1}{\sum_o S'(p,W)}$. This can be thought of as the pass-through of increased renewable generation. In Appendix B.1 I discuss how this is related to, but different from, the conventional pass-through rate of a cost shock or tax.

Electricity markets are often considered to be imperfectly competitive because of capacity and transmission constraints, a degree of market power, as well as vertical and horizontal relations. I incorporate competitive conduct into Equation 2 with the inclusion of δ_o in the numerator. Without placing structure on the market or market participants' incentives it is impossible to sign this value. The sign of this term suggests the extent to which increased renewable generation changes each market participant's behavior. If the term is positive the market participant offers more generation quantity to the market at any given price in response to increased renewable generation. This "competitive" outcome arises if the firm is trying to ensure their generation clears in the market, and is not displaced by the increased renewable generation.[17] The implication is that renewable generation would decrease the price by more than the change in cost of the marginal unit. Conversely, when the term is negative, the supplier is offering less quantity from conventional generators to the market at any given price. This "uncompetitive" outcome could be an attempt by the firm to offset the merit order effect of increased renewable generation or internalize the benefits of low-cost renewable generation.

[17] Ciarreta, Espinosa, and Pizarro-Irizar (2017) finds evidence of this in the Spanish electricity market by looking at the difference in the offer curves over long periods of time.

2.2 Market Participants' Strategy and Testable Predictions

A firm with market power can internalize the benefits associated with increased renewable generation. Figure 2 provides the intuition. When a market participant with market power is considering the incentives to withhold, they are comparing a higher price and smaller quantity to a lower price and larger quantity. When this market participant owns a wind turbine that is also generating electricity, they receive additional benefit of increasing the price directly proportional to the quantity of electricity generated by their wind turbine. This is because they receive revenue from the inframarginal wind turbine but do not incur any cost. This is consistent with the idea of bid shading in multi-unit uniform price auctions presented by Ausubel et al. (2014).

The strategies employed by market participants in wholesale electricity markets can be characterized by Klemperer and Meyer's (1989) Supply Function Equilibrium framework. Market participants choose the supply function $S_o(p,W)$ that maximizes their profit, mapping different realizations of ε to price-quantity pairs. Appendix A.1 shows the optimal strategy of market participant o with conventional assets and wind turbines can be characterized by

$$p - C_o'(S_o^*(p,W)) = -\frac{S_o^*(p,W) + \theta_o W}{RD_o'(p)} \tag{3}$$

where $RD_o'(p) \equiv d'(p) - \sum_o \xi_{j\neq o}'(p)$ is the slope of residual demand for market participant o. This general first order condition relates to the inverse elasticity pricing rule and is commonly used in the application to wholesale electricity markets.[18] The slope of the residual demand reflects the firm's market power. As it decreases in absolute value, the firm's incentive and ability to markup the offer price over marginal cost increases. Appendix A.2 evaluates how the best response function changes when there is more wind generation in a given hour, providing the following

[18] See Green and Newbery (1992); Wolak (2001, 2007); McRae and Wolak (2009); Hortaçsu and Puller (2008); Ryan (2017); Reguant (2014); Ito and Reguant (2016); Mercadal (2015).

expression for the strategic component of the market participant's supply function:

$$\delta_o^* = -\frac{\theta_o}{1 - RD'(p)C_o''(S_o^*(p,W))}. \tag{4}$$

Because residual demand is weakly negative, $RD'(p) \leq 0$, and costs are assumed to be weakly convex, $C_o''(S_o^*(p,W)) \geq 0$, this expression is weakly negative, $\delta_o^* \leq 0$, implying there is an uncompetitive effect associated with more renewable generation in the form of physical withholding. If marginal costs are locally constant,[19] $C_o''(S_o(p,W)) = 0$, and residual demand is finite,[20] $-RD'(p) < \infty$, Equation 4 equals $-\theta_o$; a market participant will withhold their conventional generation by the quantity of wind generated, one for one. In this case the market participant would be generating the same electricity across all of their assets, however replacing their higher cost conventional generation with lower cost renewable generation.

In a perfectly competitive, or marginal cost pricing, scenario the market participants are price takers and residual demand is flat, $RD'(p) = -\infty$. As a result Equation 4 would be $\delta_0 = 0$ and more renewable generation would not be associated with any physical withholding.

Equation 4 provides the following testable predictions:

Testable Predictions

(i) Only market participants that own wind turbines will reduce their quantity offered in response to more wind generation. Market participants that do not own wind turbines will not change their offer curve in response to more wind generation. For these firms $\theta_o = 0$ at all times implying $\delta_o^* = 0$ always.

(ii) Market participants that generate a larger share of the total wind generation will reduce the quantity offered by a larger amount in response to more wind generation so long as they have some market power. This follows from $\frac{\partial \delta_o^*}{\partial \theta_o} = -\frac{1}{1-RD'(p)C_o''(S_o^*(p,W))} < 0$ when $RD'(p) > -\infty$.

[19]This is a common assumption when considering the supply function of a single unit, for example see Woerman (2019), Reguant (2014), Hortaçsu and Puller (2008), Wolfram (1998, 1999). In general, I am considering the supply function across multiple units. This assumption is reasonable so long as as the price change is small enough to not encourage the firm to adjust more than one unit at a time.

[20]That is to say, the firm has some market power.

(iii) Market participants will only change their offer curve in response to their own wind generation, not in response to the wind generation of other market participants. This can be seen by noting that only the market participant's own wind generation, $\theta_o W$, appears in Equation 3. Their optimal strategy does not directly depend on $\sum_{j \neq o} \theta_j W$.

Appendix B.3 discusses the assumptions that lead to these testable predictions including the lack of forward markets and the restriction on the class of supply functions. In general, these assumptions don't modify the general testable conditions in a significant way.

3 Empirical Evidence of Strategic Withholding

I use data from the Midcontinent Independent System Operator (MISO) to quantify how market participants' strategy can alter the magnitude of the merit order effect and realized consumer surplus.[21] I first look directly at the price effects of more renewable generation in this market, then show evidence of physical withholding consistent with the testable predictions outlined above. Finally, I directly estimate an aggregate withholding parameter used in consumer surplus calculations.

Since the incorporation of the Southern Region in 2013, MISO has become one of the largest wholesale electricity markets in the United States with a total of 180 gigawatts of generation capacity, conducting market operations from Montana to Michigan to Louisiana. Figure 3 shows the distribution of wind turbines and conventional electricity generating assets that sell electricity into MISO according the Energy Information Agency. In this market there are a number of large market participants, all of which operate a diverse portfolio of assets. Figure 4 shows the effective capacity of the 30 largest ones.[22] Several of these large asset owners are integrated, owning wind turbines and other assets, and so will have an incentive to withhold their output when their own wind turbines are generating electricity. Appendix C outlines key institutional details of MISO that

[21] MISO is a great setting for looking at renewable generation and wholesale electricity market operations because its footprint is home to a large share of utility-scale wind generation and has rich data, with time-invariant owner codes, publicly available on-line.

[22] Here, effective capacity is measured as the maxmimum output from a unit (in MW) during the sample period.

diverge from the framework presented in section 2 and provides a more thorough characterization of the wholesale market.

MISO publishes market operations data on their website as Market Reports. In what follows, I use the daily real-time generation offers of cleared generation units from January 1st, 2014 to December 26th, 2016.[23] These data provide a time consistent unit and owner identification code, the generating unit type (steam, combustion, wind turbine, hydro), the ex-post quantity generated and LMP received at five minute intervals, as well as details on the generating unit's supply bid including up to ten price-quantity pairs that outline their offer strategy, $s_{okt}(p)$. The characteristics of the electricity generating units in terms of their capacity, capacity factor and frequency of clearing are summarized in Table 1. This table shows that electricity generating units operated by integrated market participants appear otherwise similar to units operated by market participants that are not integrated.

3.1 Price Effects of Renewable Generation by Wind Owner

I use two approaches in assessing how more renewable generation impacts the price of electricity in MISO. The first, consistent with the majority of the literature evaluating the merit order effect, is to estimate the parameters in the following linear regression model:

$$Price_t = \alpha Wind\ Generation\ GWh_t + X_t\beta + \omega_{ymh} + \varepsilon_t \tag{5}$$

Where $Price_t$ is the MEC component of the LMP, $Wind\ Generation\ GWh_t$ is MISO's total wind generation in GWh, and X_t are other control variables for hour t.[24] In this equation ω denotes a fixed effect for every year-month-hour combination (e.g. June 2014, 5pm). The inclusion of ω implies that α is identified off of deviations in $Wind\ Generation\ GWh_t$ from the average value

[23] The start date is a few months after when the Southern Region was integrated into MISO. The end date is when MISO stopped reporting unit specific identification numbers to preserve the privacy of the asset owners. I focus on the real-time market because there are no purely financial players in the real-time market, increasing the benefits from withholding output.

[24] I control for daily Henry-Hub natural gas price, daily maximum temperature in MISO's footprint, hourly net generation in MISO, and hourly net exports in MISO, as all of these likely influence the market price.

of *Wind Generation* GWh_t in a year-month-hour.[25] These fixed effects control month-to-month trends (for example, determined by fuel prices), and hour-to-hour trends within a month (for example, determined by electricity demand patterns).

Table 2, Panel A, shows the point estimates. An additional GWh of wind generation decreases the hourly price of electricity by \$0.79 on average. For reference, average wind generation in MISO is near 5 GWh and the average Marginal Energy Component (MEC) is \$30/MWh. Column (2) of Table 2, Panel A, decomposes total hourly wind generation into the quantity produced by integrated market participants, who have an incentive to withhold their output, and the quantity produced by independent wind turbine operators. Wind generation from integrated market participants has a smaller price effect than wind generation from independent wind turbines, roughly half as large. This is consistent with integrated market participants strategically withholding their output when their own wind turbines are generating electricity to mitigate the merit order effect, and increase the revenues from their own wind turbines. Neither estimate has a p-value less than 0.05 because the two values are extremely correlated (correlation = 0.93); this severe multicollinearity inflates the standard errors. Columns (3) and (4) shows that the relationship holds, and the estimates are statistically significant, when including only one of the two estimates of wind generation.[26]

Second, I use the hourly price-quantity pairs submitted as generation offers to reconstruct the equilibrium price, as described in B.2. With the slope of supply and demand at the equilibrium I calculate an exact expression of the analytical merit order effect, Equation 2, for every hour. I do so under two assumptions. One assumption in which firms are not responding to more wind generation, what I am calling "no withholding," in which case $\delta_0 = 0$. This is consistent with marginal cost pricing, or zero market power. Alternatively, I assume market participants are withholding their output perfectly in-line with their incentives in a supply function equilibrium framework when marginal costs are constant, $\delta_o = \theta_o$, what I am calling "full withholding."[27] For every MWh

[25] For the example, there are thirty instances of June 2014, 5pm for the thirty days in June. The estimate for α comes from comparing the market price on windy instances of June 2014, 5pm to market price on less windy instances of June 2014, 5pm, controlling for other determinants of the market price.

[26] These point estimates, however, have negative bias because they are positively correlated with the other source of wind generation which itself is negative correlated with the market price.

[27] Increasing marginal cost would result in a value of δ_0 smaller in absolute value, and less withholding. Constant

of electricity generated by integrated wind turbines, integrated market participant withhold that same amount of electricity from their marginal generators. Together, these two assumption create bounds on how a market participant's strategy can influence the merit order effect.

Table 2, Panel B, shows summary statistics for the hourly analytical merit order effect under these two assumptions. These values are smaller in absolute value than the empirical merit order effects in Panel A.[28] A one GWh increase in wind generation for a given hour corresponds to an average price decrease of $0.65/MWh with no withholding by market participants, and $0.19/MWh if market participants withhold proportionate to their own wind generation. For each assumption, I find the total price for each hour by multiplying the analytical merit order effect by the amount of wind generation in that hour. This is also summarized in Table 2, Panel B.

For context, a one GWh increase in wind generation wind has been associated with a 3.18% price decline in Spain (Böckers, Giessing, and Rösch, 2013), 0.8 to 2.3 €/MWh price decline in Germany (Cludius et al., 2014), 1.5 to 11.4 $/MWh price decline in California (Woo et al., 2016), and 3.9 to 15.2$/Mh price decline in Texas (Woo et al., 2011). My estimates of the merit order effect is slightly smaller than these others for two reasons: I ignore congestion and transmission constraints, and MISO has more similar-cost coal power plants than most other wholesale markets.

3.2 Main Evidence of Strategic Withholding

The difference between the "no withholding" and "full withholding" price effects, presented in Table 2, Panel B, highlights the importance of each firm's strategy in how renewable generation can influence the price of electricity. However, these calculations rely on assumptions of how firms are competing in the wholesale market and responding to more renewable generation. In this section, I use detailed data on the strategies of market participants to first evaluate if integrated market participants are withholding their output in response to more renewable generation. I then directly estimate a parameter that summarizes these firms' strategies, and as a result side-step

marginal cost is assumed for illustrative purposes, as it is associated with the maximum a market participant would be willing to withhold in response to more wind generation.

