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

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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.

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Non-Technical Summary

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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*

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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 and stronger competition or enhanced efficiency.

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

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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 price discrimination (generically referred to as '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 banning third-degree price discrimination or promoting price arbitrage need not be welfare-enhancing. The reason is that a move from price discrimination 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

[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?

in a primary market, followed by trade in secondary markets. Price discrimination across 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 of goods.

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 productive efficiency. More specifically, the benefits of mitigating market power in the early markets spread across subsequent markets, in which efficiency improves as a result.

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 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 impact prices and efficiency.

In our empirical analysis of the impact of forward contracts on market power and price discrimination, we use data from the Spanish electricity market covering a period in which renewables regulation changed twice. Prior to February 2013, wind producers were paid

[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.

according to variable prices, i.e., market prices plus a fixed premium (the so-called Feed-in-Premiums or FiPs).[5] However, in February 2013, wind producers were moved to fixed tariffs (the so-called Feed-in-Tariffs or FiTs).[6] A second regulatory change took place in June 2014, when the new regulation exposed wind plants (and all other renewables) to variable prices again. Access to very detailed wholesale market bid data allows us to conduct an empirical analysis of the effects of such regulatory changes on firms' bidding behaviour and the resulting impacts on market power and price discrimination across markets.

Our starting point is the observation that paying renewables according to fixed prices (FiTs) is equivalent to making them subject to 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 price differences across markets. To the extent that forward contracts not only mitigate market power but also reduce arbitrage, it is unclear how they compare to variable prices.

In order to capture this trade-off, we first extend the theoretical analysis by Ito and Reguant (2016) to explicitly model the renewables pricing schemes. Our 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), with the latter paid according to either fixed prices or market prices. Consumers' demand is fully cleared in the day-ahead market, while the spot market serves to re-shuffle production between firms.[8] Therefore, consumer surplus depends on day-ahead prices, while total efficiency

[5]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.

[6]Nowadays, FiTs are often set through auctions for new investments (Cantillon, 2014), but they have traditionally been set by regulators.

[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.

[8]This is common in the procurement of many goods (e.g., T-bills, primary market issuance, emission

depends on spot market prices.

In this setting, we show that paying renewables according to fixed prices mitigates market power and price discrimination through a *forward contract effect*: the dominant firm has weaker incentives to exercise market power as its renewable output would not benefit from it. The same is true regarding variable prices, though the channel is different. Through an *arbitrage effect*, the renewable fringe firms reduce the dominant firm's market power in the day-ahead market at the expense of increasing it in the spot market. The *forward contract effect* is relatively stronger than the *arbitrage effect* the higher the share of renewables in the hands of the dominant firm. Hence, if the structure of renewable ownership is highly concentrated, fixed prices tend to induce relatively more competitive day-ahead market outcomes and less price discrimination than variable prices.[9] Importantly, the comparison in terms of productive efficiency is unambiguous: fixed prices induce more efficient outcomes as compared to variable prices as the former (latter) mitigate (enhance) market power in the spot market.

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*. 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. Instead, 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.

However, the slopes of the residual demands in the day-ahead market are an endogenous object, also affected by the pricing scheme in place. For this reason, the second piece of our analysis analyzes how changes in the pricing schemes affected the fringe firms' incentives to arbitrage, which is a key determinant of the residual demands. 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 rely 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)

rights, etc.): the auctioneer typically buys or sells the total quantity in the primary market, and then allows for trade in secondary markets.

[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.

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. In sum, regardless of which control group we choose, our analysis confirms the relevance of the empirical *arbitrage effect*.

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, our empirical analysis shows that price differences across markets were larger on average under fixed prices. Consistently with our theoretical predictions, an 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*).

Regarding market power, we leverage on our structural estimates to compute markups in the day-ahead market. We find that mark-ups were significantly lower while firms were subject to fixed prices as compared to variable prices. The average mark-up during the FiT period was 6.3%, while it was 8.3% and 10.9% under the first and second FiP regimes. A similar conclusion applies when comparing the mark-ups of each dominant firm individually, when comparing mark-ups in very windy versus less windy hours, or for peak versus off-peak hours.

In sum, our empirical analysis allows us to 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. Instead, the *arbitrage effect* dominated over the *forward contract effect* in reducing price discrimination more under the variable price regime. To the extent that this latter effect was achieved through higher spot market prices, exposing renewables to variable prices might have led to greater productive inefficiencies. The comparison of market power and price discrimination under fixed and variable prices thus illustrates an important idea, namely, increased price convergence should not be in general equated with stronger competition or enhanced efficiency.

Other Related Papers In response to the increasing share of renewables in the energy mix, a growing literature has analyzed their short-run and long-run effects. This literature includes analyses on their impacts on energy prices (Gowrisankaran, Reynolds and Samano (2016); Genc and Reynolds (2019); Acemoglu, Kakhbod and Ozdaglar (2017)), 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.

Most analyses of fixed prices (FiT) versus variable prices (FiP) focus on their key 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.[10] Instead, our analysis focuses on the largely unexplored issue of how such schemes affect their bidding incentives for given capacities, ultimately affecting the performance of electricity markets.[11]

As far as we are aware of, only few other papers compare the effects of renewables pricing schemes for given capacities. From a theoretical perspective, Dressler (2016) also notes that FiTs act like forward contracts. She abstracts from the impacts of FiTs on price arbitrage, but focuses instead on the impact they might have on the incentives to enter into forward contracts. In line with Ritz (2016), she finds that FiTs might crowd out other forms of forward contracting. From an empirical perspective, Bohland and Schwenen (2020) explore the market power impacts of renewables' pricing schemes through a reduced form approach. Like us, they also use Spanish data but focus on the early period of renewables deployment when renewables represented a small fraction in the energy mix.

The remainder of the paper is organized as follows. Section 2 describes the model of optimal bidding across sequential markets, with renewable producers paid according to fixed prices or variable prices. Section 3 provides an overview of the institutional setting and data used in the analysis. Section 4 performs the empirical analysis through four angles: price-setting incentives in the day-ahead market, arbitrage and price discrimination across markets, and mark-ups in the day-ahead market. Section 5 concludes. Proofs and additional figures are postponed to the Appendix.

[10] See Ritzenhofen, Birge and Spinler (2016) for further references.

[11] 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. Our model extends Ito and Reguant (2016) by explicitly modeling renewables under alternative pricing schemes.

Markets Electricity is traded in two sequential markets: a day-ahead market ($t = 1$) and a spot market ($t = 2$). Total forecasted demand is inelastically given by A, and it is fully cleared in the day-ahead market. The spot market allows firms to fine-tune their day-ahead commitments. Hence, consumers' surplus only depends on day-ahead market prices. In turn, with demand being inelastic, total welfare only depends on productive efficiency, which is a function of the final output allocation in the spot market.

Firms and Technologies 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 own either renewable or conventional assets.

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 firm i's available and maximum wind capacity, with $w_i \leq k_i$. The dominant firm's conventional technology has constant marginal costs of production, $c > 0$, while the fringe faces linear marginal costs q/b.[12]

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

Fringe Firms' Behavior Fringe firms are assumed to be price-takers. Accordingly, the conventional fringe producers offer their output at marginal costs. Since the renewable fringe producers have zero marginal costs but limited capacity, they have to decide where to sell their available capacity, either in the day-ahead market, w_{1f}, or in the spot market, w_{2f}, with $w_{1f} + w_{2f} \leq w_f$. The incentives of renewable fringe producers depend on the pricing scheme in place. We consider two commonly used pricing schemes: renewable producers receive *fixed prices* for their output, regardless of where they sell it (FiT); or

[12] To capture the fact that the costs of adjusting production tend to be higher close to real-time, in the appendix we parametrize the fringe firms' marginal costs as q/b_t, where $b_1 \leq b_2$. The results presented in the main text are thus a particular case with $b_1 = b_2 = b$. The main results remain unchanged.

variable prices, i.e., the prices of the market where they sell their output, plus a fixed premium (FiP).[13]

The Dominant Firm's Behavior The dominant firm sets prices in both markets, taking into account the production decisions of the fringe players. The residual demand faced by the dominant producer in the day-ahead market is thus given by $D_1(p_1) = A - bp_1 - w_{1f}$, i.e., total forecasted demand minus the supply of the conventional and renewable fringe producers, respectively.

If the price difference across markets $\Delta p \equiv p_1 - p_2$ is positive, the conventional fringe producers find it less costly to buy $b\Delta p$ in the spot market rather than having to satisfy their day-ahead commitments with their own production only. Hence, the net residual demand faced by the dominant producer in the spot market can be expressed as $D_2(p_1, p_2) = b\Delta p - w_{2f}$. Instead, if Δp is positive, the conventional fringe producers increase their sales in the spot market.

2.1 Benchmark Model

Before analyzing the equilibrium when firms are paid according to either fixed or variable prices, we revisit Ito and Reguant (2016)'s first result, which will serve as our benchmark. In particular, we assume that all renewable output is paid at market prices while arbitrage across markets is not allowed, i.e., the conventional fringe producers offer their output at marginal cost and the renewable fringe producers offer all their output in the day-ahead market, $w_{1f} = w_f$ and $w_{2f} = 0$. The residual demands faced by the dominant firm in the day-ahead market and in the spot market are thus given by

$$D_1(p_1) = A - bp_1 - w_f \tag{1}$$

$$D_2(p_1, p_2) = b\Delta p \tag{2}$$

We solve the game by backwards induction. In the spot market, once p_1 is chosen, the dominant firm sets p_2 so as to maximize its profits,

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

where $q_1 = D_1(p_1)$ and $q_2 = D_2(p_1, p_2)$, as characterized in (1) and (2) above.

