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Working Paper

A Comment on "Market Power and Price Exposure: Learning from Changes in Renewable Energy Regulation"

I4R Discussion Paper Series, No. 258

Provided in Cooperation with:

The Institute for Replication (I4R)

Suggested Citation: Bryan, Calvin; Donovan, Pierce; Kacker, Kanishka; Pham, Linh (2025) : A Comment on "Market Power and Price Exposure: Learning from Changes in Renewable Energy Regulation", I4R Discussion Paper Series, No. 258, Institute for Replication (I4R), s.l.

This Version is available at:

<https://hdl.handle.net/10419/324169>

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No. 258

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August 2025

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A Comment on “Market Power and Price Exposure: Learning from Changes in Renewable Energy Regulation”

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AUGUST 2025

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Calvin Bryan  Pierce Donovan  Kanishka Kacker  and Linh Pham*

July 2024

Abstract

[Fabra and Imelda \(2023\)](#) study how the method of payment for renewable energy can reduce the ability of energy producers to exert market power in electricity markets. Their theoretical model provides predictions for dominant and fringe firm behavior under incentives using fixed prices or market exposure. Across several reported specifications, they measure the price depressing effects under both economic instruments. The authors find that in the case of the Spanish electricity market, fixed prices for renewables mitigate market power more than exposure to market pricing. We successfully computationally reproduce 100% of the main claims of the paper. We then explore the robustness of these findings to a placebo event test and modeling choices concerning seasonality and sample selection. These robustness checks typically replicate the main findings of the original paper in sign, but consistently reduce the magnitude and statistical significance of measured results.

KEYWORDS: market power, forward contracts, arbitrage, renewables

JEL CODES: L13, L94, L98, Q42, Q48

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1 Introduction

[Fabra and Imelda \(2023\)](#), henceforth F&I, investigate the degree to which market price exposure for renewable energy impacts its price-depressing effect in wholesale electricity markets. They first establish a theoretical model which demonstrates that both market-based and fixed payments for renewable energy create channels for price depressing effects. In the first case, a dominant firm is free to exercise market power for both conventional and renewable output. They choose to withhold selling all of their production in the day-ahead market, driving up the price of electricity, with lower-priced residual sales resuming in the spot market the following day. This strategy is profitable on net, however fringe firms producing renewable energy may then arbitrage across the two markets and reduce the impact of the dominant firm. In the second case, a forward contract effect reduces the incentive to exercise market power, since it only stands to impact the profits from the non-renewable portion of a dominant firm's portfolio given the permanent option to sell renewable energy at a constant price.

It is an empirical query that would determine whether the arbitrage effect or forward contract effect is larger.¹ Theoretically, when most of the renewable generation is held by the dominant firm, the arbitrage effect is weakened, and thus the fixed pricing regime will have a greater price depressing effect. In the case that the fringe firms hold most of the generation, the arbitrage effect dominates. Thus, consumer welfare is dependent on the distribution of renewable ownership.

F&I demonstrate that the fixed pricing regime reduced wholesale electricity prices 2-4% relative to the market pricing regime in a study of the Spanish electricity market in the early 2010s, due to the high concentration of renewable ownership among the dominant generating firms (as is common in most electricity markets). The authors take advantage of a natural experiment involving two abrupt regulation changes that switched the pricing of renewable energy from market-based prices to fixed prices, then back to market-based prices. To make the above comparison of effects, they use hourly data on electricity bids and production from the Iberian wholesale electricity market, hourly production data from the grid operator, daily plant level data on production costs, and daily weather data from the Spanish meteorological agency.

In the present report prepared for the Institute for Replication ([Brodeur et al. 2024](#)), we investigate whether their analytical results are computationally reproducible. In Section 2, we successfully reproduce F&I's analysis data, as well as their main tables and figures. There are no discrepancies in point estimates in Ta-

¹In either case, an increase in the supply of renewable energy will also shift the dominant firm's residual demand curve to the left and lower the price of electricity, but since this effect occurs in either pricing regime, it will not be measured in a relative comparison of the two.

bles 2.2 through 2.6, and no visual differences in Figures 2.1 or 2.2 (or Appendix Figure A1) relative to the exhibits in the original paper. In all tables, we have reported precision metrics in terms of p-values rather than the original standard errors.

To summarize their core results (presented on page 345) concerning the market impacts of renewable pricing schemes, (1) the forward contract effect exists and has an impact of 1.2 euro/MWh reduction in energy prices during the temporary fixed price regime (p-value of 0.0000025, mix of structural modeling and 2SLS), (2) the arbitrage effect exists, although only the sign of the effect was of interest (p-values of 3.3×10^{-20} , 3.7×10^{-9} , and 0.0073 across three control groups, difference-in-differences), (3) the wind share of the dominant firm impacts the price differential between markets (all twelve coefficients of interest have expected sign and p-value below 0.05, estimated with 2SLS) and (4) the markups in the day-ahead electricity market are consistently and significantly higher in the market price regimes than in the fixed price regime, as evidenced by a Kolmogorov-Smirnov test of the two markup distributions (p-value of 0.01).

We further test their replicability and robustness to: (1) placebo regime dates, (2) seasonality in predicted spot market prices, and (3) heterogeneous effects of regime switches. In Section 3, we find that re-running the analysis with placebo dates for the price regime change(s) leads to no presence of a forward contract effect and smaller markups during market price regimes. Changing how seasonality is modeled when predicting spot market prices reduces estimated coefficients down to approximately a third of the estimates in the paper. In addition, evidence for the arbitrage effect becomes much weaker, with two out of the three estimates no longer statistically significant at the 5% level of significance (and changing sign). Finally, the heterogeneity analysis shows various effects of the regime switches across types of power plants (e.g., coal v. natural gas) and high and low-demand periods (e.g., peak v. non-peak hours, weekdays v. weekends).

2 Computational Reproducibility

We use the replication package found [here \(REPEC\)](#). The cleaning and analysis codes were provided in the replication package, and the cleaned data is provided, however a component of the raw data must be requested from the original data source. The paper is thus computationally reproducible from analysis data, and we successfully computationally reproduced Tables 1 through 5 of their paper (represented as Tables 2.2 through 2.6 in this manuscript; standard errors replaced by p-values) from their analysis data, as well as Figures 1-3 (Figures 2.1, 2.2, and A1 here). See Table 2.1 for a description of the replication package.