[28] Although both fall within each other's 95% confidence interval.

structural assumptions on how the firms are competing. This approach is valuable in wholesale electricity markets, where there is convincing evidence that market participants are not always acting in a way that is fully rational (Hortaçsu and Puller, 2008; Hortaçsu et al., 2017).

I use detailed data on each market participants hourly offer curve to evaluate how their offer strategy changes in response to more renewable generation. I begin by aggregating the quantity offered at a given price, across all conventional electricity generating units that cleared the market, by owner code for every hour.[29] This gives me an hourly supply curve of the cleared conventional assets for each market participant on a common support. For computational purposes, I limit the prices to be every \$3 interval between 10 and 70 dollars.[30] These curves are defined by a set of $b = 1 \dots 21$ price quantity pairs, (p_b, q_{otb}), for owner o at time t. The set of p_b are the same for all market participants, for all hours, only the quantities offered at these prices change.

To directly test for and estimate strategic physical withholding, I see how the quantity offered at a given price changes in response to increased renewable generation. The general estimating equation of interest through out this section is:

$$q_{otb} = \delta Wind\ Generation\ GWh_t + X_t\beta + \eta_{oymhb} + \varepsilon_{otb} \qquad (6)$$

where q_{otb} is the quantity offered, in MW, by market participant o at time t and price bin p_b. X represents other determinants of a market participant's strategy including hourly cleared GWh in MISO, hourly net exports, daily temperature and natural gas prices. Identification comes from owner specific, year-month-hour, fixed effects for every price bin: η_{oymhb}. This captures the average quantity offered by market participant o at price p_b within a year-month-hour (e.g. September 2014, 4pm). Therefore the coefficient δ is identified off the deviation from the market participant's average supply curve in a year-month-hour. Figure 5 illustrates the sort variation used in this identification strategy by plotting all offer curves for a single market participant in a year-month-hour,

[29] I do not include bids from wind turbine units. In effect, I perform a horizontal summation of all conventional unit offers owned by the same market participant that cleared. In subsection 3.3 I discuss the extent to which only observing the cleared units influences my results.

[30] These bounds capture nearly all hourly MECs observed during the sample period, corresponding to the 1st and 97th percentile respectively.

and showing how these offer curves change when there is more wind generation. In application, to ensure I use only economically relevant bid prices, I discard any observations where the market price is more than the price bin plus three.[31] Further, I restrict the sample hours of peak demand, defined as 3pm to 8pm inclusive, as market participants are more likely to exert market power during these hours.[32]

Of primary importance is the estimate for δ in Equation 6, representing how the quantity of electricity offered to the market changes when there is more wind generation. This parameter has a direct connection to δ_o in Equation 4.[33] To interpret δ as a withholding parameter it is necessary for wind generation, conditional on other control variables, to be uncorrelated with other determinate of q_{otb}. Because wind generation is as good as random, the only concern would be related market conditions that are mechanically correlated to both wind generation and q_{otb}, for example transmission congestion constraints. I discuss these these concerns, among others, more thoroughly in subsection 3.3.

3.2.1 Evidence Supporting Testable Predictions

Because these data represent the ex-ante strategy of economic units owned by the firm, withholding the quantity offered at a given price would imply that $\delta < 0$. The testable predictions in section 2 suggests the coefficient of δ is (i) negative only for integrated market participants that own both wind turbines and conventional assets, (ii) increasing in the share of total wind generated by the integrated market participant, and (iii) negative only in response to a market participant's own wind generation.

Table 3 shows the estimate of δ in Equation 6 is negative. Overall, a 1 GWh increase in wind generation in an hour is associated with a 1.5 MW reduction it the quantity offered at a given price, on average, across all market participants. In column (2), I interact $WindGWh_t$ with an

[31] I add three to the price bin because the price bins are at three dollar intervals.

[32] Using all hours does little to the results that follow, as alluded in Table 8 in Appendix B.4.

[33] Note that δ in Equation 6 can be interpreted as the average value of δ_o in Equation 2, times 10^3. This conversion factor, 10^3, is to make the regression results easier to interpret, but simply corrects for the use of GWh in $Wind\ Generation\ GWh_t$ and MW in q_{otb}.

indicator variable for if a market participant owns wind turbines and conventional assets, denoted by whether they are "Integrated" or "Independent." This shows that integrated market participants reduce the quantity offered by 8.4 MW on average, while the independent market participants only reduce the quantity offered by 0.5 MW, differing by a factor greater than ten. This supports the testable prediction (i): integrated market participants reduce their quantity offered much more than independent ones on average.

Columns (3) and (4) go one step further by assessing how market participants respond to electricity generated by wind turbines they own, or do not own, for both integrated and independent market participants. Column (3) shows integrated market participants withhold an average of 131 MW of generation for every 1 GWh of electricity generated by their own wind turbines. In contrast, these same market participants only withhold 4.6 MW of generation for every 1 GWh of electricity generated by wind turbines they don't own. Column (4) shows independent market participants, which do not own wind turbines, withhold only 0.4 MW of wind in capacity in response to 1 GWh of wind generated by other market participants, a quantity that is effectively *de minimis*. Estimates within column (3) is strong support for testable prediction (iii), integrated market participants respond much more to their own wind generation than to the wind generation of other market participants.

The estimates presented in Table 3 are the average effects for all market participants, or at best separated by if a market participant owns wind turbines. Market participants vary in their portfolio of wind-based generation and their bidding sophistication. As a result, I expect there to be substantial heterogeneity in how they respond to increased renewable generation.

To uncover this heterogeneity, I interact $WindGWh_t$ in Equation 6 with the owner code of every market participant to get a unit specific estimate of δ_o. In particular, I estimate parameters in the following equation

$$q_{otb} = \delta_o Wind\ Generation\ GWh_t \cdot OwnerCode_o + X_t\beta + \eta_{oymhb} + \varepsilon_{otb} \tag{7}$$

with notation otherwise similar to Equation 6.

The top panel of Figure 6 presents the density of all owner-specific point estimates separated by whether or not the market participant owns wind turbines. This shows the coefficients for the market participants that do not own wind generation are near zero, whereas the density for integrated market participants has an obvious right skew and is centered above zero, further support for testable prediction (i). The point estimates of $\hat{\delta}_o$ for all 23 integrated market participants is presented in Table 8 of Appendix B.4.

The top panel of Figure 6, demonstrates that some market participants withhold much more of their conventional generation than others. To evaluate testable prediction (ii), I match each market participant's estimated withholding parameter, $\hat{\delta}_o$, with the average fraction of all wind generation produced by that specific market participant, a proxy for θ_o. Market participants with a larger value of θ_o have a larger incentive to withhold their output in response to more wind generation. If marginal costs are constant and market participants were profit maximizing in a supply function equilibrium framework, Equation 4 suggests δ_o exactly equals $-\theta_o$, representing the maximum each market participant would be willing to withhold. The bottom panel of Figure 6 shows the market participants with the largest-in-absolute-value withholding parameter estimate, $\hat{\delta}_o$, typically produce a larger proportion of all electricity generated in an hour, and so have a higher value of θ_o.[34]

The relationship presented in the bottom panel of Figure 6 shows a number of market participants withhold less than what is optimal in a supply function equilibrium with constant costs, on average. This is likely due to increasing marginal costs and effective deterrence by market monitors. To directly test if market participants are withholding their output in line with the incentives in a supply function equilibrium and marginal cost setting, I estimate τ_o in the following equation.

$$q_{otb} = \tau_o \theta_{ot} Wind\ Generation\ MWh_t \cdot OwnerCode_o + X_t \beta + \eta_{oymhb} + \varepsilon_{otb} \tag{8}$$

[34]Note they differ by a factor fo 10^3 because $\hat{\delta}_o$ is estimated using GWh of wind generation but MW of generation offered. As referenced in footnote 33, this choice of units is to make the regression results easier to interpret.

Here, $\theta_{ot} WindMWh_t$ represents the wind generation produced by market participant o in hour t. If market participants were not withholding any of their conventional production in response to their own wind generation, τ_o would be equal to zero. Conversely, if market participants were withholding output from conventional resources for every one unit increase in wind generation, τ_o would equal negative one.

Figure 7 presents the estimates of τ_o for all integrated market participants along with each market participant's wind turbine capacity. For nearly all market participants we can reject the null hypothesis they are withholding consistent with their incentives in a supply function equilibrium ($\tau_o = -1$). And we can reject the null hypothesis that market participants are not withholding at all ($\tau = 0$) for less than half of all market participants. Across all market participants, the average of $\hat{\tau}_o$ is -0.24.

3.2.2 Estimating Withholding Parameter for Consumer Surplus Calculation

To quantify how physical withholding attenuated the merit order effect, and consumer surplus from low-cost renewable generation, it is sufficient to credibly estimate $\sum_o \delta_o$ as described in section 2. One readily available candidate is the sum of all $\hat{\delta}_o$, estimated from Equation 7 for diverse market participants. Presented in Table 8 of Appendix B.4, this estimates of δ_o imply 211 MW of electricity withheld from conventional resources for every 1 GWh of electricity. Put another way, 21% of every GWh of electricity from wind generation is replacing a withheld unit.

Because some of the market participants own very little wind generation, some estimates of δ_o are not precisely estimated. To overcome this concern, I directly estimate the aggregate quantity of electricity production withheld across all integrate market participants for each additional unit of total wind generation with the following equation:

$$Q_{tb} = \Omega WindGWh_t + X_t \beta + \chi_{ymhb} + \varepsilon_{tb} \tag{9}$$

where $Q_{tb} = \sum_{o \in V} q_{otb}$ is the sum across integrated market participants, and notation is otherwise similar to Equation 7. The estimate $\hat{\Omega}$ represents the aggregate response across all integrated market participants to aggregate wind generation and can be interpreted as $\sum_{o \in V} \delta_o$. Column 1 of Table 4 shows every GWh of aggregate wind generation is associated with 205 MW of withheld production on average, or 20.5% of wind production is replacing withheld units.

3.3 Alternative Explanations of Main Evidence

So far, all the results support the idea that market participants withhold their output from their traditional units when their own wind turbines are generating electricity. Alternative explanations are possible however, especially given the complexity of wholesale electricity markets and the limited nature of the real-time offer data. In this section I show the main estimates used for consumer surplus calculations are robust, to the extent possible, these alternative explanations.

Endogenous Sample. Publicly available data from MISO report only the offer curves of units for hours they clear the market. Implicitly in my analysis, I assume units that do not clear the market submit an offer of zero MW for all economically relevant price bins. This assumption is well grounded if units intentionally change their strategy so they do not clear when there is more wind generation.[35] If, however, a unit does not clear for other economic reasons that are correlated with wind generation and not related to issues of market power, my estimates would be biased. In particular, I would incorrectly ascribe units not cleared for economic reasons as acting strategically when in fact they were simply responding to correlated economic conditions in the market.

As a first pass, I test how much of this is an issue by directly quantifying how more wind generation differentially affects the probability units owned by integrated or independent market

[35]For example, a unit can intentionally change their status to unavailable or not participating so they do not need to submit an offer to the market operator. Even if they do submit an offer to the market operator, there are a number of ways they can change their strategy so they do not clear. In speaking with the market monitor, this can be accomplished by increasing the required start cost, incremental cost, energy cost, required start time, required notification time, minimum down time, or reducing their maximum daily starts, or dispatch maximum. Unfortunately, I can not directly test for this because as I do not observe the offers of units that do not clear.

participants clear by estimating a linear probability model of the general form:

$$On_{it} = \left(\alpha^{I} Integrated_i + \alpha^{N} Independent_i\right) \cdot WindGWh_t + X\beta + \omega_{ymh} + \varepsilon_{it} \tag{10}$$

Here, On_{it} is an indicator variable equal to one if unit i cleared the market in hour t, $Integrated_i$ equals one if unit hour belongs to a market participant that also owns wind turbines, and $Independent_i$ is one minus $Integrated_i$. The matrix X includes a number of controls depending on the specification, including total net generation, net exports, Henry-Hub gas prices, maximum daily temperature, and unit-type fixed effects or unit fixed effects.

If more wind generation forces integrated market participants to clear less often in general, and relative to units owned by independent market participants. In the context of Equation 10, this implies $\alpha^{I} < 0$ and $\alpha^{I} < \alpha^{N}$. Table 5 presents the main estimates of Equation 10 in column (1), showing more wind generation does not cause integrated units to clear less often in general, or relative to independent units, on average. Because different unit types are better suited to respond to market conditions, column (2) controls for how unit-types differentially respond to wind generation. Column (3) takes this one step further and controls for each unit's base-line probability of being on during the entire sample. Neither columns show that integrated are less likely to clear the market when there is more wind generation on average.

