Market Power and Price Discrimination: Learning from Changes in Renewables Regulation

Natalia Fabra and Imelda

July 2020

EEL Discussion Paper 105

In many settings, market power gives rise to price differences across markets. While arbitrage reduces market power and price discrimination, it need not be welfare-enhancing. Instead, as shown in this paper, addressing market power directly (e.g., through forward contracts) also reduces price discrimination while improving consumers' and social welfare. Empirical evidence from the Spanish electricity market confirms our theoretical predictions. Using detailed bid data, we exploit two regulatory changes that switched from paying renewables according to variable or fixed prices, and vice-versa. Overall, we find that fixed prices (which act as forward contracts) were more effective in weakening firms' market power, even though variable prices led to less price discrimination through arbitrage. This shows that it is in general not correct to equate increased price convergence and stronger competition or enhanced efficiency.

Keywords market power, forward contracts, arbitrage, renewables.

http://energyecolab.uc3m.es/

uc3m | Universidad Carlos III de Madrid
DEPARTAMENTO DE ECONOMÍA

ENERGYECOLAB

Non-Technical Summary

Market Power and Price Discrimination: Learning from Changes in Renewables Regulation

In this paper we explore the impact of firms' price exposure on market power and price discrimination across sequential markets. We highlight two countervailing incentives. On the one hand, as first pointed out by Allaz and Vila (1993), reducing price exposure mitigates firms' incentives to increase prices, which also leads to less price discrimination. On the other hand, if firms are insulated from price changes, they face weaker incentives to arbitrage price differences across markets, which would ultimately mitigate the incentives of the dominant producers to exercise market power.

These issues apply to many goods (e.g., gas, electricity, emission allowances, bonds, stocks.) that are commonly traded in sequential markets, with forward markets followed by spot markets. Here, we focus on the impact of forward contracts on the performance of electricity markets, and in particular, on the debate as to how to pay for renewables. Under one of the most commonly used pricing schemes (Feed-in-Tariffs or FiTs), renewables receive a fixed price, equivalently to a forward contract. The alternative (Feed-in-Premia or FiPs) is to expose renewables to changes in wholesale market prices.

The changes in the renewable regulation that took place in the Spanish electricity market between 2013 and 2014 provide a unique opportunity to test these predictions, as wind producers were switched from FiPs to FITs in 2013, and then back to FiPs in 2014. Using detailed bid data, our empirical analysis provides four main findings. **First**, using a structural approach, we document a forward contract effect: when firms receive fixed tariffs, they do not internalize the market price increases on their wind output. Instead, under variable prices, firms internalize the price effects on their total output, including wind. Thus, all else equal, firms' markups are lower under fixed prices. **Second**, using a differences-in-differences approach, we document an arbitrage effect: wind producers stop arbitraging price differences after the switch from variable prices to fixed prices, but they resume arbitrage once exposed to variable prices again. **Third**, using a reduced form approach, we show that price differences across the day ahead and the spot markets are larger under fixed prices because the arbitrage effect dominates over the forward contract effect in mitigating price discrimination. However, leveraging on our structural estimates, our **fourth** result shows that firms' markups are lower under fixed prices. Now, the reason is the opposite: the forward contract effect dominates over the arbitrage effect in mitigating market power. In sum, our empirical analysis allows us to conclude that, given the market structure of the Spanish electricity market, FiTs led to more efficient wholesale market outcomes than FiPs.

These results shed light on the current debate about renewables' regulation in electricity markets, but more broadly, they uncover the mechanisms giving rise or avoiding price discrimination as a tool for market power in sequential markets, and vice-versa.

Market Power and Price Discrimination:

Learning from Changes in Renewables Regulation*

Natalia Fabra and Imelda
Universidad Carlos III de Madrid

9 July 2020

Abstract

In many settings, market power gives rise to price differences across markets. While arbitrage reduces market power and price discrimination, it need not be welfare-enhancing. Instead, as shown in this paper, addressing market power directly (e.g., through forward contracts) also reduces price discrimination while improving consumers' and social welfare. Empirical evidence from the Spanish electricity market confirms our theoretical predictions. Using detailed bid data, we exploit two regulatory changes that switched from paying renewables according to variable or fixed prices, and vice-versa. Overall, we find that fixed prices (which act as forward contracts) were more effective in weakening firms' market power, even though variable prices led to less price discrimination through arbitrage. This shows that it is in general not correct to equate increased price convergence with stronger competition or enhanced efficiency.

Keywords: market power, forward contracts, arbitrage, price discrimination, renewables.

*Emails: natalia.fabra@uc3m.es and iimelda@eco.uc3m.es. Comments by David Benatia, James Bushnell, Richard Green, Gerard Llobet, Nils May, Juan Pablo Montero, Mateus Nogueira, Stanley Reynolds, Robert Ritz, Jan Sthuler, and Andre Veiga as well as seminar participants at PUC (Santiago de Chile), CREST (Paris), Dauphine (Paris), Imperial College (London), UC Davis (California), and Carlos III (Madrid) are gratefully acknowledged. This Project has received funding from the European Research Council (ERC) under the European Union Horizon 2020 Research and Innovation Program (Grant Agreement No 772331).

1 Introduction

In many settings, similar goods are sold at different prices across markets. Market boundaries are often defined geographically (as in national markets), inter-temporally (as in sequential markets), or across customer groups (as under personalized pricing).[1] The welfare consequences of such forms of 'third-degree price discrimination' have been extensively discussed in the literature, starting with the seminal work of Robinson (1933) to the more recent contribution by Aguirre, Cowan and Vickers (2010). By now, it is well understood that reducing price discrimination (e.g., through arbitrage) need not be welfare-enhancing. The reason is that a move towards price uniformity reduces the price in some markets but raises it in others, leading to an overall ambiguous welfare effect. Yet, a reduction in price discrimination is likely to benefit consumers as firms lose a powerful tool to extract their surplus (Cowan, 2012).

Increasing concerns about the distributional consequences of price discrimination (both across consumers as well as between firms and consumers) have often led policymakers to introduce non-discrimination clauses or to remove restrictions on arbitrage.[2] A natural question arises: is it possible to mitigate the adverse distributional implications of price discrimination without sacrificing social welfare?

In this paper, we show that addressing market power directly (as opposed to indirectly via arbitrage) reduces price discrimination with positive effects on both consumers and overall welfare. To illustrate this, we focus on the role that forward contracts can play in reducing market power and price discrimination across sequential markets.[3]

Many goods (electricity, gas and oil, emission allowances, bonds, or stocks, among others) are commonly traded across sequential markets. Typically, the goods are first sold in a primary market, followed by trade in secondary markets. Price discrimination across

[1]Examples of these are found, among others, in the pharmaceutical industry where there are large cross-national price differences for drugs (Danzon and Chao, 2000), in electricity and financial markets where there are systematic price differences between forward and spot markets (Ito and Reguant, 2016; Borenstein et al., 2008; Longstaff and Wang, 2004), or in digital markets where prices are often set according to consumer characteristics (OECD, 2018).

[2]For instance, Hviid and Waddams (2012) analyze the impact of a non-discrimination clause in the UK energy retail market; Dubois and Sæthre (2018) analyze the impact of price arbitrage across countries in the pharmaceutical industry (known as parallel trade), and Mercadal (2015), Birge et al. (2018) and Jha and Wolak (2015) analyze the welfare implications of allowing financial traders to arbitrage price differences in electricity markets (known as virtual bidding).

[3]This is motivated by our empirical application. However, one could pose a similar question in other settings. For instance, consider price discrimination by a monopolist across countries. Which policy is more welfare-enhancing: allowing for arbitrage across countries, or introducing competition through entry?

these sequential markets is similar to other forms of third-degree price discrimination, with two differences: (i) the prices in the early markets determine the extent of unserved demand, and hence the size of later markets; and (ii) total welfare depends on the prices set in the last market that determine the final allocation.

Since the work pioneered by Allaz and Vila (1993), and the rich empirical literature that followed (Wolak, 2000; Bushnell, Mansur and Saravia, 2008; Hortaçsu and Puller, 2008), it is well understood that forward contracts weaken firms' incentives to raise prices.[4] The reason is that firms only internalize the effects of increasing prices on their uncovered sales, given that the price they receive for their contracted output is fixed at the forward contract price. Beyond this well-known effect, we show that forward contracts also reduce price discrimination across sequential markets, with unambiguously positive effects on consumers and total welfare.

Electricity markets, an ideal laboratory. Several features of electricity markets make them particularly well suited to analyze the impact of forward contracts on market power and price discrimination. First, most electricity markets are organized as sequential markets, with a day-ahead market followed by one or more markets that operate closer to real-time. Second, several types of forward contracting are common in electricity markets, including vertical integration and other vertical arrangements between generators and electricity suppliers (Bushnell, Mansur and Saravia, 2008), futures trading through organized exchanges, or forward contract obligations such as virtual divestitures (de Frutos and Fabra, 2012). Third, electricity markets provide a rich source of data that allows us to analyze equilibrium outcomes as well as firms' strategies.

And last, but not least, the impacts of forward contracts on market performance are relevant for a key policy debate in electricity markets; namely, how to pay for renewables. Since compliance with the environmental targets requires massive investments in renewables, it is paramount to understand how alternative pricing schemes for renewables impact market prices and efficiency. One of the key messages of the paper is that understanding the impact of renewable policy requires an analysis of the interaction between conventional and renewable suppliers, and not just of renewables alone. The interplay between the two types of suppliers drives much of the outcomes and efficiency results of the paper.

[4] Other papers point at the potential anti-competitive effects of forward contracting, particularly so when firms compete *a la* Bertrand (Mahenc and Salanie, 2004) or when they can reach collusive outcomes through repeated play (Liski and Montero, 2006). As part of our empirical analysis, we assess whether forward contracting had pro-competitive or anti-competitive effects in the context of the Spanish electricity market.

Our analysis contributes towards an understanding of the market impacts of pricing rules for given capacities, which is a needed first step towards analyzing the endogenous choice of long-run variables such as entry, exit, or the capacity and location of the new investments. Furthermore, in many countries, renewable capacities are often not chosen by firms but by regulators, who are increasingly resorting to auctions to procure the new renewable capacities (Cantillon, 2014). Our paper sheds light on the consequences of procuring renewable capacity under alternative pricing rules.[5]

There are two commonly used pricing rules for paying renewable output: according to fixed prices (the so-called Feed-in-Tariffs or FiTs), or according to variable prices, i.e., market prices plus a fixed premium (the so-called Feed-in-Premiums or FiPs).[6] The starting point of our analysis is the observation that fixed prices act as forward contracts for a quantity equal to the firm's renewable output.[7] Such equivalence suggests that paying renewables at fixed prices should have similar pro-competitive effects as forward contracts (Allaz and Vila, 1993). However, as pointed out by Ito and Reguant (2016), paying producers according to fixed rather than variable prices reduces their incentives to arbitrage. To the extent that forward contracts not only mitigate market power but also reduce arbitrage, it is, at first sight, unclear how they compare to variable prices.

Changes in the renewables regulation provide a unique opportunity to understand the market power impact of forward contracts relative to arbitrage. We study the Spanish electricity market during a period when renewables regulation changed twice: from variable prices to fixed prices in 2013, and then back to variable prices in 2014. Access

[5]For instance, under the new auction design in the Spanish electricity market (released in July 2020), payments to renewables will be equal to a weighted average of a fixed price (to be determined through the auction) and a variable market price. For each auction, the regulator has to choose the parameter of price exposure that serves to compute the weighted average. The scheme can vary from a pure fixed price to giving a (50,50) weight to the fixed and to the variable price.

[6]This premium can take several forms; it can be a direct payment by the regulator, it can be a tax credit (as the federal Production Tax Credit in the US), or it might derive from the sale of renewable energy credits to electricity providers that are required to procure a proportion of their sales with renewable energy (as the system of Revenue Obligation Certificates (ROCs) in the UK, or the Renewable Portfolio Standard (RPS) in the US). See Newbery (2016) for a description of the ROCs, and Greenstone, McDowell and Nath (2019) for an analysis of RPS.

[7]To some extent, FiTs are similar to the so-called Contracts-for-Differences (CfDs), under which renewable producers sell their output at the market price and receive (or pay) the difference between a *reference market* price and a strike price that is set ex-ante. However, unlike FiTs, CfDs preserve firms' incentives to arbitrage given that the financial settlement is not computed as a function of the actual market revenues obtained by the plant. Similar conclusions apply to schemes with sliding feed-in premiums, which are common across Europe, as long as prices in the reference market are above the contract price. Appendix A.1 contains an analysis of the results under CfDs.

to very detailed wholesale market bid data allows us to conduct an empirical analysis of the causal effects of such regulatory changes on firms' bidding behavior and the resulting impacts on market power and price discrimination across markets.

Our theoretical analysis. In order to understand the effects of these changes, we first build a modified version of the theoretical analysis in Ito and Reguant (2016). Notably, our model explicitly incorporates two alternative renewables pricing schemes: variable or fixed pricing.[8] The model has two sequential markets (a day-ahead market and a spot market), two types of firms (dominant and fringe), and two types of technologies (conventional and renewables). Consumer surplus depends on the prices in the two markets, while total efficiency depends on the spot market price as it determines final consumption.

In our benchmark (renewables are paid according to variable prices and arbitrage is not allowed), the dominant firm exercises market power by withholding output from the day-ahead market and by reselling it in the spot market. Thus, market power gives rise to price differences across markets, with day-ahead prices exceeding spot market prices. However, we show that paying producers according to fixed prices mitigates market power in both markets, thereby reducing price discrimination (*forward contract effect*). Allowing for arbitrage also weakens market power in the day-ahead market, but it does so at the cost of increasing the spot market price (*arbitrage effect*). Hence, while paying renewables according to fixed prices increases efficiency and consumer surplus, allowing for arbitrage reduces efficiency and leads to an ambiguous impact on consumers.

If there are limits to arbitrage, i.e., all transactions have to be backed by physical assets, the fringe renewable producers are the only ones with the ability and the incentives to arbitrage, but only if they are exposed to variable prices. Paying renewables according to fixed prices essentially bars them from serving as arbitrageurs across markets as they receive the same price regardless of where they sell their output. Thus, the comparison between fixed and variable prices bolts down to the comparison between the *forward contract effect* and the *arbitrage effect*. As a result, fixed prices tend to benefit consumers relatively more than variable prices when the ownership structure of renewables is concentrated in the hands of the dominant producer, as this strengthens the *forward*

[8] Our model also differs from Ito and Reguant (2016) in how we microfound the demand elasticity. In our model, we derive it from consumers' demand elasticity, which is important to assess the impacts on consumer surplus. Instead, they derive the demand elasticity from an elastic fringe supply.

contract effect and weakens the *arbitrage effect*.[9] Nevertheless, the comparison in terms of overall welfare does not depend on the ownership structure: for given capacities, paying renewables according to fixed prices always delivers more efficient market outcomes than exposing them to variable prices.

Our empirical analysis. We test these predictions in the context of the Spanish electricity market. First, we estimate a structural model of price-setting incentives in the day-ahead market, which confirms the empirical relevance of the *forward contract effect*. On the one hand, taking the slopes of the realized residual demands as given, we show that when firms received fixed tariffs, they did not internalize the market price increases on their wind output. On the other, under variable prices, firms internalized the price effects on their total output, including wind. Thus, all else equal, the *forward contract effect* reduced firms' markups under fixed prices.

Second, we analyze how changes in the pricing schemes affected the fringe firms' incentives to arbitrage. To ensure that time-varying changes in unobservable variables do not confound the effects, we rely on a differences-in-differences (DiD) approach. An appealing feature of our analysis is that we can exploit the two regulatory changes, from variable prices (FiP I) to fixed prices (FiT) in February 2013 and then back to variable prices (FiP II) in June 2014. We consider on two control groups: (i) independent retailers, which faced the same arbitrage incentives as renewables before the first and after the second regulatory change; and (ii) renewables other than wind, which faced similar arbitrage incentives as wind after the first regulatory change. Our DiD analysis shows that wind producers stopped arbitraging price differences after the switch from variable prices to fixed prices, but they resumed arbitrage once they were exposed to variable prices again. Our analysis confirms the empirical relevance of the *arbitrage effect* and its robustness regardless of which control group we choose.

These two pieces of evidence (price-setting incentives in the day-ahead market and arbitrage incentives) highlight the trade-off between the *forward contract* and the *arbitrage effects*. In order to understand which of these effects dominated, the last two pieces of our empirical analysis compare price discrimination and market power across pricing schemes.

Regarding price discrimination, we show that price differences across markets were on average larger under fixed prices. Consistently with our theoretical predictions, an

[9] Acemoglu, Kakhbod and Ozdaglar (2017) and Genc and Reynolds (2019) also point out the relevance of market structure in shaping the price depressing effects of renewables in a Cournot model. However, they do not assess the effects of market structure on the relative performance of FiP versus FiT simply because they only consider the former.

increase in the dominant firm's wind share reduced price discrimination under fixed prices (due to a stronger *forward contract effect*), but enlarged it under variable prices (due to a weaker *arbitrage effect*).

Lastly, we leverage our structural estimates to compute markups in the day-ahead market to assess how pricing schemes affect market power. We find that markups were significantly lower while firms were subject to fixed prices as compared to variable prices. The average markup during the FiT period was 6.3%, while it was 8.3% and 10.9% under the first and second FiP regimes. Our results are robust to alternative ways of comparing the markups (i.e., by firms, by windy-*vs.*-less-windy hours, by peak-*vs.*-off-peak hours).

