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"Private management and strategic bidding behavior in electricity markets: Evidence from Colombia"

Carlos Suarez

UBIREA Institut de Recerca en Economia Aplicada Regional i Pública

Abstract

In this paper I undertake a policy evaluation of the impact of the switch from public to private management of electricity generation units on their price bidding strategies. I draw on information about the bidding strategies of units in the Colombian electricity market to perform a double difference analysis. The evidence observed is coherent with theoretical behavioral predictions for profit maximizing agents facing short positions in forward contracts.

JEL classification: L13, L94, C10.

Keywords: Electricity Markets, Market Power, Privatization, Mixed Oligopoly, Double Differences.

Carlos Suarez: Department of Econometrics, Statistics and Applied Economics, Research Group on Governments and Markets, University of Barcelona, Avinguda Diagonal 690, 08034 Barcelona, Tower 6 Floor 3. Engineering Department, Research Group on Energy, Environment and Development, Jorge Tadeo Lozano University. Email: casuarez1978@gmail.com

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1 Introduction

In this paper I adopt a policy evaluation approach based on double difference (or difference-in-difference) techniques to test the hypothesis that the bidding prices of generation units change following a shift from public to private management. I draw on bidding data and information concerning changes in management structures for the period 2006 to 2017 in the Colombian wholesale electricity market.

The objectives of this paper are twofold. First, it seeks to contribute to empirical evidence on the effectiveness of reforms adopted in the electricity sector in the 1990s. The aim here is to determine whether privatization is the right decision in an environment of imperfect competition. Specifically, this study approaches privatization as a public policy program and assesses the effect of a shift to private management on the competitive behavior of electric power generators. I seek to answer the question: Is the price bidding of generation units more aggressive after switching from public to private management? Second, this study seeks to provide new insights into how private and public enterprises compete in an oligopolistic environment. Specifically, I wish to determine whether the empirical evidence is coherent with the theoretical models that study competition between private and public firms and those that study imperfect competition in electricity markets.

In relation to the first of these objectives, it should be noted that privatization was first adopted as an instrument for market liberalization in the electricity industry during the reforms implemented in the 1990s. Several authors have studied the relationship between market-oriented reforms and privatization, both theoretically (Roland, 2002; Sappington and Stiglitz, 1987; Shapiro and Willig, 1990; Tirole, 1991) and empirically (Frydman et al., 1999; La Porta and Lopez-de Silanes, 1999; Lopez-de Silanes et al., 1997; Megginson and Netter, 2001).

Tirole (1991) concluded that a competitive market structure must necessarily precede privatization. The argument is that although private firms pursue cost reduction, they do not pursue a higher level of competition because this reduces their market power and, hence, their profits. In the specific case of electricity generation services, once the possibilities of scope economies with other segments of the production chain and scale economies had been ruled out, competition was introduced and privatization served as a tool for ownership separation and the entry of new competitors (Green and Newbery, 1992; Newbery, 2005). And, moreover, once the reforms had produced markets based on competition and price signals, the implicit promise of privatization was a reduction in electricity generation costs. Furthermore, such a reduction would offset the strategic component of potential unilateral market power.

Accordingly, thanks to the reforms, the final consumer observes more cost representative prices, and the overall efficiency of the sector improves (Joskow, 1998). However, after more than 30 years of liberalization and privatization experiences, market power issues of various kinds have been identified in many electricity markets (Joskow, 2008). Several papers have focused on the effects of liberalization and deregulation on electricity generation costs (Cicala, 2015; Davis and Wolfram, 2012; Fabrizio et al., 2007) however, only the paper of MacKay and Mercadal (2020) have studied whether costs reductions resulting from these reforms are traslated into lower prices. In this paper I gather empirical evidence to establish whether private management has effectively promoted more competitive price bids, where "competitive" is understood to mean more cost reflective, and not necessarily lower, price bids. This study differs from that carried out by MacKay and Mercadal (2020) because these authors place their attention on effective deregulation of markets, while this document specifically emphasizes on the roll of private management.

As for the second objective, it is worth stressing that the question studied herein bridges two branches of literature: that of mixed oligopoly theory, which studies how private and public companies interact in an environment of imperfect competition; and that of empirical studies of comparison between public and private firms, which examine the consequences of privatization in the framework of the wave of the reforms of utilities in the 1980s and 1990s.

The main concerns of the mixed oligopoly literature have been (1) the optimal level of privatization (De Fraja and Delbono, 1989; Matsumura, 1998); (2) the role of public enterprises as an instrument of economic policy (Beato and Mas-Colell, 1984; Cremer et al., 1989); and (3) the incentive compatibility between the objectives of corporate managers and shareholders of both private and public firms (Barros, 1995). However, few papers have concerned themselves with the empirical differences in strategic behavior in a mixed oligopoly environment (Barros and Modesto, 1999).

On the other hand the empirical literature of comparison between state-owned and privately-owned firms has mostly focused in their relative performance regarding efficiency and profitability (Frydman et al., 1999; La Porta and Lopez-de Silanes, 1999). These studies aims to investigate whether the processes of privatization have been successful in transforming former state owned enterprises into more efficient and more competitive private enterprises (Megginson and Netter, 2001). However, in the majority of cases these studies make comparisons without taking account if the form of production is a natural monopoly or if the activity is subject to regulation. This paper contributes to the literature because its approach adopt two novel elements. First, it is more focused in behavioral differences and allocative efficiency than in performance differences and productive efficiency. Second, it compares the behavior of private and public firms in an environment in which they compete in a daily basis in the same relevant market. This study aims to establish whether there is any coherence between the empirical evidence and the behavioral differences of public and private companies as identified by mixed oligopoly models. It seeks to verify the congruence of the data with theoretical predictions made about the bidding behavior of the firms, according to their forward contract positions in the market (Green, 1999; Newbery, 1998).

The rest of this paper proceeds as follows: the second section describes the main features of the Colombian wholesale electricity market and the introduction of private management structures the country's electricity generation. The third section explains the theoretical background underpinning the identification strategy used. The fourth presents a general description of the data set, delineates the identification strategy and discusses the suitability of the double difference methodology. The fifth section presents the results of the application of the double difference analysis to the price bids of the generation units that switched from public to private management. In this section, I also perform several robustness checks for different econometric alternatives. The final part summarizes the results and presents my conclusions.

2 Institutional context

2.1 Colombian electricity market reforms

To understand how the Colombian electricity generation market is structured, we need a clear overview of its institutional framework and of the direction taken by the sector's reforms implemented in the mid-1990s. The institutional structure of the Colombian electricity sector clearly reflects the spirit of the 1991 Political Constitution and Laws 142 and 143 enacted in 1994. The Constitution adopted a new model of economic development which, among other major features, opened up the public service sector to private investment, establishing as basic principles, free entry and the introduction of competition where possible. Based on this mandate, the electricity generation and retailing segments were defined as competitive, while its transmission and distribution services were defined as natural monopolies subject to regulation.

Electricity Law 143 of 1994 structured the sector's generation activities around a wholesale electricity market, organized in the form of a pool, in which generators are able to sell their energy output via bilateral forward contracts or directly on the spot market. The Colombian energy spot market operates as a first-price multi-product auction. Generators report a bid price per block of energy offered to the market operator. The aggregate supply curve is then constructed by organizing the generation units in merit order (from the cheapest to the most expensive). The equilibrium price is the minimum bid price at which the total demand for electricity can be met. All generators bidding a price below the equilibrium price are dispatched and all are paid the marginal price that clears the market. Electricity producers must bid a daily price for each of the generation units they have. For each hour of the day, the market operator determines the price that balances the supply from the generators with total demand, and the units that will be dispatched. Forward contracts between generators and traders, or those entered into directly with final customers, are permitted. This system serves as a hedging tool against market risk. The positive or negative differences between the contracted quantities and the quantities generated by each agent are settled at the spot price.