Columns (4)-(6) of Table 5 separately evaluates the sample of units that are most likely to respond economic conditions: combustion turbines, combined cycle turbines, and steam turbines. Of these three, both combustion and combined cycle units do, in fact, clear less often when there is more wind generation in general, and units owned by integrated market participants are less likely to clear than units owned by independent market participants. This could be consistent with integrated market participants strategically changing their offer so their units do not clear when there is more wind generation, or their units not clearing because wind generation changes the economics of them operating in a given hour.

To assess whether the main estimate in Table 4 is robust to endogenous sample selection concerns, I evaluate the aggregate offer curve of a subset of units that clear the market most often. In particular, I identify the set of units that clear in at least 80% of the sample hours. This is a total of 142 units owned by integrated market participants (30% of all units owned by integrated market participants) of which 72 are steam-based units, 32 are combustion-based units, 24 are hydro-based units, and two are combined cycle turbines.[36]

These select units clear in most economic conditions, and so, are resilient to changing market conditions in general. In particular, because these units clear the market most of the time, they can largely ignore the costs of ramping up (or down) their production in response to changing economic conditions. This is important, ramping costs are a non-trivial determinant of which units produce electricity in wholesale electricity markets (Reguant, 2014; Cullen and Shcherbakov, 2011). Further, the units that are less likely to clear because of wind generation (combustion and combined cycle) are under-represented in this sample. Table 4, column (2), shows the aggregate withholding parameter across these select units is slightly attenuated, as expected, however quantitatively similar to the estimate in column (1). This suggests the estimated withholding parameter is not overtly influenced by units simply not clearing for economic reasons correlated with wind generation.

Correlated Market Conditions. Other market conditions might be correlated with wind generation and also determine the optimal quantity offered to the market by market participants. Of primary concern is transmission congestion constraints that makes conventional electricity generators less economic when there is more wind generation. In an ideal setting, I would be able to directly identify if congestion constraints contribute to some units not clearing when there is more wind generation. This would require decoding masked unit codes to identify the location and identity of market participants.[37] Instead, I subset the sample and estimate aggregate withholding for the hours when transmission congestion is less likely to be a concern. Column (3) selects only the hours when the maximum losses and congestion component of all nodal LMPs in MISO is in

[36]This includes units from 22 of the 23 integrated market participants. Table Table 1 shows, this represents %40, %16, %57, and %6.5 of integrated steam-based, combustion-based, hydro-based, and combined cycle turbines respectively.

[37]I've tried doing this with public data on nodal and unit LMPs, however only sixty percent of the units can be matched confidently.

the smallest decile across all hours. Column (4) selects only the hours when there is one of fewer binding constraints in all of MISO.[38] During the hours of these sub-samples, MISO is operating the most like a singular market with a uniform price. Both columns (3) and (4) show similar estimates to column (1), suggesting the aggregate withholding parameter is not driven by units not clearing because of transmission congestion.

In parallel to a real-time market for energy, MISO also manages a real-time market or ancillary services that ensure that demand is equal to supply at every moment.[39] Electricity generators can sell into both of these markets. If wind generation increases the value of ancillary service, and decreases the value of energy by suppressing the market price, a rational market participant would reduce the quantity offered in the energy market and increase the quantity offered in the ancillary services market. To assess if this concern, I directly control for the MW of regulation, spinning, and supplemental reserves services cleared in MISO's ancillary services market. Because this data is only available since 2015, the number of observations is diminished. Column (5) of Table 4 presents the results, showing the aggregate withholding parameter is slightly larger in absolute value, but quantitatively similar to column (1).

Alternative Price Bins. Finally, my use of with-in price variation of the quantity offered by market participants is a novel method for identifying physical withholding in electricity markets. To ensure I am only looking at each market participant's economically relevant strategy, I discard all price bins above the market clearing price in practice. This has an unintended consequence however - higher price bins will appear in the sample less often. If the change in quantity offered due to more wind generation varies by price bin, this will bias my estimates away from the average effect of wind generation on withholding.[40]

[38] A binding constraint occurs when transmission line capacity limits the flow of electricity to other parts of the grid. Each constraint has a shadow price, representing the difference in energy cost on both sides of the constraint, and a flow limit, that characterizes how much electricity can not be transported because of the constraint. Together, the shadow price and flow of a constraint determines the congestion component of the LMP.

[39] There are three ancillary services products in MISO. Generally, they fill in the gaps between supply and demand to ensure the alternating current transmission system power line is operating at 60 Hertz. Regulation reserves exist to match supply and demand minute to minute, spinning reserves are electric power plants that operating and ready to provide electricity if needed within the hour, and supplemental reserves are plants that are not currently running, but are able to run if needed because of large deviations between supply and demand.

[40] See, generally, Miller, Shenhav, and Grosz (2019) for a discussion of how this "selection into identification" can bias

I take two steps to address this concern. First, I re-estimate Equation 9 using all price bins in my sample. As a result, the estimate for Ω is the average change in quantity offered across all price bins, even those that are not economically relevant. Column (6) of Table 4 shows slightly more withholding on average across all price bins, but not a significant difference from the estimate in column 1. Second, I reestimate Equation 9 using a constant set of price bins that capture over 70% of all hourly MECs, between 20 and 40 USD. Both columns (6) and (7) of Table 4 shows an estimate similar to column (1).

4 Implications for Consumer Surplus

In this section, I calculate the change in consumer surplus resulting from more low-marginal-cost renewable generation. I do so using the analytical merit order effect, based on the slope of supply and demand at the market equilibrium and a parameter that characterizes the strategic response of market participants to more wind generation. It is important to note, this calculation is for the consumers in the wholesale market, typically a distribution utility or electricity retailer. The change in surplus for ultimate electricity consumers is likely to be different, as utilities do not always pass-on wholesale savings (Hausman, 2018) and have complex rate structures. In which case, this is an upper-bound on the change in surplus for ultimate consumers, representing the maximum available possible benefits. This is not a total welfare calculation as I do not quantify the dead-weight loss associated with strategic withholding.

I model consumer surplus from electricity during hour t at market price p as

$$CS_t(p) = \int_p^{\infty} D_t(x)dx$$

where $D_t(x)$ is the demand for electricity at time t and price x. This implies the aggregate change

average treatment effects.

in consumer surplus due to the merit order effect during the entire sample period is

$$\Delta CS = -\sum_t D_t(p) \frac{dp}{dW}_t dW_t. \tag{11}$$

I calculate Equation 11 using either hourly demand in MISO, or net generation in MISO, to represent $D_t(p)$ and observed wind generation to represent dW_t. Of critical importance is the hourly analytical merit order effect, $\frac{dp}{dW}_t$. Like subsection 3.1, I consider two 49.5/57settings which bound the role of physical withholding by assuming how market participants behave. One in which there is no physical withholding, and one in which market participants withhold their output in-line with their incentives in a supply function equilibrium. These two calculations place bounds on the role of market power in determining the incidence of the benefits of more renewable generation. I consider one additional consumer surplus calculation that uses the aggregate withholding parameter, Ω, based on Equation 9 and presented in Table 4 column (1).[41]

Table 6 presents all estimates of the total change in consumer surplus, as well as market revenue over the sample period. I normalized these totals to a value per person per year assuming 50 million people live within MISO's footprint.[42] The potential consumer surplus from increased renewable generation in the cost of no physical withholding is seven to ten billion USD over three years, equivalent to 50 to 69 USD per person per year. This number is greatly diminished if integrated market participants withhold perfectly in-line with their incentives. in which case the total consumer surplus would be only 2 to 2.8 billion USD, or 14 to 19 USD per person per year. Using the estimated aggregate withholding coefficient, $\hat{\Omega}$, to calculate consumer surplus provides a benefit of 39 to 55 USD per person per year, suggesting that observed withholding by integrated market participants reduces consumer surplus by 10 to 14 USD per person per year.[43]

[41]Calculating consumer surplus with the aggregate withholding parameter and aggregate wind generation provides similar estimates to a method using withholding parameters and wind generation specific to each market participant.

[42]This population estimate is my best guess given that 61 million individuals live in the states of Arkansas, Illinois, Indiana, Iowa, Louisiana, Michigan, Minnesota, Mississippi, Missouri, North Dakota, Wisconsin according to the 2016 US Census Bureau estimates.

[43]Instead of normalizing the consumer surplus per person per year, it's possible to normalize it by the total MWh of wind generation. This presents ΔCS_{comp} between 57 and 79 \$/MWh per MWh wind, ΔCS_{obs} between 45 and 63 \$/MWh per MWh wind, ΔCS_{sfe} between 16 and 21 \$/MWh per MWh wind.

The potential consumer benefit is large relative to the existing subsidy payments for renewable generation. For example, during the sample period the United States government spent a total of 6.6 billion dollars on subsidizing wind production for the entire United States (Sherlock, 2014).[44] This result echoes studies of European electricity markets which show policies supporting wind generation provide consumer benefits in-net of the program's costs (Abrell, Kosch, and Rausch, 2019; Liski and Vehviläinen, 2020). Finally, it is important emphasize that this loss in consumer surplus is not dead-weight loss. Likely, there is some dead-weight loss from higher cost units replacing withheld units, however a majority of the loss in consumer surplus is a transfer from producers to consumers.[45] If the producers were to take the captured revenue and directly invest it into more renewable generation, the observed withholding estimates suggests this would add approximately 2 GW of wind turbine capacity, increasing capacity of wind turbines in MISO by more than 10%.[46]

To quantify the effect of strategic withholding on greenhouse gas or local air pollution, it is necessary to know the emission intensity of the units that are being withheld and the units that are replacing the withheld units. Data limitations preclude this analysis. In particular, the bidding data from MISO details the type of electricity generator (steam turbine, combustion turbine, or combined cycle plant), however does not provide the fuel type (coal, gas, or oil powered). I observe in the data that withheld units are typically combustion or combined cycle units, which are usually, but not always, natural gas plants. If the withheld units are powered by natural gas, and the units replacing them are oil or diesel powered peaking plants, there is an additional welfare loss of physical withholding in the form of increased air pollution. This is because oil and diesel power plants emit more carbon dioxide and local air pollutants per unit of energy. Conversely, if oil and diesel peaking plants are withheld and replaced by cleaner natural gas plants, then physical withholding has social benefits in the form of reduced air pollution.

[44] This estimate is for the federal production tax credit and doesn't include the federal investment tax credit or implicit subsidies from state policies like renewable portfolio standards or PURPA.

[45] Uncovering the identity of each unit would allow a calculation of dead-weight loss using information on fuel type and heat rate.

[46] A generous estimate for new wind turbine capacity is $1 billion per GW of capacity (US-DOE, 2017).

5 Discussion

The increase in renewable generation capacity within the United States has created immense value by providing low-marginal-cost electricity. However, the incidence of this value depends largely on how horizontally integrated market participants, owning wind turbines, compete in wholesale electricity markets. I first derive an analytical expression for how increased renewable generation should impact the price of electricity. I show the strategic response of conventional electricity generators to increased wind generation is an important factor to consider in price formation. In particular, a supply function equilibrium model with horizontally integrated generating units predicts that integrated market participants will reduce their generation offer in response to an increase of their own wind generation. Using detailed data on supply and demand from 2014 to 2016 in MISO's wholesale electricity market, I quantify the expected price reduction under a model of perfect competition and a supply function equilibrium model with withholding.

I directly test for evidence of physical withholding by integrated market participants using month-of-sample by hour, price, owner fixed effects. Indeed, it is the integrated market participants that reduce the quantity offered, and they do it more in response to their own wind generation. This has important implications for consumer surplus and overall economic efficiency if this withholding leads to less efficient units having merit in the dispatch order. The analytical merit order effect I calculate and withholding coefficients I estimate imply increased renewable generation has the potential to increase consumer surplus by 50 to 69 USD per person per year, however observed withholding by integrated market participants reduces consumer surplus by 10 to 14 USD per person per year. This has implications for the market monitor in these wholesale electricity markets, as increased renewable generation might be associated with un-competitive behavior.

There are several policy implications that come from these results as well as avenues for future research. For one, the ownership of the renewable generation assets is not neutral to the incidence of consumer and producer surplus. Wind turbines and solar panels owned by integrated market participants in wholesale markets will not reduce the price of electricity by as much as the same assets owned by independent market participants or assets compensated by purchasing power agreements. If the policy goal is to use renewable generation to reduce the price paid by consumers, policy makers should pay attention to which type of resources they are subsidizing.