Based on our empirical analysis, we conclude that, given the market structure of the Spanish electricity market, the *forward contract effect* dominated over the *arbitrage effect* in promoting more competitive outcomes under fixed prices. Conversely, the *arbitrage effect* dominated over the *forward contract effect* in reducing price discrimination more under the variable price regime. To the extent that arbitrage led to higher spot market prices, exposing renewables to variable prices might have reduced overall efficiency. Thus, even though fixed prices did not reduce price discrimination as much as variable prices, they succeeded in fostering more efficient outcomes to the benefit of consumers. The comparison of market power and price discrimination under fixed and variable prices thus illustrates that increased price convergence should not be in general equated with stronger competition or enhanced efficiency.

Our contribution. Our contribution is to capture the relative merits between market power mitigation instruments versus arbitrage in reducing market power and price discrimination, an issue which is relevant in electricity markets and beyond. In particular, this article provides a tractable model and a structural analysis comparing firms' behavior under two pricing regimes: fixed prices (which mitigate market power) and variable prices (which promote arbitrage). To our knowledge, this article is also the first to make use of two regulatory changes to provide a causal interpretation of the impact of pricing rules on firms' bidding behavior.

In regards to the role of arbitrage, our work is most closely related to Ito and Reguant (2016). From a theoretical point of view, our equilibrium characterization under variable prices is similar to theirs, but we also add and compare the equilibrium characterization under fixed prices. More importantly, our empirical strategy is quite distinct. First, we identify the impact of pricing rules on market power using a structural model of bidding behavior, which also serves to compute markups. We also strengthen the empirical identification by using a differences-in-differences approach, which allows to capture the magnitude of the arbitrage effect while avoiding the potential confounding effects of event studies. Our empirical results regarding arbitrage and price discrimination give further support to those in Ito and Reguant (2016), extend them over a longer time period, and add new evidence of the impact of pricing rules on market power.

Our results provide key insights into the ongoing debate about how to support the deployment of renewables at least cost. We focus on the largely unexplored issue of how renewables pricing schemes affect firms' bidding incentives for given capacities, an important determinant of the performance of electricity markets. Most analyses of pricing schemes focus on their impacts on the costs of investments. For instance, Newbery et al. (2018) and May and Neuhoff (2017) favor the use of pricing schemes with limited price exposure, as price volatility increases the costs of financing the new projects (see Ritzenhofen, Birge and Spinler (2016) for further references).[10] To our knowledge, only a few papers explore the effects of renewables pricing schemes for given capacities. From a theoretical perspective, Dressler (2016) highlights that FiTs act like forward contracts. However, she abstracts from the impacts of FiTs on price arbitrage, and focuses instead on the impacts on forward trading. She finds that FiTs might crowd out other forms of forward contracting, in line with Ritz (2016). From an empirical perspective, Bohland and Schwenen (2020) attempt to explore the market power impacts of a voluntary change in the pricing scheme in the Spanish Electricity market during 2005, a period when renewables represented less than 10% in the energy mix.

Finally, our work complements the growing literature exploring the short-run and long-run effects of renewables, including their impacts on energy prices (Gowrisankaran, Reynolds and Samano (2016); Genc and Reynolds (2019); Acemoglu, Kakhbod and Ozdaglar (2017)), on the nature of competition (Fabra and Llobet (2019)), on emissions (Cullen (2013) and Novan (2015)), or on the profits earned by the conventional producers (Bushnell and Novan (2018); Liski and Vehviläinen (2017)), among others. All of these papers apply to settings in which renewables are exposed to market prices but do not analyze whether the effects of renewables would differ if they were subject to fixed prices instead.

The remainder of the paper is organized as follows. Section 2 builds and solves a model of optimal bidding across sequential markets. Section 3 provides an overview of the institutional setting and data used in the analysis. Section 4 performs the empirical analysis and Section 5 concludes. Proofs are postponed to the Appendix.

[10] Some papers compare renewable support schemes in other dimensions. For instance, Reguant (2019) conducts a simulation that also accounts for the interaction between renewable energy policies and the retail tariff design to compare their efficiency and distributional impacts.

2 The Model

In this section, we develop a simple model of strategic bidding that tries to mimic some of the key ingredients of electricity markets. We propose a modified version of Ito and Reguant (2016) to explicitly model renewables under alternative pricing schemes. Similarly to their model and in line with Allaz and Vila (1993), we abstract from uncertainty and risk aversion in order to focus on the impact of pricing schemes on market power and price discrimination.

We assume linear demand of the form $D(p) = A - bp$. This demand can be thought of as the sum of the demand of households, which tends to be price unresponsive, and the demand of large energy consumers and retailers, which is price responsive.[11] Both types of consumers are assumed to be myopic.[12]

Transactions take place in two sequential markets: a day-ahead market ($t = 1$) and a spot market ($t = 2$). Demand in the day-ahead market is $D_1(p_1) = A - bp_1$, while $D_2(p_1, p_2) = D(p_2) - D_1(p_1) = b\Delta p$ is the remaining demand that is traded in the spot market, where $\Delta p \equiv p_1 - p_2$ denotes the price difference across markets. If $\Delta p > 0$, the price responsive consumers increase their demand in the spot market. Instead, if $\Delta p < 0$, the price responsive consumers profit by reselling a fraction of their day-ahead commitments. Note that, whereas consumer surplus depends on the two prices, total welfare is solely a function of the spot market price. Changes in day-ahead and spot prices might also have distributional implications across consumer groups, e.g., households are only affected by changes in day-ahead prices, while retailers and large energy consumers are also affected by changes in spot prices.

Electricity is produced by two types of technologies (renewable and conventional) and two types of firms (dominant and fringe, respectively denoted by $i = d, f$). The dominant firm owns both technologies, while fringe firms only own renewable assets. While fringe firms are price-takers, the dominant firm sets prices in both markets, taking into account the decisions of the fringe players.

Renewables, which we generically refer to as *wind*, allow firms to produce at zero marginal costs up to their available capacities. We use w_i and k_i to respectively denote

[11] As in Ito and Reguant (2016), an equivalent micro foundation for demand elasticity is that $A - bp$ is total demand net of the demand of a myopic competitive fringe with marginal costs q/b.

[12] In reality, the demand of households is inelastically cleared in the day-ahead market. Hence it is reasonable to assume that they are myopic. Large consumers and retailers can participate in both markets and could thus wait to buy in the spot market if they expect that prices will be lower than in the day-ahead market. We allow for this possibility in the empirical analysis. For the theoretical analysis, we will allow for this possibility through the role of financial arbitrageurs. Modeling arbitrage by large energy buyers would be analytically equivalent.

firm i's available and maximum wind capacity,[13] with $w_i \leq k_i$, $i = d, f$. The dominant firm's conventional technology has constant marginal costs of production, $c > 0$.

Throughout, we assume that the conventional technology is needed to satisfy total demand, i.e., $A - bc - w_d - w_f > 0$. This implies that the dominant firm's marginal cost is c. Relaxing this assumption would require considering several subcases, without altering the main insights of the analysis.

We consider two commonly used pricing schemes for renewables:[14] under variable prices (FiPs), renewable producers receive the price of the market where they sell their output, plus a premium; under fixed prices (FiTs), renewable producers receive a fixed price for their output regardless of the market at which they sell it.

2.1 No Arbitrage

We first consider the case in which renewable producers are required to offer all their output in the day-ahead market. This will serve as a benchmark to assess the effects of allowing for arbitrage across markets. The residual demands faced by the dominant firm in the day-ahead market and in the spot market are thus given by

$$\begin{aligned} q_1(p_1) &= A - bp_1 - w_f & (1) \\ q_2(p_1, p_2) &= b\Delta p. & (2) \end{aligned}$$

We solve the game by backward induction. In the spot market, once p_1 is chosen, the dominant firm sets p_2 so as to maximize its profits. Under both pricing rules, the profit maximization problem can be written as

$$\max_{p_2} \left[p_2 q_2(p_1, p_2) - c\left(q_1(p_1) + q_2(p_1, p_2) - w_d\right)\right], \tag{3}$$

In the day-ahead market, under variable prices, renewable output is paid at the market price p_1 plus a fixed premium $\underline{p}$. Hence, the dominant firm's profit maximization problem is

$$\max_{p_1} \left[p_1 q_1(p_1) + p_2^*(p_1)\, q_2^*(p_1) - c\left(q_1(p_1) + q_2^*(p_1) - w_d\right) + w_d \underline{p}\right] \tag{4}$$

[13]This assumes that firms are able to perfectly predict their available capacities. Fabra and Llobet (2019) report empirical evidence on the wind forecast errors in the Spanish electricity market and show that these tend to be small. Still, they show that uncertainty and private information over available capacities impacts equilibrium bidding behavior when renewables are exposed to variable prices. However, if this uncertainty is small, the impact is second-order as compared to the impact of changes in the pricing rules.

[14]We focus on these two schemes since these are the ones used in the Spanish electricity market, which is the subject of our empirical investigation. However, for completeness, in the appendix, we also characterize the equilibrium under an alternative pricing scheme: Contracts-for-Differences (CfDs).

where $p_2^*(p_1)$ and $q_2^*(p_1)$ denote the solution to the spot market problem in (3).

Under fixed prices, the profit maximization problem in the day-ahead market changes, as renewable output is now paid at $\overline{p}$. This reduces the dominant firm's price exposure, as shown in the first term of the following profit expression,

$$\max_{p_1} \left[p_1(q_1(p_1) - w_d) + p_2^*(p_1)\, q_2^*(p_1) - c\,(q_1(p_1) + q_2^*(p_1) - w_d) + w_d\overline{p}\right]. \tag{5}$$

Our first lemma characterizes the solution under both pricing rules.

Lemma 1 *Suppose that arbitrage is not allowed* (NA)*:*

(i) Under variable prices, equilibrium prices are

$$\begin{aligned} p_1^V(NA) &= [2(A - w_f) + bc]/3b > c \\ p_2^V(NA) &= [A - w_f + 2bc]/3b > c \end{aligned}$$

leading to

$$\Delta p^V(NA) = (A - w_f - bc)/3b > 0.$$

(ii) Under fixed prices, equilibrium prices are

$$\begin{aligned} p_1^F(NA) &= p_1^V(NA) - 2w_d/3b > c \\ p_2^F(NA) &= p_2^V(NA) - w_d/3b > c \end{aligned} \tag{6}$$

leading to

$$\Delta p^F(NA) = \Delta p^V(NA) - w_d/3b > 0.$$

Proof. See the Appendix. ■

Under both pricing rules, the dominant firm exercises market power in the day-ahead market by setting its price above marginal costs. When the spot market opens, its day-ahead position is already sunk. Hence, the firm has an incentive to lower the spot price below the day-ahead price in order to meet some of the unserved demand. This leads to a positive price differential across markets.

A larger and steeper residual demand enhances the dominant firm's market power. Accordingly, the two prices increase in A but decrease in b and w_f. Furthermore, under fixed prices, the price in the two markets, as well as the difference between the two, are decreasing in w_d as wind production in the hands of the dominant firm mitigates its market power (*forward contract effect*). The dominant firm has weaker incentives to raise day-ahead prices as this would not translate into higher payments for its renewable output. This translates directly into the comparison across pricing rules, which shows that equilibrium prices, as well as the price differential, are lower under fixed prices than under variable prices. The difference is captured by the terms $-2w_d/3b$ and $-w_d/3b$ in the equilibrium price expressions (6).

2.2 Unlimited Arbitrage

Given the positive price differential across markets, there are profitable arbitrage opportunities. These involve selling output in the day-ahead market at a high price and re-buying it in the spot market at a lower price. Letting s denote the quantity that is arbitraged, the residual demands faced by the dominant firm in both markets are now given by

$$q_1(p_1) = A - bp_1 - w_f - s \quad (7)$$

$$q_2(p_1, p_2) = b\Delta p + s \quad (8)$$

If there are no limits on s, and if arbitrage is competitive, the price differential across markets is competed away until both prices convergence, $p_1 = p_2$. However, this does not mean that market power is eliminated: since the dominant firm's output is still needed to cover total demand, it still retains market power. The resulting price in both markets thus depends on the incentives of the dominant firm to exercise market power, an issue which in turn depends on the renewables pricing rule in place. This is shown in our next lemma.

Lemma 2 *Suppose that there is unlimited competitive arbitrage* (UA)*:*

(i) Under variable prices, equilibrium arbitrage is $s^V(UA) = (A - w_f - bc)/2$ *and equilibrium prices are*

$$p_1^V(UA) = p_1^V(NA) - s^V(UA)/3b > c$$

$$p_2^V(UA) = p_1^V(NA) + s^V(UA)/3b > c$$

leading to

$$\Delta p^V(UA) = 0.$$

(ii) Under fixed prices, equilibrium arbitrage is $s^F(UA) = s^V(UA) - w_d/2$*, and equilibrium prices are, for* $t = 1, 2$*,*

$$p_t^F(UA) = p_t^V(UA) - w_d/2b > c$$

leading to

$$\Delta p^F(UA) = 0.$$

Proof. See the Appendix. ■

Arbitrage reduces the residual demand in the day-ahead market but increases the residual demand in the spot market. Since pricing incentives are directly linked to market size, under both pricing rules, the day-ahead price goes down while the spot price goes up as compared to the case with no- arbitrage (Lemma 1). This effect, which we refer to as the *arbitrage effect*, is captured by the terms $\pm s/3b$ in the equilibrium price expressions. Since total welfare depends on the spot market price, the resulting allocation is now less efficient. Households are better off as they buy all their demand in the day-ahead market, whereas the impact on retailers and large energy consumers can go either way, depending on parameter values.

The comparison across pricing rules shows that the fixed price scheme leads to lower equilibrium prices in both markets. Again, the underlying reason is that the *forward contract effect* weakens the dominant firm's incentives to exercise market power. The scale of arbitrage needed to achieve full price convergence is smaller under fixed prices given that the price differential in the absence of arbitrage is narrower (Lemma 1). Also, the reduction in total welfare due to arbitrage is relatively smaller under fixed prices, and the change in consumer surplus is more likely to be positive.

2.3 Limits on Arbitrage

The previous analysis assumed unlimited arbitrage. However, in many electricity markets in practice (including the one in our empirical application), market rules impose limits on arbitrage. Typically, in markets that do not allow for virtual bidding, all transactions need to be backed by physical assets. This implies that arbitrage can only come from market agents and only up to their capacities. This leaves some scope for wind producers to engage in arbitrage as, depending on weather conditions, their capacity constraint $w_f \leq k_f$ is rarely binding. Given the positive price differential, they can thus arbitrage by selling k_f in the day-ahead market to then buy $(k_f - w_f)$ back in the spot market.

Under variable prices, fringe firms have incentives to engage in arbitrage to obtain arbitrage profits. Instead, under fixed prices, fringe firms have no incentives to engage in arbitrage as they obtain the same price regardless of where they sell their output. Given this indifference, and in line with empirical evidence, we assume that they offer all their renewable output in the day-ahead market. Accordingly, the residual demands faced by the dominant firm are as in (7) and (8), with $s = (k_f - w_f)$ under variable prices and $s = 0$ under fixed prices.

Our next lemma characterizes equilibrium pricing under limited arbitrage.

Lemma 3 *Suppose that firms can only arbitrage up to their productive capacities* (LA).

(i) Under variable prices, $s^V(LA) = \min\left\{k_f - w_f, s^V(UA)\right\}$. *Equilibrium prices are the same as in Lemma 2, with* $s^V(UA)$ *replaced by* $s^V(LA)$. *The price differential is*

(weakly) positive,

$$\Delta p^V(LA) = \Delta p^V(NA) - 2s^V(LA)/3b \geq 0.$$

(ii) Under fixed prices, $s^F(LA) = 0$. *Equilibrium prices are the same as under no arbitrage (Lemma 1).*

Proof. See the Appendix. ■

Under variable prices, if the arbitrage constraint is binding, full-price convergence is no longer achieved. As compared to the case with no-arbitrage, the day-ahead market price goes down and the spot market price goes up, but not as much as under unlimited arbitrage. Similar to the no-arbitrage case, the price differential is increasing in A and decreasing in b. However, the price differential is now increasing in w_f as the more wind the fringe has, the more limited is its ability to arbitrage price differences. If w_d and w_f are correlated, an increase in wind could reduce the price differential, but the effect is always weaker as compared to the one under the no-arbitrage case.

Under fixed prices, since there is no arbitrage in equilibrium, results are the same as those reported in Lemma 1. It follows that the comparison between fixed prices versus variable prices essentially bolts down to the comparison between the *forward contract* and the *arbitrage effects*, which in turn depends on the renewables ownership structure. This is shown in our next Proposition.

Proposition 1 *Under limited arbitrage, the comparison of equilibrium outcomes across pricing schemes (fixed versus variable prices) shows that:*
(i) $p_1^F(LA) < p_1^V(LA)$ *if and only if* $w_d > s^V(LA)/2$.
(ii) $p_2^F(LA) < p_2^V(LA)$.
(iii) $\Delta p^F(LA) < \Delta p^V(LA)$ *if and only if* $w_d > 2s^V(LA)$.