[13] 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, Appendix A.1 contains the analysis of an alternative pricing scheme: Contracts-for-Differences (CfDs). It shows that CfDs lead to less market power and less discrimination as compared to either fixed or variable prices. However, overall efficiency is in between the two.

In the day-ahead market, the profit maximization problem becomes

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

where $q_1 = D_1(p_1)$, and $p_2\left(p_1\right)$ and $q_2\left(p_1\right)$ are given by the solution to the spot market problem (3).

Our first lemma characterizes the benchmark solution, which we denote with superscript B (for Benchmark). It is illustrated in Figure 1.

Lemma 1 *If renewable producers are exposed to variable prices and arbitrage is not allowed, the day-ahead and spot market equilibrium prices are given by*

$$p_1^B = \beta\left[2\left(A - w_f\right) + bc\right] > \beta\left[A - w_f + 2c\right] = p_2^B > c,$$

leading to a positive price differential

$$\Delta p^B = \beta\left(A - w_f - bc\right) > 0,$$

where $\beta = (3b)^{-1} > 0$.

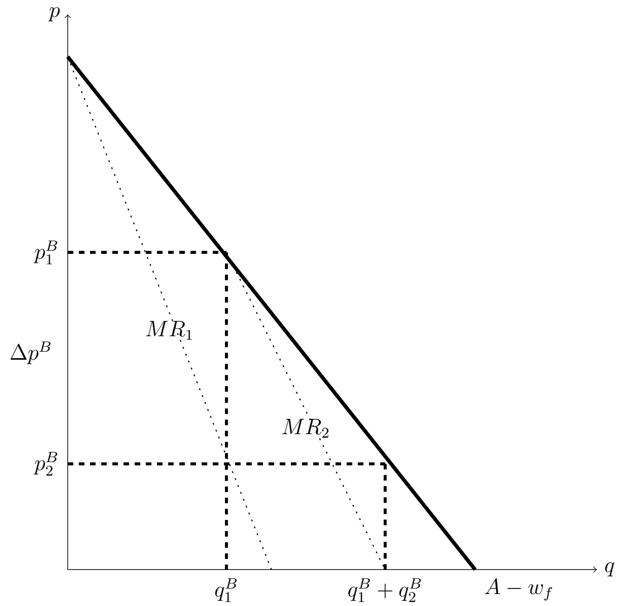
Proof. See the Appendix. ■

The dominant firm exercises market power in the day-ahead market by setting its price above marginal costs, $p_1^B > c$. 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, $p_1^B > p_2^B > c$.

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. The same comparative statics apply to the price differential. Since our focus will be on the incentives of renewable producers, note in particular that an increase in the fringe's renewable output w_f reduces the day-ahead residual demand. This induces the dominant firm to set a lower day-ahead price, thereby reducing the extent of unserved demand. In turn, this leads the dominant firm to also set a lower spot market price, which reduces the price differential.

Given the positive price differential across markets, fringe producers could gain through arbitrage, i.e., by overselling in the day-ahead market at a high price and undoing their long position in the spot market at a low price. However, market rules typically impose limits on arbitrage, i.e., since all transactions need to be backed by physical assets, firms cannot offer to sell above their capacity. This rules out arbitrage by the conventional producers, but leaves some scope for wind producers to engage in arbitrage. In particular, since their capacity constraint $w_f \leq k_f$ is rarely binding, the wind producers can arbitrage by overselling their idle capacity $(k_f - w_f)$ in the day-ahead market. However, whether they have incentives to do so depends on the pricing scheme in place, as shown next.

Figure 1: Solution of the model with variable prices and no arbitrage



Notes: This figure illustrates the equilibrium under the Benchmark model, with renewables facing variable prices and no arbitrage. It assumes $c = 0$. Note that the dominant firm equalizes marginal revenues across both sequential markets.

2.2 Fixed Prices (FiT)

Suppose that renewable producers are paid at a fixed price (FiT), denoted $\overline{p}$. Hence, even if allowed to arbitrage up to their capacities, they do not have incentives to do so given that they receive the same price regardless of the market in which they sell their output. They thus sell all their renewable output in the day-ahead market, $w_{1f} = w_f$ and $w_{2f} = 0$. This leaves the residual demands faced by the dominant firm as in equations (1) and (2).

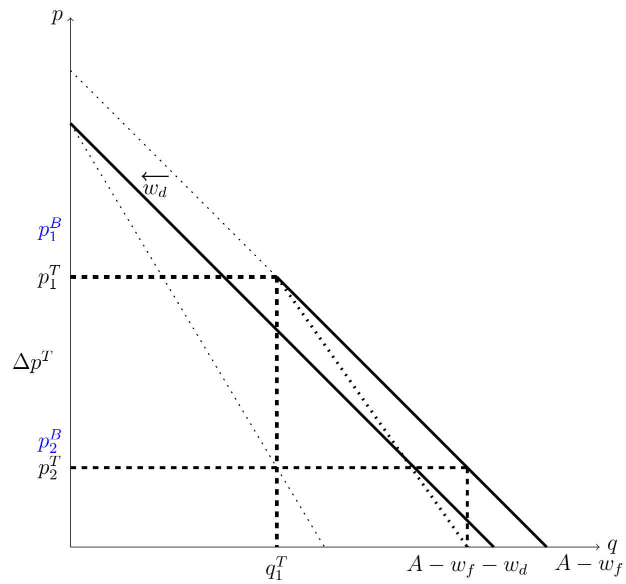
In the absence of arbitrage, the problem faced by the dominant firm in the spot market remains as in (3). In contrast, its problem in the day-ahead market changes as its renewable output is now paid at $\overline{p}$ rather than p_1. In particular, this reduces the firm's price exposure to its total sales net of its wind output, as shown in the first term of the profit expression,

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

where $q_1 = D_1(p_1)$ and $p_2\left(p_1\right)$ and $q_2\left(p_1\right)$ are given by the solution to the spot market problem in (3).

Our second lemma characterizes the solution when firms are paid according to fixed

Figure 2: Solution of the model with fixed prices (FiT)



Notes: This figure illustrates the equilibrium under the model with fixed prices. Firms do not engage in arbitrage, even if allowed. The dominant firm optimizes over a smaller residual demand, which is shifted in by its renewable output w_d. This pushes p_1 down. As this leaves less unserved demand for the spot market, p_2 also goes down. Since the reduction in p_1 is stronger, the price gap Δp shrinks.

prices, which we denote with the super-script T (for Tariffs). It is illustrated in Figure 2.

Lemma 2 *Suppose that renewable producers are subject to fixed prices and arbitrage is allowed. The day-ahead and spot market equilibrium prices are given by*

$$p_1^T = p_1^B - 2\beta w_d > p_2^B - \beta w_d = p_2^T > c,$$

leading to a positive price differential

$$\Delta p^T = \Delta p^B - \beta w_d > 0,$$

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

Proof. See the Appendix. ■

Both prices, as well as the price differential, are lower than at the benchmark, as captured by the terms $-2\beta w_d$ and $-\beta w_d$ in the equilibrium price expressions. This reflects an important effect, which we refer to as the *forward contract effect*: exposing renewables to fixed prices reduces the dominant firm's market power. The dominant firm has weaker incentives to raise day-ahead prices as this would not translate into higher payments for its renewable output.

Since the forward contract effect is channeled through the dominant firm's renewable output, the higher w_d the stronger is the reduction in both prices as well as in the price differential. Just as under the benchmark, the price differential is also increasing in A, but it decreases in b and w_f.

2.3 Variable Prices (FiP)

Suppose now that renewable producers are exposed to variable prices (FiP), i.e., their output is paid at market prices plus a fixed premium.[14] Unlike the previous case, the fringe renewable producers now have incentives to engage in arbitrage by selling all their capacity k_f in the day-ahead market and undoing their long position $(k_f - w_f)$ in the spot market. This implies that, as compared to expressions (1) and (2), the dominant firm now faces a smaller day-ahead residual demand but a larger spot market demand. In particular,

$$D_1(p_1) = A - bp_1 - k_f \quad (6)$$

$$D_2(p_1, p_2) = b\Delta p + (k_f - w_f) \quad (7)$$

Other than this, the profit maximization problems are equivalent to those in the benchmark model, problems (3) and (4), with the residual demands now given by equations (6) and (7).

Our third lemma characterizes the solution when renewable producers are subject to variable prices (FiP), which we denote with the super-script P (for Premiums). It is illustrated in Figure 3.