This incentive structure is interesting in a dynamic sense. The ability of horizontally integrated market participants to capture the benefits of low-marginal-cost generation through strategic withholding increases their incentive to invest in renewable generation. Because renewable generation reduces emission externalities associated with electricity generation, additional investment in this technology can be good from a social planner's perspective. As a result, the short run exercise of market power might be offset by the long run investment incentives in more renewable generation capacity. One possible way to increase renewable generation capacity is to allow integrated market participants to exercise market power when their own wind turbines are generating electricity.

This research shows that more renewable generation isn't always displacing the most expensive generating units because of profit motives. There might be technical reasons for this in addition to the economic incentives shown here. Better understanding why this might be the case can increase the value derived from renewable generation. Further, accessing proprietary data characterizing the emissions of the withheld units, as well as the units replacing the withheld units, can be used to comment on the emission implications of strategic behavior.

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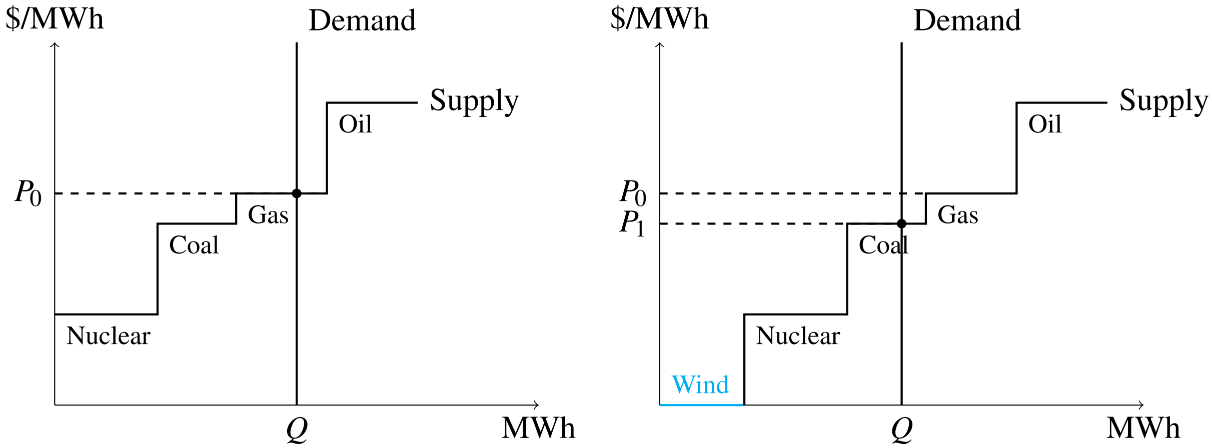
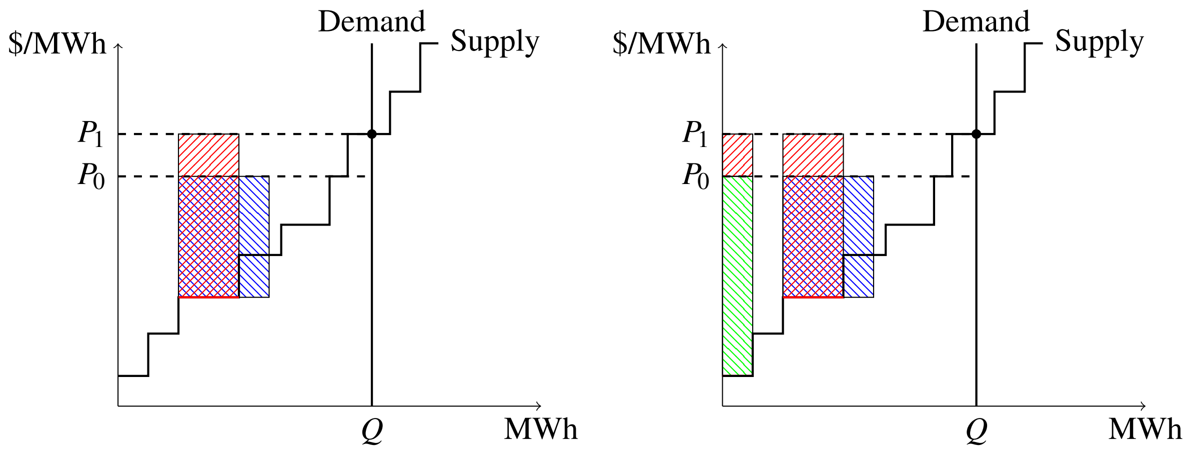
Tables and Figures

Figure 1: The Merit Order Effect of Renewable Generation.



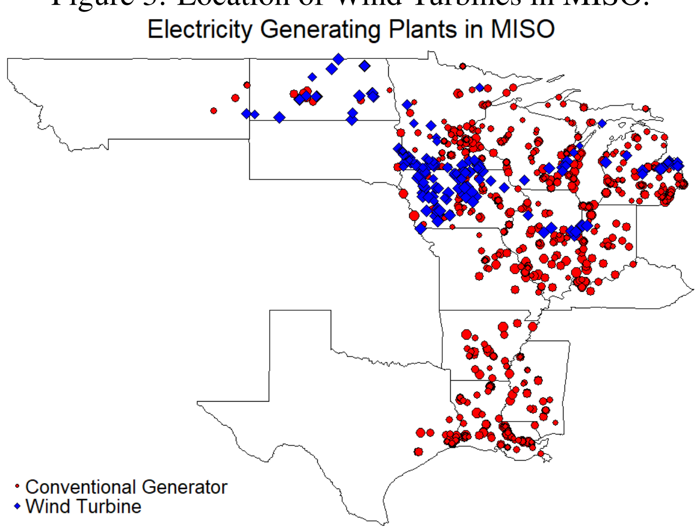
Electricity markets are conceived as a Merit Order; the lowest cost resources have merit and are the first to be dispatched. When wind turbines generate electricity, the highest cost units are displaced in the merit order and the equilibrium price decreases. This is visualized in the second panel, where additional wind generation decreases the equilibrium price of electricity decreases from P_0 to P_1. This simplified model does not consider how increased wind generation influences conventional electricity generators' incentives.

Figure 2: The Incentive for an Integrated Market Participant to Withhold Their Output in Response to Their Own Wind Generation.



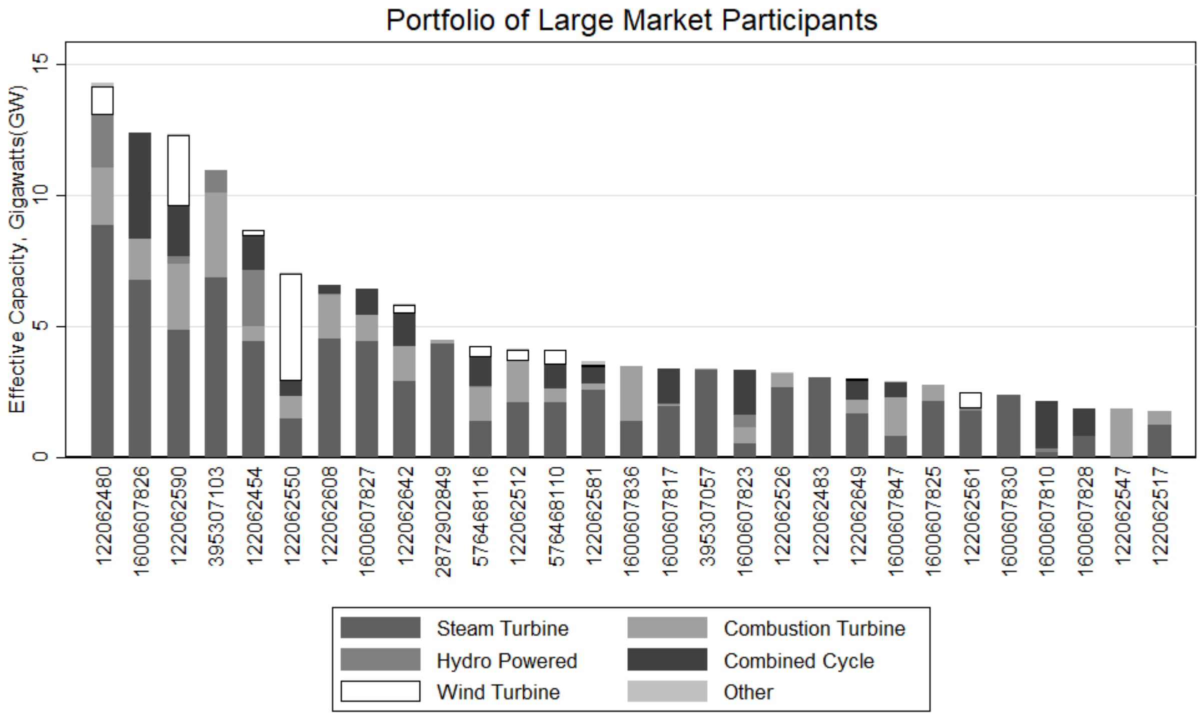
When a firm with market power considers the incentives to withhold their output they trade off a lower price and a larger quantity with a higher price and a smaller quantity. This trade off is represented in the first figure, for the firm that submits a bid corresponding to the red step, by the area of the only blue cross hatch and the only red cross hatch rectangles. When the market participant is integrated, owning wind turbines and conventional generators, they receive additional revenue from a higher price on their wind based assets. In the second panel, the green cross hatch represents the revenue from the wind turbine if the firm does not withhold and the additional red only cross hatch rectangle shows the revenue received from the wind based asset if they withhold their output.

Figure 3: Location of Wind Turbines in MISO.



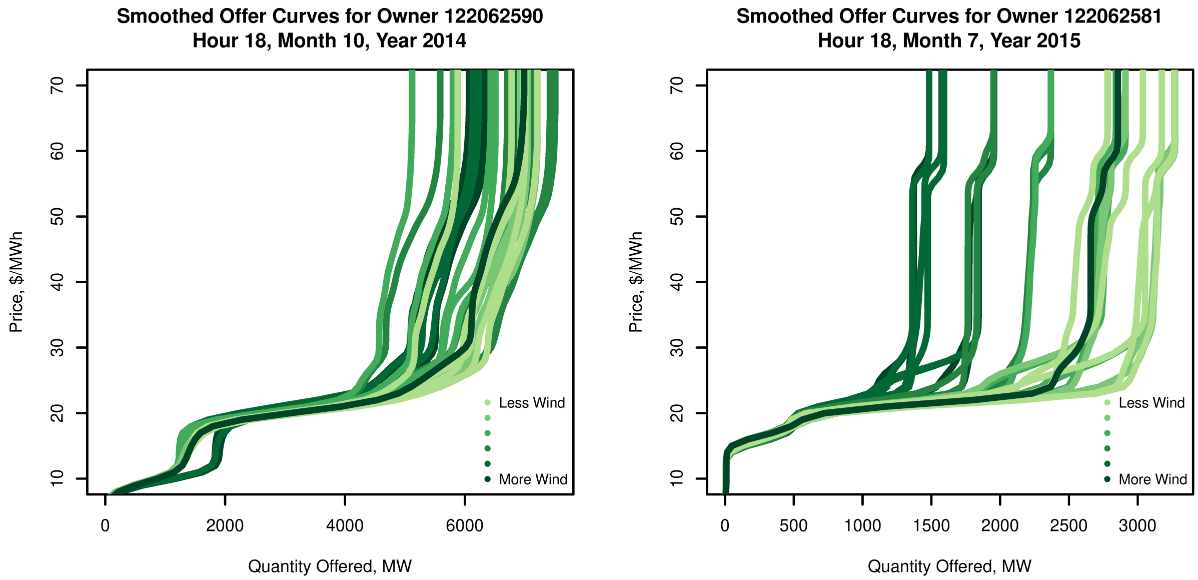
The locations of all electricity generating units in MISO according to the Energy Information Agency form 860 for the year 2016. Wind turbines are blue diamonds while conventional generators are red circles. The size of the point is proportional to the log of the generating unit's capacity.

Figure 4: Capacity and Portfolio of Market Participants in MISO.