Proof. See the Appendix. ■

Point (i) of the Proposition shows that the comparison of day-ahead prices across pricing schemes depends on the renewables ownership structure. In particular, day-ahead prices are lower under fixed prices when the dominant firm owns a big share of renewables. The reason is that the *forward contract effect* under fixed prices is channeled through the dominant firm's renewable output, while the *arbitrage effect* under variable prices is channeled through the fringe firms' ability to arbitrage, which depends negatively on its own renewable production.

All the factors that enhance market power in the day-ahead market also strengthen the extent of price discrimination across markets. Hence, point (iii) of the Proposition is in line with point (*i*). Namely, the price differential across markets is relatively smaller under fixed prices when the ownership of renewables is concentrated in the hands of the dominant producer. However, fixed prices are relatively more effective in mitigating market power than in reducing price discrimination, i.e., the condition on w_d is more stringent in (*iii*) than in (*i*). This implies that fixed prices could result in greater price discrimination across markets and yet result in lower day-ahead prices as compared to variable prices.

Last, point (*ii*) of the Proposition also shows that fixed prices ambiguously give rise to lower spot prices than variable prices. Intuitively, the *arbitrage effect* under variable prices translates into a higher demand in the spot market, which pushes spot prices up. Instead, the *forward contract effect* under fixed prices weakens the incentives of the dominant producer to raise the day-ahead price, which in turn reduces the extent of unserved demand, leading to lower spot prices.

The above result leads to an important conclusion: overall welfare is greater under fixed prices than under variable prices. However, the difference in consumer surplus depends on parameter values, as prices might be greater for some consumers but lower for others.[15] Hence, we face a standard trade-off as fixed prices give rise to greater efficiency but, depending on parameter values, they might result in lower consumer surplus.

In any event, if we take the case with variable prices and no-arbitrage as our benchmark, and consider two alternatives, either allowing for arbitrage, or switching to fixed prices, we can unambiguously conclude the following:

Proposition 2 *Consider the benchmark case with variable prices and no arbitrage (Lemma 1, point (i)):*

(i) Allowing for unlimited or limited arbitrage (Lemmas 2 and 3, point (i)), reduces efficiency and might increase or decrease consumer surplus, depending on the parameter values. Price discrimination goes down.

(ii) Moving to fixed prices (Lemmas 1 and 3, point (ii)) increases efficiency and consumer surplus. Price discrimination goes down.

Proof. See the appendix. ■

[15] To see this, note that we can write the difference in consumer surplus as:

$$CS^F - CS^V = \int_{p_2^F}^{p_2^V} D(\rho)\, d\rho - \left[q_1^F \Delta p^F - q_1^V \Delta p^V\right]. \tag{9}$$

While the first term is positive, the second term can be positive or negative depending on parameter values.

Both alternatives lead to less price discrimination, but for different reasons: due to arbitrage under (i) and due to reduced market power under (ii). However, while allowing for arbitrage benefits households and, depending on parameter values, it might also benefit the retailers and large energy consumers, it does so at the cost of reducing total welfare (as the increase in the spot market price reduces total consumption). In contrast, moving to fixed prices unambiguously leads to greater surplus for all consumers (as it pushes down the prices in the two markets),[16] while simultaneous leading to greater welfare (due to the reduction in the spot market price).

2.4 Testable Predictions

The above analysis provides theoretical predictions which we will test in the empirical section of the paper. We group them in four blocks:

(*i*) **Price-setting incentives in the day-ahead market:** Under fixed prices, the *forward contract effect* implies that, for given residual demands, the dominant firms do not internalize the price impact on their own wind output. This is unlike the case in which firms are exposed to variable prices.

(*ii*) **Arbitrage across markets:** Under variable prices, the *arbitrage effect* implies that fringe producers oversell in the day-ahead market as compared to their final commitments. Their incentives to do so are greater the larger the price differential across markets. Since this effect is not present under fixed prices, any differences between the renewable fringe producers' day-ahead and final commitments should be orthogonal to the price differential.

(*iii*) **Price discrimination across markets:** All the factors that enhance the dominant producers' market power should enlarge price differences across markets (e.g., a larger demand and a steeper residual demand). Furthermore, price differences across markets should be decreasing in the dominant firms' wind output under fixed prices, and increasing in the fringe firms' wind output under variable prices.

(*iv*) **Market power in the day-ahead market:** The interplay between the *forward contract* and the *arbitrage effects* imply that the comparison of market power under

[16] For completeness, the comparison between fixed and variable prices also depends on the regulated components, i.e., the level of the fixed price and the level of the fixed premium under the variable price regime. Our comparison abstracts from differences in such regulated components by implicit assuming that absent strategic considerations, the expected firm payments would be the same under the two pricing regimes.

fixed or variable prices could go either way, depending on market structure.

Before we take these predictions to the data, we move on to describing some of the institutional details of the Spanish electricity market.

3 Context and Data

In this section, we describe the institutional setting, which is key for understanding the pricing incentives faced by the Spanish electricity producers, and we describe our data sources.

3.1 Market design and regulation

The Spanish electricity market is organized as a sequence of markets: the day-ahead market, seven intraday markets that operate close to real-time, and several balancing mechanisms managed by the System Operator. In order to participate in these markets, plants must have offered their output in the day-ahead market first. Electricity producers and consumers can also enter into bilateral contracts whose quantities have to be communicated to the Market Operator, or auctioneer, on an hourly basis one day ahead.

In our empirical analysis, we analyze bidding in the day-ahead market and arbitrage between the day-ahead market and the first intraday market (which we refer to as the spot market). Both markets concentrate the vast majority of all trades, contributing to approximately 80% of the final electricity price. The day-ahead market opens every day at 12 pm to determine the exchange of electricity to be delivered each hour of the day after. It is organized through a uniform-price central auction mechanism. On the supply side, producers submit price-quantity offers specifying the minimum price at which they are willing to produce with each of their units. The demand side works as a mirror image. The auctioneer ranks the supply bids in an increasing order and the demand bids in a decreasing order so as to construct the aggregate supply and demand curves, respectively. The market clears at the intersection of the two: the winning supply (demand) units are those that bid below (above) the market-clearing price. All winning units receive (pay) such price.

The intraday markets work in a similar fashion as the day-ahead market, with the difference being that all units - regardless of whether they are supply or demand units - can enter both sides of the market in order to fine-tune their day-ahead commitments. For instance, if a supplier wants to sell less (more) than its day-ahead commitment, it can submit a demand (supply) bid in the intraday markets. The same applies to consumers.

The first intra-day market opens at 4pm on the day-ahead, 4 hours after the day-ahead market. Because of their volume of trade, our empirical analysis will focus on comparing the day-ahead and the first intra-day market (which we will refer to as the *spot market*). Firms face a fine if their actual production deviates from their final commitment, which provides strong incentives to avoid imbalances.

In some cases, non-strategic reasons can give rise to differences between the day-ahead and the final commitments. For instance, a plant might suffer an outage after the day-ahead market has closed, forcing it to buy back whatever it committed to produce. Similarly, a renewable producer might have to buy or sell additional output if its wind or solar forecasts turn out to be wrong.

However, in other cases, such differences might be explained by strategic considerations. In particular, if market agents expect a positive price difference between the day-ahead and intraday markets, they might want to engage in arbitrage. Producers oversell in the day-ahead market at a high price and buy back their excess production in the intraday market at a lower price. Similarly, retailers delay their purchases to the intraday market as much as they can.

However, as we considered in the theoretical analysis, the rules of the Spanish electricity market impose some constraints on arbitrage. In particular, supply (demand) bids have to be tied to a particular generation (consumption) unit, and the quantity offered (demanded) cannot exceed their maximum production (consumption) capacity. This implies that renewable plants (or big consumers and retailers) have relatively more flexibility to arbitrage than coal or gas plants, as these are more often operating at capacity. For instance, renewables can offer to produce at their nameplate capacity in the day-ahead market even when they forecast that their actual available capacity will be lower. Likewise, retailers can commit to consume below or above their expected consumption knowing that they will have more opportunities to trade in the intraday markets.

Beyond differences in the ability to arbitrage, the regulation also introduces differences in their incentives to do so, across technologies and market agents. Big customers and retailers face full price exposure, as they pay the market price and can keep any potential profits from arbitrage. Instead, the incentives of renewable producers to arbitrage depend on the pricing scheme they are subject to. We next describe the pricing schemes of Spanish renewables, which are key for our identification strategy.

3.2 Pricing schemes for renewables

The pricing schemes for Spanish renewables have been subject to various regulatory changes.[17] In our empirical analysis, we will exploit the occurrence of the two most recent regulatory changes affecting wind operators.

Prior to February 2013, the existing regulation (Royal Decree 661/2007) gave all wind producers the ability to choose between two pricing schemes: either a Feed-in-Premium (FiP) or a Feed-in-Tariff (FiT). Under the FiP option, wind producers had to sell their electricity directly into the wholesale market and would receive a premium payment on top. Under the FiT option, wind producers were obliged to bid their output at a zero price into the wholesale market and would receive a fixed price for it (RD 661/2007; article 31). Since expected payments under the FiP option were notably higher than under the FiT option, the vast majority of wind operators opted for the former. Hence when, on 2 February 2013 (Royal Decree Law 2/2013), the Government decided to abolish the FiP option "without any former notice",[18] all wind producers were *de facto* moved from FiP to FiT.

The FiT regime only lasted until June 2014, when the government published the details for computing a new remuneration for each type of renewable installation (the Royal Decree 413/2014 was published on June 6, and Ministerial Order IET 1045/2014 that came into force on June 21).[19] In two earlier pieces of legislation (Royal Decree 9/2013 on July 14, 2013, and Law 26/2013 on December 27, 2013), the Government had already announced the main guidelines of the new regulation, but it did not actually implement it until June 2014.[20]

In general terms, the new scheme that was introduced in June 2014 (still in place) moved all renewable generators to FiP. They have to sell their production into the Spanish electricity wholesale market and receive the market price for such sales plus additional

[17] See del Rio (2008) for an overview of the changes up to 2007, and Mir-Artiguesa, Cerda and del Rio (2014) for the 2013 reform.

[18] The quotes are taken from 'Pain in Spain: New Retroactive Changes Hinder Renewable Energy', published in April 2013 at www.renewableenergyworld.com. Similar quotes can be found in other industry publications.

[19] Various reasons explained these changes, including the regulator's lack of a forward-looking understanding of market performance as well as the attempt to hide payment cuts under the change of pricing format. Prior to 2013, market prices were relatively higher as compared to the fixed tariffs. Hence, the regulator thought that by moving wind producers to the fixed price regime their payments would be reduced. The opposite occurred prior to the 2014 regulatory change.

[20] We have ran placebo tests with these dates, which show that these laws had no effect.

regulated payments.[21] The latter is based on technology and vintage specific standards, and are thus independent of the actual market revenues made by each firm. In particular, the old wind farms (i.e., those that were commissioned before 2005) do not receive any additional payment under the premise that they had previously received enough revenues to cover their investment costs. Hence, some differences exist mainly in the level of support. Nonetheless, the pre-February 2013 FiP and the post-June 2014 FiP have one thing in common: renewable producers are exposed to market prices.

3.3 Data

We use different sources of data on bids, costs, actual and forecast renewable production, and weather data. First, we use detailed bid data from the Iberian market operator (OMIE), which reports all the supply and demand functions submitted by all plants, every hour, in the day-ahead market as well as in the intraday markets. We match the plants' bid codes with the plants' names to obtain information on their owners and types (e.g., for supply units, we know their technology and maximum capacity; for demand units, we know whether they are big customers with direct market access, retailers of last resort, or liberalized retailers). With these bid data, we can construct each firm's residual demand by subtracting the supply functions of all its competitors from the aggregate demand curve. We also observe the market-clearing price, the marginal unit that set it, and the units that submitted prices close to it.

Second, we have data on the cost characteristics of all the coal plants and Combined Cycle Gas Turbines (CCGTs), including their efficiency rates (i.e., how much fuel they burn per unit of electricity) and their emission rates (i.e., how much carbon they emit per unit of electricity). Together with Bloomberg daily data on coal prices (API2), gas prices (TTF), and CO2 prices (ETS), we compute engineering-based estimates of each thermal plant's marginal cost, on a daily basis.[22] While these are reliable sources of

[21] These include a remuneration per MW of installed capacity, meant to compensate those investment costs that cannot be reasonably recovered through the market, and a remuneration per MWh produced, meant to cover the costs of operating the plants. These two regulated payments are based, not on the actual investment costs or market revenues of the plant, but rather on those of a so-called *efficient and well-managed company* subject to technology-dependent standards.

[22] A 7% tax was levied at the start of 2013 on all electricity producers, including both conventional and renewables. We take this into account when computing marginal costs in our empirical analysis.

cost data,[23] we cannot rule out measurement errors. For instance, the price of coal and gas in international markets need not reflect the correct opportunity cost firms face when burning their fossil fuels. This might be due to transaction costs, transportation costs, or contractual constraints on firms' ability to resell the gas they buy on long term contracts. Indeed, large disparities between the load factors of various CCGTs in the market suggest that one of the dominant firms might have had access to cheaper gas, well below the price of gas in the international exchanges.[24]

Third, we use publicly available data provided by the System Operator (REE) on the hourly production of all the plants in the Spanish electricity market, including the fraction that they sold through the market or through bilateral contracts.[25] These data allow us to compute, on an hourly basis, the market shares of the various technologies (including renewables) and firms. Since we observe the supply and demand allocated to the vertically integrated firms, we can compute their hourly net positions, i.e., their production net of their bilateral contracts and vertical commitments.[26] Furthermore, by computing each plants' day-ahead and final commitments, we can assess whether firms engaged in arbitrage markets. The System Operator also provides detailed information on the hourly demand and wind forecasts one day ahead, right before the market opens.

Last, we also use publicly available weather data (including temperature, wind speed, and precipitation) provided by the Spanish Meteorological Agency (AEMET).

In order to encompass the two main regulatory changes affecting renewables in the Spanish electricity market, the time frame of our empirical study runs from February 2012 until February 2015. During this period, there were no major capacity additions

[23]The cost parameters were provided to us by the Spanish System Operator (REE). We previously used them in Fabra and Toro (2005) and Fabra and Reguant (2014), and we have recently updated them to include the new capacity additions. The efficiency and emission rates are in line with standard measures for each technology, but incorporate finer heterogeneity across plants, e.g., reflecting their vintage, or, for the coal plants, incorporating the exact type of coal they burn which affects both their efficiency as well as their emission rate.

[24]For instance, as reported by REE, in 2014 Gas Natural's CCGTs had the highest load factors (22% on average, as compared to 4% of all the other CGGTs). Notably, this was true also for twin CCGTs (i.e., at the same location and same vintage, owned by different companies). For instance, Besos 4 owned by Gas Natural operated at a 65% load factor, while Besos 3 owned by Endesa operated at an 8% load factor. The same was true for San Roque 1 (owned by Gas Natural, 59% load factor) and 2 (owned by Endesa, 12% load factor).

[25]One drawback of these data is that it does not include information on the units located in Portugal. However, as these plants were not affected by the regulatory changes implemented by the Spanish Government, we exclude them from the analysis.

[26]We do not include vertical commitments due to regulated sales since these are simply pass-through market prices to the final consumers.

or other relevant changes in the market structure. There were three main vertically-integrated firms, which we refer to as the *dominant firms*: Iberdrola (firm 1), Endesa (firm 2), and Gas Natural (firm 3). They all owned various technologies, with differences in the weight of each technology in their portfolios. Notably, Iberdrola was the largest wind producer, while Gas Natural was the main owner of CCGTs.[27] There was also a fringe of conventional producers, renewable producers, and independent retailers. The market structure in the renewable segment was more fragmented than in the conventional segment. The market shares for the dominant firms and the fringe were (60%, 40%) in the renewable segment and (80%, 20%) in the conventional segment. Annual renewable production ranged from 42% to 45% of total generation, and the rest came from nuclear (19%), hydro (10% to 18%), coal (13% to 15%) and CCGTs (3% to 9%).

Table 1 reports the summary statistics. We use hourly data in all of our analysis and there were a total of 26,304 hourly observations, split into 8,784 observations for the first period with FiP (1 February 2012 to 31 January 2013), 12,120 observations for the period with FiT (1 February 2013 to 21 June 2014) and 5,400 observations for the second period with FiP (22 June 2014 to 31 January 2015). The day-ahead price ranged between 38 to 52 Euro/MWh, being lower on average but also more volatile during the FiT period. The spot market price was consistently lower than the day-ahead price. The average price differential across the two markets ranged between 0.3 and 1.2 Euro/MWh, being lower during the FiP II period. Demand and wind forecasts were similar on average across all three periods.

3.4 A first look at the data

It is illustrative to provide a first look at the raw data. Figure 1 depicts the evolution of the price differences between the day-ahead and the spot market. It shows that the price differences across markets were positive, and tended to be smaller at the end of the sample period when firms were paid according to market prices (FiP II).[28]

Figure 2 plots the difference between the day-ahead and the final output commitments for wind plants belonging to the fringe and to the dominant firms (positive numbers

[27] This explains why Gas Natural is the price-setter during a large fraction of the time. This, together with the fact that Gas Natural had long-term contracts for gas at prices below the international spot price for gas, explains why we sometimes find negative markups in the day-ahead market prices.

[28] The average price differences conditional on the hour of the day can be seen in Figure B.1 in the Appendix. The hourly plot gives a similar conclusion. Recall that, even though wind was exposed to market prices under both FiP I and FiP II, these two regulatory regimes were not the same. Notably, the level and scope of the support were different. Moreover, renewables other than wind were subject to fixed prices under FiP I and to market prices under FiP II.