2.2 Transition from public to private management

As mentioned above, Public Service Law 142 and Electricity Law 143 ushered in reforms to promote private enterprise in the electricity industry. The changes in the management structures in the generation units studied herein can be accounted for in terms of privatization processes and the ending of power purchase agreements (PPAs). Privatization in the form of the sale of stakes in, or the transfer of assets from, public enterprises was not exclusive to the energy sector. Private management policy formed part of other structural reforms oriented at opening up the Colombian economy. Privatization programs were also initiated in manufacturing, natural gas, fuel distribution, water sanitization and the banking industries. This, added to the separation of the activities of vertically integrated public companies in the electricity industry, triggered a series of sales of generation assets. At the same time, central and municipal governments attracted private investment for generation services via the signing of PPAs.

The main privatization sales of Colombian generation services occurred in two waves: The first in the 1990s, before the period of analysis considered in this study, and the second in the mid-2000s. The latter were related to the liquidation processes of the vertically integrated companies that had already transferred their assets to other activities and in which only the assets of the generation segment remained to be disposed of. At the beginning of the period of analysis, in 2006, the total installed capacity of the Colombian generation market was 13.313 MW. At the end of the period of analysis, in 2017, it was 16.689 MW.

In 2007, the Pacific Energy Company (EPSA) became the new owner of the Prado

Hydroelectric Power Plant (46 MW). This asset had previously been owned by the public company, Gestion Energetica (GENSA). In 2008, the Colombian Investment Company, Colinversiones (later CELSIA), acquired the assets and energy contracts of the Las Flores Thermoelectric Power Plant (160 MW), previously under the control of the public company, GECELCA. On June 30, 2010, the municipality-owned firm EMCALI sold 92% of the shares of the thermal unit Termoemcali I to the new private partners, TE Holdings Colombia S.A.S (owned by the Infrastructure Fund Colombia Ashmore I) and Maguro Ltd. The reason given by EMCALI for making this sale was to enable it to make the necessary investments in drinking water and sanitation infrastructure.

Although privatization continued in the distribution segment, only one new privatization was made in that of electricity generation in the years up to 2016. The Canadian fund, Brookfield, acquired 57.6% of Isagen which had been the property of the national government. The government's argument for selling off Isagen was to raise funds to finance third-generation road projects. Isagen is Colombia's second largest generator, accumulating a total installed capacity of 3,032 MW, of which 2,732 MW are hydraulic and 300 MW are thermal technologies. As for the PPAs, in 1995 the state-owned firm CORELCA signed a PPA for the sale of the energy from the Termobarranquilla 3, Termobarranquilla 4 and TEBSA units. In 2006, the rights of the PPA were transferred to the state-owned firm GECELCA due to the restructuring and liquidation of CORELCA. Under the PPA contract, GECELCA was made responsible for the commercial management in the wholesale electricity market of the energy generated by the aforementioned units, although the property infrastructure remained the concern of the private firm TEBSA. On April 21, 2016 the PPA was terminated and TEBSA began to participate in direct sales in the wholesale energy market.

Based on these changes, it is apparent that the transition from public to private management of the generation units analyzed herein was part of a general restructuring of the entire economic development model, in which the generation activity was just a modest part. Moreover, the reasons offered for the privatization or the change in management often differed and included such arguments as an attempt at restructuring firm processes,

Table 1: Privatized Generation Units 2006-2017

Date	Unit	Technology	Installed Capacity (MW)	From State Owner	To Private Owner
August 2007	Hidroprado	Hydro	56	GENSA	EPSA
August 2007	Prado IV	Hydro	5.7	GENSA	EPSA
November 2008	Termoflores	Thermal, Gas fired, combined cycle	150	GECELCA	COLINVERSIONES
June 2010	Termoemcali I	Thermal, Gas fired, combined cycle	213	EMCALI	Holdings Col., Ashmore I, and Maguro LTD
January 2016	Calderas	Hydro	26	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
January 2016	Miel	Hydro	396	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
January 2016	Jaguas	Hydro	170	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
January 2016	San Carlos	Hydro	1.240	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
January 2016	Sogamoso	Hydro	820	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
January 2016	Termocentro	Thermal, Gas fired, combined cycle	300	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
April 2016	Termobarranquilla 3	Thermal, Gas fired, simple cycle	64	GECELCA	TEBSA
April 2016	Termobarranquilla 4	Thermal, Gas fired, simple cycle	63	GECELCA	TEBSA
April 2016	TEBSA	Thermal, Gas fired, combined cycle	791	GECELCA	TEBSA

Source: own elaboration

funding strategic assets or terminating the PPAs. As such, these privatizations can be considered exogenous to the interactions of competition in the wholesale market and to the productive performance of these units. Table 1 lists the generation units that have passed from state to private control in the twelve-year period of 2006 to 2017.

Given the processes of privatization and divestiture, the resulting ownership structure of the main generation companies operating in Colombia is heterogeneous in terms of the private or public nature of the main shareholders. The Colombian generation stock has a high proportion of publicly owned or mixed companies that are under the control of public entities.

3 The mixed oligopoly model

This section presents various theoretical predictions of the effects of private magement on bidding strategies in electricity markets. I base my analysis on the extrapolation of behavioral and cost assumuptions from mixed oligopoly studies to a simple model of best response in the context of oligopoly competition in the electricity market.

Models of mixed oligopoly necessarily entail adopting different assumptions for private and public firms. There are two basic types of difference, and several models combine them both: Namely, 1) Behavioral differences, i.e. differences in the objective function of the firms. In most cases, the mixed oligopoly models assume that private firms aim to maximize profits while the objective function of public (or mixed) firms is to maximize social welfare; 2) Costs differences, i.e. differences in productive efficiency. Typically, it is assumed that private firms operate at lower costs than public enterprises. From these different assumptions, opposite effects on pricing strategies and, hence, on competition, can arise.

The analysis for profit maximizing firms builds on the theoretical arguments proposed by (McRae and Wolak, 2009; Wolak, 2000). Assuming the firm has previously sold an amount of energy q_i^c at a fixed price p_i^c by forward contracts, the profit function is defined by the following expression:

$$\pi_i = p_i^{RD}(q_i)(q_i - q_i^c) + p_i^c q_i^c - C_i(q_i)$$

where π_i is the profit of the firm i, $p_i^{RD}(.)$ is the inverse residual demand function of firm i, q_i is the quantity sold by firm i and $C_i(.)$ is the total cost function of firm i. Note that the market clearing price and the total cost are functions of the quantity. Given that in electricity markets demand is necessarily equal to supply, at equilibrium the residual demand of firm i is equal to the total quantity produced by this firm: $RD_i = q_i$. From the first order conditions of the profit maximization problem, we can then obtain the following expression for the price:

$$p^{RD}(q_i) = \frac{\partial C_i(q_i)}{\partial q_i} \underbrace{- \frac{\partial p^{RD}(q_i)}{\partial q_i}(q_i - q_i^c)}_{\text{strategic element}} \tag{1}$$

This is the best response of a profit maximizing firm. The first term on the right-hand side of this equation is the marginal cost and the second term is the strategic component. The latter is equal to the interaction of the inverse of the slope of the residual demand curve and the net forward contract position of the firm. Thus, the greater the amount of energy sold by the firm through fixed price forward contracts, the lower the incentive to increase the spot price. It should be noted that in cases where the generator is in a short position, it has the incentive to exercise market power to reduce the price. This is the expected behavior of a private firm which, according to the mixed oligopoly assumptions, is profit maximizing.