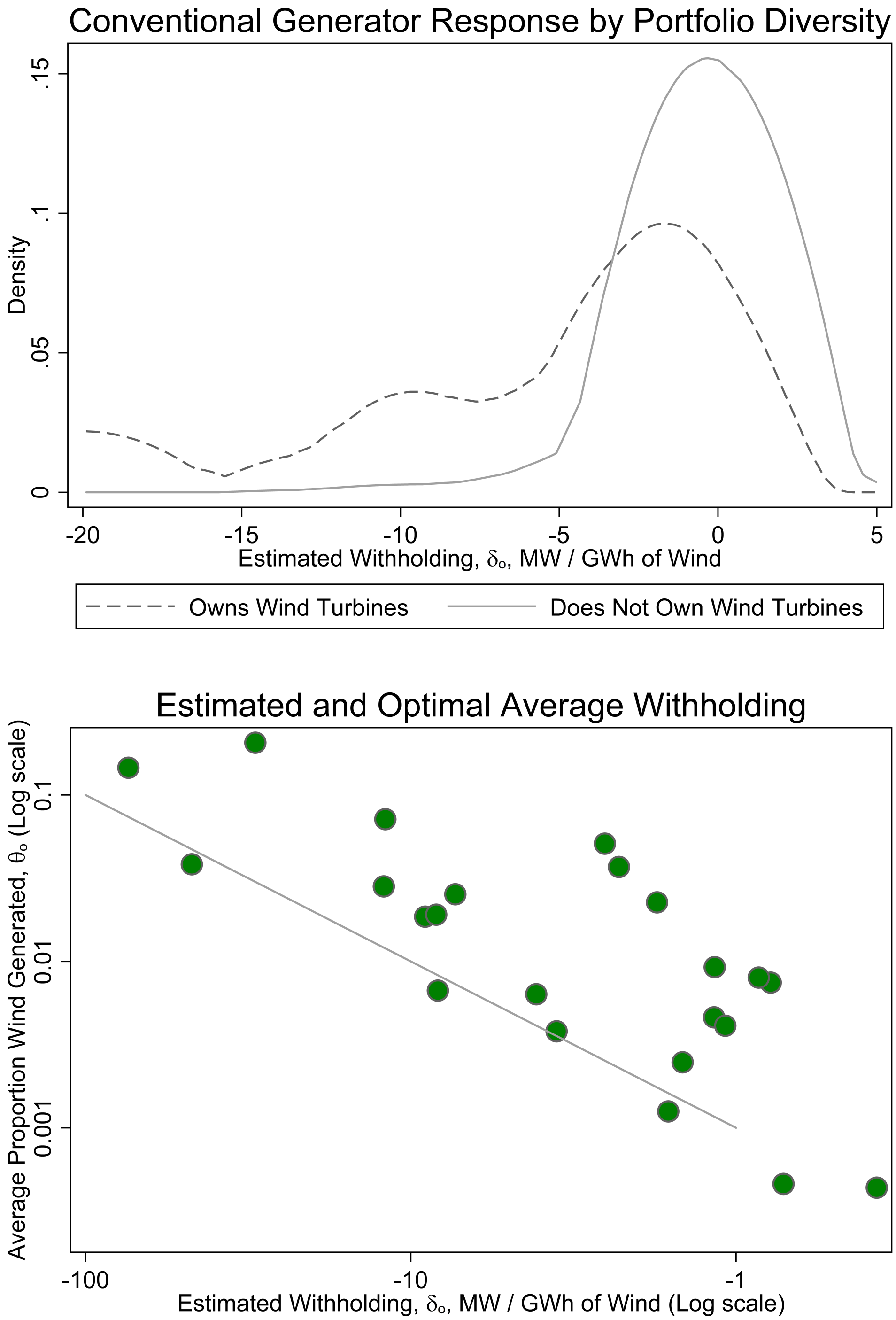
The capacity and portfolio of the thirty largest market participants in MISO. Capacity is measured as the maximum MWh produced by a unit during the entire sample period. The bar labels are the Market Participant's coded identification number. This shows large market participants own wind generation and conventional assets. There are approximately 220 smaller market participants that appear during the sample period.

Figure 5: Sample Offer Curves.



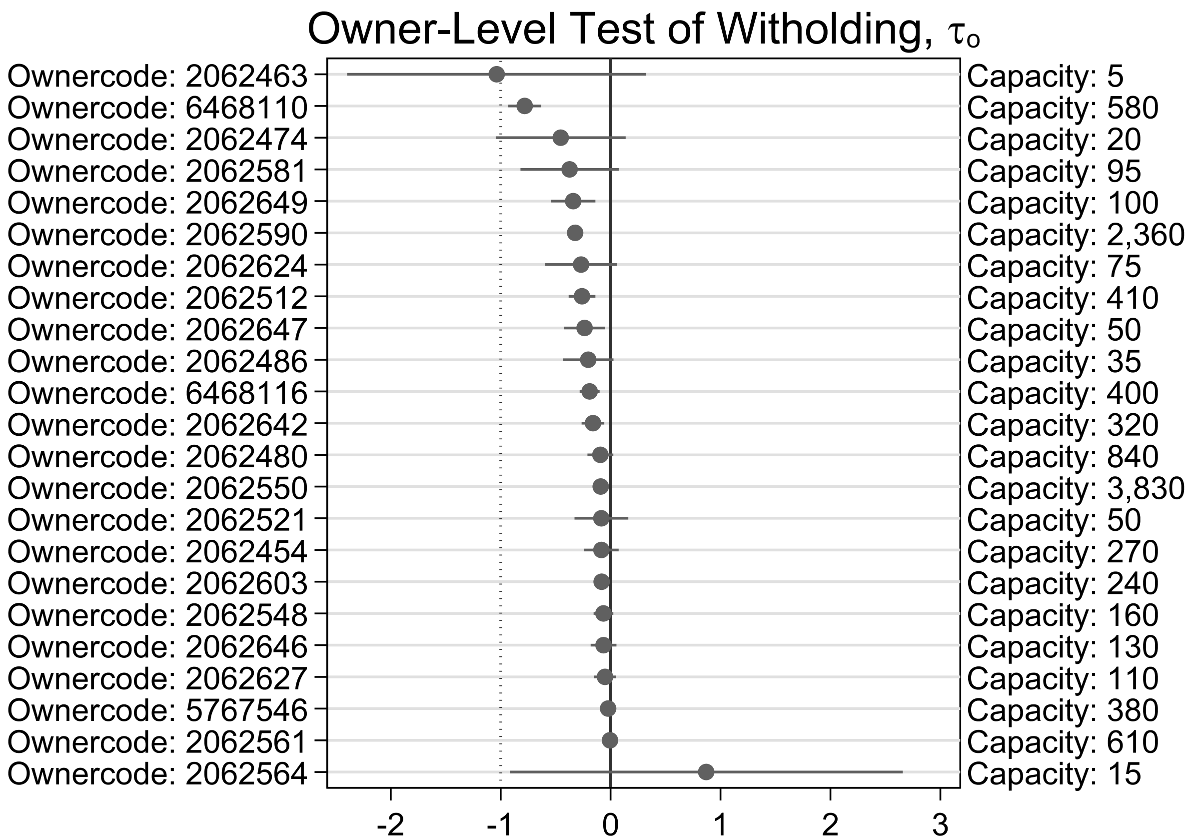
As an example, this plot shows all the offer curve of all cleared units for two separate market participants, in two different month-of-sample hours.

Figure 6: Heterogeneity of Withholding Coefficients.



Top panel is Kernel density of withholding coefficients, $\hat{\delta}_o$, for ever market participant separated by the market participant's portfolio diversity. Densities use a Epanechnikov Kernal with a bandwidth of two dollars. Values below -20 MW/GWh are truncated. Bottom Panel is owner specific withholding coefficient and owner total wind turbine capacity for integrated market participants. Withholding coefficients are estimates from Equation 7, average proportion wind generation is each market participants share of hourly wind generation on average. The line represents the relationship $\delta_0 = -\theta_o$, as suggested by Equation 4, in the case of constant marginal costs. Both axes in the bottom panel are $\log_{10}$.

Figure 7: Owner-Level Test for Withholding.



Estimates of τ_o from Equation 8, representing the proportion of wind generation by market participant o that is replacing withheld units by market participant o. Error bars represent the 95% confidence. Standard errors are clustered by owner and month of sample. Capacity, along the right hand axis represents the effective wind turbine capacity during the sample period.

Table 1: Unit Summary Statistics.

	Intergrated		Independent		All	
	Mean	Std. Dev.	Mean	Std. Dev.		
Effective Capacity, MW	118.93	(153.12)	172.36	(220.56)	146.47	(192.67)
Steam-Turbine	214.48	(214.81)	286.78	(269.46)	254.94	(249.21)
Combustion-Turbine	64.27	(53.20)	104.93	(147.97)	86.67	(117.13)
Hydro-Powered	111.36	(148.49)	62.92	(93.83)	87.43	(126.15)
Combined-Cycle	248.79	(185.39)	396.38	(194.88)	336.18	(203.37)
Wind-Turbine	80.46	(72.86)	66.74	(52.87)	76.27	(67.57)
Other	14.64	(20.04)	28.03	(65.91)	22.44	(52.18)
Effective Capacity Factor	0.24	(0.24)	0.22	(0.25)	0.23	(0.24)
Steam-Turbine	0.44	(0.23)	0.37	(0.27)	0.40	(0.26)
Combustion-Turbine	0.02	(0.05)	0.08	(0.15)	0.05	(0.12)
Hydro-Powered	0.32	(0.25)	0.32	(0.21)	0.32	(0.23)
Combined-Cycle	0.24	(0.25)	0.25	(0.20)	0.25	(0.22)
Wind-Turbine	0.31	(0.11)	0.31	(0.10)	0.31	(0.11)
Other	0.05	(0.15)	0.06	(0.18)	0.06	(0.17)
Proportion Hours Cleared	0.53	(0.39)	0.42	(0.38)	0.47	(0.39)
Steam-Turbine	0.65	(0.27)	0.52	(0.33)	0.58	(0.31)
Combustion-Turbine	0.24	(0.36)	0.22	(0.32)	0.23	(0.33)
Hydro-Powered	0.70	(0.35)	0.59	(0.33)	0.65	(0.34)
Combined-Cycle	0.34	(0.32)	0.39	(0.29)	0.37	(0.30)
Wind-Turbine	0.82	(0.25)	0.88	(0.24)	0.84	(0.25)
Other	0.28	(0.41)	0.28	(0.35)	0.28	(0.37)
Number of Units	643		684		1327	
Steam-Turbine	181		230		411	
Combustion-Turbine	198		243		441	
Hydro-Powered	42		41		83	
Combined-Cycle	31		45		76	
Wind-Turbine	148		65		213	
Other	43		60		103	

Notes: Unit characteristics from MISO's real-time cleared offers by unit type and integrated status. Effective Capacity is each electricity generation unit's maximum output during the sample period (Jan 1 2014 to Dec 24 2016). Effective Capacity Factor is the average generation (in MW) in proportion to the effective capacity. The unit's generation is zero for the hours it does not clear. Proportion Hours Cleared represents the number of sample hours the unit is observed in the offer data.

Table 2: The Merit Order Effect.

Panel A: Regression-Based Merit Order Effect.

	(1)	(2)	(3)	(4)
		Market MEC, USD/MWh		
Wind GWh	-0.788***			
	(0.134)			
Ind. Wind, GWh		-1.198	-2.946***	
		(0.801)	(0.519)	
Integrated Wind, GWh		-0.652*		-1.036***
		(0.248)		(0.174)
Year-Month-Hour Fixed Effects	Yes	Yes	Yes	Yes
Other Controls	Yes	Yes	Yes	Yes
Observations	26,117	26,117	26,117	26,117
R-squared	0.36	0.36	0.36	0.36

Panel B: Analytical Merit Order Effect.

	Mean	Std. Dev.	Minimum	Maximum
Analytical Merit Order Effect, USD/GWh				
No Withholding	-0.65	1.05	-57.10	-0.13
Full Withholding	-0.19	0.29	-15.64	-0.03
Total Price Effect, USD				
No Withholding	-3.73	8.87	-477.07	-0.04
Full Withholding	-1.02	2.36	-130.66	-0.02

Notes: Panel A shows the regression estimates from Equation 5, using hourly observations from Jan 1 2014 to Dec 24 2016. Other Controls include hourly net generation, daily Henry-Hub price and maximum temperature, and hourly net exports from MISO. Standard errors, in parenthesis, are clustered by month of sample. *, **, *** denote p-value less than 0.1, 0.05, and 0.01 respectively. Panel B presents the Analytical Merit Order Effects, using hourly data on the slope of supply and demand as explained in Appendix B.2. Full withholding assumes $\delta_o = -\theta_0$, where as no withholding assumes $\delta_o = 0$. Total Price Effect is the analytical merit order effect times the hourly wind generation.

Table 3: Withholding of Offer Curve in Response to Wind Generation.

	(1)	(2)	(3)	(4)
	Quantity Offered, MW			
Wind GWh	-1.536***			
	(0.145)			
Ind. × Wind GWh		-0.532***		
		(0.104)		
Integrated × Wind GWh		-8.390***		
		(0.813)		
Other's Wind, GWh			-4.603***	-0.449***
			(0.598)	(0.104)
Own Wind, GWh			-131.4***	0
			(13.74)	(.)
OPYMH Fixed Effects	Yes	Yes	Yes	Yes
Other Controls	Yes	Yes	Yes	Yes
Market Participants	All	All	Integrated	Independent
Observations	9,615,600	9,615,600	1,282,080	8,333,520
R-squared	0.97	0.97	0.97	0.97

Notes: Data comes from MISO real-time Offer Market Reports January 1, 2014 to December 24, 2016. This sample is all offers by market participants during peak hours, defined as 3pm to 8pm inclusive. All specifications include fixed effects for the average quantity offered by the market participant at the price for a given month-hour, denoted by OPYMH. Other controls include hourly net exports, daily temperature, daily natural gas price. Standard errors, in parenthesis, are clustered by month of sample and owner. *, **, *** denote p-value less than 0.1, 0.05, and 0.01 respectively.