Table 1: Summary Statistics

	FiP I		FiT		FiP II	
	Mean	SD	Mean	SD	Mean	SD
Price Day-ahead	50.2	(13.8)	38.1	(22.2)	52.0	(11.2)
Price Intra-day 1	48.9	(14.2)	37.2	(22.1)	51.7	(11.7)
Price premium	1.2	(5.0)	1.0	(5.6)	0.3	(3.9)
Marginal Cost	47.5	(6.6)	42.3	(7.2)	37.0	(3.8)
Demand Forecast	29.8	(4.8)	28.5	(4.6)	28.1	(4.3)
Wind Forecast	5.7	(3.4)	6.5	(3.6)	5.0	(3.2)
Dominant wind share	0.6	(0.0)	0.7	(0.0)	0.6	(0.0)
Fringe wind share	0.4	(0.0)	0.3	(0.0)	0.4	(0.0)
Dominant non-wind share	0.8	(0.0)	0.8	(0.1)	0.8	(0.1)
Fringe non-wind share	0.2	(0.0)	0.2	(0.1)	0.2	(0.1)

Notes: Sample from 1 February 2012 to 31 January 2015. FiP I is from 1 February 2012 to 31 January 2013; FiT 2013 is from 1 February 2013 to 21 June 2014; FiP II is from 22 June 2014 to 31 January 2015. Prices are in Euro/MWh. Demand and wind forecasts are in GWh.

reflect overselling in the day-ahead market, while negative numbers reflect withholding). As can be seen, when paid according to fixed prices (FiT), the fringe wind producers did not engage in arbitrage (i.e., on average, they sold all of their output in the day-ahead market). Instead, when paid according to variable prices (FiP I and FiP II) they actively engaged in arbitrage by overselling their wind output in the day-ahead market.[29]

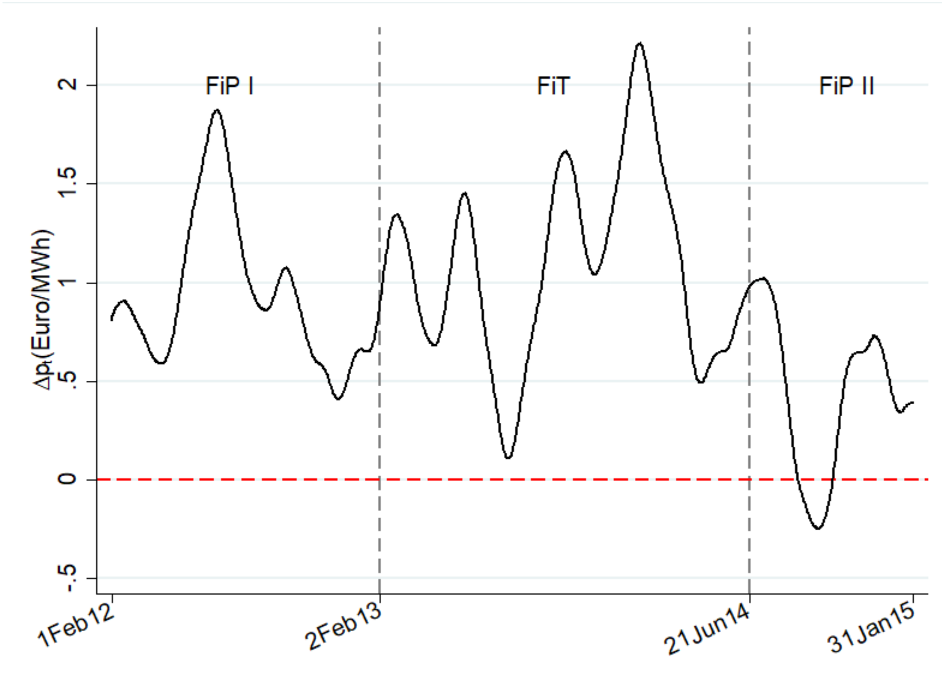
The change in the pricing schemes also had a strong impact on the dominant producers' behavior. The dominant producers withheld more wind output across markets when exposed to variable prices, notably so after the switch from FiT to FiP II.[30]

While these figures suggest that changes in the pricing schemes had a strong impact on firms' bidding behavior, it would be misleading to derive further conclusions from these figures alone. First, since these three pieces - price differences, overselling, and withholding across markets - are all jointly determined in equilibrium, they cannot be

[29]This is consistent with Ito and Reguant (2016), who showed that fringe firms stopped arbitraging after the switch from FiP I to FiT. Our results further show that they resumed arbitrage after the switch from FiT to FiP II. The smaller amount of arbitrage by wind plants is likely due to the smaller price differences across markets.

[30]Figure B.2 in the Appendix shows that these effects showed up not only on average, but also across all hours of the day, and particularly so at peak times.

Figure 1: Price discrimination across markets

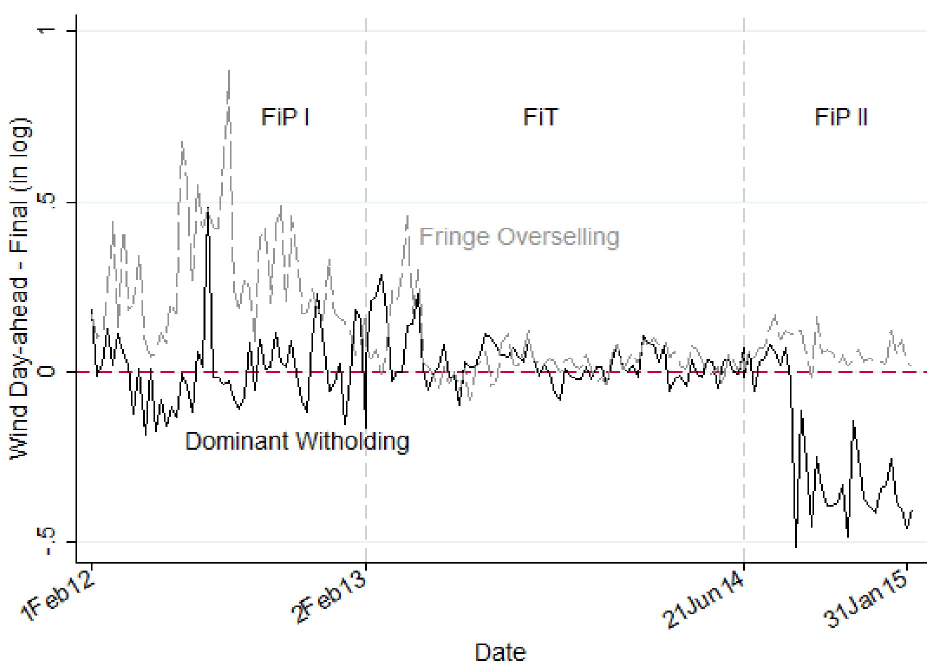


Notes: This figure is a smoothed plot of the price premium (day-ahead price minus the price in the first intra-day market) using a locally weighted regression. The weights are applied using a tricube weighting function (Cleveland, 1979) with a bandwidth of 0.1. The sample ranges from 1 February 2012 to 31 January 2015.

assessed in isolation. For instance, why did the dominant firms start withholding when they were moved to variable prices? Is it because variable prices led to more market power than fixed prices, or is it because arbitrage by the fringe reduced the price differences so much, to the extent that withholding across markets was no longer costly? Furthermore, one needs to take into account the dominant firms' overall behavior, not just the one that is reflected in the supply of their wind plants. For instance, did the dominant firms compensate the increase in withholding by the wind plants with a reduction in withholding with other plants? Last, but not least, exogenous changes in some of the relevant variables (e.g., wind availability, or demand factors) could also be confounding some of the effects.

Therefore, to properly analyze the impacts of renewables pricing rules on market power and price discrimination, one needs to undertake a deeper empirical analysis, an issue to which we devote the rest of the paper.

Figure 2: Overselling and withholding across markets by wind producers



Notes: This figure shows the day-ahead minus the final commitments of wind producers belonging to both the dominant and the fringe firms. Positive numbers reflect overselling, while negative numbers reflect withholding. The vertical lines date the changes in the pricing schemes for renewables.

4 Empirical Analysis

In this section, we perform an empirical analysis of the market impacts of renewables pricing schemes. To disentangle the mechanisms at play, we decompose the analysis in four steps. First, we perform a structural analysis of the determinants of the dominant firms' price-setting incentives in the day-ahead market. Second, we use a differences-in-differences approach to assess the effects of pricing schemes on the fringe's incentives to engage in arbitrage. Third, we analyze the determinants of price discrimination across markets, including the impact of changes in the pricing schemes. Last, we leverage on our structural estimates to construct estimates of market power under the two pricing schemes.

4.1 Price-setting incentives in the day-ahead market

We use a structural approach to assess whether the changes in the renewables' pricing schemes affected the price-setting incentives of the dominant producers in the day-ahead market.

Building on our theoretical analysis, and in line with standard oligopoly models, the first order condition of profit maximization can be written as

$$p = c_i + \left| \frac{\partial DR_i}{\partial p} \right|^{-1} (q_i - I_t w_i), \tag{10}$$

where $I_t = 1$ when renewable output receives fixed prices (FiT) and $I_t = 0$ otherwise (FiP). In words, the market price p equals the marginal cost c_i of the price-setting firm, plus a markup component which captures the firm's ability to exercise market power. The markup is decreasing in the slope of the residual demand faced by the firm, DR_i, and it is increasing in the firm's output that is exposed to market prices. Under variable prices (FiP), this includes the firm's total sales, net of its vertical and forward contract commitments, i.e., q_i. Under fixed prices (FiT), it only includes its non-wind net sales, i.e., $q_i - w_i$.

The above first-order condition is not only valid for the price-setting unit, but also for those units with an ex-ante positive probability of setting the market price. Accordingly, in our analysis, we include all the units with bids around the market-clearing price (within a 1 Euro/MWh range)[31] belonging to one of the dominant firms.[32] We exclude (i) hydro units (since it is difficult to assess the true opportunity costs of using their stored water), as well as (ii) units that operate on either the first or last step in their bidding functions (since their constraints for reducing or increasing their output might be binding, invalidating the use of the above first-order condition).[33]

Our detailed bid data allows us to construct all the variables in the first-order condition (10), as described in Section 3. Notably, since we observe all bids, we can build the realized residual demand curve faced by each firm and compute its slope at the market-clearing price. We fit a quadratic function to the residual demand curve and calculate the slope at the market-clearing price (see Figures B.6 in the Appendix for an illustration).[34]

[31] Results are robust to making this range slightly larger to increase the number of observations. Table B.1 in the Appendix reports the results using a 5 Euro/MWh range.

[32] If a dominant firm owns more than one unit with these characteristics, we include them all in the analysis.

[33] We follow a similar approach as Fabra and Reguant (2014) and Reguant (2014).

[34] Approximating the slope of residual demand is common in the existing literature, see also Wolak (2003); Reguant (2014); Fabra and Reguant (2014); Ito and Reguant (2016). To avoid the flat region of the inverse residual demand curve occurred at zero price, which makes our linear approximation poorly predict the local slopes, we truncate the residual demand to the minimum quantity that firms are willing to serve at zero price. Note that we also explore the other alternative methods such as kernel smoothing around the market price (Reguant, 2014) and fitting linear splines with 10 knots to the residual demand curve. Our conclusions are similar regardless the method of approximation we use.

Pricing schemes might affect the slope of the residual demand through several channels, as they affect equilibrium bidding in the day-ahead market as well as arbitrage by the fringe or withholding by the dominant firms across markets, or both. However, since we can control for the slopes of firms' residual demands, our focus here is on whether the dominant firms internalize the changes in their wind output when setting prices, and whether this depends on the pricing scheme in place, as predicted by our theoretical model.

For this purpose, we estimate the following empirical equation in hours t in which firm i is bidding at or close to the market-clearing price:

$$b_{ijt} = \rho c_{ijt} + \beta \left| \frac{q_{it}}{DR'_{it}} \right| + \sum_{s=1}^{3} \theta^s \left| \frac{w_{it}}{DR'_{it}} \right| I_t^s + \alpha_{ij} + \gamma_t + \epsilon_{ijt}, \tag{11}$$

where b_{ijt} is the marginal bid of firm i when bidding at or close to the market-clearing price with unit j at time t; c_{ijt} is the marginal cost of the price-setting unit j belonging to firm i at time t; q_{it} is firm i's total sales net of its vertical and forward commitments at time t; DR'_{it} is the slope of firm i's residual demand at time t at the market-clearing price; w_{it} is firm i's wind output at time t; I_t^s are three indicator variables for each pricing scheme (FIP I, FIT, and FIP II);[35] α_{ij} are unit fixed effects, γ_t are time fixed effects. We include unit and quarterly fixed-effects, while month, day-of-the-week, and hour fixed effects are added in a cumulative fashion. We force the intercept to be zero to satisfy our structural equation (i.e., when the marginal cost and markup terms equal zero, we expect the price to be zero as well). ϵ_{ijt} is the error term clustered at the week of sample to allow errors to be correlated within the same week.

Since we want to understand whether firms' markups are affected by their wind output, our parameter of interest is θ. We expect it to take a negative value under fixed prices (FiT), but we expect it to be not significantly different from zero under variable prices (FiP). This would reflect that firms do not (do) internalize the price effects on their wind output when it is paid at fixed (variable) prices.

When estimating equation (11), it is important to realize that marginal costs are likely to be endogenous. In particular, the identity of the marginal unit, and thus its marginal cost, is potentially affected by supply and demand shocks, some of which might be unobservable. Indeed, the marginal cost of the marginal unit is strongly and negatively correlated with wind: the more wind there is, the smaller is the residual demand that

[35] We define the FiP I, FiT, and FiP II indicator variables using the February 1, 2013 and June 22, 2014 cutoffs, respectively, which is when the regulatory changes were fully implemented, as described in Section 3.4.

has to be satisfied with the remaining non-wind units, and thus the lower is the marginal cost of the price-setting unit. Similarly, the slope of the residual demand at the market-clearing price might be endogenous, thus making the markup terms endogenous as well.

To address these concerns, we instrument the two endogenous variables in equation (11): the marginal cost of the marginal unit, c_{ijt}, and the slope of the day-ahead residual demand, DR'_{it}. We use nine instruments: wind speed and precipitation (and each of them interacted with three dummies for the pricing scheme) as residual demand shifters, and the carbon price as one of the key components of the marginal cost. The exclusion restriction holds under the assumption that, conditional on unit and time fixed effects, wind speed, precipitation, and the carbon price affect firms' marginal bids only through the marginal cost and through our markup parameters. This assumption is plausible and common in the literature (Fabra and Reguant, 2014; Ito and Reguant, 2016). The carbon price is set in international markets, thus independently of what happens in the Spanish electricity market. While wind speed and precipitation may influence the firm's inframarginal quantity, they are unlikely to influence the marginal quantity directly. We then use Two-Stage Least Squares (2SLS) regression to estimate equation (11).

The results are shown in Table 2. In columns (1)-(3), we constrain the coefficient on the firm's markup over its total output to be equal to one. In all specifications, the marginal cost coefficient is positive, and close to 1, as expected. The results confirm that wind output has a significant price-depressing effect when renewable output is paid at fixed prices, but it has a small and noisy effect otherwise, consistently with our predictions. Moreover, these coefficients are stable across the different specifications, reassuring robustness regardless of the set of fixed effects we use. In column (4), we allow the coefficient for the firm's total output markup to vary.[36] The estimated coefficient for the FiT indicator variable is still similar, although smaller relative to the other specifications. The sign of the coefficient for the firm's total output markup is positive as expected, as more output and a steeper residual demand enhance market power.

It would be misleading to compare the coefficients on the various variables given that their means are very different. To get some orders of magnitude of the *forward contract effect*, take for instance the mean of a dominant firm's hourly wind production during FiT, 277 MWh, over the mean of the slope of its residual demand, 398 Euro/MWh. Using the estimates in our preferred specification, column (3), an increase in wind output of ten percent over its mean would imply a price reduction of 1.8 Euro/MWh (approximately, a 4 percent reduction over the average price) during the FiT period.

[36] For this specification, we add minimum temperature as an additional instrument as we have markups from total output as an additional endogenous variable.

Table 2: The Forward Contract Effect

	2SLS			
	(1)	(2)	(3)	(4)
Marginal Cost_{it}	0.97**	0.96***	0.99***	0.86***
	(0.39)	(0.29)	(0.31)	(0.30)
FiP I $\times \frac{w_{it}}{DR'_{it}}$	-2.15	-7.78	-9.00*	-9.57*
	(7.22)	(5.18)	(5.08)	(4.95)
FiT $\times \frac{w_{it}}{DR'_{it}}$	-29.1***	-24.3***	-25.5***	-18.3***
	(7.96)	(7.28)	(7.15)	(6.17)
FiP II $\times \frac{w_{it}}{DR'_{it}}$	-0.18	1.74	-0.040	0.46
	(7.76)	(6.30)	(6.67)	(5.46)
$\frac{q_{it}}{DR'_{it}}$				2.94**
				(1.26)
Month and DoW FE	N	Y	Y	Y
Hour FE	N	N	Y	Y
Observations	13,328	13,328	13,328	13,328

Notes: This table shows the estimation results of equation (11) using 2SLS. All regressions include unit and quarterly dummies, while month, day-of-the-week, and hour fixed effects are added in a cumulative fashion in columns (2) and (3). We constraint the coefficient for markups from firm's total output to be one in columns (1) to (3), and we relax this by allowing the markup coefficient to be varied in column (4). We limit hourly prices to be within 1 Euro/MWh range relative to the market price and exclude the outliers (bids with market prices below the 1st percentile and above the 99th percentile). FiP I, FiT, FiP II are indicators for days during 1 February 2012 - 31 January 2013, 2 February 2013 - 21 June 2014, 22 June 2014 - 31 January 2015. We instrument markups and the marginal cost with wind speed, precipitation, each of them interacted with three indicators of pricing scheme, and the carbon price. The standard errors are clustered at the week of sample.