Table 2.1: Replication Package Contents and Reproducibility

Replication Package Item	Fully	Partial	No
Raw data provided		✓	
Analysis data provided	✓		
Cleaning code provided	✓		
Analysis code provided	✓		
Reproducible from raw data		✓	
Reproducible from analysis data	✓		

Notes: Replication package contents from [Fabra and Imelda \(2023\)](#).

2.1 Data replicability

Table 2.2: Summary Statistics

	Regime I Market Prices		Regime II Fixed Prices		Regime III Market Prices	
	Mean	SD	Mean	SD	Mean	SD
Price day-ahead	50.2	(13.8)	38.2	(22.1)	52.1	(11.0)
Price intra-day 1	48.9	(14.2)	37.2	(22.1)	51.8	(11.7)
Price premium	1.2	(5.0)	0.9	(5.6)	0.3	(3.9)
Marginal Cost	47.5	(6.6)	42.3	(7.3)	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)	4.9	(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)
Investment wind	22.8		23.0		23.0	
Dominant non-wind share	0.8	(0.0)	0.8	(0.1)	0.8	(0.0)
Fringe non-wind share	0.2	(0.0)	0.2	(0.1)	0.2	(0.0)
Investment non-wind	99.8		100.2		100.1	

Notes: Sample from February 1, 2012, to January 31, 2015. Regime I is from February 1, 2012, to January 31, 2013; Regime II is from February 1, 2013, to June 21, 2014; Regime III is from June 22, 2014, to January 31, 2015. Prices and marginal cost are expressed in euro/MWh. The marginal cost refers to the marginal cost of the last unit produced. Demand and wind forecasts express the average hourly values during each regime in GWh. Installed capacities are expressed in gigawatts.

Table 2.2 demonstrates that our replication is indeed using the same analysis data as F&I. We find no discrepancies in the summary statistics presented. Figure 2.1 illustrates that the pricing scheme for renewables does in fact change dominant and fringe firm bidding behavior, with dominant firm withholding and fringe firm arbitrage occurring in the two market pricing regimes, as expected by F&I's model. We find no differences between this figure and the one in the original paper.

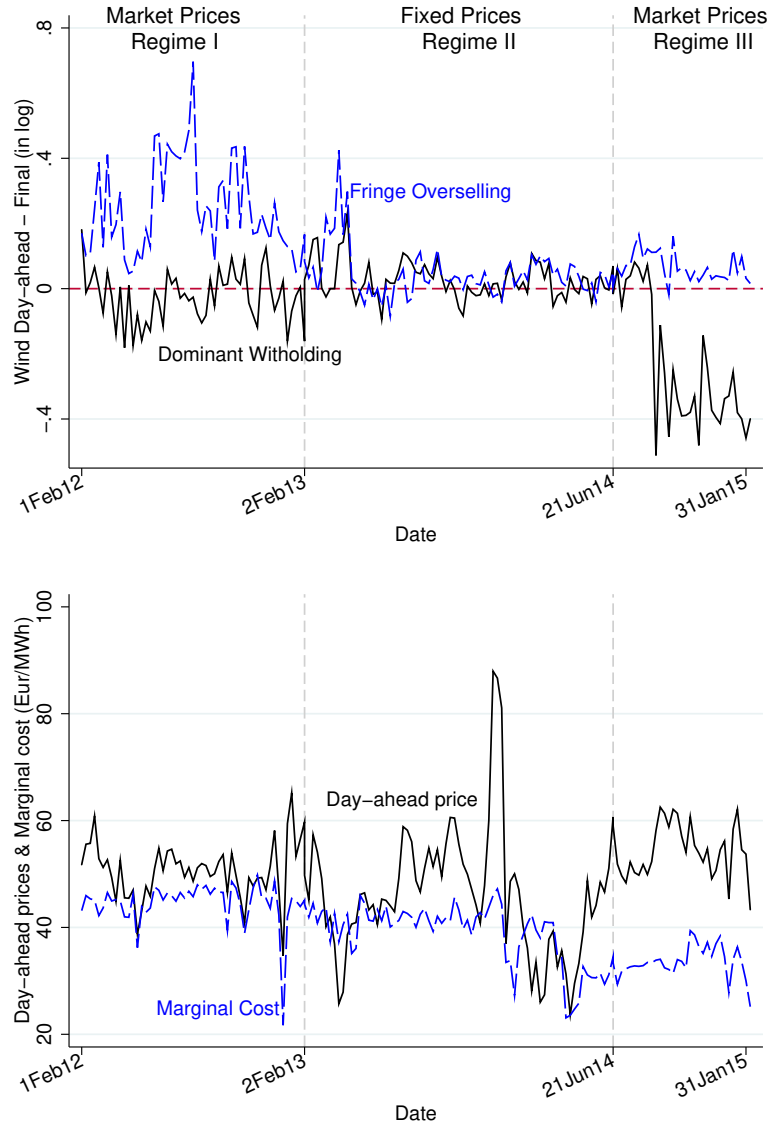


Figure 2.1: Wind Sales across Markets, Day-Ahead Prices, and Marginal Costs

Notes: The upper figure shows the day-ahead production commitments relative to final production. If the day-ahead commitment exceeds (is lower than) the final production, the value reported is greater (lower) than 0, and we refer to this as overselling (withholding). Data are reported for the wind producers belonging to the strategic firms (solid line) and the fringe firms (dash line). The lower figure shows the weekly average of hourly day-ahead prices (solid line) and the engineering estimates of marginal costs (dashed line). The vertical lines date the changes in the pricing schemes for renewables.

2.2 Price setting in the day-ahead market

The authors estimate the following regression for the marginal bid of firm i for unit j of electricity at time t :

$$b_{ijt} = \rho \hat{p}_{2t} + \beta \left| \frac{q_{it}}{DR'_{it}} \right| + \sum_{s=1}^3 \theta^s \left| \frac{w_{it}}{DR'_{it}} \right| I_t^s + \alpha_{ij} + \gamma_t + \epsilon_{ijt} , \quad (\text{F\&I } 11)$$

where \hat{p}_{2t} is the expected spot price at time t , q_{it} is firm i 's total sales at time t , DR'_{it} is the slope of firm i 's residual demand at time t at the market-clearing price, w_{it} is firm i 's wind output at time t , I_t^s are three indicator variables for each pricing scheme s (Regimes I, II, and III), with controls for fixed effects for unit and time (quarter and hour), and errors clustered at the plant level.