Next, the welfare maximizing assumptions for public firms (which typify mixed oligopoly theory) are extrapolated to this simple model of electricity markets and the results compared to equation 1 so as to highlight the difference between private and public enterprises. The welfare function is the sum of the consumer surplus and the firms' profits:

$$W = \underbrace{\int_0^Q p\big(x(q_0)\big)dx - p(x)\sum_{j=0}^{N}(q_j - q_j^c) - \sum_{j=0}^{N} p_j^c q_j^c}_{\text{Consumer Surplus}} + \underbrace{\sum_{j=0}^{N}\big(p(x)(q_j - q_j^c) + p_j^c q_j^c - C_j(q_j)\big)}_{\text{Industry Profits}}$$

where $p(x)$ is the inverse demand function, Q is the equilibrium total quantity and the other variables are as described above. For convention's sake, we identify the variables of the public firm using the sub-index 0. The first three terms are the consumer surplus and the remaining are the sum of industry profits. Note that the sum of the income from the spot price and forward markets is simply a transfer from consumers to producers. Thus, this expression can be simplified to:

$$W = \int_0^Q p\big(x(q_0)\big)dx - \sum_{j=0}^{N} C_j(q_j)$$

From the first order conditions of the maximization of this welfare function, the following expression can be obtained for the price :

$$p(Q) = \frac{\partial C_0(q_0)}{\partial q_0} \tag{2}$$

This equation indicates that the best response for a welfare maximizing firm is to apply the marginal cost pricing rule. This result is coherent with the findings of Beato and Mas-Colell (1984) who demonstrated theoretically that a public firm is able to restore market efficiency by applying this pricing rule.

Equations 1 and 2 allow two potential effects of the change from public (welfare maximizing) to private (profit-maximization) management to be identified: the behavioral and the cost effects.

In the case of the behavioral effect (marginal costs being equal), the comparison of equations 1 and 2 leads to the conclusion that more cost reflective pricing (though, recall not necessarily lower pricing) is achieved by public enterprises. Note that the difference between equations 1 and 2 is the strategic component. The sign of this component depends on the difference between the total quantity produced by the firm (q_i) and its total forward contract commitments (q_i^c). Moreover, the strategic component is relevant only if the slope of the residual demand is steep enough, that is, if the new manager has sufficient market power. Hence, as far as the behavioral effect is concerned, the sign of the effect of the change from public to private management will depend on the contracting levels of the firms and their market power. For high (low) contracting levels, a negative (positive) effect is expected. The greater the market power enjoyed by the firm, the greater the magnitude of these effects.

In the case of the cost effect (assuming identical behavior of both private and public firms), the canonical assumption of mixed oligopoly models of a more cost effective performance of private firms, i.e. $\frac{\partial C_j}{\partial q_j} < \frac{\partial C_0}{\partial q_0}$, leads to the conclusion of a pro-competitive effect of private management that necessarily entails lower equilibrium prices.[1] In this scenario, the effect of switching from public to private management would be expected to lead to a decrease in price bidding.

In subsection 4.2, I explain the strategy for disentangling these effects and in section 5 I present the results.

4 Empirical analysis

4.1 Data

I assess the impact of private management on the bidding prices of generation units in Colombia by using data from the wholesale electricity market. The data set contains the daily observations of 65 generation units, owned by 25 generation firms, during the period January 2006 to December 2017. Note I only include the generation units that bid prices in the wholesale electricity market.[2] In addition, there are several units that ceased to operate and others which started operations during the period of analysis. Hence, the data constitute an unbalanced panel of 348.331 observations.

Information about daily price bids, commercial availability and sales in forward contracts (requisite information for computing the forward contract level of the unit's owner) was extracted from the website of the Colombian wholesale electricity market operator, XM. Information about changes to the administrative structures of the generation units (see table 1) was extracted from press releases and the websites of the current owners. As a time varying control variable, an estimation of the marginal costs of the generation units was used. Table 2 highlights the main descriptive statistics of each of the variables

[1] Several theories seek to disentangle the source of the cost discrepancy between private and public firms. Such studies are oriented towards examining regulated private firms (Shapiro and Willig, 1990), the effects of transition from centrally planned to market-based economies (Roland, 2002; Tirole, 1991) and the role of transaction costs on the production of private and public firms (Sappington and Stiglitz, 1987). Similarly, a large number of studies have been devoted to finding empirical evidence for this discrepancy. Although the evidence is contradictory, many of these studies identify improvements in performance following privatization (Frydman et al., 1999; La Porta and Lopez-de Silanes, 1999; Megginson and Netter, 2001).

[2] Small units (generation capacity less than 20MW) are incorporated automatically as base generation.

Table 2: Variables in the econometric model

Variable	Units	Obs	Mean	Std. Dev.	Min	Max
Bid Price (b)	Pesos/KWh	348331	403.32	451.98	37.06	22552.48
Logarithm Bid Price ($Ln(b)$)	Ln(Pesos/KWh)	348331	5.51	1.01	3.61	10.02
Marginal Costs (C)	Pesos/KWh	348331	40.32	49.93	0.00	443.90
Daily Commercial Availability (A)	GWh	348331	30.14	24.04	0.00	75.22
Daily Forward Contracts (F)	GWh	348331	14.81	13.22	0.00	52.10
Index of contracting (IC)	Percentage	343860	51.78	23768.57	0.00	1.33E+07
Indicator of under contracting (L)	Dummy	343860	0.88	0.33	0.00	1.00
Indicator of over contracting (H)	Dummy	343860	0.12	0.33	0.00	1.00
Control Group						
Variable	Units	Obs	Mean	Std. Dev.	Min	Max
Bid Price (b)	Pesos/KWh	277288	401.53	449.75	37.06	22552.48
Logarithm Bid Price ($Ln(b)$)	Ln(Pesos/KWh)	277288	5.51	1.01	3.61	10.02
Marginal Costs (C)	Pesos/KWh	277288	41.97	50.55	0.00	443.90
Daily Commercial Availability (A)	GWh	277288	30.24	25.57	0.00	75.22
Daily Forward Contracts (F)	GWh	277288	14.99	13.89	0.00	52.10
Index of contracting (IC)	Percentage	273227	65.05	26664.41	0.00	1.33E+07
Indicator of under contracting (L)	Dummy	273227	0.85	0.36	0.00	1.00
Indicator of over contracting (H)	Dummy	273227	0.15	0.36	0.00	1.00
Treated Group						
Variable	Units	Obs	Mean	Std. Dev.	Min	Max
Bid Price (b)	Pesos/KWh	71043	410.31	460.51	40.57	12387.83
Logarithm Bid Price ($Ln(b)$)	Ln(Pesos/KWh)	71043	5.53	1.01	3.70	9.42
Marginal Costs (C)	Pesos/KWh	71043	33.91	46.87	0.00	420.11
Daily Commercial Availability (A)	GWh	71043	29.76	16.83	0.00	69.70
Daily Forward Contracts (F)	GWh	71043	14.10	10.13	0.00	35.91
Index of contracting (IC)	Percentage	70633	0.45	0.67	0.00	155.98
Indicator of under contracting (L)	Dummy	70633	0.98	0.13	0.00	1.00
Indicator of over contracting (H)	Dummy	70633	0.02	0.13	0.00	1.00

Source: XM - Colombian Market Operator

included in the model.