4.2 Arbitrage across markets

Since day-ahead prices were systematically higher than prices in the spot market, fringe producers had an incentive to engage in arbitrage by overselling in the day-ahead market at high prices and buying back their excess supply at the lower spot market price. However, differences between the day-ahead and the final commitments could also be explained by non-strategic reasons, such as wind or demand forecast errors. What distinguishes arbitrage from non-strategic reasons is that the former is linked to price differences across markets, whereas the latter are not. Accordingly, in order to understand whether pricing rules affected firms' incentives to engage in arbitrage, we examine whether the response of overselling to the predicted price differential differed when renewables were paid according to fixed (FiT) or variable prices (FiP).[37]

One approach would be to regress the differences between the day-ahead and the final output commitments on the price differential, interacted with a dummy variable for each pricing regime. However, one potential concern of this approach is that other unobservable time-variant factors may also influence arbitrage through the price differential. Not properly accounting for these factors might result in an omitted variable bias. To address this concern, we compare the price response of wind producers with that of two potential control groups: (i) non-wind renewable producers (i.e., solar, small hydro and cogeneration units), and (ii) retailers in the liberalized market. On the one hand, the non-wind renewable producers were subject to fixed prices until the second regulatory change, when they were also moved into variable prices (FiP) just like wind. Hence, their incentives to engage in arbitrage should be similar to those of wind during the FiT and the FiP II regimes but should differ during the FiP I regime. On the other hand, retailers should always have incentives to engage in arbitrage, just like wind under the FiP regimes, and unlike wind during the FiT regime.

We want to understand how the fringe firms reacted to changes in the price differential across markets that they could forecast at the time of bidding. For this purpose, we first construct a forecasted price premium using two exogenous variables that were available to firms prior to bidding: demand and wind forecasts.[38] Specifically, we regress demand and wind forecasts, hourly dummies, and date dummies on the price premium.[39] We then use the regression coefficients to obtain the forecasted price premium at time t, $\Delta\hat{p}_t$.

To illustrate the similarities and differences between the price response of wind producers, non-wind renewable producers, and retailers, we first document the response of

[37]Our results are consistent with Ito and Reguant (2016), who show that after the first regulatory change, from FiP to FiT, fringe producers stopped arbitraging. We further show that the second regulatory change, from FiT to FiP, had the opposite effect. Unlike their event study analysis, we rely on a differences-in-differences approach using two possible control groups.

[38]Note that this also removes concerns about the potential endogeneity between the price premium and arbitrage.

[39]The estimating equation is $\Delta p_t = \alpha D_t^{fc} + \beta w_t^{fc} + X_t + Y_t + \epsilon_t$, where the two first regressors are the demand and wind forecasts. We allow all the coefficients to vary across pricing regimes considering that firms are aware of the different degrees of arbitrage, so the relationship between the price premium, demand, and wind forecasts need not be the same. The errors are clustered within day. The regressions have R-squared ranging from 0.3 - 0.4.

each group's arbitrage to the predicted price premium on a quarterly basis. We regress the forecasted price premium, $\Delta\hat{p}_t$, on the difference between the logs of the day-ahead and the final commitments of firms in group g (wind producers, non-wind renewable producers, and retailers), $\Delta \ln q_{tg}$. Our sample includes 13 quarters, from Q1 2012 to Q1 2015. We control for demand and wind forecast errors, denoted D_t^{er} and w_t^{er}, as these could give rise to differences between day-ahead and final commitments which are unrelated to arbitrage.[40] We also control for seasonality (i.e., through dummies for days-of-the-week and week of sample dummies), for daily solar radiation, daily precipitation, and temperature, all captured in $\mathbf{X}_t$. The estimating equation is

$$\Delta \ln q_{tg} = \alpha + \sum_{q=1}^{13} \theta_g^q \Delta\hat{p}_t + \gamma D_t^{er} + \delta w_t^{er} + \rho \mathbf{X}_t + \eta_{tg} \tag{12}$$

where η_{tg} is the error term. Our coefficients of interest are θ_g^q, which capture the response of arbitrage by group g at quarter q to the predicted price differential. We cluster standard errors at the week of sample.

Figures 3 and 4 plot the θ_g^q coefficients for each quarter.[41] As expected, in Figure 3, during the FiT regime (Q1 2013 to Q2 2014), the price response of arbitrage by the non-wind renewable producers is similar to that of wind producers and not significantly different from zero. Similarly, in Figure 4, during the FiT regime (Q1 2013 to Q2 2014), the price response of the retailers' arbitrage is positive and very similar to that of the wind producers during the FiP I and FiP II regimes (2012 and Q3 2014 onwards). These periods (FiT regime in Figure 3 and FiP regimes in Figure 4) provide graphical evidence on the parallel trend between wind and each of the control groups.[42]

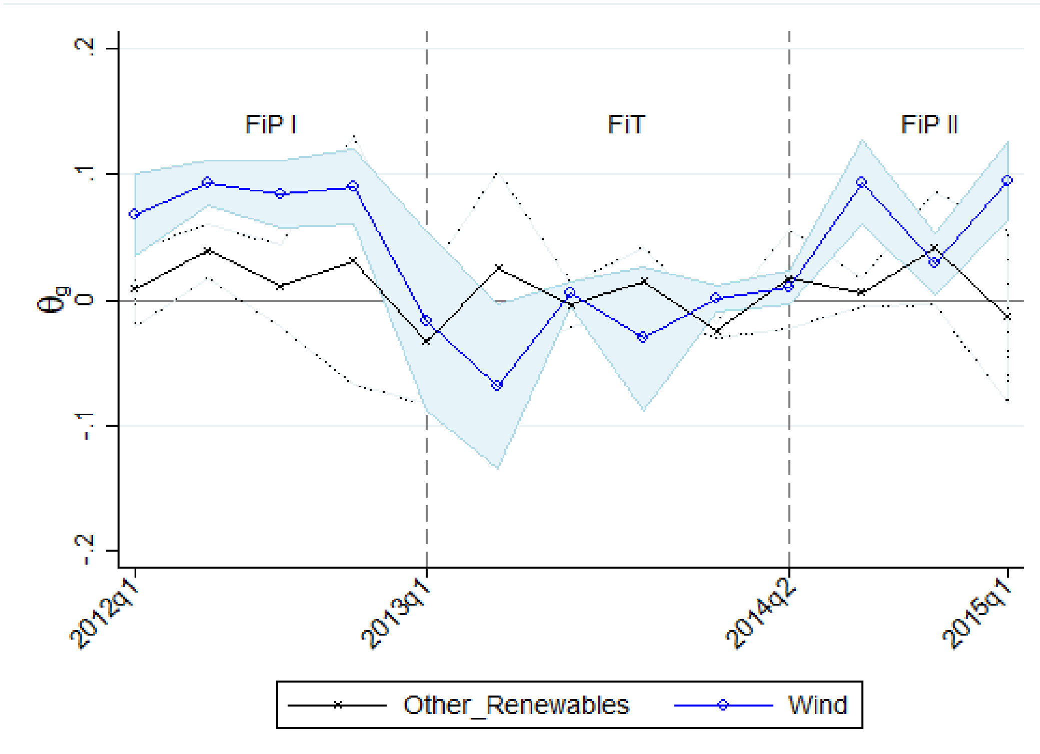
Equipped by the graphical evidence, we proceed to analyze the overselling behavior of wind fringe using the differences-in-differences (DiD) approach. To measure the impact of renewables pricing schemes on arbitrage, we split the sample in two, each of which contains one regulatory change. The first sample ($d = 1$), which ranges from February 1, 2012, to February 1, 2014, contains the change from variable to fixed prices that took place on February 1, 2013. The second sample ($d = 2$), which ranges from February 1,

[40]Demand and wind forecast errors are computed by subtracting the hourly forecast and the observed values. The forecast values are publicly available to firms the day before.

[41]For this graphical evidence, hours when the predicted price differential gives a poor prediction for the observed price differential are excluded (i.e., when the difference between predicted and observed price differential is above the 50th percentile). Figure B.3 in the Appendix shows that, in some hours, the predicted price differential departs substantially from the observed one, probably due to some unobservables not included in our estimating equation.

[42]The statistical test for the parallel trend is provided in Table B.2 in the Appendix.

Figure 3: Arbitrage by Fringe Wind vs. Non-Wind Renewables



Notes: This figure plots the coefficients of the OLS regression in equation (12) for wind and other non-wind renewable producers (i.e., solar, small hydro, and co-generation production units). It captures the response of overselling to the predicted price differential. Positive numbers suggest that overselling was increasing in the predicted price differential. No strategic price arbitrage is associated with a zero coefficient. The sample includes hours from 1 January 2012 to 31 March 2015 to ensure that the number of observations is comparable in each quarter. Hours when the predicted price differential gives a poor prediction for the observed price differential are excluded.

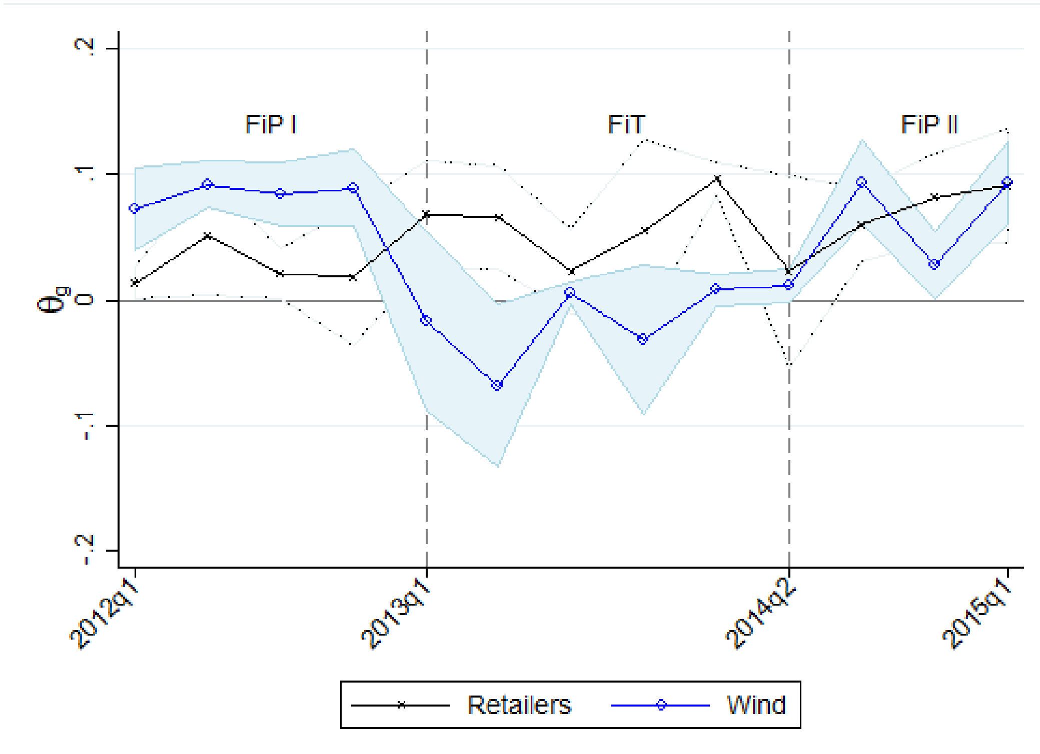
2013, to January 31, 2015, contains the change from fixed to variable prices that took place on June 22, 2014.

Following a DiD approach, we run four separate OLS regressions, one for each sample $d = 1, 2$ and each control group $g=$ non-wind renewables, retailers. To measure whether overselling responded to the predicted price premium, we estimate the following equation,

$$\begin{aligned}\Delta \ln q_t =& \alpha + \beta_1 W I_t^d \Delta\hat{p}_t + \beta_2 W \Delta\hat{p}_t + \beta_3 W I_t^d + \beta_4 I_t^d \Delta\hat{p}_t + \beta_5 \Delta\hat{p}_t + \\ & \beta_6 W + \beta_7 I_t^d + \rho \mathbf{X}_t + \eta_t\end{aligned} \tag{13}$$

For sample $d = 1$, which contains the switch from variable to fixed prices, I_t^1 is an indicator for fixed prices (FiT); for sample $d = 2$, which contains the switch from fixed to variable prices, I_t^2 is an indicator for variable prices (FiP). For both samples, W is an indicator for the treated group, i.e., wind fringe producers. We include a set of control

Figure 4: Arbitrage by Fringe Wind vs. Retailers



Notes: This figure plots the coefficients of the OLS regression in equation (12) for wind producers and independent retailers. It captures the response of overselling to the predicted price differential. Positive numbers suggest that overselling was increasing in the predicted price differential. No strategic price arbitrage is associated with a zero coefficient. The sample includes hours from 1 January 2012 to 31 March 2015 to ensure that the number of observations is comparable in each quarter. Hours when the predicted price differential gives a poor prediction for the observed price differential are excluded.

variables such as the hourly demand forecast error, the hourly wind forecast error, week of sample fixed effects, and day-of-week fixed effects. Standard errors are clustered at the week of sample.

Our coefficient of interest, β_1, captures the change in the price response of arbitrage by wind producers relative to the control group. We expect the sign of this coefficient to be negative using sample 1, as the switch from variable to fixed prices should reduce the wind producers' incentives to engage in arbitrage. On the contrary, we expect the coefficient for β_1 to be positive using sample 2, as the switch from fixed to variable prices should induce wind producers to engage in arbitrage again.

We report the β_1 coefficients in Table 3.[43] The impact of the switch from variable prices (FiP) to fixed prices (FiT) is shown in columns (1) and (2), depending on whether

[43]The complete results with the overselling response to price premium (and its corresponding p-values) are reported in the Appendix Table B.2.

we use non-wind renewables or retailers as the control group, respectively. In both cases, the negative coefficients show that this switch reduced arbitrage relative to both control groups, and by a similar magnitude. In contrast, the impact of the switch from fixed (FiT) to variable prices (FiP), shown in column (3), was positive, thus indicating that this switch brought wind fringe producers back to arbitrage.[44] Overall, these results are all consistent with our predictions.

Table 3: Impacts of Changing the Pricing Schemes on Overselling by Wind

	Non-wind renewables	Retailers	
	(1)	(2)	(3)
$\Delta\hat{p}\times$ Wind $\times$ FiT	-0.071***	-0.069***	
	(0.0068)	(0.014)	
$\Delta\hat{p}\times$ Wind $\times$ FiP			0.059***
			(0.011)
Observations	41,080	41,080	34,194

Notes: This table shows the β_1 coefficients from equation (13). Each column is a different regression using the log of overselling as the dependent variable. Non-wind renewables is the control group in columns (1), retailers in columns (2)-(3). Columns (1) and (2) use sample $d = 1$ from 1 February 2012 to 1 February 2014, with the FiT indicator equal to one for days after 1 February 2013, while column (3) uses the sample from 1 February 2013 to 31 January 2015, with the FiP equal to one for days after 22 June 2014. All regressions include seasonality controls, hour of day, and week fixed effects. Note that, Under FiP II, non-wind renewables are also affected by the regulation. Hence, we prefer not to use it as a control group in our analysis during FiP II period. The standard errors are clustered at the week of sample.

Having confirmed the empirical relevance of the forward contract and the arbitrage effects, we are now ready to assess how their interaction affected the extent of price discrimination and market power.

4.3 Price differences across markets

Our model predicts that price discrimination can be lower or higher under fixed prices relative to variable prices depending on the ownership structure of renewables. To test

[44] As mentioned earlier, during FiP II, all renewables are exposed to market prices, hence we expect to see their price responses are not very different with wind's. Here, we do not report the effect of the move from FiT to FiP II as the other renewables were also affected by it. The treatment effect is also positive, but smaller than that on column (3). See the Appendix Table B.2.

for this, we estimate the following empirical equation:

$$\Delta p_t = \alpha + \sum_{s=1}^{2} \beta_1^s I_t + \beta_2 w_t + \sum_{s=1}^{2} \beta_3^s w_t I_t + \alpha_1 D\hat{R}'_{1t} + \alpha_2 D\hat{R}'_{2t} + \gamma \mathbf{X}_t + \epsilon_t \qquad (14)$$

where Δp_t is the price premium at time t; I_t takes two values (1=FiP I and 2=FiP II), and it is zero during FiT (the reference point); $D\hat{R}'_{1t}$ and $D\hat{R}'_{2t}$ capture the (instrumented) slopes of the residual demands faced by the dominant firms in the day-ahead and intraday markets respectively;[45] and X_t is a set of controls, such as demand forecast and dummies for seasonality; last, ϵ_t is the error term.