Table 4: Aggregate Withholding and Robustness of Results.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Aggregate Quantity Offered by Integrated Market Participants, MW						
Wind Gen., GWh	-204.8***	-168.6***	-213.6***	-222.6***	-239.2***	-302.2***	-318.3***
	(17.13)	(14.03)	(22.01)	(23.93)	(17.09)	(19.08)	(21.48)
Price-Year-Month-Hour Fixed Effects	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Other Controls	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Units in Sample	All	Clear Often	All	All	All	All	All
Hours in Sample	All	All	Small Congestion	<=1 Constraint	All	All	All
Ancillary Controls	No	No	No	No	Yes	No	No
Price Bins	<MEC	<MEC	<MEC	<MEC	<MEC	All	Constant
Observations	53,420	53,420	3,016	1,857	28,460	160,020	53,340
R-squared	0.98	0.98	0.98	0.99	0.98	0.97	0.93

Notes: Estimates from Equation 9. Units that "Clear Often" are observed in the real-time Offer Market Reports over 80% of the sample hours. "Small Congestion" hours occur when maximum congestion and losses component of all LMPs in MISO is less than the tenth percentile of all hours. "<=1 Constriant" hours occur when there is one or few binding constraints across all of MISO on average in that hour. "Ancillary Controls" include the total MW of spinning, regulation and supplemental reserves that cleared in the ancillary services market for that hour. Standard errors, in parenthesis, are clustered by month of sample. *, **, *** denote p-value less than 0.1, 0.05, and 0.01 respectively.

Table 5: Linear Probability Unit Clears.

	(1)	(2)	(3)	(4)	(5)	(6)
	Probability Unit Clears (Percentage Points)					
Independent × Wind GWh	-0.73*	-0.11	0.46***	-0.06	-0.26*	-0.08
	(0.29)	(0.41)	(0.13)	(0.07)	(0.10)	(0.10)
Integrated × Wind GWh	0.39	1.01*	0.16	-0.32***	-2.62**	-0.29
	(0.31)	(0.46)	(0.12)	(0.08)	(0.79)	(0.15)
Year-Month-Hour Fixed Effects	Yes	Yes	Yes	Yes	Yes	Yes
Other Controls	Yes	Yes	Yes	Yes	Yes	Yes
Unit-type Fixed Effects	Yes	Yes	No	No	No	No
Unit-type × Wind	No	Yes	Yes	No	No	No
Unit Fixed Effects	No	No	Yes	Yes	Yes	Yes
Units in Sample	All	All	All	Combustion	Comb. Cycle	Steam
Observations	28,545,881	28,545,881	28,545,881	11,517,597	1,540,903	10,734,087
R-squared	0.18	0.18	0.58	0.65	0.34	0.42

Notes: Estimates from Equation 10. A unit is said to clear the market when their offer curve is observed in the real-time Offer Market Reports. Other controls include daily Henry-Hub natural gas price, maximum temperature in MISO's footprint, net exports and net generation in MISO. Unit-types are characterized in Table 1. Price bins "< MEC" include only the price bins that are less than the marginal energy component of the LMP plus three dollars. "All" price bins include every price bin from ten dollars to seventy dollars, inclusive, and "Constant" price bins include the same price bins for all hours, between 20 and 40 dollars. Standard errors are clustered by month-of-sample and owner code. *, **, *** denote p-value less than 0.1, 0.05, and 0.01 respectively.

Table 6: Calculation of Consumer Surplus.

	Net Demand		MISO Demand	
	Total Bil. USD	Annual USD/Person	Total Bil. USD	Annual USD/Person
Revenue	58.70	393.93	55.33	371.34
ΔCS_{comp}, no curtail	7.38	49.51	10.22	68.62
ΔCS_{obs}, observed	5.87	39.37	8.13	54.57
ΔCS_{sfe}, full curtail	2.03	13.61	2.78	18.66
$\Delta CS_{comp} - \Delta CS_{obs}$	1.51	10.14	2.09	14.05
$\Delta CS_{comp} - \Delta CS_{sfe}$	5.35	35.90	7.44	49.96

Notes: Time period of interest is from January 1st, 2014 to December 24th, 2016. $comp$, obs, and sfe represent the consumer surplus under no, observed, and full withholding as described in section 4. Revenue is the sum of Market MEC times the market generation quantity in MWh for all hours. "Net Demand" uses the analytical merit order effect and production quantity at the equilibrium where supply net of wind equals demand less net exports. "MISO Demand" uses the equilibrium where supply net of wind equals total demand within MISO. Bil. stands for billion. Annual per person calculations divides the total quantity by 2.98 years and 50 million people. This number is the authors best guess for the population within MISO's footprint based on the cumulative population of 61 million in the states of Arkansas, Illinois, Indiana, Iowa, Louisiana, Michigan, Minnesota, Mississippi, Missouri, North Dakota, Wisconsin according to the 2016 US Census Bureau estimates. All numbers are in nominal US dollars.

Appendices for Online Publication

A Derivations

A.1 Firm's Best Response

Given the notation presented in 2, market participant o's profit at time t is characterized by

$$\Pi_o(S_o(p,W)) = p[S_o(p,W_t) + \theta_o W] - C_o(S_o(p,W_t)) \tag{12}$$

Where p is the market price, $\theta_o \in [0,1]$ is the fraction of total wind generation produced by market participant o, W is the perfectly forecast-able quantity of electricity generated by wind turbines, and $C_o(S_o(p,W))$ is the cost of producing $S_o(p,W)$.[47] All market participants have perfect information on the cost of production of all other market participants.

Demand is composed of a forecast-able quantity and a random forecast error, $D(p) = d(p) + \varepsilon$, where ε is an $i.i.d.$ random variable with expectation equal to zero.[48] Taking the strategies of the other market participants as given, all uncertainty in the market participant's payoff is from the demand forecast error, ε. Market participants choose a supply function mapping the ex-post market price to the quantity they want to produce. The Nash-equilibrium is defined by all market participants choosing the supply function that maximizes their expected profits, taking the other (profit-maximizing) supply functions as given. Because the equilibrium in this model is defined by a system of differential equations with considerable asymmetry, I only consider the firm's best response.

To characterize the equilibrium, I show that every realization of ε is associated with one price-quantity pair which outlines the optimal supply function for that firm, following Klemperer and Meyer (1989). If we first assume the profit maximizing price-quantity pairs *can be* characterized by a supply function $q_o = S_o(p,W)$, the profit maximizing price associated with a realization of ε will tell us the optimal quantity profit maximizing. Also noting that the quantity produced by

[47] Cost are strictly increase and weakly convex in $S_o(p,W)$

[48] Demand is strictly decreasing in price.

market participant is defined by the residual demand $RD(p,\varepsilon) = d(p) + \varepsilon - \sum_{j\neq o} S_j(p,W_t) - W$, we can write the market participants profit function as

$$p[RD(p,\varepsilon) + \theta_o W] - C_o(RD(p,\varepsilon)) \tag{13}$$

with the first order condition with respect to price provides

$$p - C'(RD(p,\varepsilon)) = -\frac{RD(p,\varepsilon) + \theta_o W}{RD'(p,\varepsilon)} \tag{14}$$

where $RD'(p,\varepsilon)$ is the slope of the residual demand with respect to price ($d'(p) - \sum_{j\neq o} \xi_j'(p)$).

This implicitly defines the optimal price as a function of the demand shock ε, $p_o^*(\varepsilon)$, taking forecast-able demand, the strategy of other players, and the forecast-able wind generation as given. The corresponding profit maximizing quantity is $RD(p_o^*(\varepsilon),\varepsilon) \equiv q_o^*(\varepsilon)$, providing a locus of parametrized profit maximizing price-quantity pairs: $p_o^*(\varepsilon), q_o^*(\varepsilon)$. As long as there is a one to one mapping between ε and p_o^*, we have that $p_o^*(\varepsilon)$ is invertible and the optimal supply function conditional on W is $S_o(p,W) = q_o((p_o^*)^{-1}(p))$.

Finally, substituting $S_o(p,W)$ for $RD(p_o^*(\varepsilon),\varepsilon) \equiv q_o^*(\varepsilon)$ and $d'(p) - \sum_{j\neq o} \xi_j'(p)$ for $RD'(p,\varepsilon)$ in Equation 14 we have

$$p - C'(S_o(p,W_t)) = -\frac{S_o(p,W) + \theta_o W}{d'(p) - \sum_{j\neq o} \xi_j'(p)} \tag{15}$$

A.2 Comparative Static with Respect to More Wind Generation

To determine how the best response function changes when there is more wind generation, I rearrange the first order condition so that all terms are are one side of the equality and substitute in $\xi_o(p) + \delta_o W$ for $S_o(p,W)$

$$\xi_o(p) + \delta_o W + \theta_o W + \left[p - C_o'(\xi_o(p) + \delta_o W)\right] RD_o'(p) = 0 \tag{16}$$

Taking the derivative with respect W provides,

$$\delta_o + \theta_o - C_o''(\xi_o(p) + \delta_o W) R D_o'(p) \delta_o = 0 \tag{17}$$

which can be rearranged as

$$\delta_o = -\frac{\theta_o}{1 - C_o''(\xi_o(p) + \delta_o W) R D_o'(p)} \tag{18}$$

B Supplemental Discussion & Tables

B.1 Relation to Economic Pass-through

This is related to, but different from, the conventional pass-through rate of a cost shock or tax. To show this, consider the market equilibrium with a unit tax, $d(p) = \sum S_o(p-t)$, under perfect competition. Implicitly differentiating the market equilibrium with respect to t uncovers the well-known pass-through formula $\frac{dp}{dt} = \frac{\sum S_o'}{\sum S_o' - d'} = \frac{1}{1+\frac{\varepsilon_D}{\varepsilon_S}}$ where ε_D and ε_S denote the own-price and market supply elasticities respectively. The denominators of Equation 2 and the unsimplified traditional pass-through equation are identical, representing a marginal deviation from the market equilibrium. The numerator is different because the shock impacts supply differently. An increase in wind generation impacts the total quantity supplied, while the tax impacts the cost of production.[49]

B.2 Recovering Supply Curves and Market Equilibrium

I recover the market equilibrium in MISO using the detailed publicly available data on cleared supply offers and demand bids. First, I interpolating the ten price-quantity pairs for each electricity generating unit on a common support (e.g. from -10 dollars to 100 dollars at an interval of 1 dollar). When appropriate, I extrapolate or truncate the quantity offered using the maximum and minimum

[49] This is related to the concept exogenous quantity pass-through described by Weyl and Fabinger (2013). It differs in that wind generation is an increase in the aggregate market quantity, while Weyl and Fabinger (2013) model the exogenous quantity as a firm specific quantity, identical across firms.

quantity available. To ensure the function is everywhere differentiable and monotonic I smooth the offer curve using a normal kernel following Wolak (2001). For a set of price and quantity pairs, (p_{ikt}, q_{ikt}), $i = 1 \ldots N$, for unit k at time t, the smoothed supply function is

$$\hat{s}_{kt}(p) = \sum_i q_{ikt} \Phi\left(\frac{p - p_{ikt}}{h}\right)$$

where Φ is the standard normal cumulative distribution function and h is smoothing parameter.[50] I aggregate these unit level supply functions by market participant. Because I only observe the supply functions of cleared units, this implicitly assume the bid from the not cleared units was zero at all prices.

I repeat this process for demand bids from load serving entities and electricity retailers. Overwhelmingly, the demand bids are inelastic with respect to price.

To find the slopes at equilibrium, I aggregate all of the generating unit supply curves within MISO to obtain a market supply curve.[51] To find the market equilibrium, I find the price where supply is equal to demand as shown in Figure 8.[52] At this equilibrium I calculate the local slope of supply and demand as the difference in the quantity, along the curve, for a one step increase in price. The equilibrium prices and slopes are summarized in Panel B of Table 7. This price should correspond to the Marginal Energy Component of the LMP.

B.3 Discussion of Theoretical Assumptions

Bids are additively separable in Wind Generation

The simple expression in Equation 4 and testable predictions are based on the linear and sep-

[50] I use a bandwidth of three dollars, as does Kim (2017). It is important to note that changing the bandwidth will impact the consumer surplus calculation, but not the estimation results. Changing the bandwidth does not alter the consumer surplus calculations significantly.

[51] Here I define the entire MISO region as a single market. I've considered other market definitions including subregions within MISO and price clusters similar to Mercadal (2015).