This specification is derived from the first-order condition of their theoretical model for the dominant firm. The \hat{p} and DR variables are derived from auxiliary regressions, some of which are not replicable without the raw data. The specification is estimated by 2SLS with temperature and wind instruments to avoid the endogeneity between the marginal bid and the residual demand.

Table 2.3: The Forward Contract Effect

	2SLS			
	(1)	(2)	(3)	(4)
Market Prices (RI) $\times \frac{w_{it}}{DR'_{it}}$	6.35 (0.21)	9.31 (0.14)	9.10 (0.14)	5.54 (0.31)
Fixed Prices (RII) $\times \frac{w_{it}}{DR'_{it}}$	-14.2 (0.0000025)	-14.5 (0.00000046)	-14.9 (0.00000076)	-14.3 (0.000010)
Market Prices (RIII) $\times \frac{w_{it}}{DR'_{it}}$	1.72 (0.67)	0.049 (0.99)	0.60 (0.85)	5.69 (0.28)
Expected spot price (\hat{p}_{2t})	0.77 (0)	0.78 (0)	0.77 (0)	0.38 (0.0093)
Markup term ($\frac{q_{it}}{DR'_{it}}$)				4.81 (0.00012)
Linear Trends	N	Y	Y	Y
Quad. Trends	N	N	Y	Y
Observations	19,805	19,805	19,805	19,805

Notes: This table shows the estimation results of equation (11) using 2SLS. All regressions include unit, firm, and quarterly dummies. Columns (2)–(4) add day-of-the-week dummies, hour fixed effects, and quadratic time trends cumulatively. The markup coefficient is constrained to one in columns (1) to (3). Analysis data are limited to a five euro/MWh range relative to the market price and excludes outliers (bids with market prices below the first percentile and above the ninety-ninth percentile). Markups are instrumented by wind speed and precipitation, each interacted with the three pricing scheme indicators. Standard errors are clustered at the plant level.

Table 2.3 shows the results of the above regression. The expectations of F&I are that the first and third rows would yield statistical zeros, and that the second row would yield a negative effect. This represents the price-depressing effect of the fixed price regime, which removes the ability for higher price-setting in the day-ahead electricity market. The p-value for this estimate is 0.0000025, and the magnitude, when converted into meaningful units (using the estimates in the first column), suggests that an increase in wind output of 10 percent over its mean would imply a price reduction of 1.2 euro/MWh (a 3.1 percent reduction over the average price)

during Regime II.

2.3 Arbitrage across markets

As Figure 2.1 previously showed the existence of arbitrage behavior by the fringe firms in the market-based pricing regimes, F&I explored the magnitude of this arbitrage effect on the day-ahead price of electricity. They use a differences-in-differences design to show how overselling of wind capacity existed in the market-based pricing regimes, but not in the fixed price regime, using three combinations of counterfactual control groups and date ranges in the following specification.

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

(F&I 12)

where the two control groups are downstream suppliers and non-wind renewables, and the two date ranges d are the second and third pricing regimes. Since non-wind renewables are impacted by the transition back to market prices, this iteration of the regression is omitted. I_t^1 is an indicator for fixed prices (Regime II), I_t^2 is an indicator for market prices (Regime III), W is an indicator for wind fringe producers, and controls for daily solar radiation time and precipitation, the hourly demand forecast error, the hourly wind forecast error, week-of-sample fixed effects, and day-of-week fixed effects are all captured in X_t . Standard errors are clustered at the week of sample.

Table 2.4: Impacts of Changing the Pricing Schemes on Overselling by Wind

	Non-wind renewables	Downstream suppliers	
	(1)	(2)	(3)
$\Delta \hat{p} \times \text{Wind} \times \text{Fixed Prices (RII)}$	-0.059 (3.3e-20)	-0.069 (3.7e-09)	
$\Delta \hat{p} \times \text{Wind} \times \text{Market Prices (RIII)}$			0.035 (0.0073)
Observations	41,080	41,080	34,194

Notes: This table shows the β_1 coefficients from equation (12). Each column is a different regression using the log of overselling as the dependent variable. Nonwind renewables is the control group in column (1), and downstream suppliers is the control group in columns (2)–(3). Columns (1) and (2) use sample $d = 1$ from February 1, 2012, to February 1, 2014, with the Regime II indicator equal to one for days after February 1, 2013, while column (3) uses the sample from February 1, 2013, to January 31, 2015, with the Regime III indicator equal to one for days after June 22, 2014. All regressions include seasonality controls and hour-of-day and week fixed effects. Under Regime III, nonwind renewables are also affected by the regulation and is not used as a control group during Regime III. Standard errors are clustered at the week of sample.

Table 2.4 reports a negative impact on the arbitrage response when the pricing regime switches from market to fixed prices, and a positive effect upon return to

market prices. These impacts are statistically significant, but the magnitudes are difficult to parse due to the derived nature of both the dependent and independent variables of interest. F&I only use this regression to determine that arbitrage is in fact incentivized by market prices in the predicted direction.

In order to confirm the validity of the parallel trends assumption, the authors create similar metrics of overselling for the control groups, then plot these metrics in Figure A1. The figure supports their assumptions, and we replicate it in our Appendix.

2.4 Price differences across markets

F&I next show that the price differential between the day-ahead and spot market decreases with increasing share of renewables being held by fringe firms in the market price regimes. They do this with another 2SLS specification, below.

$$\Delta p_t = \alpha + \sum_{s=1}^2 \beta_1^s I_t + \beta_2 \frac{w_{dt}}{W_t} + \sum_{s=1}^2 \beta_3^s I_t \frac{w_{dt}}{W_t} + \alpha_1 D\hat{R}'_{1t} + \alpha_2 D\hat{R}'_{2t} + \gamma \mathbf{X}_t + \epsilon_t \quad (\text{F\&I 14})$$

where Δp_t is the price premium at time t , I_t takes two values (1 for Regime I and 2 for Regime III, and Regime II serves as the reference point), w_{dt}/W_t captures the wind share of the strategic firms, and $D\hat{R}'_{1t}$ and $D\hat{R}'_{2t}$ capture the (instrumented) slopes of the residual demands faced by the strategic firms in the day-ahead and spot markets, respectively.

Table 2.5 provides estimates of β_2 and β_3 in the above equation, and shows that across specifications, additional predictions about wind share from the F&I model appear to be validated. Of the twelve listed hypothesis tests, all of them provide statistically significant results at the 5% level. Like in the previous section, the effect sizes are not the focus of the original analysis.