The coefficient β_1 compares the extent of price discrimination across pricing schemes. Coefficients β_2 and β_3 capture the wind impacts on the price premium. Our theoretical model predicts that an increase in wind output should reduce the price differential relatively more when renewables are subject to fixed prices. Furthermore, the differences in the impact of wind across pricing schemes should be stronger when the share of the dominant firms' wind output goes up. We consider two main specifications to test these predictions. First, we focus on the interaction between the pricing scheme and the forecast of total wind (w_t) on price discrimination. Second, we look at the impact on price discrimination through its wind ownership structure. Here, we let w_t capture the share of the dominant firms' wind output over the fringe firms' wind output, w_{dt}/w_{ft}. Regarding the other coefficients, we expect that all the variables that enhance market power –a higher demand and a steeper (flatter) demand at day-ahead (spot)– also enlarge price differences.

Table 4 reports the results of estimating equation (14), which are broadly consistent with our theoretical predictions. In Column (1), we can see that the price premium is lower when firms are exposed to variable prices (FiP) relative to the period with fixed prices (FiT). The wind forecast is associated with a smaller price premium. However, wind enlarges the price premium under variable prices (FiP) relative to fixed prices (FiT). Columns (2) - (4) show that when the wind production of the dominant firms increases relative to that of the fringe, the price premium is relatively larger under the regimes with variable prices. The sign of the other coefficients, such as those on total demand

[45] We compute the aggregate hourly residual demand faced by the dominant firms in the day ahead and in the intraday markets using the same approach as discussed in footnote 34. Similar to our earlier concern, the slopes of the residual demands can be endogenous. Therefore, we instrument the two slopes of the residual demands in both markets (DR'_1 and DR'_2) with daily and hourly weather variables (daily average, minimum, and maximum temperature, and average temperature interacted with hourly dummies). Note that the demand forecast is predetermined before the day-ahead market, i.e., it is exogenous.

and the slopes of the residual demands in the day-ahead and in the intraday markets, are respectively positive, negative, and positive, as expected.

4.4 Market power in the day-ahead market

Our results in 4.1 showed that, given the observed residual demands, firms had weaker incentives to increase day-ahead prices when their renewable output was paid according to fixed rather than to variable prices. However, this alone does not allow us to conclude that reducing firms' price exposure mitigated market power in the day-ahead market. As our previous results also show, the pricing schemes also affected these residual demands through the impacts on overselling and price discrimination across markets. Therefore, to evaluate the overall impact of the pricing schemes on market power in the day-ahead market, in this section we compute and compare firms' markups across pricing regimes.

Using the first-order condition of profit-maximization, equation (10), markups can be expressed as

$$\frac{p - c_i}{p} = \left| \frac{\partial DR_i}{\partial p} \right|^{-1} \frac{q_i - I_t w_i}{p}$$

for $I_t = 1$ under FiT and $I_t = 0$ under FiP.

Leveraging on the structural estimates obtained in Section 4.1, Table 5 reports firms' average markups and Figure 5 shows the distribution.[46] Markups are always relatively lower under fixed prices: the average markup during the FiT regime was 6.3%, while it was 8.3% and 10.9% under the FiP I and FiP II regimes, respectively. A two-sample Kolmogorov–Smirnov test rejects at 1% significance level the hypothesis that the markup distributions are the same across pricing regimes. A similar conclusion applies when comparing the markups of each dominant firm individually, for off-peak versus on-peak hours, or for more windy or less windy hours. This evidence on the markups comparison is also consistent with the slopes of the residual demands being relatively larger under fixed prices, thus indicating that the weaker incentives to exercise market power induced firms to submit flatter supply functions. This effect seems to have played a stronger role than the absence of significant arbitrage.

[46]An alternative approach to computing markups is simply to rely on the observed prices and on engineering estimates for marginal costs. This approach is common in the literature (see Borenstein, Bushnell and Wolak (2002), Fabra and Toro (2005), or Fabra and Reguant (2014), among others). However, this approach leads to noisier markups due to potential measurement errors in the marginal cost estimates. For instance, we see some negative markups which could be explained by firms buying coal and gas through long-term contracts at prices below the spot market price. Nonetheless, our overall conclusion –that markups were lower under the FiT regime– also holds when relying on the engineering estimates for marginal costs (results available upon request).

Table 4: The Impact of Pricing Schemes on Price Differences across Markets

	2SLS			
	(1)	(2)	(3)	(4)
FiP I	-1.7***	3.0***	-5.2***	-0.6
	(0.2)	(0.5)	(1.3)	(0.9)
FiP II	-1.4***	-0.2	-1.1**	-1.9***
	(0.2)	(0.4)	(0.5)	(0.5)
FiP I × Wind Forecast (GWh)	0.2***			
	(0.03)			
FiP II × Wind Forecast (GWh)	0.1***			
	(0.03)			
Wind Forecast (GWh)	-0.1***			
	(0.03)			
Demand Forecast (GWh)	0.07***	0.2***	0.07***	0.1***
	(0.009)	(0.02)	(0.02)	(0.02)
$\frac{w_{dt}}{w_{ft}}$		-0.5***	-0.7***	-0.4***
		(0.1)	(0.1)	(0.1)
FiP I × $\frac{w_{dt}}{w_{ft}}$		0.9***	0.4*	0.7***
		(0.2)	(0.2)	(0.2)
FiP II × $\frac{w_{dt}}{w_{ft}}$		0.7***	0.7***	0.7***
		(0.2)	(0.2)	(0.2)
DR'$_1$	-0.002	-0.07***	-0.07***	-0.03*
	(0.004)	(0.01)	(0.02)	(0.01)
DR'$_2$	0.08***	0.2***	0.2***	0.10***
	(0.009)	(0.02)	(0.03)	(0.02)
DoW FE	Y	Y	N	Y
Year X Month FE	N	Y	N	Y
Week FE	N	N	Y	Y
Hour FE	N	N	N	Y
Observations	25,334	25,334	25,334	25,334

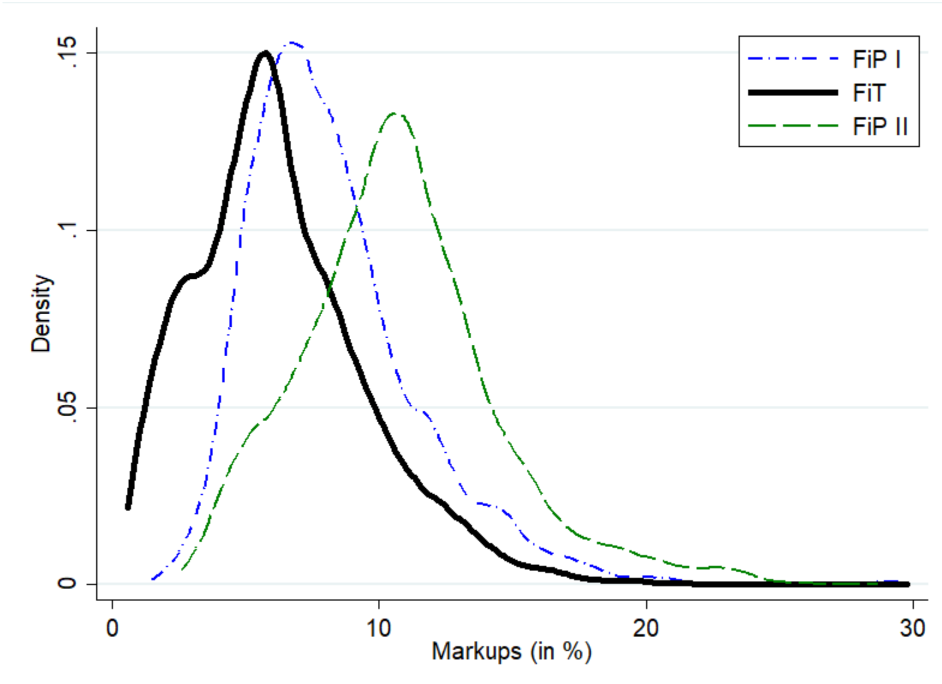
Notes: This table shows the coefficients from equation (14). The slopes of the residual demands DR'_1 and DR'_2 are instrumented using daily average, minimum, and maximum temperature, and average temperature interacted with hourly dummies. I_t takes two values: 1 for FiP I, 2 for FiP II; $I_t = 0$ for FiT (the reference point). Standard errors are clustered at year x month x days of the week.

Table 5: Average Markups on Day-ahead Market

	FiP I		FiT		FiP II	
	Mean	SD	Mean	SD	Mean	SD
Markups (in %) – Simple average						
All	8.3	(3.3)	6.3	(3.3)	10.7	(3.7)
Firm 1	7.0	(2.2)	7.0	(2.6)	12.1	(4.4)
Firm 2	12.3	(4.1)	8.2	(5.1)	14.7	(4.4)
Firm 3	7.7	(2.3)	6.0	(3.3)	10.3	(3.3)
Slope of day-ahead residual demand (in MWh/euros)						
All	524.2	(78.2)	553.6	(120.7)	418.2	(73.0)
Firm 1	506.6	(50.5)	458.4	(72.7)	411.0	(62.4)
Firm 2	508.5	(71.8)	556.4	(165.0)	453.8	(99.8)
Firm 3	538.2	(88.7)	573.3	(117.2)	418.0	(73.2)

Notes: Sample from February 2012 to January 2015, includes the markups for those units bidding within a 5 Euro/MWh range around the market price, for hours with prices above 25 Euro/MWh. FiP I is from 1 February 2012 to 31 January 2013; FiT is from 1 February 2013 to 21 June 2014; FiP II is from 22 June 2014 to 31 January 2015.

Figure 5: Markup Distribution



Notes: This figure plots the markup distributions of all firms by pricing regimes for hours with prices above 25 Euro/MWh. Plots by firms (Figure B.4) in the Appendix show a very similar pattern. To absorb some seasonal variation in the markups, Figure B.5 by wind quartiles in the Appendix suggests that markups are still lower during FiT, although they are relatively lower during windy hours than low-wind hours.

5 Conclusions

In this paper, we have assessed whether market power and price discrimination are best addressed indirectly through arbitrage or by acting directly on the firms' incentives to exercise market power. In particular, we have explored the market power impact of reducing firms' price exposure through forward contracts, taking into account two countervailing incentives. On the one hand, as first pointed out by Allaz and Vila (1993), reducing firms' price exposure mitigates firms' incentives to increase prices, which also leads to less price discrimination. On the other hand, if firms are insulated from price changes, they face weaker incentives to arbitrage price differences, which would ultimately mitigate the dominant producers' incentive to exercise market power. From a theoretical perspective, our model points out that forward contracts lead to more efficient outcomes than arbitrage. However, when it comes to assessing the impacts on consumers, the comparison depends on market structure.

We have used the electricity sector as a lab to explore this trade-off. First, the availability of very detailed data makes this exercise feasible. Second, the current debate about renewables regulation makes this analysis particularly relevant. In particular, the choice between fixed prices (Feed-in-Tariffs) versus variable prices (Feed-in-Premiums) is equivalent to choosing whether producers should be partially or totally exposed to spot price volatility.

In the context of the Spanish electricity market, our empirical analysis confirms that the dominant producers attempted to exercise market power by withholding output in the day-ahead market. When exposed to variable prices, independent wind producers made this strategy more costly by overselling their idle capacity in the day-ahead market in order to arbitrage price differences across markets. Instead, paying renewables according to fixed tariffs reduced arbitrage, but it also mitigated the dominant producers' incentives to withhold output in the first place. The latter effect dominated, giving rise to relatively lower markups under fixed tariffs. This made most consumers better-off, including households, as the prices they pay are a function of the day-ahead prices. Yet, price discrimination across markets remained larger under fixed prices as compared to variable prices. The long-run impacts of such differences on capacity building are left for future research.

References

Acemoglu, Daron, Ali Kakhbod, and Asuman Ozdaglar. 2017. "Competition in Electricity Markets with Renewable Energy Sources." *The Energy Journal*, 38(KAPSARC Special Issue).

Aguirre, Iñaki, Simon Cowan, and John Vickers. 2010. "Monopoly Price Discrimination and Demand Curvature." *American Economic Review*, 100(4): 1601–15.

Allaz, Blaise, and Jean-Luc Vila. 1993. "Cournot Competition, Forward Markets and Efficiency." *Journal of Economic Theory*, 59(1): 1–16.

Birge, John R., Ali Hortaçsu, Ignacia Mercadal, and J. Michael Pavlin. 2018. "Limits to Arbitrage in Electricity Markets: A Case Study of MISO." *Energy Economics*, 75(C): 518–533.

Bohland, M., and S. Schwenen. 2020. "Technology Policy and Market Structure: Evidence from the Power Sector." *DIW 1856, April.*

Borenstein, Severin, James Bushnell, and Frank Wolak. 2002. "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market." *American Economic Review*, 92(5): 1376–1405.

Borenstein, Severin, James Bushnell, Christopher R. Knittel, and Catherine Wolfram. 2008. "Inefficiencies and Market Power in Financial Arbitrage: A Study of California's Electricity Markets." *The Journal of Industrial Economics*, 56(2): 347–378.

Bushnell, James, and Kevin Novan. 2018. "Setting With the Sun: The Impacts of Renewable Energy on Wholesale Power Markets." Energy Institute at Hass WP 292.

Bushnell, James B, Erin T Mansur, and Celeste Saravia. 2008. "Vertical Arrangements, Market structure, and Competition: An Analysis of Restructured US Electricity Markets." *American Economic Review*, 98(1): 237–66.

Cantillon, Estelle. 2014. "Auctions for the Support of Renewables: When and How?" European Commission.

Cleveland, William S. 1979. "Robust Locally Weighted Regression and Smoothing Scatterplots." *Journal of the American statistical association*, 74(368): 829–836.

Cowan, Simon. 2012. "Third-Degree Price Discrimination and Consumer Surplus." *The Journal of Industrial Economics*, 60.

Cullen, Joseph. 2013. "Measuring the Environmental Benefits of Wind-Generated Electricity." *American Economic Journal: Economic Policy*, 5(4): 107–33.

Danzon, Patricia M., and Li-Wei Chao. 2000. "Cross-National Price Differences for Pharmaceuticals: How Large, and Why?" *Journal of Health Economics*, 19(2): 159–195.

de Frutos, María-Ángeles, and Natalia Fabra. 2012. "How to Allocate Forward Contracts: The case of Electricity Markets." *European Economic Review*, 56(3): 451–469.

del Rio, Pablo. 2008. "Ten Years of Renewable Electricity Policies in Spain: An Analysis of Successive Feed-In Tariff Reforms." *Energy Policy*, 36: 2917–2929.

Dressler, Luisa. 2016. "Support Schemes for Renewable Electricity in the European Union: Producer Strategies and Competition." *Energy economics*, 60: 186–196.

Dubois, Pierre, and Morten Sæthre. 2018. "On the Effect of Parallel Trade on Manufacturers' and Retailers' Profits in the Pharmaceutical Sector."

Fabra, Natalia, and Gerard Llobet. 2019. "Auctions with Unknown Capacities: Understanding Competition among Renewables." CEPR CEPR Discussion Papers 14060.

Fabra, Natalia, and Juan Toro. 2005. "Price Wars and Collusion in the Spanish Electricity Market." *International Journal of Industrial Organisation*, 23(3-4): 155–181.

Fabra, Natalia, and Mar Reguant. 2014. "Pass-through of Emmissions Costs in Electricity Markets." *American Economic Review*, 104(9): 2872–2899.

Genc, Talat S., and Stanley S. Reynolds. 2019. "Who Should Own a Renewable Technology? Ownership Theory and an Application." *International Journal of Industrial Organization*, 63: 213–238.

Gowrisankaran, Gautam, Stanley S. Reynolds, and Mario Samano. 2016. "Intermittency and the Value of Renewable Energy." *Journal of Political Economy*, 124(4): 1187–1234.

Greenstone, Michael, Richard McDowell, and Ishan Nath. 2019. "Do Renewable Portfolio Standards Deliver?" *EPIC Working Paper*, 2019-62.

Hortaçsu, Ali, and Steven Puller. 2008. "Understanding Strategic Bidding in Multi-Unit Auctions: A Case Study of the Texas Electricity Spot Market." *RAND Journal of Economics*, 39.

Hviid, Morten, and Catherine Waddams. 2012. "Non-Discrimination Clauses in the Retail Energy Sector." *The Economic Journal*, Number 122.

Ito, Koichiro, and Mar Reguant. 2016. "Sequential Markets, Market Power, and Arbitrage." *American Economic Review*, 106(7): 1921–57.

Jha, Akshaya, and Frank Wolak. 2015. "Testing for Market Efficiency with Transactions Costs: An Application to Convergence Bidding in Wholesale Electricity Markets." *mimeo.*

Liski, Matti, and Iivo Vehviläinen. 2017. "Gone With the Wind: An Empirical Analysis of the Renewable Energy Rent Transfer." Energy Policy Research Group, University of Cambridge Working Papers EPRG 1701.

Liski, Matti, and Juan-Pablo Montero. 2006. "Forward Trading and Collusion in Oligopoly." *Journal of Economic Theory*, 131(1): 212–230.

Longstaff, Francis A., and Ashley W. Wang. 2004. "Electricity Forward Prices: A High-Frequency Empirical Analysis." *Journal of Finance*, 59(4): 1877–1900.

Mahenc, P., and F. Salanie. 2004. "Softening Competition Through Forward Trading." *Journal of Economic Theory*, 116(2): 282–293.