[52] Because I am interested in the impact of wind on the price of electricity, I define the equilibrium without using the supply bids by the wind generating units. As a default, I use generation within the market instead of market demand, as this is a measure of demand net of imports. Alternatively, I use the demand bids and find little difference in the equilibrium slopes.

arable assumption, that market participant's supply function slope does not change in response to the wind forecast. If this assumption does not hold, Equation 4 would be equivalent to a second-order partial differential equation which is difficult to solve and has many solutions. In particular, substituting in $S_o(p,W)$ in for $\xi_o(p)+\delta_o W$ and re-deriving the steps in Appendix A.2 would make Equation 4 instead equal to

$$\frac{\partial S_o(p,W)}{\partial W} = -\frac{\theta_o}{1-C_o''(S_o(p,W))} + \frac{p-C_o'(S_o(p,W))}{1-C_o''(S_o(p,W))}\frac{\partial^2 S_o(p,W)}{\partial p \partial W}$$

In general, the intuition from Equation 4 is similar with or without this assumption, especially if price-cost markups are sufficiently small. If markups are not small, all market participants will choose to withhold their output in response to more renewable generation in contradiction to testable prediction (i). However, integrated market participants have a greater and additional incentive to withhold their output. Further, integrated market participants will withhold their output in response to all wind generation contradicting testable prediction *(iii)*. Again, however, integrated market participants have a greater incentive to withhold their output more in response to their own wind generation than the wind generation of others. In the empirical setting below, I find it is mainly the integrated market participants that withhold their output, almost exclusively, and they withhold their output much more in response to their own wind generation, consistent with testable predictions above.

Absence of Forward Markets

Before presenting the testable predictions, it is important to discuss how Equation 3 and Equation 4 would differ if there were a forward market. The optimal strategy by each market participant would be a supply function net of the quantity sold in the forward market.[53] However, the change in the optimal strategy in response to more wind generation would be identical. Further,

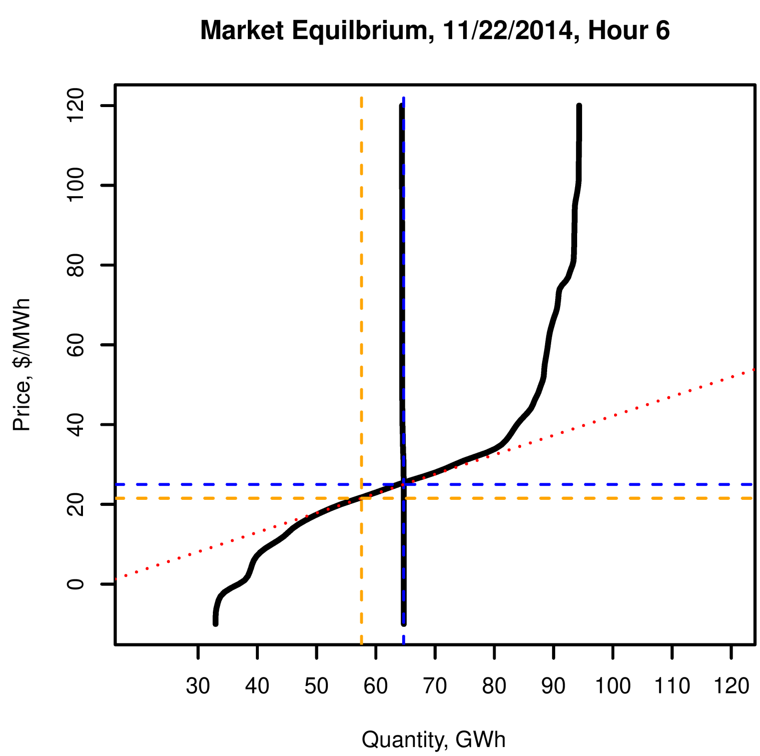
[53] If firm o has the forward quantity contract Q^f, the first order condition would become

$$p - C_o'(S_o^*(p,W)) = -\frac{S_o^*(p,W)+\theta_o W - Q^f}{RD_o'(p)}$$

the incentives to reduce the quantity offered in response to more wind generation would extend to the day-ahead market. This is exactly the case in the Cournot-Nash equilibrium presented by Acemoglu, Kakhbod, and Ozdaglar (2017). More wind generation will reduce forward precommitments because it reduces the real-time price. However, more integrated ownership increases forward precommitments because that increases the real-time price. Together, the incentives to response strategically that exist in the real time market are identical to the incentives in the forward market.

B.4 Additional Tables and Figures

Figure 8: Reconstructed Equilibrium.



The reconstructed market supply and demand curves, in black, for a sample hour form the equilibrium price. The equilibrium is denoted by the dashed blue lines. The calculated merit order effect for a one unit increase is shown by the dashed red line. Walking down the merit order effect from the equilibrium shows the expected price reduction with the yellow dashed lines.

Table 7: Market Level Summary Statistics.

	Mean	Std. Dev.	Minimum	Median	Maximum	Observations
Panel A						
Market LMP, USD/MWh	27	20.8	-26.8	23.7	1,571	26,117
Market MEC, USD/MWh	29.9	22.7	-28.7	25.8	1,806	26,117
Market GWh Generated	71.4	12.6	42.1	70.4	116	26,117
Coal GWh	36.8	8.46	16.5	36.6	56.8	26,117
Gas GWh	15.9	6.21	4.57	15.3	43.4	26,117
Hydro GWh	.988	.5	.305	.843	3.29	26,117
Nuclear GWh	11.4	1.23	6.1	11.7	13.3	26,117
Other GWh	1.35	.852	.295	1.07	7.74	26,117
Wind GWh	4.96	2.79	.132	4.61	13.7	26,117
Wind GWh, Diverse	3.58	2.1	.0551	3.29	10.2	26,117
Wind GWh, Independent	1.37	.722	.0693	1.3	3.61	26,117
Shadow Price of Constraints	-.947	1.28	-17.3	-.506	0	26,117
Number of Binding Constraints	3.79	2.65	0	3.17	19.2	26,117
Max Daily Temperature, C	17.6	10.4	-11.7	19.5	33.4	26,117
Natural Gas Price, USD/MMBtu	3.13	1.01	1.49	2.84	7.88	26,117
Net Exports GWh	4.41	1.99	-1.77	4.27	11.6	26,117
Wind Forecast Error, GWh	-.00594	.965	-4.13	.00101	4.32	26,093
Panel B						
Equilibrium Price, USD/MWh	28.8	8.47	17	26	118	26,117
Supply Slope, $\Delta MWh/\Delta\frac{USD}{MWh}$	2,627	1,512	17.5	2,307	7,432	26,117
Demand Slope, $\Delta MWh/\Delta\frac{USD}{MWh}$	-4.98	7.49	-67.7	-1.25	0	26,117

Notes: Market-Hour observations from January 1, 2014 to December, 24, 2016. Market LMP, from the Nodal LMP Market Report, is taken as the average of all LMPs with an hour. The MEC is found by subtracting the Loss and Congestion Component from the LMP for each hour. Generation quantity in GWh comes from the Fuel Mix Market Report. The decomposition of Wind into Integrated and Independent Owners comes from the Cleared Offers Market Report. Integrated is defined as wind generation that is owned by a market participant that owns assets other than wind turbines. Independent wind comes from market participants that own only wind based resources. Shadow Price, in thousand USD, and Number of Binding Constraints comes from MISO's Real Time Binding Constraint Market Report. Temperature data is an average of all temperature readings within MISO's footprint from the Global Historical Climatology Network operated by NOAA. Wind Forecast Error and day ahead Henry Hub natural gas price and comes from Yes Energy. The wind data is missing one day of data from June of 2015. Equilibrium Price, Supply Slope, and Demand Slope are recovered from the offer supply and demand curves. The equilibrium is where the offered supply net of wind equals the demand less of net imports.

Table 8: Owner-Specific Withholding of Integrated Market Participants.

	(1)		(2)	
	Quantity Offered, MW			
Owner Code=122062454 × Wind GWh	-8.076**	(2.537)	-9.031**	(2.915)
Owner Code=122062463 × Wind GWh	-0.567	(0.595)	-0.714	(0.727)
Owner Code=122062474 × Wind GWh	-1.357	(0.695)	-1.615	(0.852)
Owner Code=122062480 × Wind GWh	-10.43	(7.028)	-11.97	(7.592)
Owner Code=122062486 × Wind GWh	-1.138	(0.679)	-1.459	(0.803)
Owner Code=122062512 × Wind GWh	-9.080***	(2.629)	-12.10***	(3.081)
Owner Code=122062521 × Wind GWh	-0.881	(0.639)	-1.168	(0.737)
Owner Code=122062548 × Wind GWh	-0.960	(0.766)	-1.163	(0.903)
Owner Code=122062550 × Wind GWh	-27.79***	(2.842)	-30.04***	(3.198)
Owner Code=122062561 × Wind GWh	-2.045	(1.623)	-2.530	(1.511)
Owner Code=122062564 × Wind GWh	-0.134	(0.597)	-0.369	(0.680)
Owner Code=122062581 × Wind GWh	-4.054	(3.012)	-4.112	(2.939)
Owner Code=122062590 × Wind GWh	-70.08***	(6.860)	-73.78***	(7.654)
Owner Code=122062603 × Wind GWh	-1.408	(1.068)	-1.749	(1.233)
Owner Code=122062624 × Wind GWh	-1.892	(1.441)	-1.079	(1.559)
Owner Code=122062627 × Wind GWh	-0.704	(0.626)	-0.782	(0.746)
Owner Code=122062642 × Wind GWh	-7.982**	(2.703)	-8.351**	(3.070)
Owner Code=122062646 × Wind GWh	-0.697	(0.708)	-0.851	(0.804)
Owner Code=122062647 × Wind GWh	-2.509***	(0.626)	-3.560***	(0.839)
Owner Code=122062649 × Wind GWh	-7.646***	(1.688)	-8.252***	(2.012)
Owner Code=125767546 × Wind GWh	-1.791	(1.552)	-2.290	(1.579)
Owner Code=576468110 × Wind GWh	-44.72***	(3.415)	-47.10***	(3.694)
Owner Code=576468116 × Wind GWh	-5.677**	(1.925)	-7.291***	(2.193)
Owner-Price-Year-Month-Hour Fixed Effects	Yes		Yes	
Controls for Demand	Yes		Yes	
Peak	No		Yes	
Sum of Coefficients	-211.63		-227.80	
Standard Error of Sum	13.29		14.63	
Observations	4,612,121		1,568,048	
R-squared	0.97		0.97	

Notes: Data comes from MISO real-time Offer Market Reports January 1, 2014 to December 24, 2016. This sample is all offers by integrated market participants. Column (1) uses the full sample, while column (2) is only for peak hours, defined as 3pm to 8pm inclusive. Offer curves are are interpolated and defined at $3 intervals between 0 and 60 USD. All unit level offers are aggregated to the market participant. One observation is the quantity offered by all unit owned by the same market participant at a given price for the hour. Sample includes all integrated market participants. All specifications include a fixed effect for the average quantity offered by the market participant at the price for a given month-hour, and control for hourly demand. Other controls include hourly net imports, daily temperature, daily natural gas price. Standard errors, in parenthesis, are clustered by month of sample and owner. *, **, *** denote p-value less than 0.1, 0.05, and 0.01 respectively for each hypothesis test.

Table 9: Operations of Utilities with Large Wind Capacity in MISO, 2016

Utility	Capacity	Wind Capacity	TWh	% Wholesale Purchase	% Sale for Resale
MidAmerican Energy Co	9504	4083	33.2	0.12	0.26
Northern States Power Co - MN	9563	852	48.6	0.27	0.26
ALLETE, Inc.	2098	520	14.7	0.33	0.41
DTE Electric Company	11955	449	47.3	0.21	0.05
Wisconsin Electric Power Co	7397	339	36.8	0.29	0.26
Basin Electric Power Coop	5176	287	29.6	0.37	0.94
Wisconsin Power & Light Co	4173	269	14.8	0.39	0.24
Consumers Energy Co	7639	212	38.6	0.58	0.08
Interstate Power and Light Co	3217	200	17.1	0.53	0.12
Montana-Dakota Utilities Co	547	157	3.5	0.25	0.01

Notes: Capacity is total installed, operating, capacity in megawatts. Wind capacity is the capacity of all wind turbines. All data comes from EIA-860 and EIA-861 for the year 2016. TWh stands for terawatt-hour, and represents the thousand of gigawatt-hours sourced and dispositioned that year. Of the total amount sources, the % Wholesale Purchase represents the amount of electricity they purchased from the wholesale market, the remaining percent (from 100) is the share they generated. The % Sale for Resale is the percentage of total disposition that was sold to a third party (e.g. the wholesale market) the remaining share was sold to retail customers.