Lemma 3 *Suppose that renewable producers are exposed to variable prices and arbitrage is allowed. If $A > A' \equiv 2(k_f - w_f) + w_f + bc$, the day-ahead and spot market equilibrium prices are given by*

$$p_1^P = p_1^B - \beta(k_f - w_f) > p_2^B + \beta(k_f - w_f) = p_2^P > c$$

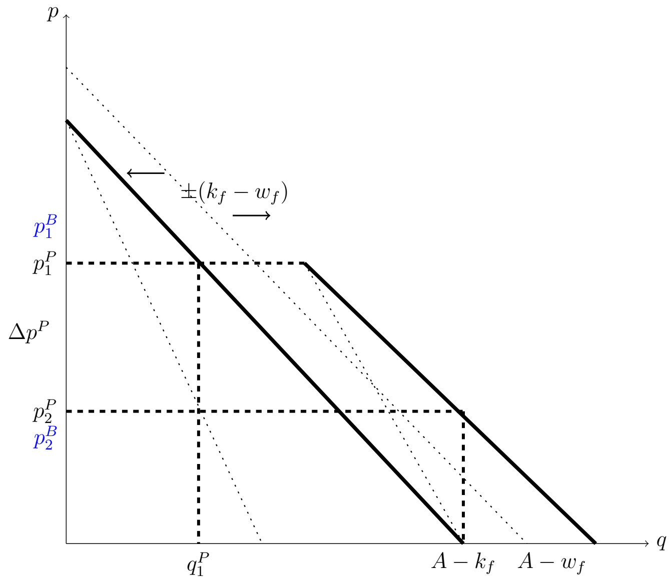
leading to a positive price differential

$$\Delta p^P = \Delta p^B - 2\beta(k_f - w_f) > 0,$$

where $\beta = (3b)^{-1} > 0$, and p_1^B, p_2^B and Δp^B are those in Lemma 1. Otherwise, if $A \leq A'$, then $\Delta p^P = 0$ with

$$p_1^P = p_2^P = \frac{A - w_f + cb}{2b} > c.$$

Figure 3: Solution of the model with variable prices (FiP)



Notes: This figure illustrates the equilibrium under the model with variable prices in which arbitrage is allowed. Note that the day-ahead demand shifts in while the spot market demand shifts out by the renewables idle capacity $k_f - w_f$. The day-ahead p_1 goes down while the spot price p_2 goes up, so the price gap Δp shrinks.

Proof. See the Appendix. ■

As compared to the benchmark, allowing for arbitrage has two opposite effects: it weakens the dominant firm's market power in the day-ahead market, but it strengthens its market power in the spot market. Intuitively, in order to benefit from the positive price differential, the fringe renewable producers sell k_f in the day-ahead market but then need to buy $(k_f - w_f)$ in the spot market. This 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, the day-ahead price goes up while the spot price goes down. This effect, which we refer to as the *arbitrage effect*, is captured by the terms $\pm\beta\,(k_f - w_f)$ in the equilibrium price expressions.

Arbitrage reduces the price differential, as captured by the term $-2\beta\,(k_f - w_f)$, but it does not fully close the price gap if total demand A is large enough relative to the fringe's idle capacity. In this case, just as under the benchmark, the price differential is increasing in A and decreasing in b. However, and in contrast to the comparative statics of the benchmark model and the model with fixed prices, the price differential is now increasing in w_f as the more wind the fringe has, the more limited its ability to arbitrage price differences. If w_d and w_f are correlated, an increase in wind could reduce the price

[14] Since this premium is fixed, it has no effect on equilibrium prices. We thus save on notation.

differential, but the effect is always weaker as compared to the one under the benchmark model or under the model with fixed prices.

Last, if A is not large enough, arbitrage fully closes the price gap across markets, yet resulting in prices that exceed marginal costs, i.e., even when price discrimination is fully eliminated, market power remains.

2.4 Fixed versus variable prices

Having characterized the equilibria under fixed and variable prices, we are now ready to compare the resulting equilibrium outcomes across pricing schemes. The next proposition compares consumer surplus (which depends on day-ahead prices), price discrimination (which depends on the price difference between the day-ahead and the spot markets), and total welfare (which depends on spot market prices).

Proposition 1 *The comparison of equilibrium outcomes across pricing schemes (fixed versus variable prices) shows that:*

(i) A sufficient condition for consumer surplus to be higher when firms are paid according to fixed prices is $w_d > (k_f - w_f)/2$. *If* $w_d < (k_f - w_f)/2$*, the sufficient condition is* $A < 4w_d + w_f + cb$.

(ii) A necessary and sufficient condition for price discrimination across markets to be lower when firms are paid according to fixed prices is $w_d > 2(k_f - w_f)$.

(iii) Total welfare is unambiguously higher when firms are paid according to fixed prices.

Proof. It follows from comparing Lemmas 2 and 3. See the appendix for details. ■

Since demand is fully cleared in the day-ahead market, consumer surplus solely depends on day-ahead prices. 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 (and consumer surplus higher) under fixed prices when the dominant firm owns a big share of renewables, or at least big enough relative to demand. 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' idle renewable capacity.

All the factors that enhance market power in the day-ahead market also strengthen the extent of price discrimination across markets. Hence, point (ii) of the Proposition is in line with point (i). Namely, the price differential across markets is relatively smaller (larger) under fixed prices when the ownership of renewables is concentrated in the hands of the dominant producer (fringe). 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 (*ii*) than in (*i*). This implies that fixed prices could result in greater price discrimination across markets and yet result in higher consumer surplus.

In contrast to the above results, the welfare comparison is unambiguous: fixed prices give rise to higher efficiency than variable prices. Given that demand is price inelastic, total welfare solely depends on productive efficiency, which in turn is a function of the final allocation set at the spot market. Under variable prices, spot prices are relatively higher than under fixed prices, thus implying that a greater fraction of total output is inefficiently produced by the fringe. 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.[15]

2.5 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 mark-ups of the dominant firms are decreasing in their own wind. Since this effect is not present when firms are exposed to variable prices, the mark-ups of the dominant firms should be independent of their own wind.

(*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 fringe producers' day-ahead and final commitments should be orthogonal to the price differential.

[15] This result remains true even if there is a cost of production adjustment at the spot market, i.e., $b_1 > b_2$. On the one hand, arbitrage under FiPs transfers some demand of the wind producers to the spot market; on the other, price discrimination might be lower under FiPs depending on parameter values. While the first effect pushes q_2 up, the second effect pushes it down. The former effect always dominates, leading to greater adjustment costs under FiPs. See Appendix for details.

(*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 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, i.e., only 4 hours later than they day-ahead market. Hence, very often, there is little new information revealed between the two markets. 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, 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. 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.[16] In our empirical analysis, we will exploit the occurrence of the two most recent regulatory changes affecting wind operators.

Prior to February 2012, 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",[17] 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). 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.

In general terms, the new scheme that was introduced in June 2014 (and 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 regulated payments.[18] The latter is based on technology and vintage specific

[16] 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.

[17] 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.

[18] 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

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. There are significant differences between the pre-February 2013 FiP and the post-June 2014 FiP. Such differences refer mainly to the level of support, but they still 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.[19] While these are reliable sources of cost data,[20] we cannot rule out measurement errors. For instance, the price of coal and

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.

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

[20] 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

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.[21]

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.[22] 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.[23] 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 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.[24] There was also a

efficiency as well as their emission rate.

[21]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).

[22]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.

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

[24]This explains why Gas Natural is the price-setter during a large fraction of the time. This, together

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. 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.

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)

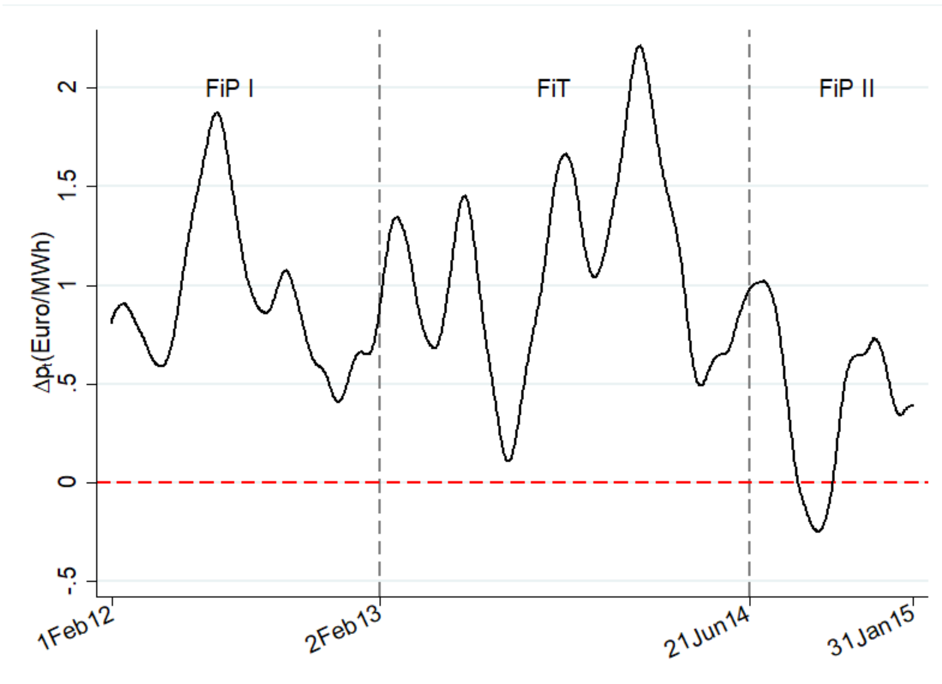
Notes: Sample from 1 February 2012 to 31 January 2015. FiP I is from 1 February 2012 to 31 January 2013; FiT 2013 is from 1 February 2013 to 21 June 2014; FiP II is from 22 June 2014 to 31 January 2015. Prices are in Euro/MWh. Demand and wind forecasts are in GWh.

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 mark-ups in the day-ahead market prices.