2.5 Market power in the day-ahead market

The final result is a derived one that does not rely on a regression specification. F&I calculate the markup on day-ahead electricity prices,

$$\frac{p_{1t} - \hat{p}_{2t}}{p_{1t}} = \left| \frac{\partial DR_{i1t}}{\partial p_{1t}} \right|^{-1} \frac{q_{i1t} - I_t w_{i1}}{p_{1t}}, \quad (\text{F\&I 15})$$

using previous calculations. I_t equals one during the fixed price regime, and q_{i1t} and w_{i1} represent the conventional and wind energy output sold by firm i .

F&I find that markups are consistently lower during the fixed price regime than they are in the market price regime. We recreate Table 2.6 and Figure 2.2 below.

Table 2.5: The Impact of Pricing Schemes on Price Differences across Markets

	2SLS			
	(1)	(2)	(3)	(4)
Dominant Wind Share ($\frac{w_{dt}}{W_t}$)	-0.59 (0.00092)	-0.50 (0.0041)	-0.59 (0.0013)	-0.50 (0.0055)
Market Prices (RI) $\times \frac{w_{dt}}{W_t}$	0.44 (0.032)	0.46 (0.014)	0.44 (0.033)	0.46 (0.033)
Fixed Prices (RII) $\times \frac{w_{dt}}{W_t}$	0.46 (0.012)	0.41 (0.016)	0.46 (0.0045)	0.41 (0.017)
Weekend FE	N	N	Y	Y
Peak Hour FE	N	Y	N	Y
Observations	25334	25334	25334	25334

Notes: This table shows β_2 and β_3 from equation (14). The Fixed Prices period (RII) is the reference period. F&I use bootstrap standard errors with 200 replications.

F&I report that a Kolmogorov-Smirnov test rejects that the two markup distributions under either regime are similar at the 1% level; we are able to replicate this result with their code.

Table 2.6: Average Markups across Pricing Regimes

	Regime I Market Prices		Regime II Fixed Prices		Regime III Market Prices	
	Mean	SD	Mean	SD	Mean	SD
Markups (in %) – Simple average						
Day-Ahead (structural)	8.3	(3.3)	6.3	(3.3)	10.7	(3.7)
Overall (engineering)	8.6	(23.1)	8.1	(29.4)	29.7	(14.0)
Markups (in %) – Demand weighted average						
Day-Ahead (structural)	8.3	(3.2)	6.4	(3.3)	10.7	(3.6)
Overall (engineering)	10.0	(22.8)	9.2	(29.6)	30.4	(13.5)
Slope of day-ahead residual demand (in MWh/euros)	524.2	(78.2)	553.6	(120.7)	418.2	(73.0)

Notes: Mean and standard deviation of markups and slopes of the day-ahead residual demand using the sample from February 2012 to February 2015. For markups: day-ahead markups are computed using an auxiliary regression, and overall markups are computed using marginal bids minus marginal cost. Analysis only includes marginal bids around a 5 euro/MWh range and bids with prices above 25 euro/MWh.

3 Replication Robustness

We perform three replication robustness analyses. First, we perform a placebo test, where we randomly pick an arbitrary treatment date and repeat the analysis in F&I. Statistically insignificant results from the placebo test imply that the effects that

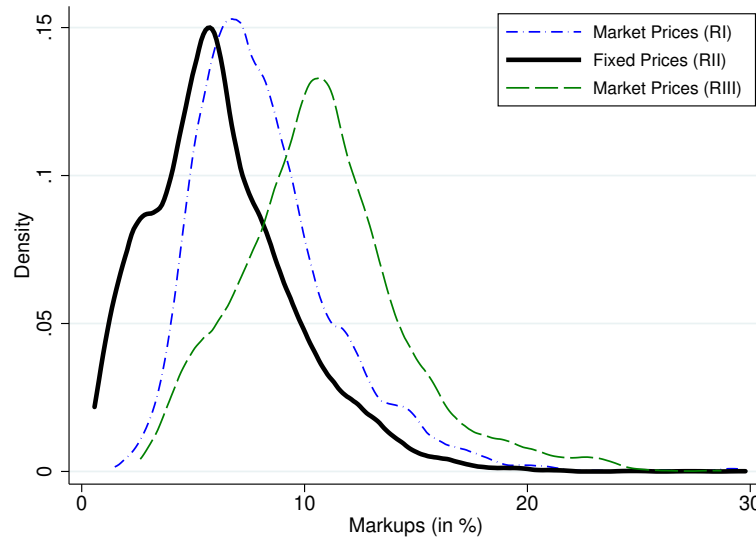


Figure 2.2: Distribution of Day-Ahead Markups

Notes: This figure plots the distributions of day-ahead markups for all firms by pricing regimes for hours with prices above 25 euro/MWh.

F&I estimate are due to the price regime switches, rather than to other idiosyncratic factors. Second, we explore the seasonality in predicted spot market prices by using alternative seasonality controls (specifically, month-year and day-of-week fixed effects. These alternative controls are more likely to capture seasonal variation than the data controls used by F&I and suggest that both the arbitrage and forward contract effects are smaller than originally stated. Finally, we explore how different market participants respond to the price regime changes. This provides insight with respect to the flexibility of firm response to changing regulations and similarly suggests smaller arbitrage and forward contract effects on the whole.

The decision to conduct these three robustness checks was taken after reading the paper but prior to observing the codes/programs. For the seasonality check in predicting spot prices, it was important first to consult the original code before deciding whether to continue with the check, because it was not clear from the paper precisely how the authors had predicted spot prices.

3.1 Placebo regime dates

The first extension we provided to the original work by F&I was a simple placebo analysis. The effects that F&I estimate may be a function of other idiosyncratic changes in the market for electricity or renewable energy, along with the changing price regimes. To evaluate the robustness of their findings, we re-produced results

as if the price regime changed on false dates.² We coded the first price regime change as July 22, 2013 (instead of February 2, 2013) and the second as May 15, 2014 (instead of June 22, 2014). Table 3.1 contains the results of estimating the forward contract effect using both price regime change *placebo* dates.