For marginal costs estimation I assume an accounting approach similar to that assumed in previous studies in the field of electricity markets (Borenstein and Bushnell, 1999; Borenstein et al., 2002; Fabra and Reguant, 2014; Green and Newbery, 1992; Wolak, 2000; Wolfram, 1998, 1999). I computed the marginal costs of thermal plants taking into account their technical parameters (heat rate), fuel costs and fuel transportation costs. The sources of the information and more detailed information concerning the assumptions for the calculation and imputation of these costs are presented in appendix C. It is important to bear in mind that these computations may contain some measurement error given that we approximate the fuel costs to references prices, and the cost per unit in the actual fuel supply contracts may be different. For hydroelectric generation units, a marginal cost equal to zero is assumed. Even when this assumption may appear to be unrealistic, the use of unit fixed effects and date fixed effects in the estimation ensures I can control for time invariant heterogeneity and common time variant factors. The validity of the result relies on the assumption that the expectation of the time variant heterogeneity component of the marginal costs is zero.

4.2 Identification strategy

This paper examines private management from the perspective of the evaluation of policy impact. The differences-in-differences methodology with staggered adoption undertakes a comparison of treated and non-treated (control) groups before and after policy intervention in a context in which the date of treatment may vary by unit. Specifically, in this paper, the generation units that switched from public to private management make up the treated group while the public generation units constitute the control group. The estimation of the impact of private management on bidding prices, using this methodology, relies on the assumption that the average change between pre- and post-treatment periods on bidding prices of the units that remained public throughout the period is an unbiased estimator of the average change in bidding prices of the treated units had they continued to be managed by public companies. This in turn entails that the unobserved time variant heterogeneity of the estimation model is uncorrelated with the switch in management structures. A major concern in the application of double differences is the possibility that treatment and control groups may differ in their pre-existing characteristics resulting, in this instance, in different bidding price strategies even if the former had not undergone private managed. Specifically, generation units may differ in two key features: i) technological characteristics, such as fuel type, installed capacity and potential for supplying auxiliary services; and ii) the forward contract exposure position of the unit's owner. Different initial conditions with regard to these characteristics could account for the different time paths of the treatment and control groups, rather than the switch to private management. In order to address this concern, in the base line estimation, I apply matching methods in order to pair observations from the treatment group with similar observations in the control, given several observable initial characteristics. First, the criteria for considering the plants in the treated and control groups as similar need to be established. Rosenbaum and Rubin (1983) proposed calculating the probability of being treated conditional on the individuals' pretreatment observable characteristics and, then, using this probability (propensity score) as criteria for matching observations. In the framework of this research, I calculate the propensity score with a cross-sectional probit model:

$$Pr\big[T_i = 1|X_i\big] = \Phi\big(X_i^T \beta\big)$$

where $Pr\big[T_i = 1|X_i\big]$ is the probability of switching from public to private management conditional to the observable variables, T_i is a dummy that takes the value of 1 if the unit was switched to private management during the period of analysis and 0 otherwise, $\Phi(.)$ is the cumulative distribution function for the standard normal and X_i is a set of key pretreatment observable characteristics: the type of fuel used by the unit, the potential for supplying an automatic generation control service, the installed capacity, the expected daily amount of energy which the unit can supply in hydro critical conditions, and the average contract position of the firm in the years 2005 and 2006, prior to any privatization process analyzed in this study.

Having calculated the propensity score, I considered as control group those units that did not switch to private management and lie in the common support region, i.e. the public plants for which the probability of their being privatized is positive, according to the probability distribution associated with the propensity score model. The observations of units that did not switch management to private and are outside the common support were dropped. In the robustness checks subsection 5.2, I examine the results of the estimation without applying propensity score matching and using more stringent matching criteria, such as nearest neighbor.

As stated above, the first objective of this empirical analysis is to establish whether private management has a significant effect on the bidding price and, if so, its magnitude. The second objective is to identify the drivers of the potential changes by exploiting information about forward contracts in the Colombian wholesale electricity market. Finally, the paper explores the features of the dynamic effect of privatization, understood as the duration, trend and variability of the impact over time. In order to tackle the first objective of this paper, i.e. to establish the net average effect of privatization on bidding prices, I propose estimating the following two-way fixed effects linear regression model:

$$b_{it} = \beta_0 + \beta_1 D_{it} + \sum_{k=2}^{N} \beta_k x_{it}^k + \gamma_i + \sigma_t + \epsilon_{it} \tag{3}$$

where b_{it} is the level or logarithm of the daily bidding price submitted by unit i in the day t; D_{it} is a dummy variable that takes the value of 1 when unit i is privately managed on the day t; x_{it}^k is a vector of time variant heterogeneous variables, in this case the marginal cost;γ_i is a generation unit fixed effect that controls for non-observable time invariant heterogeneity; and σ_t is a date fixed effect which controls for the common time variability. Finally, ϵ_{it} is the generation unit time-varying error, which is assumed to be uncorrelated with D_{it} and the vector X_{it}. Note that in the base line estimation, the control group consists of the public generation units; hence,D_{it} takes the value of one after unit i switched to private management. The parameterβ_1 represents the double difference effect of the change from public to private on price bids. The logarithmic specification of the dependent variable facilitates interpretation of this parameter as a percentage change.

Second, section 3 argued that the behavioral effect on the bidding strategy of a change in management depends on the capacity of private managers to use their market power. To capture this heterogeneity, the treatment group is split in two subgroups: i) The first includes the units that changed to being a large private incumbent and ii) the second includes the units that changed to being a new private competitor in the market. Note that the management changes affecting the first group entail an increase in market concentration while those affecting the second decrease it. Hence, the distinction between the two subgroups is based on the presumption that large private incumbents increase their market power with a change of management while new competitors do not.

In order to capture these differences in behavioral reaction due to market power, I propose estimating the following two-way fixed effects linear regression model:

$$b_{it} = \beta_0 + \beta_1 D_{it} \cdot Big_{it} + \beta_2 D_{it} \cdot New_{it} + \sum_{k=3}^{N} \beta_k x_{it}^k + \gamma_i + \sigma_t + \epsilon_{it} \tag{4}$$

where Big_{it} is a dummy variable that takes the value of 1 when unit i is privately managed by a big incumbent private firm on the day t and zero otherwise. New_{it} is a dummy variable that takes the value of 1 when unit i is privately managed by a new competitor in the market in day t and zero otherwise. The remaining variables have the same meaning as in equation 3.

Third, to identify the coherence of the effect of private management due to behavioral changes and the theoretical predictions presented in section 3, it should be borne in mind that in the case of the Colombian market the information about the forward contract position of the electricity generator is observable for the econometrician. This makes it possible to identify two different impacts of private management (parameters) corresponding to the different requirements of forward contracts. To capture any differences, I created two dummy variables corresponding to high and low levels of forward contracting, i.e. the dummy variable L_{it} (H_{it}), takes the value of one if the owner of the unit has a low (high) level of forward contracts, and zero otherwise . In order to consider the forward contracting position of a firm as low or high, I calculate an indicator for the level of contracting based on the hourly information of forward contracts and commercial availability. For each day, I calculate the sum for the 24 hours of forward contracts and commercial availability.