3.4 A first look at the data

It is illustrative to provide a first look at the raw data. Figure 4 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).[25]

Figure 4: Price discrimination across markets



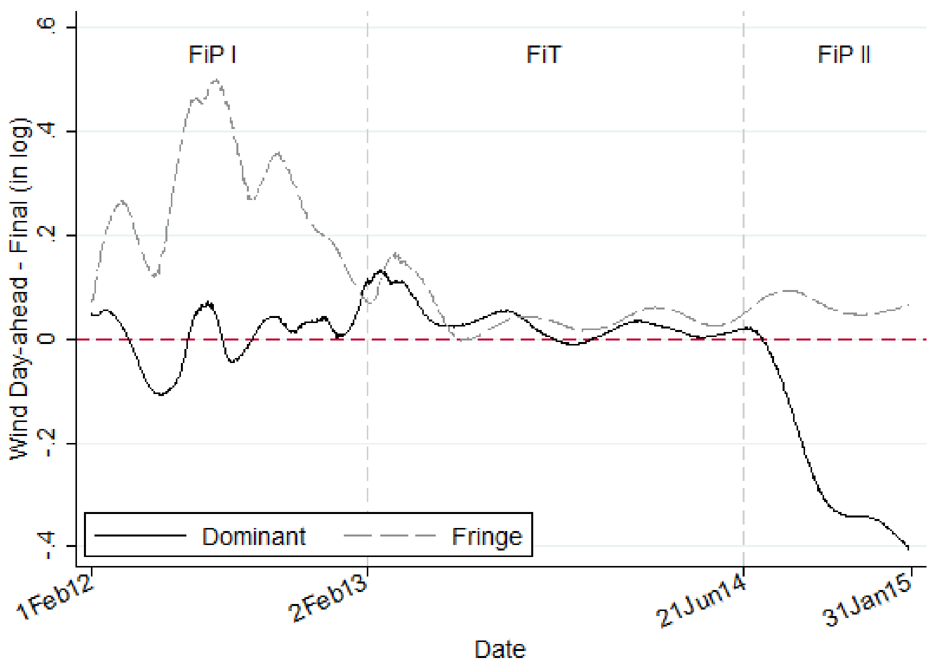
Notes: This figure is a smoothed plot of the price premium (day-ahead price minus the price in the first intra-day market) using a locally weighted regression. The weights are applied using a tricube weighting function (Cleveland, 1979) with a bandwidth of 0.1. The sample ranges from 1 February 2012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

Figure 5 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 reflect overselling in the day-ahead market, while negative numbers reflect withholding). As it 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

[25]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 was different. Moreover, renewables other than wind were subject to fixed prices under FiP I and to market prices under FiP II.

engaged in arbitrage by overselling their wind output in the day-ahead market.[26]

Figure 5: Overselling and withholding across markets by wind producers



Notes: This figure is a smoothed plot of the day-ahead commitment minus the final commitments of wind producers belonging to both the dominant and the fringe firms, using a locally weighted regression. The weights are applied using a tricube weighting function (Cleveland, 1979) with a bandwidth of 0.1. Positive numbers reflect overselling, while negative numbers reflect withholding. The vertical lines date the changes in the pricing schemes for renewables.

The change in the pricing schemes also had a strong impact on the dominant producers' behaviour. The dominant producers withheld more wind output across markets when exposed to variable prices, notably so after the switch from FiT to FiP II.[27]

While these figures suggest that changes in the pricing schemes had a strong impact on firms' bidding behaviour, 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 assessed in isolation. For instance, why did the dominant firms start withholding when

[26]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.

[27]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.

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 behaviour, 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 turn next.

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

$$p = c_i + \left| \frac{\partial DR_i}{\partial p} \right|^{-1} (q_i - I_t w_i) \, , \tag{8}$$

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 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)[28] belonging to one of the dominant firms.[29] 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).[30]

Our detailed bid data allows us to construct all the variables in the first order condition (8), 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).[31]

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 theory model.

For this purpose, we estimate the following empirical equation in hours in which firm

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

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

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

[31]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.

i is bidding at or close to the market-clearing price:

$$b_{ijt} = \rho c_{ijt} + \beta \left| \frac{q_{it}}{DR'_{it}} \right| + \theta \left| \frac{w_{it}}{DR'_{it}} \right| I_t^s + \alpha_{ij} + \gamma_t + \epsilon_{ijt}, \tag{9}$$

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 is an indicator variable that takes the value 1 when the pricing scheme at time t is $s =$ FIP I, FIT, FIP II and 0 otherwise;[32] α_{ij} are unit fixed effects, γ_t are time fixed effects, and ϵ_{ijt} is the error term.

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.

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 mark-up terms equal zero, we expect the price to be zero as well). The standard errors are clustered at the week of sample to allow errors to be correlated within the same week.

When estimating equation (9), 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 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 marginal cost of the marginal unit and the slope of the day-ahead residual demand with wind speed and precipitation (and each of them interacted with three dummies of pricing scheme) as residual demand shifters, and carbon price as one of the key components of marginal costs.[33] We then use Two-Stage Least Squares (2SLS) regression to estimate equation (9).

[32] 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.

[33] These variables are all likely to be exogenous. This is clearly so for the first two, wind speed and

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 coefficient for marginal cost 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.[34] 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 order 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 a ten percent over its mean would imply a price reduction of 1.8 Euro/MWh (approximately, a 4 percent of the average price) during the FiT period.

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 such non-strategic reasons is that the former are 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).[35]

precipitation. The carbon price is set in international markets, thus independently of what happens in the Spanish electricity market.

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

[35]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 analysis, we rely on a differences-

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 (9) 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 emissions price. The standard errors are clustered at the week of sample.

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

in-differences approach using two possible control groups.

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.[36] Specifically, we regress demand and wind forecasts, hourly dummies, and date dummies on the price premium.[37] 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 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), $\Delta\text{ln}q_{tg}$. 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. 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. The estimating equation is

$$\Delta\text{ln}q_{tg} = \alpha + \theta_g\Delta\hat{p}_t + \gamma D_t^{er} + \delta w_t^{er} + \rho\mathbf{X}_t + \eta_{tg} \qquad (10)$$

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

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

[37]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 be varied across pricing regimes considering that firms are aware that there is 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.

Figures 6 and 7 plot the θ_g coefficients for each quarter.[38] As expected, in Figure 6, 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 7, 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 6 and FiP regimes in Figure 7) provide a graphical evidence on the parallel trend between wind and each of the control groups.[39]

Equipped by the graphical evidence, we proceed to analyze the overselling behavior of wind fringe using the difference-in-difference (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, 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,

$$\begin{aligned}\Delta \ln q_t =& \alpha + \beta_1 W R_t^d \Delta\hat{p}_t + \beta_2 W \Delta\hat{p}_t + \beta_3 W R_t^d + \beta_4 R_t^d \Delta\hat{p}_{ht} + \beta_5 \Delta\hat{p}_t + \\ & \beta_6 W + \beta_7 R_t^d + \rho \mathbf{X}_t + \eta_t\end{aligned} \tag{11}$$

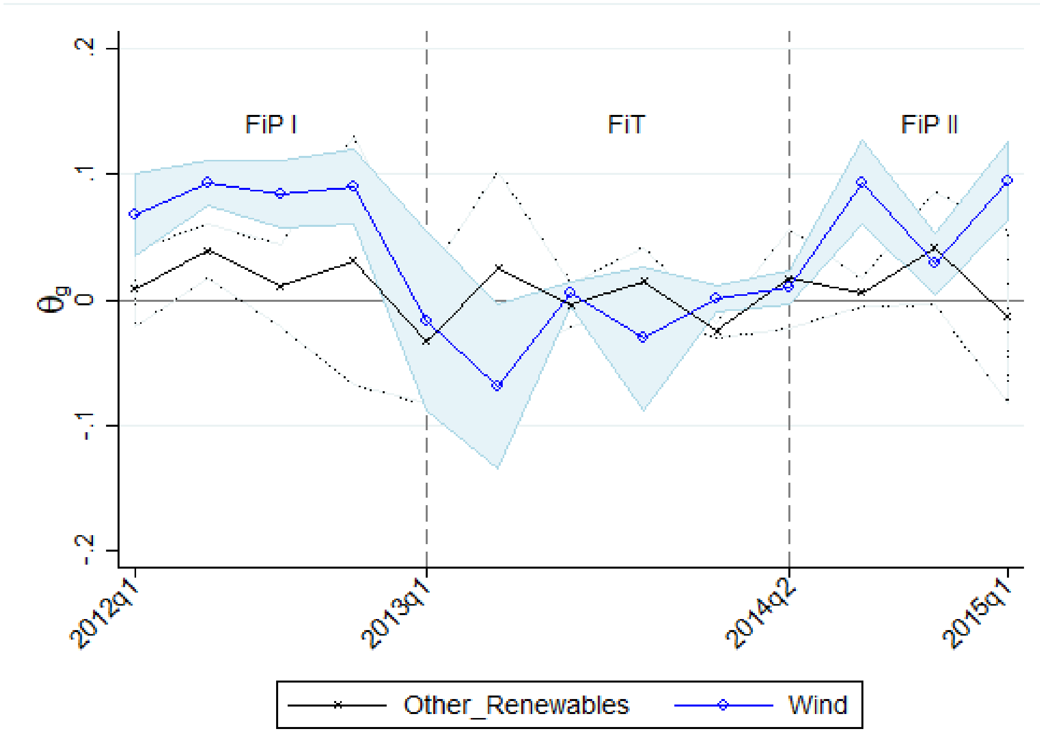
For sample $d = 1$, which contains the switch from variable to fixed prices, R_t^1 is an indicator for fixed prices (FiT). Similarly, for sample $d = 2$, which contains the switch from to fixed to variable prices, R_t^2 is an indicator for variable prices (FiP). For both samples, W is an indicator for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

[38]For these 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.