Table 3.1: The Forward Contract Effect (Table 2.3 Robustness, Placebo Dates)

	2SLS			
	(1)	(2)	(3)	(4)
Market Prices (RI) $\times \frac{w_{it}}{DR'_{it}}$	-0.82 (0.57)	-1.09 (0.52)	-0.84 (0.69)	2.54 (0.34)
Fixed Prices (RII) $\times \frac{w_{it}}{DR'_{it}}$	3.15 (0.14)	3.98 (0.089)	5.92 (0.013)	8.10 (0.0044)
Market Prices (RIII) $\times \frac{w_{it}}{DR'_{it}}$	-3.53 (0.11)	-3.48 (0.12)	-3.16 (0.15)	4.44 (0.47)
Expected spot price (\hat{p}_{2t})	0.84 (0)	0.84 (0)	0.85 (0)	0.55 (0.0028)
Markup term ($\frac{q_{it}}{DR'_{it}}$)				4.88 (0.010)
Linear Trends	N	Y	Y	Y
Quad. Trends	N	N	Y	Y
Observations	18,240	18,240	18,240	18,240

The authors find a consistent sign (and statistical significance for price regimes I & II) on the effect of price regime on bids within each individual regime. Table 2.3, replicated from the authors' original work, shows that fixed prices push bid prices down. Table 3.1 shows that the coefficient estimate for the first and third price regime (market prices) is statistically null and does not have a consistent sign. The table shows a consistent positive "effect" during the second placebo (fixed) price regime, but that is the opposite sign of the price regime that F&I find. We also estimate the effect of the differing price regimes when changing only one of the regime date changes, to see if the effect is driven by one of the price regime change dates in particular (not shown). Similar to our results in Table 2.3, the sign is not consistent within price regimes and the effect is statistically null.

Table 3.2 shows a replication of F&I's analysis of the effect of the price regime on the overselling of wind. We find coefficients of similar sign and statistical significance, but are smaller in magnitude (given the difficult nature of interpreting this dependent variable, the sign and significance are the more important takeaway for verifying the arbitrage effect). Replicating the placebo analysis with just one date, as opposed to both, would provide a similar takeaway.

²Placebo dates were selected based on the birth dates of those on the replication team.

Table 3.2: Impacts of Changing the Pricing Schemes on Overselling by Wind (Table 2.4 Robustness, Placebo Dates)

	Non-wind renewables	Downstream suppliers	
	(1)	(2)	(3)
$\Delta\hat{p} \times \text{Wind} \times \text{Fixed Prices (RII)}$	-0.056 (1.1e-18)	-0.055 (0.0000011)	
$\Delta\hat{p} \times \text{Wind} \times \text{Market Prices (RIII)}$			0.032 (0.011)
Observations	39,716	39,716	30,272

Table 3.3: The Impact of Pricing Schemes on Price Differences across Markets (Table 2.5 Robustness, Placebo Dates)

	2SLS			
	(1)	(2)	(3)	(4)
Dominant Wind Share ($\frac{w_{dt}}{W_t}$)	-0.54 (0.065)	-0.41 (0.16)	-0.54 (0.090)	-0.41 (0.15)
Market Prices (RI) $\times \frac{w_{dt}}{W_t}$	0.34 (0.15)	0.35 (0.14)	0.34 (0.14)	0.35 (0.12)
Fixed Prices (RII) $\times \frac{w_{dt}}{W_t}$	0.30 (0.14)	0.28 (0.22)	0.30 (0.21)	0.28 (0.20)
Weekend FE	N	N	Y	Y
Peak Hour FE	N	Y	N	Y
Observations	23397	23397	23397	23397

Table 3.3 shows a replication of Table 2.5. Similar to the analysis on the overselling of wind, we find similar signs of the effect of the price regime, but they are smaller in magnitude (with similar levels of statistical significance). This is also true of the effect of the share of the dominant firm's wind production. Again, replicating this result with just one price regime change provides similar results to changing both dates.

The final set of replicated results from F&I that use placebo dates for the price regime change(s) is in Table 3.4. The main takeaway when comparing these results to those in Table 2.6 is the significantly larger markup on the estimates of marginal cost produced using engineering methods. While F&I do note that these estimates are quite noisy, if anything, this table aids in confirming their findings. Given the nature of the random placebo dates selected, several months were taken away from the duration of Price Regime I (as well as one month from Price Regime III's duration) and given to the totality of the duration when fixed costs were falsely considered in place. If the effect that F&I find is the true impact of fixed (market)

Table 3.4: Average Markups across Pricing Regimes (Table 2.6 Robustness, Placebo Dates)

	Regime I Market Prices		Regime II Fixed Prices		Regime III Market Prices	
	Mean	SD	Mean	SD	Mean	SD
Markups (in %) – Simple average						
Day-Ahead (structural)	7.5	(3.5)	7.4	(3.1)	9.9	(4.3)
Overall (engineering)	4.2	(26.5)	14.9	(27.5)	28.1	(14.1)
Markups (in %) – Demand weighted average						
Day-Ahead (structural)	7.6	(3.5)	7.5	(3.1)	10.0	(4.2)
Overall (engineering)	5.7	(26.6)	16.5	(27.4)	28.7	(13.7)
Slope of day-ahead residual demand (in MWh/euros)	553.4	(101.6)	519.6	(112.3)	432.9	(88.3)

prices on markups, then we should expect to find an increased markup from our falsified fixed prices simply due to the longer time that the false fixed price regime was actually in a market price regime (when markups were increasing). We find an increased markup for fixed prices across all four estimations of marginal price, supportive of the original findings by F&I.

Just as F&I did, we ran a Kolmogorov-Smirnov test with our markup distributions using our placebo regimes. Interestingly, despite the dates we selected being exogenous to this analysis, the test also rejected that the regimes would be similar at a 1% level. At worst, this suggests that the pricing regimes may not have an effect on electricity prices, and their analysis is picking up some other changes in Spanish energy markets. At minimum, the Kolmogorov-Smirnov test with placebo data indicates the presence of other confounding factors in the relationship between pricing policy and electricity markups that aren't adequately considered in F&I's model.

3.2 Seasonality in predicted spot market prices

The authors use a predicted spot market price, which is used as a right hand side variable in the regressions used to examine evidence for the forward contract effect and the arbitrage effect. One of the variables used for this prediction is a date-of-year dummy, which is presumably meant to capture seasonality. A more straightforward approach is to capture seasonality with month-year dummies and a day-of-week dummy, as their relative coarseness match the pattern to be controlled for. Tables 2.3 and 2.4 are impacted by this change. Details of re-doing the analysis by redefining the prediction so that it uses month-year dummies and day-of-week dummies are given below.