$$F_{jt} = \sum_{h=1}^{24} F_{jth}$$

$$A_{jt} = \sum_{h=1}^{24} \sum_{i=1}^{N_j} A_{ijth}$$

where F_{jth} is the amount of energy committed in forward contracts in in hour h of day t, for firm j. A_{ijth} is the commercial availability of unit i owned by firm j in hour h of day t. N_j is the number of units owned by firm j. I calculate the index of contracting IC_{jt} of firm j in day t, as the ratio between daily forward contracting and the daily sum of commercial availability:

$$IC_{jt} = \frac{F_{jt}}{A_{jt}}$$

This can be interpreted as the fraction of the daily commercial availability of a firm that is committed to forward contracts. I consider the contracting position of a firm as high (low) when the value of the IC_{jt} of firm j is greater (less) than the average IC_{jt} of private firms prior to the first period of treatment. Here, this value is 0.26. Subsequently, I apply each of these contract position dummies to the treatment dummy, replacing the unique treatment variable for its interactions with each of the contract position dummy variables. Accordingly, I estimate the following two-way fixed effects model:

$$b_{it} = \beta_0 + \beta_1 D_{it} \cdot L_{it} + \beta_2 D_{it} \cdot H_{it} + \sum_{k=3}^{N} \beta_k x_{it}^k + \gamma_i + \sigma_t + \epsilon_{it} \tag{5}$$

where L_{it} is the low contracting position dummy, H_{it} is the high contracting position dummy,x_{it}^k is a vector of observed time variant variables that can affect the price bids of unit i on day t: marginal costs and forward contracting. The remaining variables are the same as in equation 3. Table 2 shows that the IC_{jt} for the control group presents notable outliers. These outliers are attributable to the extremely low values of the denominator. For this reason, I opt to exclude the observations for which the A_{jt} is less than 5% of the maximum A_{jt} for firm j, that is, I exclude the observations if $A_{jt} < 0,05 \cdot \max_t(A_{jt})$.

Concerning the validity of the results of the models estimated in equations 3, 4 and 5, a key assumption is the lack of significant changes in marginal costs or in the strategic component due to time variant unobservable heterogeneity attributable to other events that might alter the relative bidding behavior of the firms around the time they switched to private management. Specifically, a major El Niño event occurred between November

2014 and May 2016.[3] This period coincides with two shifts in management structure: the sale of ISAGEN shares and the finalization of the PPA signed with the TEBSA. In the following sections, I present evidence to show that the occurrence of this event does not invalidate the results.

4.3 Parallel trends

As discussed above, the correct identification of the effect of a management switch using the double difference estimator relies on the assumption that the average bidding prices of public generation units in post-private management periods are an unbiased estimator of the average bidding prices of the privatized units had they not been privatized. Given the impossibility of obtaining data for this counter-factual, statistical testing of this assumption is not feasible. However, the recent literature on the use of double differences performs statistical tests of parallel trends in the dependent variable between treatment and control groups prior to the intervention. To do likewise, I compare the bidding price of public generation units with the average bidding price of the units that were privatized prior to this change (treated before treatment - TBT group).

First, I carry out a graphical analysis to identify any marked differences. The graphs in figure 1 show the monthly average bid (panel a) and bid logarithm (panel b) for both the control and treatment groups prior to private management. Both series are noisy and it is not possible to identify clear differences between the time trends of each group simply by inspection. As for the potential effect of the 2014-2016 El Niño event, no clear break can be identified in the differences presented by the two series during this period.

Second, I implement a fixed effects regression, taking as independent variables the interactions of the linear and quadratic time trends and dummies for the control group and the TBT group, i.e.:

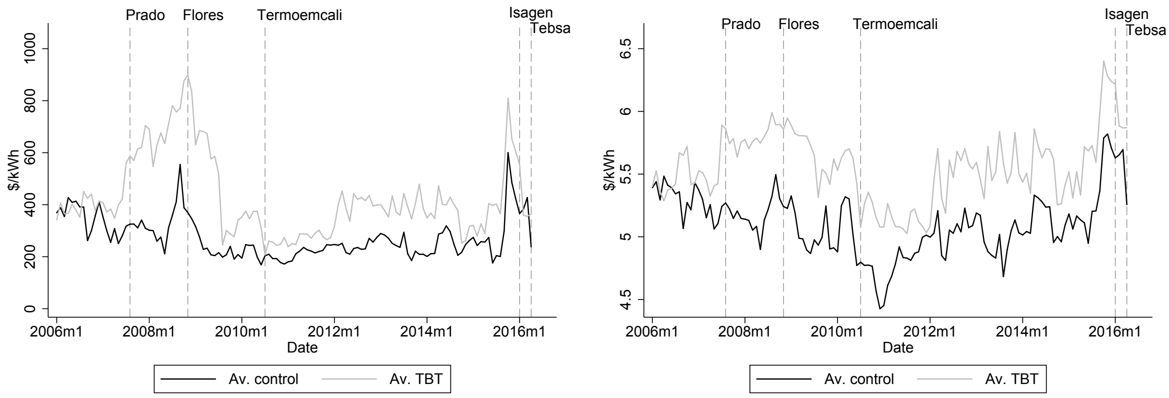
$$b_{it} = \beta_0 + \beta_1^T D^T \cdot T + \beta_2^T D^T \cdot T^2 + \beta_1^{NT} D^{NT} \cdot T + \beta_2^{NT} D^{NT} \cdot T^2 + \gamma_i + \epsilon_{it}$$

[3] The drop in rainfall caused by the El Niño phenomenon has a significantly negative impact on the availability of hydro generation resources. This translates into significant price changes on the wholesale energy market.

Figure 1: Time series treatment and control groups

(a) Bids

(b) Bids logarithms



Source: Data from XM - Elaboration: Author.

where T is the linear time trend, D^T is a dummy variable that takes the value of 1 when unit i is in the group of units that are to be private managed ; D^{NT} is a dummy variable that takes the value of 1 when unit i is in the group of non-switched units that remain public throughout the period of analysis and the remaining variables are the same as in equation 3. Later, I tested the null hypothesis: Ho: $\beta_1^T = \beta_1^{NT}$ and Ho: $\beta_2^T = \beta_2^{NT}$. Table A5 in appendix A shows the results.

The coefficients for both interactions point to a very uncertain estimation and the test for equality of coefficients indicates that there is no statistical evidence of differences between the two groups.

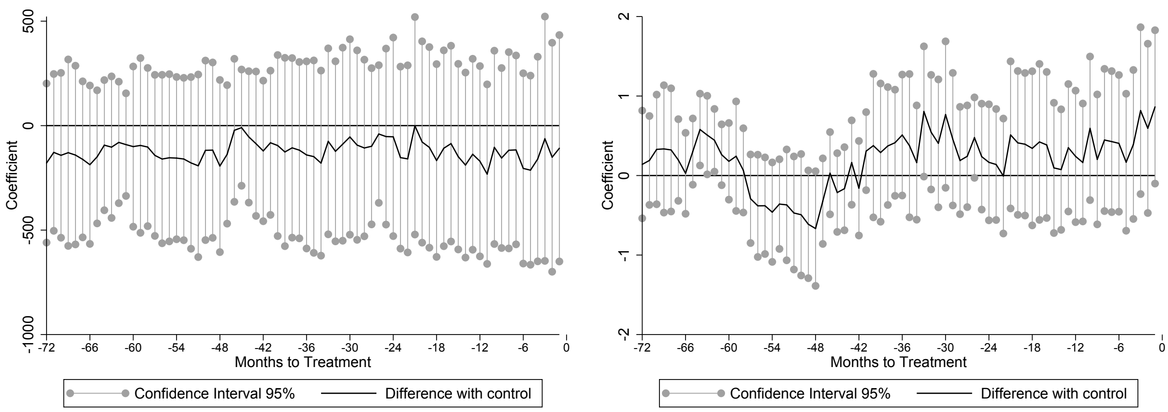
Finally, given that the parallel trend assumption should be met in relation to the moment of application of the policy and that I have different dates for the switch in management structures, I checked the relevance of differences between the treatment and control groups for the 72 months prior to the treatment date. I adopt a monthly version of the approach suggested by Galiani et al. (2005). This involves performing a two-way fixed effect estimation of the panel data, including dummy variables for each group (control and TBT), for each lag period. In this case, I estimated a coefficient for each group for the 72 months prior to the change to private management. The model estimated is:

$$b_{it} = \beta_0 + \sum_{l=1}^{72} \beta_l^T D_l^T + \sigma_t + \gamma_i + \epsilon_{it} \tag{6}$$

where D_l^T is a dummy variable that takes the value of 1 when the unit i is in the group of units that are going to switch from public to private and the day t is in the l month previous to the switch to private. The remaining variables have the same meaning as in equation 3. For this regression it was necessary to drop the treated observations in the post-treatment period. Figure 2 presents the results of the test for the differences of non-switched and switched to private groups, for each lag of the month to the treatment date.