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

Figure 6: Arbitrage by Fringe Wind vs. Non-Wind Renewables



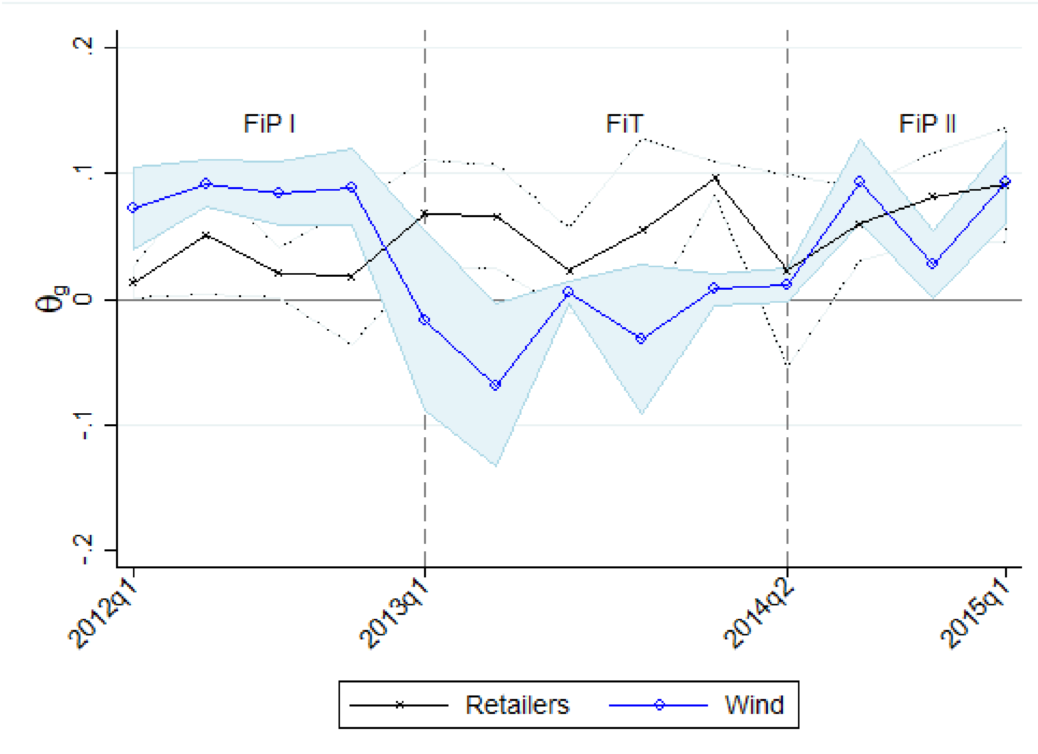
Notes: This figure plots the coefficients of the OLS regression in equation (10) for wind and other non-wind renewable producers (i.e., solar, small hydro, and co-generation production units). It captures the response of overselling to the predicted price differential. Positive numbers suggest that overselling 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 are comparable in each quarter. Hours when the predicted price differential gives a poor prediction for the observed price differential are excluded.

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.[40] The impact of the switch from variable prices (FiP) to fixed prices (FiT) is shown in columns (1) and (2), depending on whether 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

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

Figure 7: Arbitrage by Fringe Wind vs. Retailers



Notes: This figure plots the coefficients of the OLS regression in equation (10) 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 are comparable in each quarter. Hours when the predicted price differential gives a poor prediction for the observed price differential are excluded.

this switch brought wind fringe producers back to arbitrage.[41] Overall, these results are all consistent with our predictions.

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.

[41] 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.

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 (11). 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.

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 understand which was the case in our setting, we estimate the following empirical equation:

$$\Delta p_t = \alpha + \beta_1 I_t + +\beta_2 w_t + \beta_3 w_t I_t + \alpha_1 DR'_{1t} + \alpha_2 DR'_{2t} + \gamma \mathbf{X}_t + \epsilon_t \tag{12}$$

where Δp_t is the price premium at time t; I_t takes three values for periods with FiP I, FiP II, and FiT, with $I_t =$ FiT set as the reference point; DR'_{1t} and DR'_{2t} capture the slope of the residual demand faced by the dominant firms in the day-ahead and intraday markets respectively;[42] 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 theory model

[42] 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 31. We instrument DR'_1 and DR'_2 using daily average, minimum, and maximum temperature, and average temperature interacted with hourly dummies.

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. To test these predictions, we focus on the interaction between the pricing scheme and two types of wind impacts: through its total output and through its ownership structure. Accordingly, we first let w_t capture the forecast of total wind output. Second, 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 (12), 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 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 (8), mark-ups 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'

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 $\times$ Wind Forecast (GWh)	0.2***			
	(0.03)			
FiP II $\times$ 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 $\times$ $\frac{w_{dt}}{w_{ft}}$		0.9***	0.4*	0.7***
		(0.2)	(0.2)	(0.2)
FiP II $\times$ $\frac{w_{dt}}{w_{ft}}$		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 (12). 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 three values: FiP I, FiP II, and FiT; I_t = FiT is set as the reference point. Standard errors are clustered at year x month x days of the week.

markups and Figure 8 shows the distribution.[43] Markups are always relatively lower under fixed prices: the average mark-up 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 mark-up distributions are the same across pricing regimes. A similar conclusion applies when comparing the mark-ups 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.

5 Conclusions

In this paper we have assessed whether market power is best addressed indirectly through arbitrage or by acting directly on the firms' incentives to exercise market power in the first place. 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 whether one effect or the other dominates in reducing market power and price discrimination ultimately 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

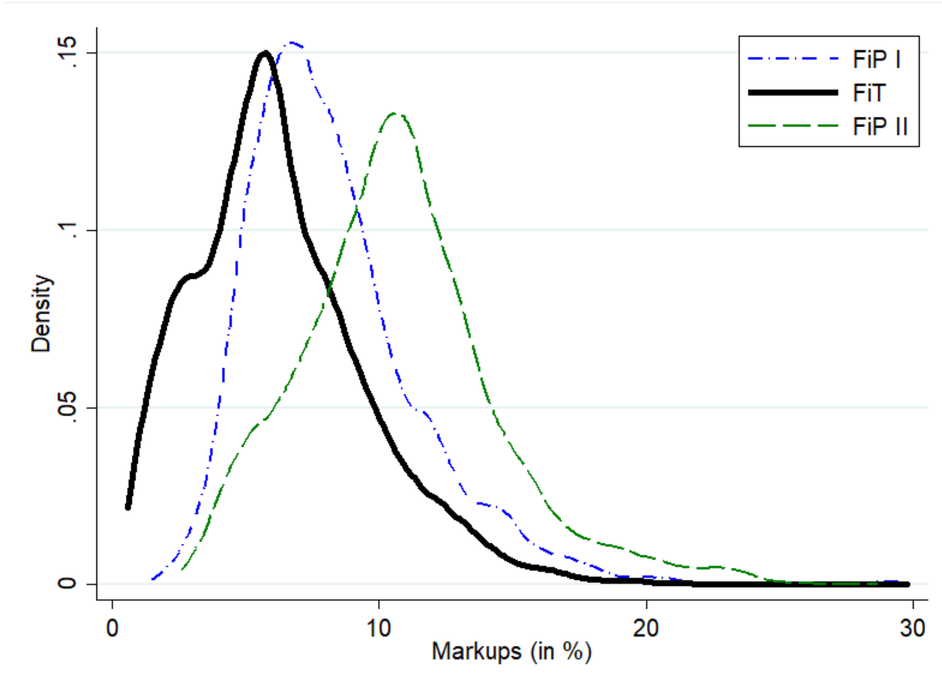
[43] An alternative approach to computing mark-ups is simply to rely on the observed prices and on engineering estimates for marginal costs. This approach is common in the literature. For example, see Borenstein, Bushnell and Wolak (2002), Fabra and Toro (2005), or Fabra and Reguant (2014), among others. 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 mark-ups were lower under the FiT regime– also holds when relying on the engineering estimates for marginal costs (results available upon request).

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 mark-ups 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 8: 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.

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 consumers better off given that the prices they pay are a function of the day-ahead prices (in contrast to real time market prices, which mainly serve to reshuffle production across firms). Yet, price discrimination across markets remained larger under fixed prices as compared to variable prices. This illustrates that price differences across markets should not be taken as a unambiguous measure of efficiency, at least in settings with market power.

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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 FiPs), but (ii) their payments are settled by differences between the contract's price, $\overline{p}$, and the day-ahead market price (similarly to FiTs). Point (i) implies that the fringe renewables have the same incentives to arbitrage as under variable prices (FiP), giving rise to the same residual demands for the dominant firm, equations (6) and (7). In turn, point (ii) implies that the dominant firm's day-ahead profit maximization problem is the same as under fixed prices (FiT), given in equation (5).

Our last lemma characterizes 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 Lemmas 2 and 3.

Lemma 4 *Suppose that renewable producers are subject to contracts-for-differences and arbitrage is allowed. The day-ahead and spot market equilibrium prices are given by*

$$p_1^C = p_1^T + \beta\left(k_f - w_f\right) > p_2^T + \beta\left(k_f - w_f\right) = p_2^C > c,$$

or equivalently to

$$p_1^C = p_1^P - 2\beta w_d > p_2^P - \beta w_d = p_2^C > c,$$

leading to a positive price differential

$$\Delta p^C = \Delta p^T - \beta w_d = \Delta p^P - 2\beta\left(k_f - w_f\right) > 0,$$

where $\beta = (3b)^{-1} > 0$, and p_1^T, p_2^T and Δp^T are those in Lemma 2, and p_1^P, p_2^P and Δp^P are those in Lemma 3.

Proof. It follows the same steps as the proofs of Lemmas 2 and 3, and it is therefore omitted ■

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

Proposition 2 *The comparison of equilibrium outcomes across pricing schemes (contracts-for-differences, fixed prices and variable prices) shows that:*

(i) Consumer surplus is higher under CfDs, as compared to either fixed or variable prices, $p_1^C < p_1^T$ and $p_1^C < p_1^P$.