May, Nils, and Karsten Neuhoff. 2017. "Financing Power: Impacts of Energy Policies in Changing Regulatory Environments." *DIW Berlin Discussion Paper*.

Mercadal, Ignacia. 2015. "Dynamic Competition and Arbitrage in Electricity Markets: The Role of Financial Players." *Job Market Paper*.

Mir-Artiguesa, Pere, Emilio Cerda, and Pablo del Rio. 2014. "Analysing the Economic Impact of the New Renewable Electricity Support Scheme on Solar PV Plants in Spain." *Energy Policy*, 118(March): 323–321.

Newbery, David M. 2016. "Towards a Green Energy Economy? The EU Energy Union's Transition to a Low-Carbon Zero Subsidy Electricity System – Lessons from the UK's Electricity Market Reform." *Applied Energy*, 179(C): 1321–1330.

Newbery, David, Michael G Pollitt, Robert A Ritz, and Wadim Strielkowski. 2018. "Market Design for a High-Renewables European Electricity System." *Renewable and Sustainable Energy Reviews*, 91: 695–707.

Novan, Kevin. 2015. "Valuing the Wind: Renewable Energy Policies and Air Pollution Avoided." *American Economic Journal: Economic Policy*, 7(3): 291–326.

OECD. 2018. "Personalised Pricing in the Digital Era ." DAF/COMP(2018)13.

Reguant, Mar. 2014. "Complementary Bidding Mechanisms and Startup Costs in Electricity Markets." *Review of Economic Studies*, 81(4): 1708–1742.

Reguant, Mar. 2019. "The Efficiency and Sectoral Distributional Impacts of Large-Scale Renewable Energy Policies." *Journal of the Association of Environmental and Resource Economists*, 6(S1): 129–168.

Ritzenhofen, Ingmar, John R. Birge, and Stefan Spinler. 2016. "The structural Impact of Renewable Portfolio Standards and Feed-In Tariffs on Electricity Markets." *European Journal of Operational Research*, 255(1): 224–242.

Ritz, Robert A. 2016. "How Does Renewables Competition Affect Forward Contracting in Electricity Markets?" *Economics Letters*, 146(C): 135–139.

Robinson, Joan. 1933. *The Economics of Imperfect Competition.* London: Macmillan.

Wolak, Frank A. 2000. "An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market." *International Economic Journal*, 14(2): 1–39.

Wolak, Frank A. 2003. "Identification and Estimation of Cost Functions Using Observed Bid Data: An Application to Competitive Electricity Markets." Chapter 4, 133–169. Cambridge University Press.

Appendix

Appendix A: Additional Results and Proofs

A.1. Contracts for Differences (CfDs)

Suppose now that renewables are paid according to Contracts-for-Differences (CfDs) by which, (i) firms receive market prices (similarly to variable prices), but (ii) their payments are settled by differences between the contract's price, $\overline{p}$, and the day-ahead market price (similarly to fixed prices). Point (i) implies that the fringe renewables have the same incentives to arbitrage as under variable prices, giving rise to the same residual demands for the dominant firm. In turn, point (ii) implies that the dominant firm's day-ahead profit maximization problem is the same as under fixed prices.

Our last lemma characterizes, under limited arbitrage, the solution when firms are subject to contracts-for-differences, which we denote with the super-script C (for Contracts). As it is clear, the solution combines elements from Lemma 3.

Lemma 4 *Suppose that renewable producers are subject to contracts-for-differences. Under limited arbitrage, the day-ahead and spot market equilibrium prices are given by*

$$\begin{aligned} p_1^C(LA) &= p_1^F(LA) + \beta(k_f - w_f) > c \\ p_2^C(LA) &= p_2^F(LA) + \beta(k_f - w_f) > c \end{aligned}$$

or equivalently to

$$\begin{aligned} p_1^C(LA) &= p_1^V(LA) - 2\beta w_d > c \\ p_2^C(LA) &= p_2^V(LA) - \beta w_d > c \end{aligned}$$

leading to a positive price differential

$$\Delta p^C(LA) = \Delta p^F(LA) - \beta w_d = \Delta p^V(LA) - 2\beta\,(k_f - w_f) > 0,$$

where $\beta = (3b)^{-1} > 0$*, and* $p_1^F(LA)$*,* $p_2^F(LA)$ *and* $\Delta p^F(LA)$ *are those in Lemma 3.*

Proof. It follows the same steps as the proofs of Lemma 3, and it is therefore omitted

■

The above characterization allows us to compare equilibrium outcomes across all three pricing schemes.

Proposition 3 *Under limited arbitrage, the comparison of equilibrium outcomes across pricing schemes (contracts-for-differences, fixed prices and variable prices) shows that:*
(i) $p_1^C(LA) < p_1^F(LA)$ *and* $p_1^C(LA) < p_1^V(LA)$*.*
(ii) $p_2^F(LA) < p_2^C(LA) < p_2^V(LA), \Delta p^C(LA) < \Delta p^F(LA)$ *and* $\Delta p^C(LA) < \Delta p^V(LA)$*.*
(iii) $\Delta p^C(LA) < \Delta p^F(LA)$ *and* $\Delta p^C(LA) < \Delta p^V(LA)$*.*

Proof. It follows from comparing Lemmas 2 to 4. ■

A.2. Proofs

Proof of Lemma 1 (No Arbitrage). We omit the label (NA) to simplify notation. We solve the profit maximization problems in (3) and (4) under variable prices and (5) under fixed prices. We do so by backward induction, with $q_1(p_1) = A - bp_1 - w_f$ and $q_2(p_1, p_2) = b\Delta p$. For given p_1, the spot market solution is given by, under both pricing rules,

$$p_2 = \frac{p_1 + c}{2}, \text{ implying } q_2 = b\frac{p_1 - c}{2}\cdot \tag{15}$$

To solve the day-ahead market problem, we first consider variable prices and then fixed prices.

(i) Under variable prices, plugging (15) into the day-ahead problem (4), one can find the day-ahead market solution

$$p_1^V = \left[2\,(A - w_f) + bc\right]/3b, \text{ implying } q_1^V = (A - w_f - bc)\,/3.$$

Plugging this back into the spot market solution gives

$$p_2^V = \left[A - w_f + 2bc\right]/3b, \text{ implying } q_2 = (A - w_f - bc)\,/3$$

Taking the difference between the two prices,

$$\Delta p^V \equiv p_1^V - p_2^V = (A - w_f - bc)\,/3b.$$

Since we have assumed $A - w_d - w_f - bc > 0$, it follows that $q_1^V > 0$, and $p_1^V > p_2^V > w_d/3b + c > c$. Note that the solution is the same as Ito and Reguant (2016)'s Result 1, with $(A - w_f)$ here in the place of A there.

(ii) Under fixed prices, plugging (15) into the day-ahead problem (5), one can find the day-ahead market solution,

$$p_1^F = [2(A - w_d - w_f) + bc]/3b = p_1^V - 2w_d/3b \tag{16}$$

implying

$$q_1^F = \frac{(A + 2w_d - w_f - bc)}{3} = q_1^V + 2w_d/3$$

Plugging this back into the spot market solution gives

$$p_2^F = [A - w_d - w_f + 2bc]/3b = p_2^V - w_d/3b$$

implying

$$q_2^F = (A - w_d - w_f - bc)/3 = q_2^V - w_d/3$$

Taking the difference between the two prices,

$$\Delta p^F = (A - w_d - w_f - bc)/3b = \Delta p^V - w_d/3b > 0.$$

Since we have assumed $A - w_d - w_f - b > 0$, it follows that $p_1^F > p_2^F > c$. The price differential is increasing in A, and it is decreasing in w_f, w_d and b.

Last, using the above expressions, we obtain

$$q_2^F = (A - w_f - w_d - bc)/3 = q_2^V - w_d/3 > 0.$$

■

Proof of Lemma 2 (Unlimited arbitrage). We omit the label (UA) to simplify notation. We now solve the profit maximization problems with unlimited arbitrage. Under each pricing rule, the residual demands are given by (7) and (8), with s adjusted so that the two prices converge. We again proceed by backward induction. For given p_1, the spot market solution is given by, under both pricing rules,

$$p_2 = \frac{p_1 + c}{2} + \frac{s}{2b}, \text{ implying } q_2 = b\frac{p_1 - c}{2} + \frac{s}{2}. \tag{17}$$

To solve the day-ahead market problem, we first consider variable prices and then fixed prices.

(i) Under variable prices, plugging (17) into the day-ahead problem (4), one can find the day-ahead market solution

$$p_1^V = [2(A - w_f) + bc - s]/3b, \text{ implying } q_1^V = (A - w_f - bc - 2s)/3.$$

Plugging this back into the spot market solution gives

$$p_2^V = [A - w_f + 2bc + s] / 3b, \text{ implying } q_2^V = (A - w_f - bc + s) / 3.$$

Taking the difference between the two prices,

$$\Delta p^V \equiv p_1^V - p_2^V = (A - w_f - bc - 2s) / 3b.$$

Setting $p_1^V = p_2^V$, we find

$$s^V = (A - w_f - bc) / 2.$$

Plugging this back into the price expressions,

$$p_1^V = p_2^V = [A - w_f + bc] / 2b$$

(ii) Under fixed prices, plugging (17) into the day-ahead problem (5), one can find the day-ahead market solution

$$p_1^F = [2 (A - w_f - w_d) + bc - s] / 3b, \text{ implying } q_1^F = (A - w_f - w_d - bc - 2s) / 3.$$

Plugging this back into the spot market solution gives

$$p_2^F = [A - w_f - w_d + 2bc + s] / 3b, \text{ implying } q_2^F = (A - w_f - w_d - bc + s) / 3.$$

Taking the difference between the two prices,

$$\Delta p^F \equiv p_1^F - p_2^F = (A - w_f - w_d - bc - 2s) / 3b = \Delta p^V - w_d/3b.$$

Setting $p_1^F = p_2^F$, we find

$$s^F = (A - w_f - w_d - bc) / 2 = s^V - w_d/2$$

Plugging this back into the price expressions,

$$p_1^F = p_2^F = [A - w_f - w_d + bc] / 2b = p_t^V - w_d/2b.$$

■

Proof of Lemma 3 (Limited arbitrage). The proof follows from the one above, simply setting $s^V = \min \{k_f - w_f, (A - w_f - bc) / 2\}$ and $s^F = 0$. ■

Proof of Proposition 1 (FiT vs. FiP). We compare the equilibrium outcomes reported in Lemma 3. Let $s^V (LA)$ be the amount of arbitrage under variable prices, depending on whether the arbitrage constraint binds or not,

$$\begin{aligned} s^V (LA) &= \min \left\{k_f - w_f, s^V (UA)\right\} \\ &= \min \{k_f - w_f, (A - w_f - bc) / 2\}. \end{aligned}$$

(i) Comparison of p_1: If the arbitrage capacity constraint does not bind, $s^V(LA) = (A - w_f - bc)/2$, then

$$p_1^V(LA) - p_1^F(LA) = -\frac{A - 4w_d - w_f - bc}{6b}$$

Hence, $p_1^V(LA) > p_1^F(LA)$ iff $w_d > (A - w_f - bc)/4 = s^V(LA)/2$.

If the arbitrage capacity constraint binds, $s^V(LA) = k_f - w_f$, then

$$p_1^V(LA) - p_1^F(LA) = [-(k_f - w_f) + 2w_d]/3b$$

Hence, $p_1^V(LA) > p_1^F(LA)$ iff $w_d > (k_f - w_f)/2 = s^V(LA)/2$.

(ii) Comparison of p_2: If the arbitrage capacity constraint does not bind,

$$p_2^V(LA) - p_2^F(LA) = \frac{A + 2w_d - w_f - bc}{6b} > 0.$$

If it binds,

$$p_2^V(LA) - p_2^F(LA) = [(k_f - w_f) + w_d]/3b > 0.$$

Hence, in all cases, $p_2^V(LA) > p_2^F(LA)$.

(iii) Comparison of Δp: If the arbitrage capacity constraint does not bind, then

$$\Delta p^V - \Delta p^F = -\Delta p^F < 0.$$

Note that over this region, our initial assumption $A - w_d - w_f - bc > 0$ implies that $w_d < (A - w_f - bc) = 2s^V(LA)$.

If the arbitrage capacity constraint binds, $s^V(LA) = k_f - w_f$, then

$$\Delta p^V - \Delta p^F = [-2(k_f - w_f) + w_d]/3b.$$

Hence, $\Delta p^V > \Delta p^F$ iff $w_d > 2(k_f - w_f) = 2s^V(LA)$. ■

Proof of Proposition 2. (i) Under variable prices, efficiency goes down when arbitrage is allowed since $p_2^V(UA) \geq p_2^V(LA) > p_1^V(NA) > p_2^V(NA)$. Instead, since price discrimination goes down, $\Delta p^V(UA) = 0 < \Delta p^V(LA) < \Delta p^V(NA)$, the consumer surplus comparison is ambiguous as (noting that in equilibrium $\Delta p^V = q_1^V$) it can be expressed as

$$\begin{aligned} CS^V(NA) - CS^V(LA) &= \int_{p_2^V(NA)}^{p_2^V(LA)} D(\rho)\, d\rho - b\left[\left(\Delta p^V(NA)\right)^2 - \left(\Delta p^V(LA)\right)^2\right] \\ CS^V(NA) - CS^V(UA) &= \int_{p_2^V(NA)}^{p_2^V(UA)} D(\rho)\, d\rho - b\left(\Delta p^V(NA)\right)^2 \end{aligned}$$

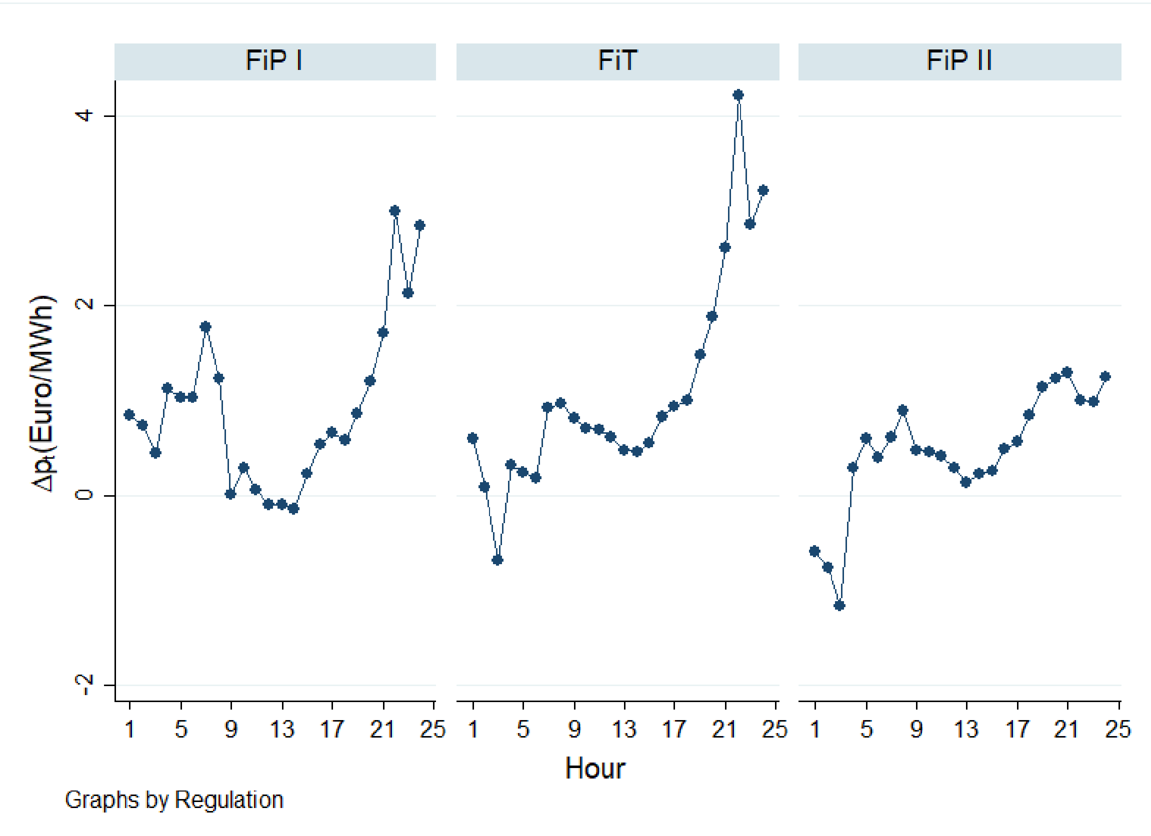
(ii) Moving to fixed prices increases efficiency $p_2^F(NA) < p_2^V(NA)$. Furthermore, firms' profits decrease. With some algebra, using equilibrium expressions in Lemma 1, the difference in firms' profits under variable prices and fixed prices with no arbitrage is given by

$$\begin{aligned}&p_1^V\left(q_1^V+w_f\right)+p_2^Vq_2^V-c\left(q_1^V+q_2^V-w_d\right)-\\&\left[p_1^F\left(q_1^F+w_f\right)+p_2^Fq_2^F-c\left(q_1^V+q_2^V-w_d\right)\right]=w_d\frac{w_d+2w_f}{3b}>0.\end{aligned}$$

Since total welfare is higher while firms' profits are lower, it follows that consumer surplus goes up when moving from variable to fixed prices. ■