Figure 2: Parallel trends in pre-treatment months

(a) Bids (b) Bids logarithms



Source: Data from XM - Calculations and elaboration: Author.

Overall, it is only possible to reject the null hypothesis of a difference equal to zero in less than 10% of the months prior to treatment. As for the potential effect of the El Niño event, the pretreatment period is sufficiently long to capture differences in the series before and after the onset of the 2014-2016 event. The onset of the El Niño phenomenon is around 14 to 17 months prior to changes in the management of ISAGEN and TEBSA. There are no major changes in the differences observed between the treated and control groups in the months coinciding with this El Niño event. This suggests that the climatic event did not influence the difference in average bidding prices between the control and treatment groups. Based on these results, the assumption of parallel trends of the treatment and control groups seems reasonable.

5 Results

5.1 Baseline estimation

In this section the double difference models described in subsection 4.2 above are applied to the data set for the wholesale electricity market in Colombia. Given the large number of time controls applied, I adopted the procedure for estimating high-dimensional fixed effects models proposed in Correia (2017). Table 3 displays the results of the baseline estimate of the models in expressions 3 and 4.

It is evident that the general effect of switching to private management on price bids is economically important but highly uncertain. For all the treated generation units I found an increasing effect around the 20% of the bidding price. However, when distinguishing between the changes to large incumbents and those to new competitors, a marked positive economic impact on the bidding strategy of the latter group can be observed. This impact reaches around the 90% of increase of the bidding price. The effect of the entry of new private competitors is economically non-significant and highly uncertain, the percentage increase in the bidding price related with it is around 3%. These results suggest that the strategic component related to market power matters.

In relation to the dynamic effects of private management, I explored the duration, trend and stability of the impact around the time of the switch from public to private management. To do so, I created a treatment dummy variable for each of the 24 months before and after the change in management structure, according to the following modification of the model proposed in expression 3:

$$b_{it} = \beta_0 + \sum_{l=-24}^{24} \alpha_l (D_{it} \cdot Z_{itl}) + \sum_{k=1}^{N} \beta_k x_{it}^k + \gamma_i + \sigma_t + \epsilon_{it} \tag{7}$$

where α_l is the average impact l months before (or after) private management, Z_{itl} is a

Table 3: Impact of private management - Bid price and Logarithm

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	86.730				0.183			
	(68.794)				(0.119)			
Ch. to P. Small to big		339.560***		358.829***		0.653***		0.642***
		(88.854)		(59.207)		(0.162)		(0.117)
Ch. to P. New comp.			-30.361	-4.622			0.014	0.029
			(42.538)	(53.015)			(0.106)	(0.111)
Marginal Costs	-2.414***	-1.847	-2.794***	-2.332**	-0.007***	-0.007***	-0.008***	-0.007***
	(0.846)	(1.110)	(0.870)	(0.882)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	90874	54683	81409	90874	90874	54683	81409	90874
R-sq	0.360	0.360	0.441	0.368	0.556	0.539	0.593	0.560

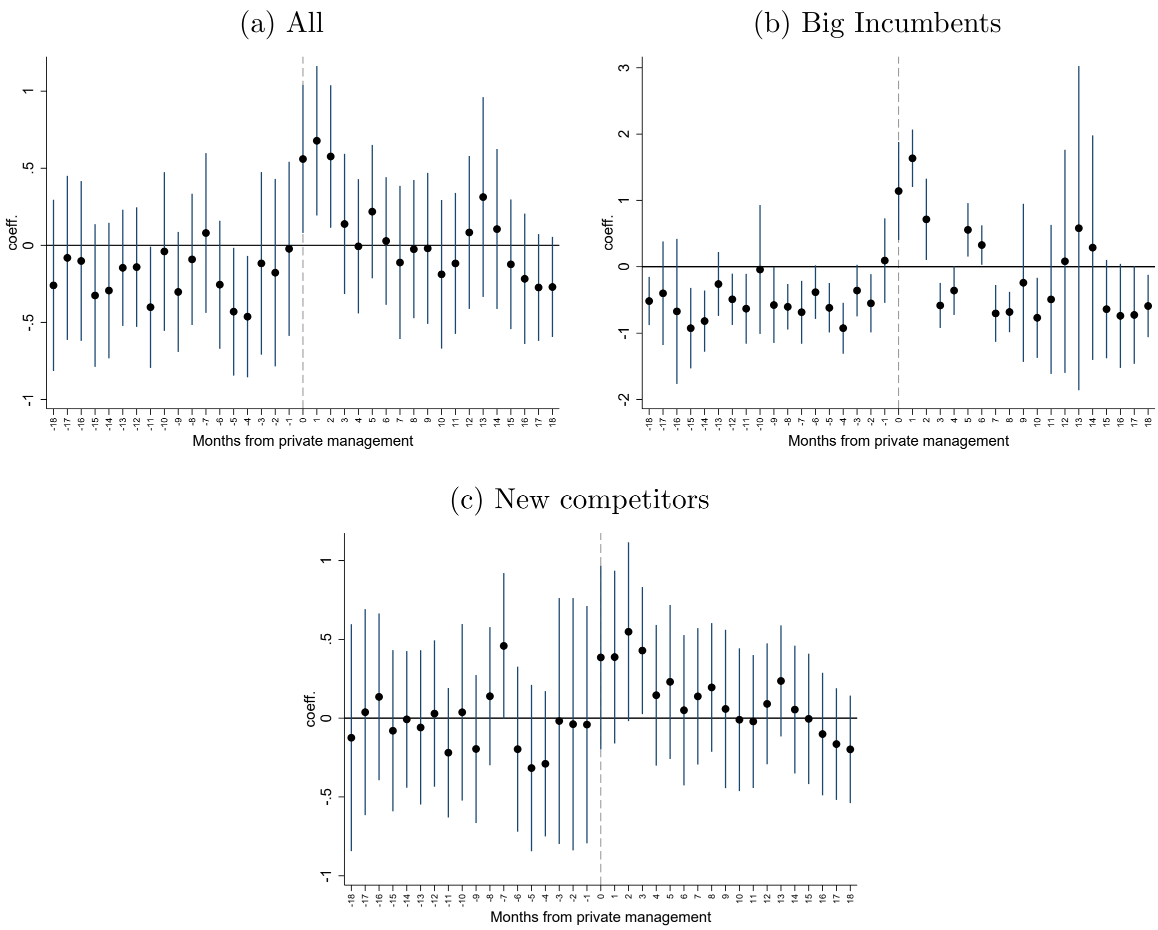
Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

dummy that takes the value of one if unit i in moment t switched to private management l months before (or after). The remaining variables and parameters are the same as those in equation 3. The results of the estimation of this model for the logarithm of the bidding price are presented in figure 3.[4]

In the estimation that does not discriminate between large incumbents and new competitors, a clear positive jump can be seen in the month of the switch to private management, which is statistically significant for the first three months. After this, the effect slowly decreases and even becomes negative after 15 months. This suggests that although the average impact of the shift from public to private management is positive and statistically significant in the short run (first three months), this impact decreases in the long run and exhibits a clear decreasing trend over time. These results can be interpreted in relation to the hypothesis that privatization may yield cost savings because of the greater efficiency achieved in the management of operations and contractual negotiations by private companies. The changes associated with these factors can be expected

[4]The results for the bidding price as dependent variable are presented in panels a, b and c of figure B5 in appendix B.