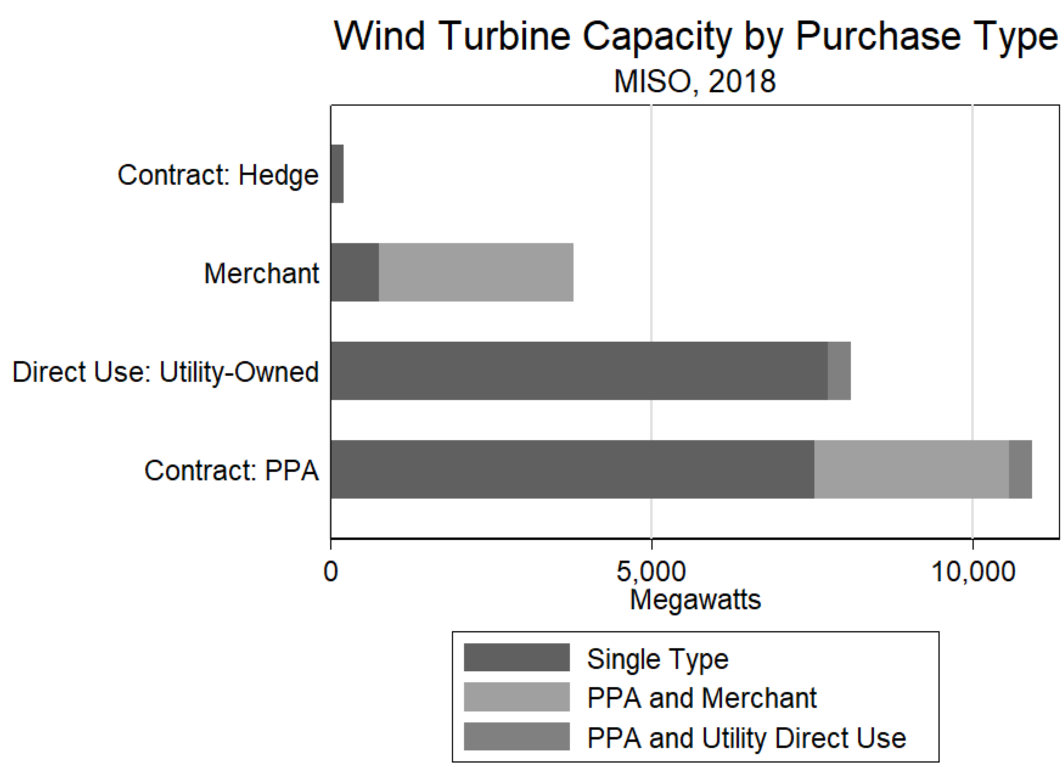


Figure 9: Notes: The sum of total project capacity by generation purchase type, for purchase for all wind turbine projects online in MISO as of June 2018. Contract: Hedge is a physical contract for differences. Merchant projects sell electricity to the wholesale market. Direct Use: Utility-Owned is direct use of the wind turbine by the utility that owns the project. Contract: PPA is a purchasing power agreement that is a virtual contract for differences. There are a number of projects that have multiple purchase types listed.

C Institutional Details on MISO

C.1 Background

MISO was formed in 1998 and approved as the first Regional Transmission Organization in the US by the Federal Energy Regulatory Commission in 2001.[54] The operator serves as a non-profit organization managing transmission and dispatch of electricity generating units within its footprint through a variety of market operations, focusing on reliability, efficiency, and the development of electricity resources.

MISO operates a number of markets in combination with planning and oversight to achieve its goals in distribution and reliability including a day ahead and real time wholesale electricity market similar to the model described in section 2. These markets capture almost all electricity generation and transmission activities within MISO's footprint that are not part of bilateral contracts.

Using the best available data, it shows a number of integrated market participants are net-sellers into wholesale markets over the course of the year and MISO is unique in having lower-than-average purchasing power agreements suggesting MISO is a appropriate setting for evaluating the testable predictions.

As show by Equation 4, the impact of renewable generation on the price of electricity can depend on who owns the wind turbines so it is important to know the portfolio of unit types owned by every market participant. I take advantage of the time-invariant owner code associated with the generating units in the supply offer data to characterize the size and content of market participants' portfolios, as all units with the same owner code are owned by the same market participant. I consider the maximum quantity generated by a unit during the sample period as a measure of its capacity, Figure 4 shows the portfolio for the thirty largest market participants and their corresponding owner code. It is evident almost all of these market participants have diverse assets, and some of the largest market participants own a sizable amount of wind generation capacity.

In addition to the micro-data on unit level offers, MISO's market reports include hourly market level information summarized in Panel A of Table 7. This market is large, clearing 71 GWh in a

[54] MISO was formerly known as the Midwest Independent System Operator up until 2013.

hour on average. A little more than half this is provided by coal based generators, and a fourth by natural gas. Wind generation provides almost 5 GWh on average, with a maximum of 13.7 GWh. While wind generation is a small portion of the market overall, there are moments when wind turbines produce more electricity than all the nuclear plants within MISO, and wind can meet up to 20% of load during periods of low demand.

C.2 Markets in MISO

Markets in MISO include a day ahead and real time wholesale electricity market to balance generation supply and load demand, a market for financial transmission rights to manage the risk of congestion, a market for ancillary services that ensure reliability through frequency regulation, and an annual capacity market. Other important components of MISO include revenue sufficiency guarantee charges to those that are causing ramping and the related make-whole payments.

Both the day ahead and real time wholesale markets serve as multi-unit uniform price auctions. Each generation unit submits the amount they are willing to generate at a given price and a number of bid parameters for every hour.[55] The day ahead market serves as a forward market, with all bids submitted by 11 am the day before market operations. The quantities are cleared and the dispatch order is determined by 3 pm the day before market operations. The real time market serves as a spot market for last minute adjustments, with all bids submitted at least 30 minutes before the market hour. All quantities in the forward market are cleared again in the real time market unless modified.

Concurrently to the submission of generation offers, municipalities and other load serving entities may submit physical demand bids in the day ahead and real time market while financial market participants may submit virtual demand bids in the day ahead market only. A few of the physical bids are price sensitive, however they are predominately price invariant representing inelastic demand for electricity in the short-run. Within MISO there are market participants offering demand response, however they bid into the supply side of the market with a curtailment price and target

[55] These parameters include cost estimates, the minimum and maximum they can produce in economic and emergency scenarios, as well as if the unit must run.

MW reduction.

A computer program uses the generation offers, demand bids, and constraint parameters to solve for the dispatch generation quantity for each unit and the market price they receive.[56] MISO's equilibrium concept is a set of locational marginal prices (LMP) at different geographic pricing nodes. The price at each node represents the market clearing price for that location as well as the marginal congestion cost and the cost of loss from transporting electricity over a significant distance. If there are no transmission constraints or transmission losses, the LMP will be the same at every location within that market.

Intermittent, or variable generation, can be a problem for the operators of transmission networks such as MISO, as unexpected deviations from the forecasted generation can impact the ability to meet security commitments. MISO addressed this in 2011 by integrating wind generating units as Dispatchable Intermittent Resources that can bid into the wholesale market. This has greatly reduced the number of manual curtailments.[57] Relatedly, the day ahead forecasts that helps determine the wind based generation offers have greatly increased in accuracy in recent years. A survey of the generation offers submitted by wind turbines show they are invariably inelastic, showing a fixed quantity, however their ex-post generation quantity does differ from their ex-ante supply offer.

C.3 Utility Structure and Turbine Finance

Most states in MISO other than Michigan and Illinois never passed laws to de-regulate their electricity market. The implication is that a number of the electricity generating units are part of a vertically integrated utility, buying the electricity they are selling within MISO's wholesale market. This can mitigate the incentives to increase the wholesale price (Bushnell, Mansur, and Saravia, 2008). I use data from the U.S. Energy Information Agency to better characterize the operations of utilities. Table 9 shows details on the total capacity and wind capacity for the ten utilities in

[56] The current computer programs used to determine dispatch include Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED). SCED is used in real time. This was changed in late 2014 to compensate quickly ramping technologies.

[57] Wind turbines can curtail the amount of electricity they generate by changing the angle of their blades.

MISO with the largest installed wind capacity in MISO according to EIA-860 form. I use EIA-861 form to show the total Tera-watt hours (TWh) of electricity they provide during the year 2016, as well as the percent of the total TWh that is sourced from wholesale markets and the percent that is deposited as sale for resale. The sale for resale percentage is the amount of electricity that is not sold to retail customers, and is instead sold to a third party like the wholesale market. We can see that for a number of large utilities, the quantity that is purchased from the wholesale market is less than the quantity that is sold into the wholesale market, on average in a year. This implies that these market participants would benefit from increasing the wholesale price within MISO.

The predominate way to finance renewable energy electricity generation projects is through long term purchasing power agreements. Here the owner of the electricity generating resource signs a contract with an offtaker, who agrees to purchase a set amount of electricity at a fixed price.[58] The electricity generators that sign this contract still sell in the wholesale market, in which case the off-taker pays the difference between the preset rate and the market rate. When the wholesale price is higher than the preset rate, the off-taker receives the revenue in excess of the preset rate. Projects financed in this way have no incentive to increase the market price. Ideally I would be able to identify these projects in the MISO data, however it is impossible given how the owner information is coded. Instead I present data from the American Wind Energy Association WindIQ database on all wind turbine projects on-line within MISO's footprint.

Figure 9 shows the total capacity in megawatts of all wind projects in MISO and the purchase type that finances them. Of the projects that are financed by only one purchase type, the most common purchase type is direct use by the utility that owns the wind project. To the extent to which the utility is selling the electricity in the wholesale market, these projects benefit from a higher wholesale market price. There are a number projects that are financed through merchant purchase type and purchase power agreements. Merchant projects, but not the power purchasing agreement projects, also benefit from a higher wholesale electricity price. With the data provided it is impossible to determine which percentage of the project is financed by a purchasing power

[58]This differs from a hedge contract in that it is a purely financial arrangement.

agreement of through merchant sales.

C.4 Market Monitoring and Mitigation

To address concerns of uncompetitive conduct in the wholesale electricity market, independent system operators will contract with an independent market monitor. These monitors continuously monitor the market for uncompetitive conduct and release semi-annual reports detailing the overall competitiveness of the market. MISO's independent market monitor is Potomac Economics. As of 2016, the assessment from Potomac is that MISO's markets are competitive except for local areas that experience chronic transmission constraints (Potomac Economics, June 2017). This is based off characterizations of the market structure and direct evaluation of market conduct.

The market structure is characterized by a Herfindahl-Hirschman Index (HHI) and the number of hours when at least one firm's output is necessary to meet total demand. In MISO, the HHI varies from 600 (not concentrated) to over 3750 (very concentrated) depending on the region. While the number of pivotal firm's is informative, a firm can still influence the price and not be pivotal.

Taking a more micro approach, Potomac directly looks the conduct of market participant by evaluating their price-cost markup, and looking for instances of economic and physical withholding. The price-cost markup is found by comparing a simulated market price under two different scenarios, for all hours. One with the market participants actual bids, another using a "reference level" based on the suppliers start-up cost, no-load cost, and incremental energy cost. These two simulated market prices are averaged over a year, with the difference of the two averages being the price-cost markup. Overall MISO finds these mark ups to be small, almost zero (Potomac Economics, June 2017). This could be the case because only the averages are being compared.

A generation offer is considered to be an instance of economic or physical withholding if it fails a conduct threshold test. Potomac has different conduct thresholds depending on if a electricity generation facility is in chronically constrained area, call a Narrowly Constrained Area (NCA), or in an area that is temporarily constrained with a limited number of firms, called a Broad Constrained Area (BCA). For example, in a BCA, a plant fails the economic withholding conduct threshold if there is a binding transmission constraint and the energy offer is more than the minimum of the reference level generation price plus $100/MWh or the the reference level generation price times four. A market participant in a BCA fails the physical withholding conduct test if a plant is taking an unapproved deration or outage, there is a binding transmission constraint, and they are withholding the minimum of 5% of their portfolio or 200 MW (MISO, 2018). Overall, in 2016, Potomac identifies 5 to 10% of the total capacity in MISO was a derating or outage.

For Potomac to mitigate a generation offer, it must fail a conduct test for physical or economic withholding and it must fail an impact test. An impact test evaluates if the generation offer, instead of the reference level default bid, increases the market price beyond an acceptable level. For a Broad Constrained Area, the impact threshold is the minimum of 3 times the reference Energy LMP or the reference LMP plus $100/MWh. It's likely that the type of anti-competitive behavior I model in this paper would not fail an impact test. This is because the incentive is to allow the wind generation to replace the market participant's more expensive generation plants. This behavior would not create a significant increase in the market price, but instead prevent it from decreasing by the amount of the merit order effect. Table 2 suggest this value, on average is $3.73/MWh.