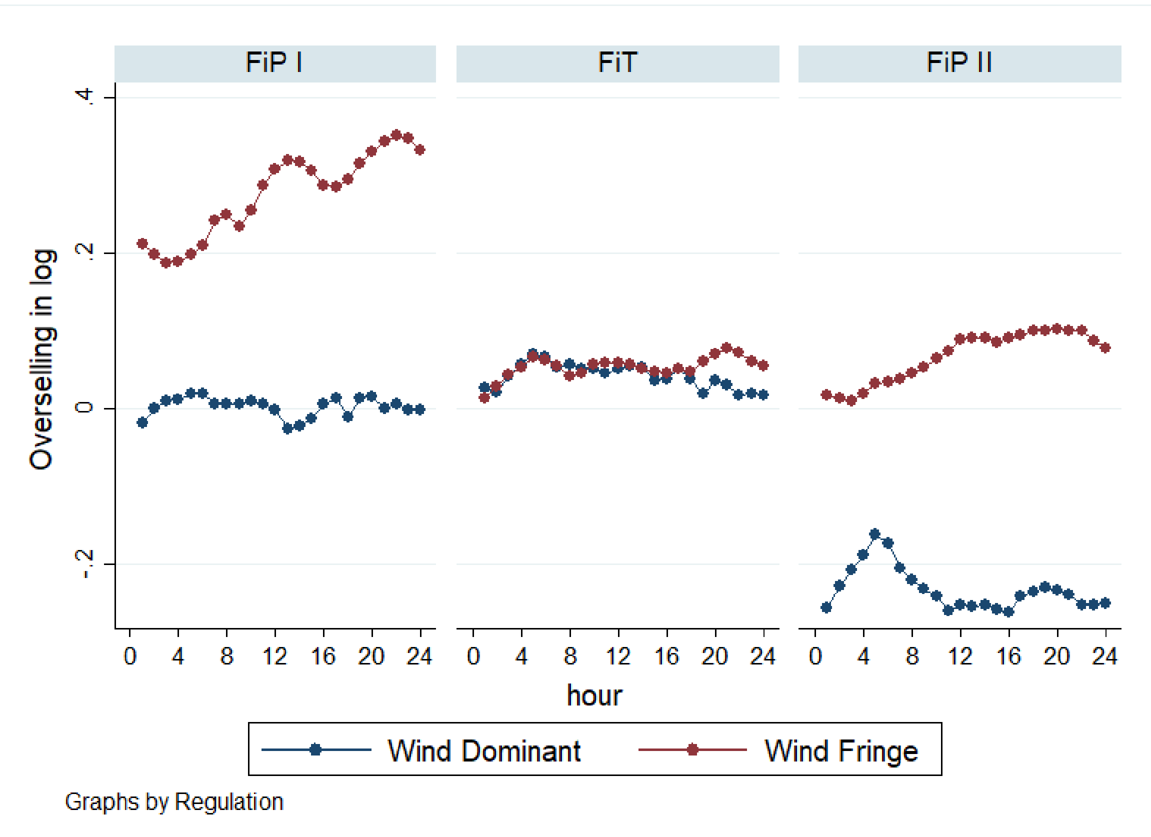
Appendix B: Additional Figures and Tables

Figure B.1: Hourly Price Premium by Pricing Regimes



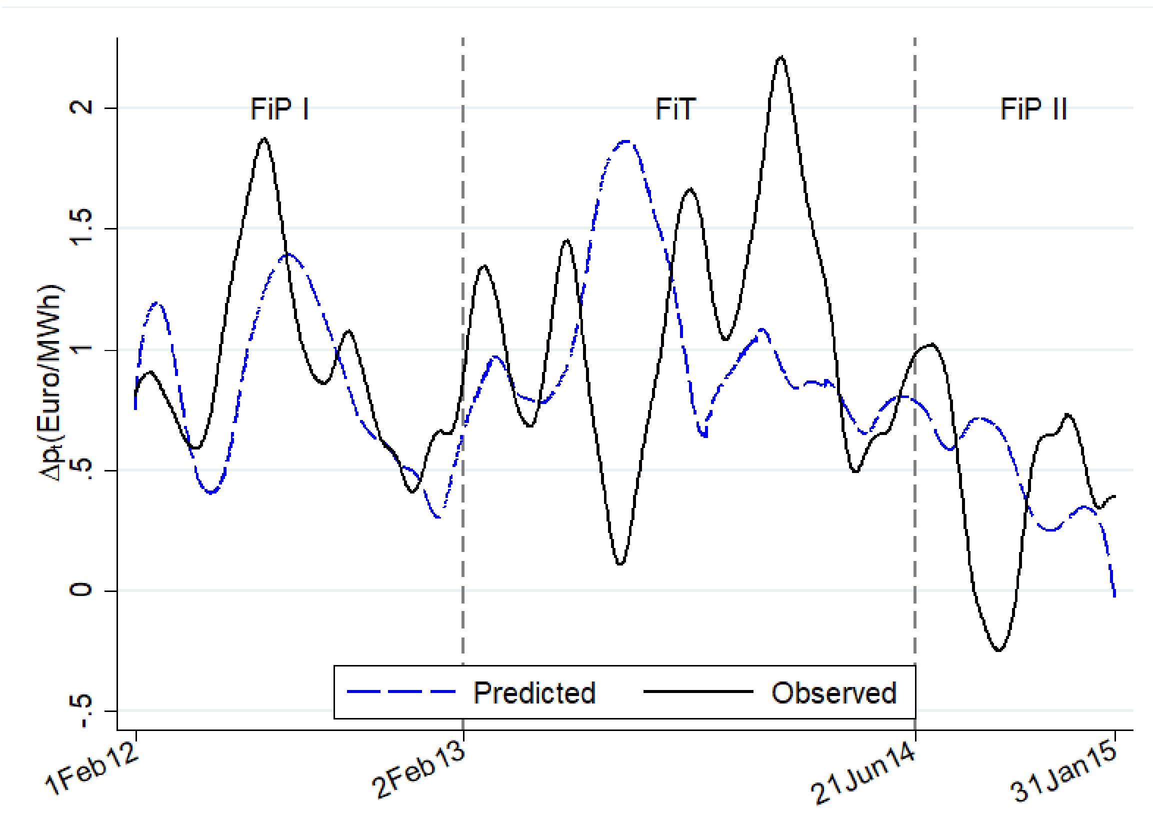
Notes: This figure shows the hourly average of price premium, split in three regulatory regimes. Sample is from 1 February 2012 to 31 January 2015. FiP I is from 1 February 2012 to 31 January 2013; FiT 2013 is from 1 February 2013 to 21 June 2014; FiP II is from 22 June 2014 to 31 January 2015.

Figure B.2: Hourly Overselling and Withholding by Wind Producers



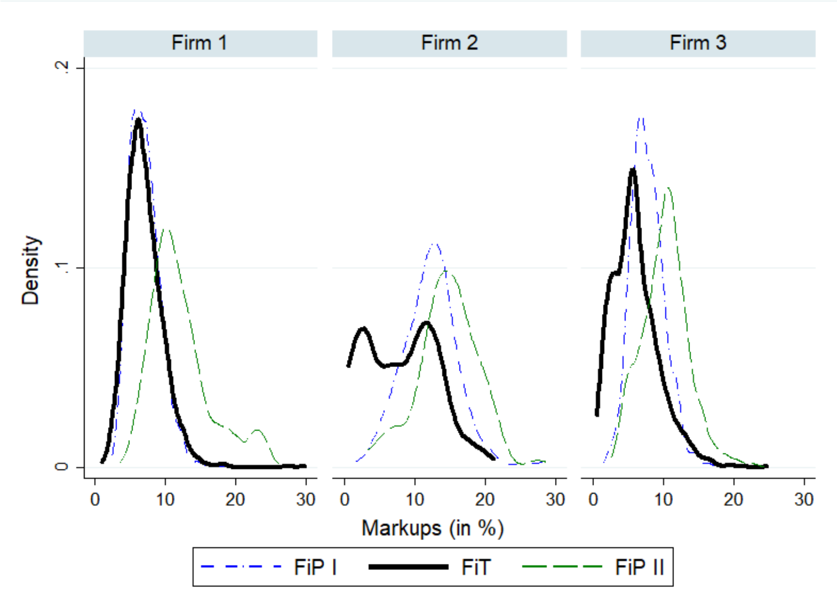
Notes: This figure shows the hourly average of the day-ahead commitments minus the final commitments of the wind producers, split in three regulatory regimes. Sample is from February 2012 to February 2015. FiP I is from 1 February 2012 to 31 January 2013; FiT 2013 is from 1 February 2013 to 21 June 2014; FiP II is from 22 June 2014 to 31 January 2015.

Figure B.3: Predicted and Observed Price Premium



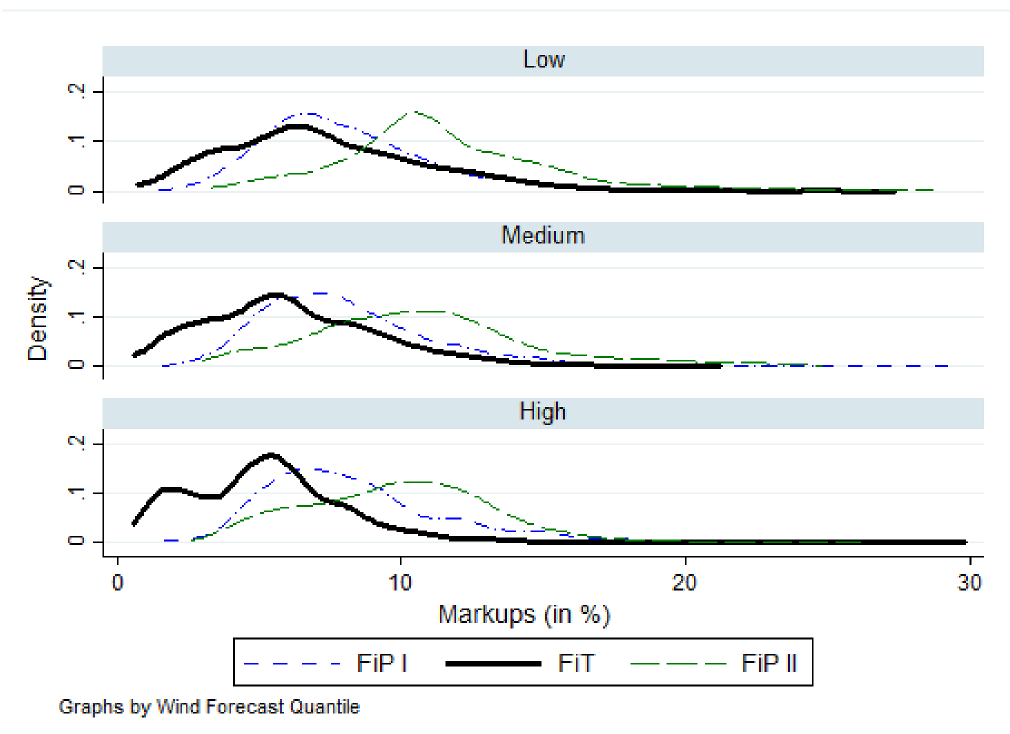
Notes: This figure shows locally weighted linear regressions of $\Delta\hat{p}_t$ (predicted) and Δp_t (observed) from February 2012 to February 2015. The weights are applied using a tricube weighting function (Cleveland, 1979) with a bandwidth of 0.1. The predictions ($\Delta\hat{p}_t$) are done using the estimated coefficients obtained from equation in footnote 39. These $\Delta\hat{p}_t$ are used in equation 12.

Figure B.4: Markup Distribution by Firm



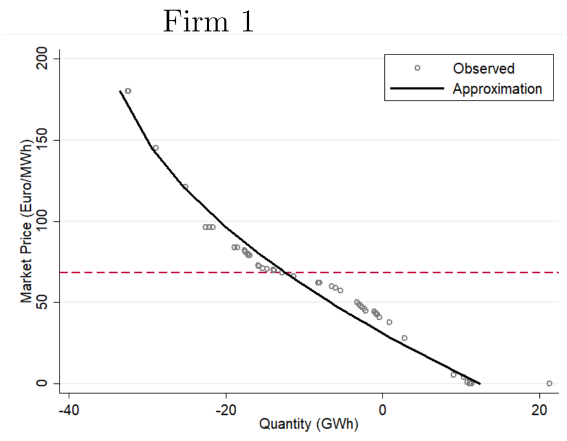
Notes: This figure plots the markup distributions for each of the dominant firms by their pricing regimes for hours with prices above 25 Euro/MWh.

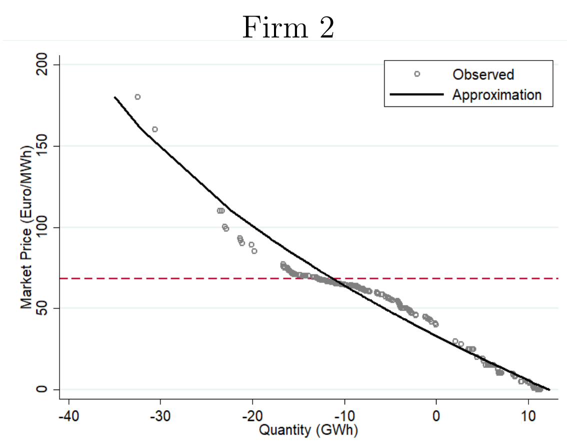
Figure B.5: Markup Distribution by Wind Quartiles

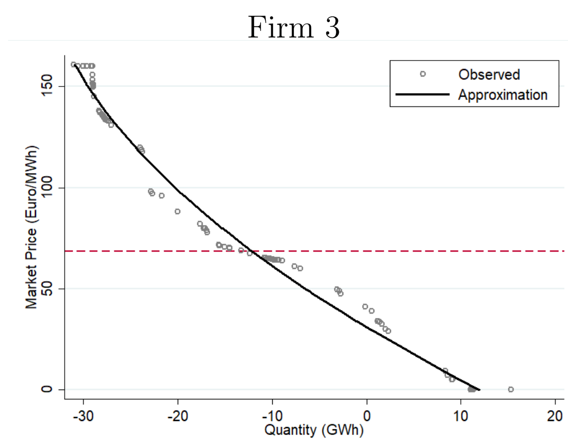


Notes: This figure compares markups distribution by wind forecast quartiles (low, medium, and high wind days) in three different pricing regimes for hours with prices above 25 Euro/MWh.

Figure B.6: Approximating the slopes of the residual demands







Notes: This figure illustrates how we use quadratic approximation to compute the local slope around the market clearing price (the horizontal line) for each of the dominant firm's residual demand curve. Here, we show each firm's the residual demand curve in October 10, 2014, 18.00.

Table B.1: The Forward Contract Effect

	2SLS			
	(1)	(2)	(3)	(4)
Marginal Cost_{it}	0.72*	0.79***	0.85***	0.65**
	(0.38)	(0.25)	(0.26)	(0.31)
FiP I $\times \frac{w_{it}}{DR'_{it}}$	0.63	-6.43	-7.26	-9.58*
	(6.82)	(4.68)	(4.68)	(5.39)
FiT $\times \frac{w_{it}}{DR'_{it}}$	-32.5***	-26.2***	-27.4***	-12.9*
	(8.56)	(7.19)	(7.03)	(6.61)
FiP II $\times \frac{w_{it}}{DR'_{it}}$	-0.78	0.69	-0.92	0.77
	(9.45)	(7.41)	(7.58)	(6.37)
$\frac{q_{it}}{DR'_{it}}$				4.23***
				(1.47)
Month and DoW FE	N	Y	Y	Y
Hour FE	N	N	Y	Y
Observations	20,100	20,100	20,100	20,100

Notes: Similar to Table 2. The only difference is that we use bids within a 5 Euro/MWh range around the market price instead of 1 Euro/MWh.

Table B.2: The Response of Overselling to the Price Premium

	Wind	Non-wind Renewables	Retailers	Diff	
	(1)	(2)	(3)	(1)-(2)	(1)-(3)
FiPI	0.064	0.008	0.079	-0.076	-0.006
	(0.000)	(0.000)	(0.000)	(0.000)	(0.529)
FiT	-0.001	-0.004	0.086	-0.005	0.063
	(0.882)	(0.004)	(0.000)	(0.151)	(0.000)
FiPII	0.032	-0.006	0.053	-0.036	0.004
	(0.000)	(0.000)	(0.000)	(0.000)	(0.503)
FiPI→FiT	-0.065	-0.013	0.008	-0.071	-0.069
	(0.000)	(0.000)	(0.334)	(0.000)	(0.000)
FiT→FiPII	0.026	-0.000	-0.049	0.03	0.059
	(0.000)	(0.812)	(0.000)	(0.000)	(0.000)

Notes: This table reports the coefficient of $\Delta \hat{p}_t$ from 25 different regressions similar to equation (12). Columns (1)-(3) only use overselling quantity from each group on the corresponding column header. The two columns on the right compare the difference in overselling from either columns (1) and (2) or columns (1) and (3). The last two rows compare two pricing regimes, either from FiP I to FiT or from FiT to FiP II. The corresponding P-values for each coefficient are in parentheses. Pre-trend assumptions are supported by the p-values in columns (1)-(2) row 2 – under FiT, wind and non-wind renewables face the same incentives to oversell – and columns (1)-(3) row 1 or row 3 – under FiP, wind, and retailers face the same incentives to oversell. The impact on the price response of overselling can be seen in the last two rows in columns (1)-(2) and (1)-(3), and it is similar to numbers reported in Table 3.