Figure 3: Dynamic effects of private management



Source: Data from XM - Calculations and elaboration: Author.

to be gradual, stable and, eventually, to reach a point of exhaustion. Assuming that privately managed firms expect to become net sellers of energy, the pattern presented in figure 3 is congruent with the hypothesis of an initial counter-competitive strategic impact that is gradually offset by the greater cost reductions implemented by the private manager.[5] This scenario supports the hypothesis that both components are relevant for explaining the differences in bidding prices between private and public enterprises.

However, this narrative presumes that firms managed privately expect to achieve positive net sales of energy on the wholesale market. For this reason, I performed additional estimates corresponding to two different impacts depending on the level of forward contracting (low or high) of the owner of the generation unit. In this way, I am able to verify the coherence of the results with the predictions of equations 1 and 2 discussed in section 3. Table 4 shows the results of the estimation of the model applied to specific situations in which the private owners of the treated units have low or high forward sales, as stated in expression 4 in subsection 4.2.

In the case of firms with low levels of forward contracting , columns 1 and 5 in table 4 show an economically significant positive effect with low levels of uncertainty. When the treatment group is split between large incumbents and new competitors, although I found the expected effect for both subgroups, that of the former was greater and less uncertain than the effect of the latter.

According to these results, when producers face low levels of forward contracting, the privatization of generation units leads to an increase in bidding prices. These results are consistent with the theoretical predictions of the model of incentives to exercise market power proposed by Wolak (2000, 2003).

In contrast, in the case of situations of high levels of forward contracting, a negative net average effect of private management on bidding prices can be detected. This is economically relevant with low levels of uncertainty for the whole sample and the subgroups of large incumbents and new competitors.

Given these results, we incorporate the level of forward contracting in the analysis

[5]Note the average IC_{it} for private firms during the analysis period is 0.37.

Table 4: Impact of private management and forward contracts

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Ch. to P./C. Low	177.05*				0.38**			
	(86.57)				(0.15)			
Ch. to P./C. High	-190.52*				-0.46***			
	(100.66)				(0.15)			
Ch. to P./C. Low Small to big		402.67***		419.91***		0.76***		0.75***
		(111.19)		(83.43)		(0.18)		(0.13)
Ch. to P./C. High Small to big		-149.42*		-155.92*		-0.34**		-0.33**
		(77.23)		(80.51)		(0.13)		(0.14)
Ch. to P./C. Low New comp.			78.57	91.69			0.29	0.29
			(100.89)	(98.14)			(0.22)	(0.22)
Ch. to P./C. High New comp.			-210.89	-189.40			-0.57**	-0.54**
			(175.82)	(174.82)			(0.26)	(0.26)
Contracts Low	61.59	76.43	66.99	60.11	0.30	0.35	0.31	0.30
	(68.00)	(65.97)	(58.61)	(60.68)	(0.20)	(0.20)	(0.19)	(0.19)
Marginal Costs	-2.93***	-2.25**	-3.33***	-2.84**	-0.01***	-0.01***	-0.01***	-0.01***
	(0.93)	(0.90)	(1.04)	(1.01)	(0.00)	(0.00)	(0.00)	(0.00)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	89607	53484	80174	89607	89607	53484	80174	89607
R-sq	0.36	0.34	0.44	0.36	0.56	0.53	0.59	0.56

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

of duration, trend and stability of the impact for the 24-month period either side of the switch to private management. Thus, I interacted the variables of low (L_{it}) and high (H_{it}) levels of contracting with the lags/leads (Z_{itl}) both 24 months before and after the change in management structure, according to the following modification of the model expressed in equation 5:

$$b_{it} = \beta_0 + \sum_{l=-24}^{24} \alpha_l^L (D_{it} \cdot Z_{itl} \cdot L_{it}) + \sum_{l=-24}^{24} \alpha_l^H (D_{it} \cdot Z_{itl} \cdot H_{it}) + \sum_{k=1}^{N} \beta_k x_{it}^k + \gamma_i + \sigma_t + \epsilon_{it} \quad (8)$$

where α_l^L is the average impact l semesters after (or before) private management with low levels of contracting, α_l^H is the average impact l semesters after (or before) private management with high levels of contracting. x_{it}^k is a vector of time variant observed variables that are not common to all the units: marginal costs and forward contracting. The remaining variables are the same as those in expression 5. I perform this estimation for the whole sample and for the sub-samples of large incumbents and new competitors. Figure 4 presents the results for the estimation of the logarithmic model.[6]

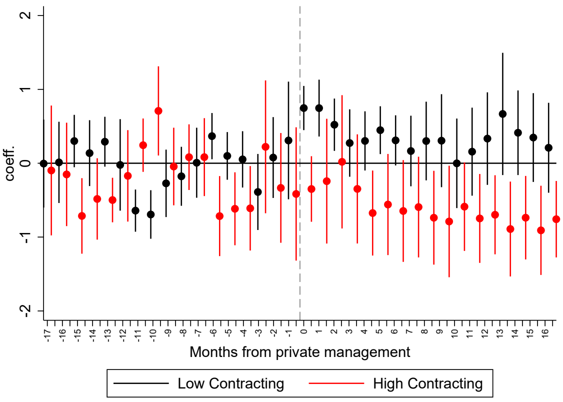
Regarding the estimation for the whole sample, in the months previous to the switch to private management there is no a clear differences in the pattern of bidding between low and high forward contracting episodes. After private management, the coefficients for low contracting locate systematically in the positive region and the coefficients for high contracting locate in the negative region.

The bidding pattern corresponding to days of low levels of contracting locates in the positive region immediately after the change to private management. As in the estimation of the model in expression 7 (which does not consider forward contracting), the first three months of private management present positive coefficients with low levels of uncertainty. In the case of bids made during days of high forward contracting, it is evident that following the change to private management the coefficients locate in the

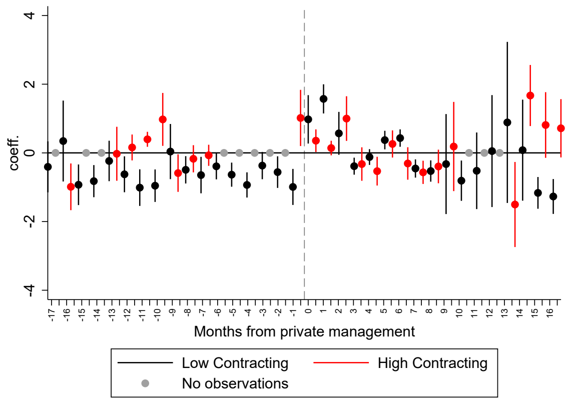
[6]The results for the model with bids as the dependent variable are presented in panels d, e and f of figure B5 in appendix B. Although the results are more uncertain, the model presents the same patterns as those of the logarithmic model.