(ii) Price discrimination is lower under CfDs, as compared to either fixed or variable prices, $\Delta p^C < \Delta p^T$ and $\Delta p^C < \Delta p^P$.

(iii) Total welfare under CfDs is lower as compared to fixed prices but higher as compared to variable prices, $p_2^T < p_2^C < p_2^P$.

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

A.2. Proofs

For completeness, the proofs for the Lemmas and Propositions given below assume that the marginal costs of the conventional fringe are given by q/b_t, for $t = 1$ (day-ahead) or $t = 2$ (spot), where $b_2 \leq b_1 \leq b_2$, i.e., to capture adjustment costs, we allow the conventional fringe's marginal costs to be greater in the spot market, but at most twice as large as compared to marginal costs in the day-ahead market. The results presented in the main text are a particular case of this, with $b_1 = b_2 = b$.

Proof of Lemma 1 (Benchmark model). We solve the profit maximization problems in (3) and (4). We do so by backward induction, with $D_1(p_1) = A - b_1 p_1 - w_f$ and $D_2(p_1, p_2) = b_2 \Delta p$.

For given p_1, the spot market solution is given by

$$p_2 = \frac{p_1 + c}{2}, \text{ implying } q_2 = b_1 \frac{p_1 - c}{2}. \tag{13}$$

Using this, for $\beta = (4b_1 - b_2)^{-1}$, the day-ahead market solution is

$$p_1^B = \beta \left[2\left(A + b_1 c - w_f\right) - b_2 c\right], \text{ implying } q_1^B = \beta\left(2b_1 - b_2\right)\left(A - w_f - b_1 c\right).$$

Plugging this back into the spot market solution gives

$$p_2^B = \beta\left[A - w_f + \left(3b_1 - b_2\right)c\right], \text{ implying } q_2^B = \beta b_2\left(A - w_f - b_1 c\right)$$

Taking the difference between the two prices,

$$\Delta p^B \equiv p_1^B - p_2^B = \beta\left(A - w_f - b_1 c\right).$$

Since we have assumed $A > w_d + w_f + b_1 c$, it follows that $q_2^B > 0$,, which implies $\Delta p^B > 0$. Also, $p_2^B > \beta\left(4b_1 - b_2\right)c = c$ so that $p_1^B > c$. 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. Last, using the above expressions, we obtain that the dominant firm is a net-seller in the spot market

$$q_2^B = \beta b_2\left(A - w_f - b_1 c\right) > 0.$$

■

Proof of Lemma 2 (FiT). We now solve the profit maximization problems in (3) and (5), with $D_1(p_1) = A - b_1 p_1 - w_f$ and $D_2(p_1, p_2) = b_2 \Delta p$.

The spot market solution is still given by (13) as the spot-market problem remains as before. The day-ahead market solution is

$$p_1^T = \beta\left[2\left(A - w_d - w_f\right) + \left(2b_1 - b_2\right)c\right] = p_1^B - 2\beta w_d \tag{14}$$

where $\beta = (4b_1 - b_2)^{-1} > 0$.

Plugging this back into the spot market solution gives

$$p_2^T = \beta \left[A - w_d - w_f + (3b_1 - b_2)\, c\right] = p_2^B - \beta w_d$$

Taking the difference between the two prices,

$$\Delta p^T = \beta \left(A - w_d - w_f - b_1 c\right) = \Delta p^B - \beta w_d > 0.$$

Since we have assumed $A > w_d + w_f + b_1 c$, it follows that $\Delta p^T > 0$, and using the above condition on A, $p_2^T > c$ so that $p_1^T > c$. The price differential is increasing in A and b_2, and it is decreasing in w_f, w_d and b_1.

Last, using the above expressions, we obtain

$$q_2^T = \beta b_2 \left(A - w_f - w_d - b_1 c\right) = q_2^B - \beta b_2 w_d > 0,$$

which is lower than q_2^B. ■

Proof of Lemma 3 (FiP). We now solve the profit maximization problems in (4) and (3), with $D_1(p_1) = A - bp_1 - k_f$ and $D_2(p_1, p_2) = b\Delta p + (k_f - w_f)$. The spot market solution is now given by

$$p_2 = \frac{p_1 + c}{2} + \frac{k_f - w_f}{2b}, \text{ implying } q_2 = b\frac{p_1 - c}{2} + \frac{k_f - w_f}{2}.$$

The day-ahead market solution is

$$p_1^P = \beta \left[2A + c\,(2b_1 - b_2) - k_f - w_f\right] = p_1^B - \beta \left(k_f - w_f\right). \tag{15}$$

Plugging this back into the spot market solution gives

$$\begin{aligned} p_2^P &= \beta \left(A + (3b_1 - b_2)\, c - \frac{k_f + w_f}{2}\right) + \frac{1}{2b_2} \left(k_f - w_f\right) \\ &= p_2^B + \frac{2b_1 - b_2}{b_2} \beta \left(k_f - w_f\right) \\ q_2^P &= \beta b_2 \left(A - b_1 c - \frac{k_f + w_f}{2}\right) + \frac{1}{2} \left(k_f - w_f\right) \end{aligned}$$

Taking the difference between the two prices,

$$\Delta p^P = \beta \left(A - b_1 c - \frac{k_f + w_f}{2}\right) - \frac{k_f - w_f}{2b_2} = \Delta p^B - \frac{2b_1}{b_2} \beta \left(k_f - w_f\right)$$

The price differential is increasing in A, b_2, w_f and it is decreasing in b_1. For this solution not to fully close the price gap, we require $\Delta p^P > 0$, which holds true for

$A > A' \equiv (2b_1/b_2)(k_f - w_f) + w_f + b_1 c$. In turn $\Delta p^P > 0$, implies $q_2^P > 0$ and, using the above condition on A,

$$p_2^P > \frac{k_f - w_f}{b_1} + c > c.$$

So that $p_1^P > p_2^P > c$.

Last, if $A < A'$, the amount of arbitrage that closes the price gap is lower than $(k_f - w_f)$. If we refer to it as s, then $D_1(p_1) = A - bp_1 - s$ and $D_2(p_1, p_2) = b\Delta p + s$. Following the same steps as before, it follows that

$$\begin{aligned} p_1^P &= p_1^B - \beta s = p_2^P = p_2^B + \frac{2b_1 - b_2}{b_2}\beta s \\ \Rightarrow\ s &= \frac{\Delta p^B}{2\beta} = (A - w_f - b_1 c)\frac{b_2}{2b_1}. \end{aligned}$$

Plugging these back into the price equations,

$$\begin{aligned} p_1^P &= p_2^P = \frac{A - w_f + cb_1}{2b_1} > c. \\ \Delta p^P &= 0. \end{aligned} \tag{16}$$

■

Proof of Proposition 1 (FiT vs. FiP). (i) First, suppose $w_d > (2b_1/b_2)(k_f - w_f)$, which implies than $A' \equiv (2b_1/b_2)(k_f - w_f) + w_f + b_1 c < w_d + w_f + b_1 c$. Hence, for all $A > w_d + w_f + b_1 c$, using the day-ahead equilibrium prices (14) and (15) and taking the difference,

$$p_1^T - p_1^P = \beta\left[(k_f - w_f) - 2w_d\right] < 0. \tag{17}$$

Second, suppose $(k_f - w_f)/2 < w_d < (2b_1/b_2)(k_f - w_f)$. Then, for $A > A'$, the price difference (14) is negative, as above. For $w_d + w_f + b_1 c < A < A'$, the day-ahead price under variable prices is now given by (16). Taking the difference between (14) and (16),

$$p_1^T - p_1^P = \frac{\beta}{2}\frac{b_2}{b_1}\left(A - 4\frac{b_1}{b_2}w_d - w_f - cb_1\right), \tag{18}$$

which is negative if and only if

$$A < A'' \equiv 4\frac{b_1}{b_2}w_d + w_f + cb_1.$$

Comparing A'' and A',

$$A'' - A' = -\frac{2b_1}{b_2}\left((k_f - w_f) - 2w_d\right) > 0$$

given that we are considering cases with $(k_f - w_f)/2 < w_d$. Hence, for $A < A' < A''$, the day-ahead price difference (18) is also negative over this range.

Last, suppose $w_d < (k_f - w_f)/2$. Now $A'' < A'$. For $A > A'$, the price difference (14) is now positive. For $A'' < A < A'$, the price difference (18) is also positive. Last, for $w_d + w_f + b_1c < A < A''$, the price difference (18) is negative.

(ii) First, suppose $w_d > (2b_1/b_2)(k_f - w_f)$, which implies that $A' < w_d + w_f + b_1c$. Hence, for all $A > w_d + w_f + b_1c$,

$$\Delta p^T - \Delta p^P = \beta \left[2 (k_f - w_f) b_1/b_2 - w_d\right] < 0. \tag{19}$$

Second, suppose $w_d < (2b_1/b_2)(k_f - w_f)$. Then, for $A > A'$, the above expressions (19) is now positive. For $w_d + w_f + b_1c < A < A'$, $\Delta p^T > \Delta p^P = 0$. It follows that $\Delta p^T < \Delta p^P$ if and only if $w_d > (2b_1/b_2)(k_f - w_f)$.

(iii) The price comparison immediately follows from $p_2^T < p_2^B < p_2^P$.