Table 3.5 runs Table 2.3, but using spot prices predicted from month and day-of-week dummies rather than date-of-year. Here, we get statistically significant results

Table 3.5: The Forward Contract Effect (Table 2.3 Robustness, Seasonality controlled by month-year and day-of-week fixed effects)

	2SLS			
	(1)	(2)	(3)	(4)
Market Prices (RI) $\times \frac{w_{it}}{DR'_{it}}$	3.10 (0.24)	3.36 (0.25)	3.11 (0.26)	3.11 (0.26)
Fixed Prices (RII) $\times \frac{w_{it}}{DR'_{it}}$	-4.95 (0.0079)	-4.99 (0.0081)	-4.82 (0.010)	-4.79 (0.013)
Market Prices (RIII) $\times \frac{w_{it}}{DR'_{it}}$	5.96 (0.10)	5.81 (0.081)	5.36 (0.076)	5.30 (0.11)
Expected spot price (\hat{p}_{2t})	0.87 (<0.01)	0.87 (<0.01)	0.87 (<0.01)	0.87 (<0.01)
Markup term ($\frac{q_{it}}{DR'_{it}}$)				0.95 (0.28)
Linear Trends	N	Y	Y	Y
Quad. Trends	N	N	Y	Y
Observations	19,805	19,805	19,805	19,805

for the fixed price regime. However, the coefficient is much smaller—about a third of the original estimate.³ These results suggest that if the authors were trying to use seasonality to predict spot market prices, then it might have been better to use months and day-of-week dummies rather than just a date-of-year. Now, it might be worthwhile to use dates to define specifically important dates of the year (such as holidays or major public events) but using just a date-of-year dummies to capture seasonality is potentially overkill without further justification. Finally, it is useful to see that the markup term is no longer statistically significant, and this comes from the reduction in the coefficient.

Interpreting the new coefficient for the variable **Fixed Prices** (RII) $\times \frac{w_{it}}{DR'_{it}}$ (from column (4)): an increase in 10% of the strategic firms' wind output reduces price by 0.4 Euro/Mwh, a reduction of approximately two-thirds. This effect is much smaller than what the original study finds, and has less practical significance for the market studied.

Table 3.6 runs Table 2.4, but now the price difference is predicted from month-year dummies and day-of-week dummies. Here, we see that using non-wind renewables as the comparison renders the original result statistically insignificant and of the opposite sign. Only the result reported in column (2) is of the similar sign and statistical significance as the original results. Again, the estimated coefficient is

³Although these are not reported, the standard errors are much smaller than the original. These results are available on request.

Table 3.6: Impacts of Changing the Pricing Schemes on Overselling by Wind (Table 2.4 Robustness, Seasonality controlled by month-year and day-of-week fixed effects)

	Non-wind renewables	Downstream suppliers	
	(1)	(2)	(3)
$\Delta\hat{p} \times \text{Wind} \times \text{Fixed Prices (RII)}$	0.0066 (0.38)	-0.023 (0.038)	
$\Delta\hat{p} \times \text{Wind} \times \text{Market Prices (RIII)}$			0.0017 (0.91)
Observations	41,080	41,080	34,194

about a third of the original estimate.

The overall implication is that by redefining the predicted spot market prices to better reflect seasonality concerns, evidence for the arbitrage effect is much weaker. While evidence for the forward contract effect remains, the estimated coefficients suggest a far smaller impact than what the original study suggests.

3.3 Heterogeneous effects

Our last sensitivity check focuses the heterogeneous effects of the regime switches. Electricity production varies across technologies (e.g., coal, gas, renewables, etc.) and over time (e.g., during high v. low demand periods). These factors determine electricity producers' flexibility, which in turn influence their ability to react to any policy change.

Table 3.7 presents the heterogeneity in the forward contract effects by estimating equation (8) of F&I across different sub-samples, with linear and quadratic time trends, forecasted spot prices and output markup terms. This specification is equivalent to column (4) of Table 2.3. Specifically, columns (1) and (2) presents the results of equation (8) by limiting the bid prices to be within \$3 and \$7 of the equilibrium prices, instead of using the threshold of \$5 in F&I. We find that the forward effects of wind output under the fixed price regime are smaller with smaller bandwidths. Columns (3)-(6) present the results by separating the samples into non-peak v. peak hours and weekdays v. weekends. We find that the forward contract effects under the fixed price regime are stronger for peak-hour and weekday bids. Finally, columns (7) and (8) distinguishes between natural gas and coal plants. We find that the price depressing effects are stronger for natural gas plants than for coal plants. This is expected, as natural gas plants tend to be more flexible than coal plants, therefore, they are more sensitive to the regime changes.

Table 3.7: The Forward Contract Effect (Table 2.3 Robustness, Heterogeneous Effects)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	BW=3	BW=7	Non-peak hours	Peak hours	Weekdays	Weekends	Natural gas plants	Coal plants
Market Prices (RI) $\times \frac{w_{it}}{DR_{it}}$	4.95 (0.30)	5.13 (0.31)	7.96 (0.29)	6.09 (0.15)	-0.0071 (1.00)	54.6 (0.025)	26.1 (0.11)	1.21 (0.53)
Fixed Prices (RII) $\times \frac{w_{it}}{DR_{it}}$	-13.6 (0.0000092)	-15.7 (0.0000023)	-6.80 (0.15)	-23.0 (0.00000025)	-15.8 (0.0082)	-10.5 (0.19)	-15.1 (0.0000012)	-7.01 (0.093)
Market Prices (RIII) $\times \frac{w_{it}}{DR_{it}}$	5.59 (0.32)	4.68 (0.38)	5.98 (0.23)	2.56 (0.73)	7.84 (0.23)	-8.12 (0.48)	-3.83 (0.47)	-0.60 (0.78)
Expected spot price (\hat{p}_{2t})	0.36 (0.015)	0.40 (0.011)	0.50 (0.0016)	0.31 (0.15)	0.10 (0.72)	1.16 (6.9e-11)	0.48 (0.00099)	0.64 (0.00013)
Markup term ($\frac{q_{it}}{DR_{it}}$)	4.89 (0.000048)	4.51 (0.0011)	5.40 (0.00091)	3.46 (0.066)	6.78 (0.0011)	2.59 (0.32)	5.12 (0.00034)	0.47 (0.85)
Linear Trends	Y	Y	Y	Y	Y	Y	Y	Y
Quad. Trends	Y	Y	Y	Y	Y	Y	Y	Y
Observations	17,390	20,949	11,466	8,339	14,160	5,645	13,324	6,481

Notes: This table shows the estimation results of equation (11) using 2SLS for **alternative sub-samples**. The specifications of the regressions are similar to column (4) of Table 2 in the original paper. Columns (1) and (2) show the results by limiting the bid prices to be within \$3 and \$7 of the equilibrium prices. Columns (3) and (4) show the results for non-peak and peak hours. Columns (5) and (6) show the results for weekdays and weekends. Finally, columns (7) and (8) consider natural gas and coal plants separately. p-values in parentheses.

Next, we explore the heterogeneous arbitrage effects (Table 3.8). To this end, we repeat the analysis in Table 2.4 across peak v. non-peak hours and weekdays v. weekends. Overall, the results across all sub-samples are consistent in signs and statistical significance with those of F&I. We find that the arbitrage effects are larger during peak hours and weekdays.

Table 3.8: Impacts of Changing the Pricing Schemes on Overselling by Wind (Table 2.4 Robustness, Heterogeneous Effects)

	Non-wind renewables	Downstream suppliers	
	(1)	(2)	(3)
Non-peak hours			
$\Delta\hat{p} \times \text{Wind} \times \text{Fixed Prices (RII)}$	-0.077 (1.1e-18)	-0.097 (2.9e-13)	
$\Delta\hat{p} \times \text{Wind} \times \text{Market Prices (RIII)}$			0.045 (0.0041)
Observations	25,744	25,744	21,448
Peak hours			
$\Delta\hat{p} \times \text{Wind} \times \text{Fixed Prices (RII)}$	-0.051 (3.4e-13)	-0.060 (0.0000078)	
$\Delta\hat{p} \times \text{Wind} \times \text{Market Prices (RIII)}$			0.073 (0.00024)
Observations	15,336	15,336	12,746
Weekdays			
$\Delta\hat{p} \times \text{Wind} \times \text{Fixed Prices (RII)}$	-0.070 (2.9e-17)	-0.082 (0.000000013)	
$\Delta\hat{p} \times \text{Wind} \times \text{Market Prices (RIII)}$			0.028 (0.059)
Observations	29,408	29,408	24,512
Weekends			
$\Delta\hat{p} \times \text{Wind} \times \text{Fixed Prices (RII)}$	-0.035 (0.0000015)	-0.042 (0.00013)	
$\Delta\hat{p} \times \text{Wind} \times \text{Market Prices (RIII)}$			0.020 (0.25)
Observations	11,672	11,672	9,682

Finally, we explore how the price differences across markets varies across the hours of the days and the days of the weeks. To this end, we modify equation (14)

in F&I as follows:

$$\begin{aligned}
\Delta p_t = & \alpha + \sum_{s=1}^2 \beta_1^s I_t + \beta_2 \frac{w_{dt}}{W_t} + \sum_{s=1}^2 \beta_3^s SAM_t \\
& + \sum_{s=1}^2 \beta_4^s I_t SAM_t + \sum_{s=1}^2 \beta_5^s I_t \frac{w_{dt}}{W_t} + \sum_{s=1}^2 \beta_6^s SAM_t \frac{w_{dt}}{W_t} \\
& + \alpha_1 D\hat{R}'_{1t} + \alpha_2 D\hat{R}'_{2t} + \gamma \mathbf{X}_t + \epsilon_t
\end{aligned} \tag{F&I 14*}$$

where SAM_t is a dummy variable that equals 1 if an observation belongs to a specific sub-sample (i.e. peak hours **or** weekends). The coefficients of interest are β_5 and β_6 , which capture the heterogeneous effects of the pricing schemes on the dayahead-intraday price differences across the sub-samples. Following F&I, we use the fixed price regime (Regime II) as the reference period. Columns (1) and (2) of Table 3.9 present the results for peak v. non-peak hours (by setting $SAM_t = 1$ if an observation is during peak hours). We find that during non-peak hours, the price premium is higher with increasing dominant wind shares during the first regime (Market Prices RI). In contrast, during peak hours, the price premium is lower with increasing dominant wind shares during the first regime (Market Prices RI). During the third regime (Market Prices RIII), the price premium is higher with increasing dominant wind shares, however, we find statistically insignificant coefficients across both non-peak and peak hours. Columns (3) and (4) of Table 3.9 present the results for weekend v. weekdays hours (by setting $SAM_t = 1$ if an observation is during weekends). We find that the price premium is higher with increasing dominant wind shares across all days of the weeks under both market price regimes (RI and RIII), however, the “weekend” effects are stronger during RI than RIII.

In summary, our empirical analysis shows that the price regime switches exhibit heterogeneous effects on the electricity market. With respect to the forward contract effect, we find that the results become weaker with larger bid bandwidths, for coal power plants and during non-peak hours. With respect to the arbitrage effect, we find consistent results with the results reported by F&I. However, the arbitrage effect estimation is based on aggregate instead of plant-level data. Thus, we may not be able to further identify nuance in the responses of renewable producers to the policy.

4 Conclusion

[Fabra and Imelda \(2023\)](#) research how the market power of the dominant firm in an energy market influences the degree to which renewable energy producers can impact the price of electricity. F&I take advantage of a unique natural experiment when the

Table 3.9: The Impact of Pricing Schemes on Price Differences across Markets
(Table 2.5 Robustness, Heterogeneous Effects)

	2SLS			
	(1)	(2)	(3)	(4)
Dominant Wind Share ($\frac{w_{dt}}{W_t}$)	-0.59 (0.0057)	-0.47 (0.019)	0.041 (0.79)	0.041 (0.79)
Market Prices (RI) $\times \frac{w_{dt}}{W_t}$	0.76 (0.00052)	0.75 (0.00016)	0.049 (0.82)	0.049 (0.83)
Market Prices (RIII) $\times \frac{w_{dt}}{W_t}$	0.24 (0.23)	0.19 (0.35)	0.38 (0.037)	0.38 (0.036)
Market Prices (RI) \times Peak Hour $\times \frac{w_{dt}}{W_t}$	-1.38 (0.0022)	-1.26 (0.0086)		
Market Prices (RIII) \times Peak Hour $\times \frac{w_{dt}}{W_t}$	0.52 (0.23)	0.54 (0.20)		
Market Prices (RI) \times Weekend $\times \frac{w_{dt}}{W_t}$			1.11 (0.011)	1.11 (0.0076)
Market Prices (RIII) \times Weekend $\times \frac{w_{dt}}{W_t}$			0.017 (0.96)	0.017 (0.97)
Weekend FE	N	Y	N	N
Peak Hour FE	N	N	N	Y
Observations	25334	25334	25334	25334

Notes: This table shows the heterogeneous effects of the regime switches on the price differences between the intraday and day-ahead markets. Fixed Prices period (RII) is the reference period. We use bootstrap standard errors with 200 replications for the price regime changes.