Furthermore, comparing the quantities that are traded in the spot market,

$$q_2^T - q_2^P = b_2 \left(\Delta p^T - \Delta p^P\right) - (k_f - w_f).$$

To sign this difference, we need to compare the various cases. First, suppose $w_d > (2b_1/b_2)(k_f - w_f)$. Since $\Delta p^T - \Delta p^P < 0$, it follows that $q_2^T < q_2^P$. Second, suppose $w_d < (2b_1/b_2)(k_f - w_f)$. Then, for $A > A'$, $\Delta p^T > \Delta p^P$. Computing the expression,

$$q_2^T - q_2^P = -b_2\beta w_d - (k_f - w_f) \frac{2b_1 - b_2}{4b_1 - b_2} < 0 \tag{20}$$

For $w_d + w_f + b_1c < A < A'$, $\Delta p^T > \Delta p^P = 0$. Computing the expression,

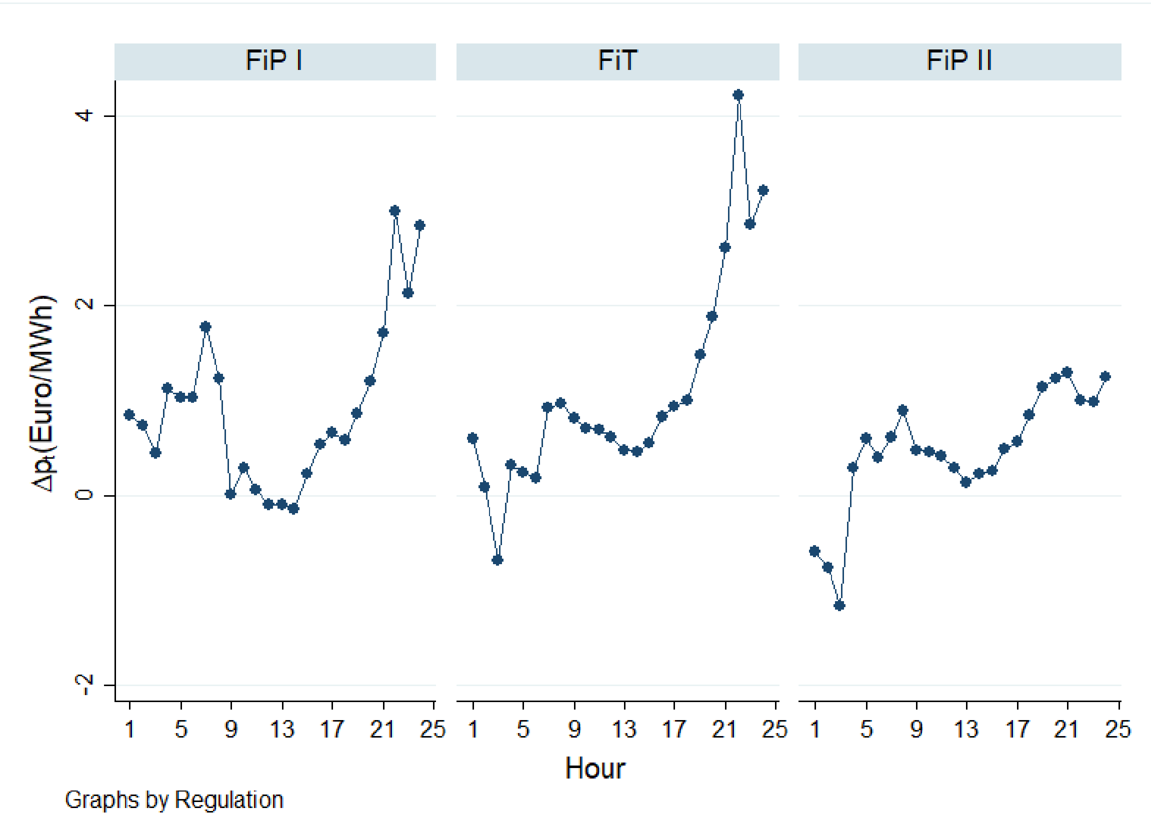
$$\begin{aligned} q_2^T - q_2^P &= b_2\beta (A - w_f - w_d - b_1c) - (k_f - w_f) \\ &< b_2\beta (A' - w_f - w_d - b_1c) - (k_f - w_f) < 0 \end{aligned}$$

where the last term equals (20), which is negative.

■

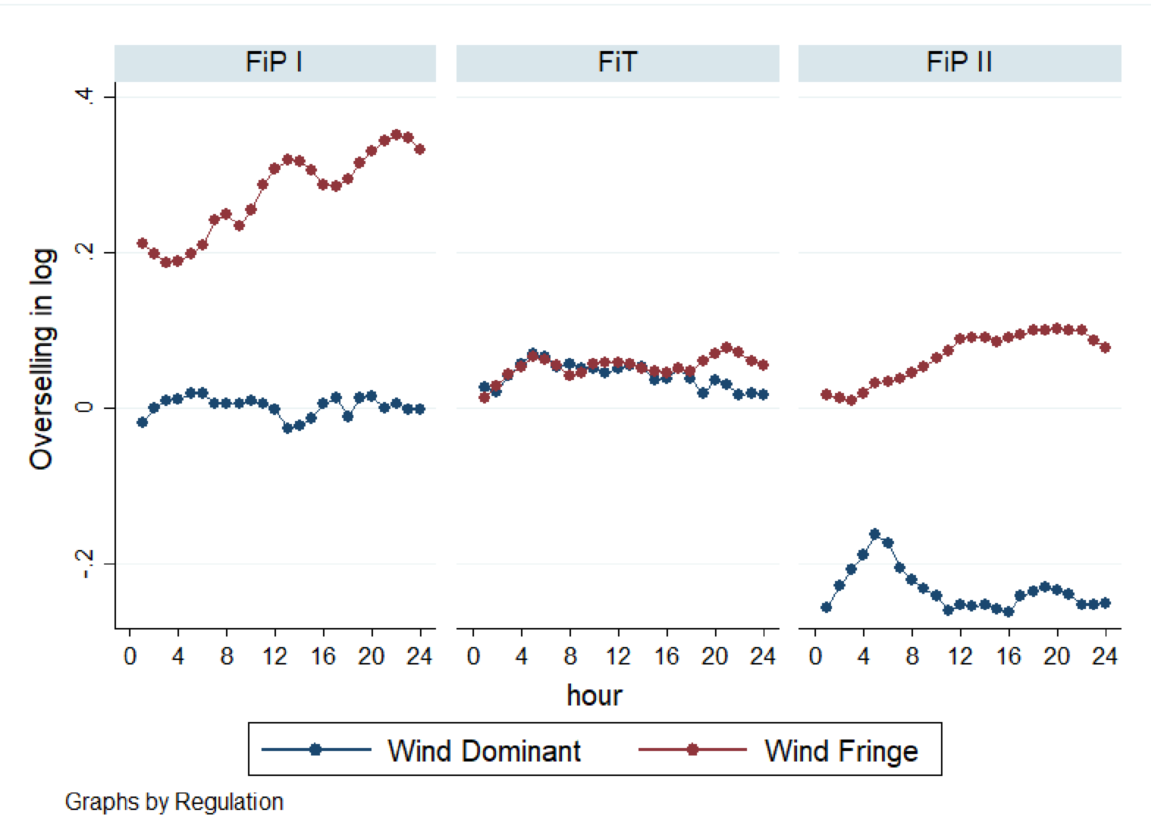
Appendix B: Additional Figures and Tables

Figure B.1: Hourly Price Premium by Pricing Regimes



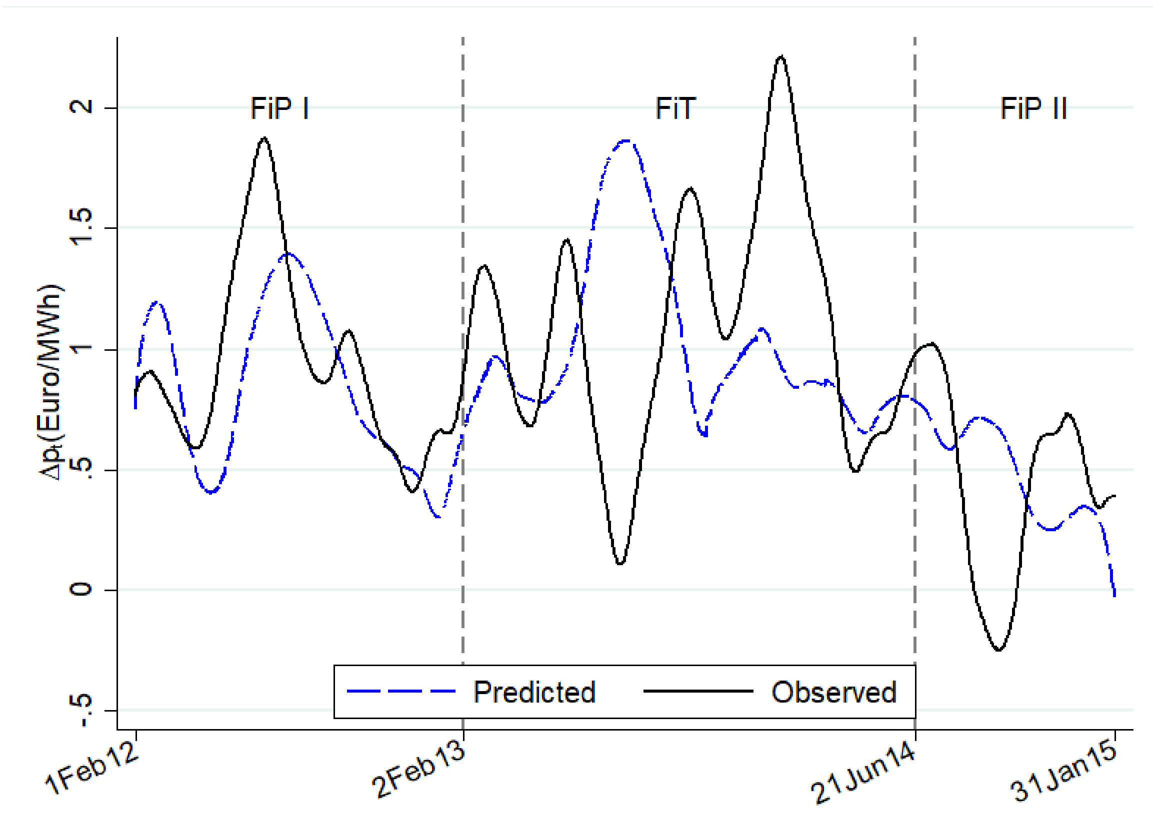
Notes: This figure shows the hourly average of price premium, split in three regulatory regimes. Sample is from 1 February 2012 to 31 January 2015. FiP I is from 1 February 2012 to 31 January 2013; FiT 2013 is from 1 February 2013 to 21 June 2014; FiP II is from 22 June 2014 to 31 January 2015.

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



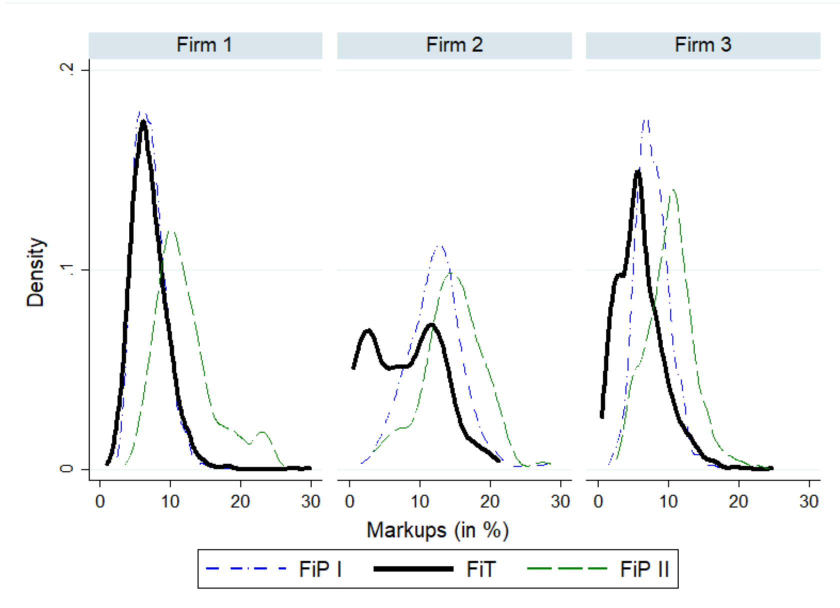
Notes: This figure shows the hourly average of the day-ahead commitments minus the final commitments of the wind producers, split in three regulatory regimes. Sample is from February 2012 to February 2015. FiP I is from 1 February 2012 to 31 January 2013; FiT 2013 is from 1 February 2013 to 21 June 2014;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

Figure B.3: Predicted and Observed Price Premium



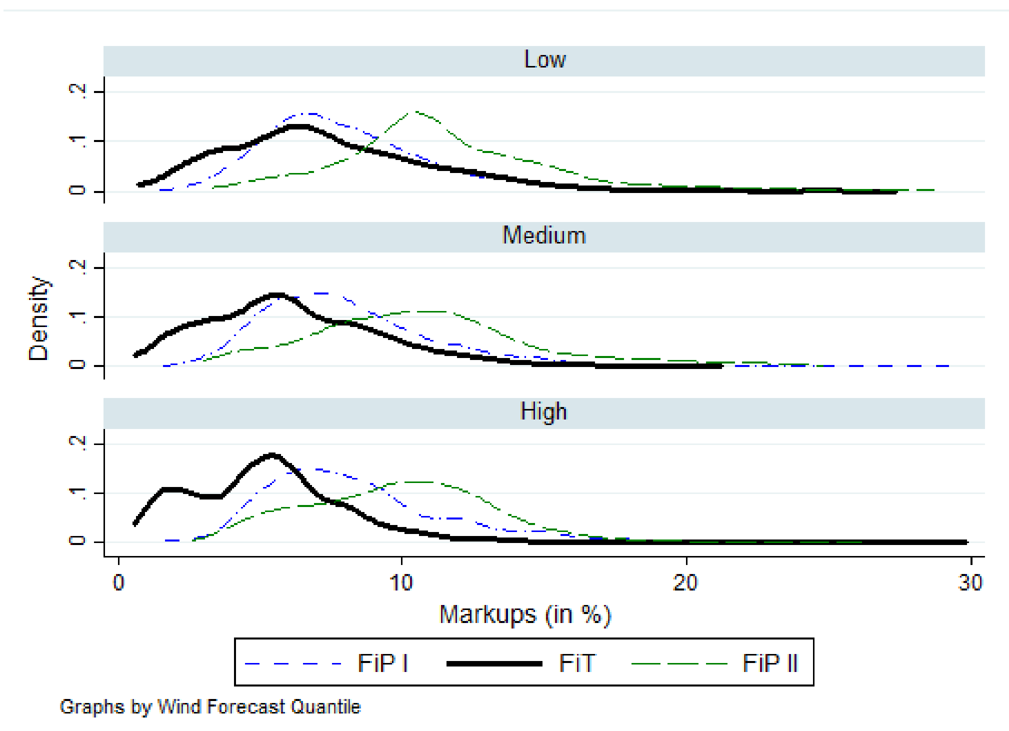
Notes: This figure shows locally weighted linear regressions of $\Delta\hat{p}_t$ (predicted) and Δp_t (observed) from February 2012 to February 2015. The weights are applied using a tricube weighting function (Cleveland, 1979) with a bandwidth of 0.1. The predictions ($\Delta\hat{p}_t$) are done using the estimated coefficients obtained from equation in footnote 37. These $\Delta\hat{p}_t$ are used in equation 10.

Figure B.4: Markup Distribution by Firm



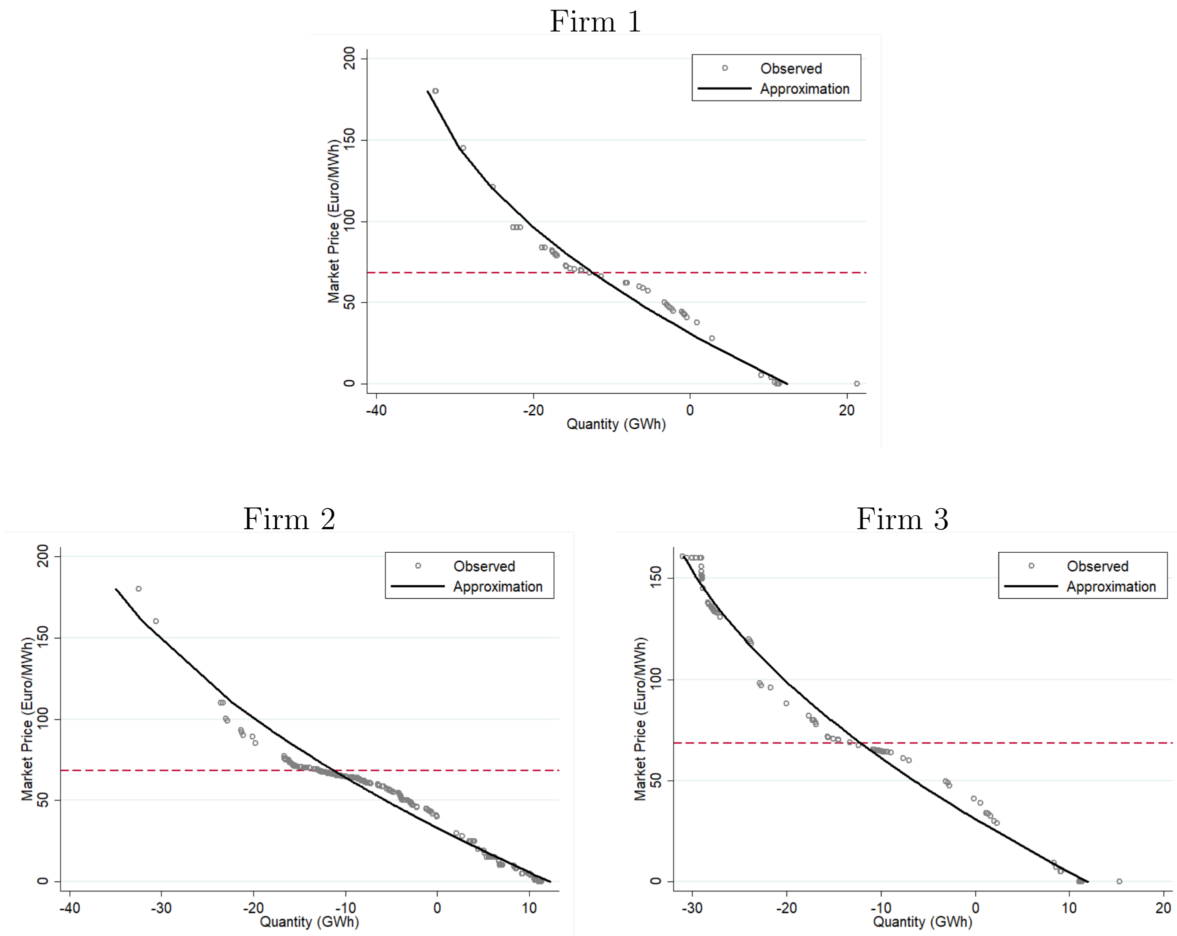
Notes: This figure plots the markup distributions for each of the dominant firms by their pricing regimes for hours with prices above 25 Euro/MWh.

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 (10). 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.