Spanish government temporarily switched into (and out of) a fixed pricing regime for electricity to see how that change influenced (1) the ability of the dominant firms to exercise their market power and (2) the ability of the fringe firms to arbitrage against them. The authors confirm the presence of both effects. On net, they find that the Spanish electricity market switching to a fixed pricing regime reduced the markup on electricity by 2-4%, suggesting the dominance of a forward contract effect. We are able to replicate their findings using their original data and code. We also subject their estimated results to a variety of robustness checks to test their findings under varying assumptions.

Our robustness replication does not yield much evidence supporting the presence of the arbitrage effect. In the placebo analysis, we find that the coefficient estimates attenuate when using falsified regime change dates, but the statistical evidence of the effect remains (in terms of sign and significance), suggesting the behavior of fringe firms could be driven by some confounding factor(s). When we changed how seasonality was modeled, we lose the original supporting evidence of the arbitrage effect. Taken together, it appears that the coefficients they estimate for the arbitrage effect are largely a function of their model specifications.

Across all of our tests, the authors' evidence of the forward contract effect was the most robust. In their original Table 2.3, they show that dominant firms reduce their withholding behavior when subjected to fixed prices. Statistical evidence of this effect remained when we changed how seasonality was considered in the model (Table 3.5), albeit with much smaller coefficient estimates. The effect was also present for all dimensions of heterogeneity (3.7) except for non-peak hours and weekends. Importantly, there was no statistical evidence of the effect when the dates of regime changes were replaced with placebos (Table 3.1).

Our robustness checks imply coefficient estimates for many of the model parameters that are smaller than those estimated by F&I. Even so, the actual estimates they produce are so small that the policy relevance of the results appears quite limited. Different pricing regimes may theoretically have important implications, but these appear to be quite modest in the Spanish market examined in this paper. Given their sensitivity to empirical specification, we find that several of the effect estimates are likely small or close to zero. Comparing the two price-depressing effects suggests that whether renewable energy providers face fixed prices or market exposure matters little when recommending future policies.

In general, we found robust support for the author's hypothesis and conclusions about the forward contract effect but found tenuous support for the other assertions in the paper. We believe the authors should have been more transparent in their justification of different empirical modeling choices. Our robustness analysis suggest that their results largely depended on these types of decisions, such as the choice to capture seasonality using a day-of-year dummy. Our replication results support a presentation of results that varies the assumed parameters in economic models and captures time trends and/or seasonality in multiple ways when using data with high temporal frequency.

References

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APPENDIX

Appendix figures

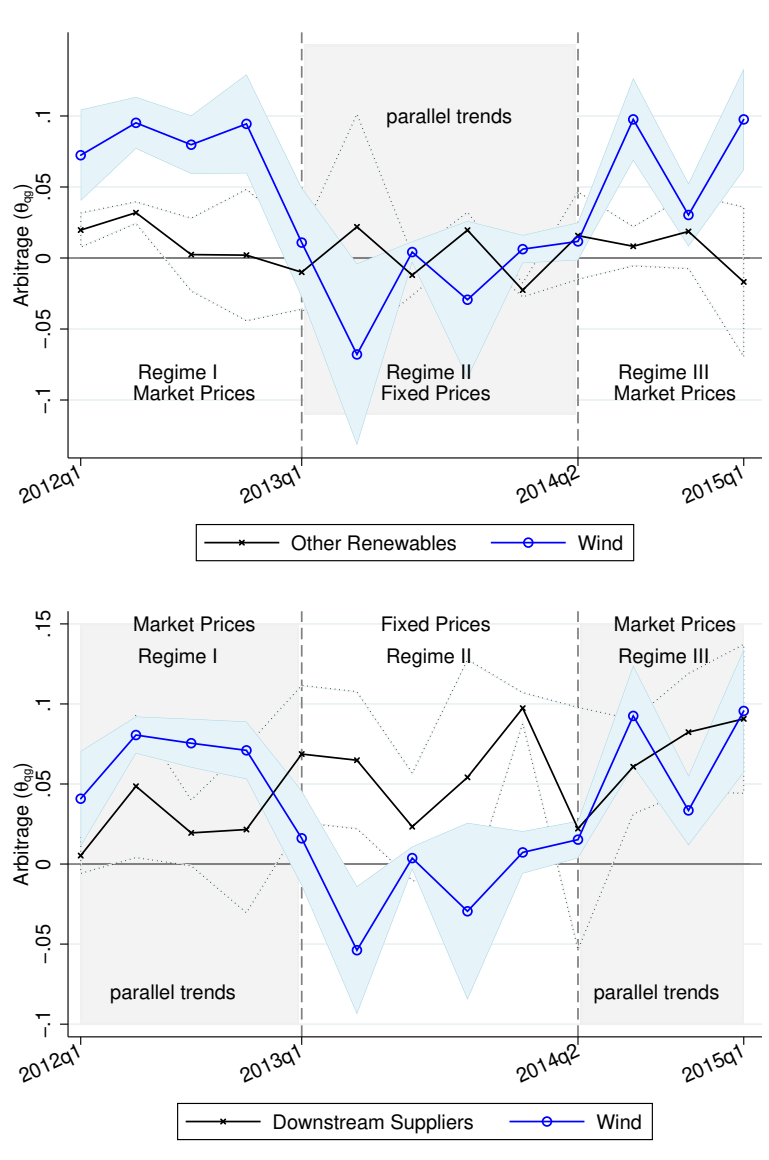


Figure A1: Arbitrage Trends by the Fringe (Wind, Nonwind Renewables, and Downstream Suppliers)

Notes: This figure plots the coefficients of the OLS regression in equation (13) for (panel A) wind versus other nonwind renewable producers and (panel B) wind versus downstream suppliers. It captures the response of overselling to the predicted price differential. Positive numbers suggest that overselling was increasing in the predicted price differential. A zero coefficient shows no attempt to arbitrage. The shaded areas show the parallel trends: during Regime II for panel A, and during Regimes I and III for panel B. The sample includes hours from January 1, 2012, to March 31, 2015, to ensure a similar number of observations in each quarter. F&I exclude hours when the predicted price differential is poorly predicted.