Figure 4: Dynamic effects and forward contracts

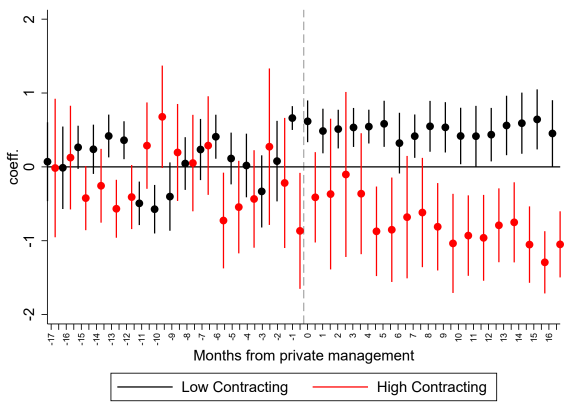
(a) All



(b) Big Incumbents



(c) New competitors



Source: Data from XM - Calculations and elaboration: Author.

negative segment. Although the first four months are uncertain and close to zero, in subsequent months these coefficients present more markedly negative values. When the sample is split between the large incumbents and new competitors, two different patterns are observed and it is evident that the general pattern observed in panel a of figure 4 is driven by that of the new competitors.

Prior to private management, the first subgroup shows negative differences with respect to the control group, especially on days of low levels of forward contracting. During the first three months of private management, the bids jump to reach positive and statistically significant values for both high and low forward contracting positions. During the first nine months of private management, the bidding strategy in both forward contracting positions seems to follow the same pattern. After the ninth month, the coefficients no longer present a clear pattern. In contrast, the group of new competitors present an unequivocal pattern of different bidding strategies depending on the forward contracting position. As predicted by the theory of incentives to exercise market power, private managers increase their bids when their contract obligations are low and decrease their bids when contract obligations are high. These results indicate that the firms' level of forward contracting is a key element in understanding the bidding strategy of privately managed firms and the differences in relation to the bidding behavior of public firms. In addition, these findings allow me to clarify the explanation for the patterns found in figure 3 and the hypothesis of initial counter-competitive effects and subsequent cost reduction attributable to the change to private management.

The findings in table 4 and panels a and c of figure 4 show that the pattern found in figure 3 reflects the composite effect of two strategies: The bidding behavior on days of low levels of forward contracting and the behavior on days of high levels of forward contracting. These results support the hypothesis that the reduction in average bidding prices several months after the switch to private management can be attributed to strategic behavior rather than to a reduction in costs.

Given the rigorous time fixed effect controls applied to the estimations, the fact that the reduction in bidding price is well explained by high levels of forward contracting is inconsistent with the hypothesis that the driving factor of the decline in bid prices following private management is the gradual reduction in costs. It should be noted that the estimated magnitude of the increase in bidding prices for days of low levels of contracting — c. 38% — and that of the decrease for days of high levels — c. 46% — are economically significant. It is implausible that such changes are attributable to a cost difference generated by improvements in the operative management of the units and a more efficient negotiation of fuel contracts. Studies that evaluate the impact of the implementation of liberalization on productive performance in electricity markets suggest that effects of this type are modest. Fabrizio et al. (2007) assessed the impacts of liberalization on the efficiency of thermal power plants in the US. They found efficiency gains from liberalization of around 3 to 12% for labor and non-fuel inputs. Davis and Wolfram (2012) evaluated the impacts of liberalization on the operating performance of nuclear plants in the US. These authors conclude that deregulation and consolidation are associated with a 10% increase in operating performance, achieved primarily by reducing the duration of reactor outages. Cicala (2015) found a fall of around 12% in the price paid for coal by deregulated generation firms after the end of cost-of-service regulation.

In contrast, the evidence found after incorporating the information of forward contracting is consistent with the theory of incentives to exert market power in electricity markets outlined in section 3. This predicts that the coefficient should exhibit opposite signs in different contract positions.

5.2 Robustness Checks

The results presented above may, however, be dependent on the particular specification of the econometric model employed. In this section I present several estimations to test the impact of changes in these specifications. Overall, the qualitative results of the model seem to be robust to the different changes. First, I estimated the model under the assumption of random unobserved heterogeneity. I performed a generalized least squares regression applying fixed effects for every week of the sample with robust standard errors clustered by unit. The results are available in table D8 in online appendix D. Second, in addition to propensity score matching, another strategy for controlling for pre-existing time invariant characteristics is to allow for the inclusion of time invariant observable control variables that may lead to different time paths for the treatment and control groups. Bernardo (2018) performed an estimation of a Prais-Winsten pooled regression model which assumes an autoregressive process of order 1 and heteroscedasticity in the error term. Although this specification may be biased by unobserved time invariant heterogeneity, it allows time invariant observable control variables or initial conditions to be included, which may lead to different time paths for the treatment and control groups. I performed this type of estimation avoiding the use of the propensity score matching but including the following control variables: the type of fuel of the unit, the potential for supplying an automatic generation control service, the installed capacity, the daily amount of energy that the unit can supply in hydro critical conditions and the average contract position of the firm in the years 2005 and 2006, prior to any switching process from public to private management analyzed in this study. The results can be consulted in table D9 in online appendix D.

Third, in the baseline estimation, I applied a matching method, using as pairing criteria the common support resulting from the propensity score matching procedure. I performed several checks employing with this methodology. First, I estimated the whole sample again but ignored the results of the propensity score matching. The results for the estimation of models of expressions 3 and 4 can be consulted in table D10 in online appendix D. The results for the dynamic effects of the switch to private management are available in figure D7 in appendix D. The second robustness check related to the matching methodology concerns the estimation model of the propensity score. I repeated this estimation using a logit model to calculate the propensity score. The matching results were identical. Likewise, I performed the estimation of the propensity score using all the data as a pooled data panel. (The results can be consulted in table D11 in online appendix D). As a third check, I modified the criterion in order to match the observations of the treatment and control groups. Instead of using the common support of the propensity score, I considered the nearest neighbor algorithm. This seeks to identify the control observation with the closest propensity score for every privatized unit. The observations that are not matched can then be dropped. The results using the nearest neighbor criterion to select the control group are available in table D12 in online appendix D.

Fourth, price bid information is available for private and public firms, which means other control groups may be considered, such as: i) any units owned by the central government that did not change managers during the time analyzed; ii) any units that did not change their managers during the time analyzed regardless of their ownership type. I took these unit sets as control groups and repeated the parallel trend tests and the baseline estimation. The results are available in figure D6 in appendix D. For both sets of unit, the parallel trend tests indicate that this is a reasonable assumption. The results of the estimation of the models in equations 3 and 4 when using these different control groups can be consulted in tables D14 and D14 in online appendix D. I also performed an estimation of the dynamic effects of the switch to private management for both samples. The results are available in figures D8 and D9 in the online appendix D, respectively. The results of the checks described above were robust and similar to the baseline estimation.

Finally, for the baseline estimation, I performed fixed effects estimations with robust standard errors clustered by each generation unit. However, Bertrand et al. (2004) showed that serial correlation in double difference applications may distort the inference, even using robust standard errors. In order to explore the possibility of serial correlation issues provoking false positive effects in units and periods in which switching to private management did not occur, I performed several placebo tests. To check the potentially significant results on non-treated plants, I dropped the observations of treated units and applied a fictional random treatment to the non-treated sample according to different probabilities of fictional treatment (25, 50 and 75%). Later, I estimated the impact for each of the probabilities assigned. The date of treatment is random and differs for each unit. The results of the estimation are shown in table B6 in appendix B. As expected, for samples in which fictional treatment is applied with probabilities of 50 and 75%, the interest coefficients are not statistically significant at conventional confidence levels. In the case of a fictional treatment being applied with a probability of 25%, statistically significant coefficients are obtained. Although opposite signs (negative) to those found in the baseline estimation are exhibited, this result warns of a potential problem of over-rejection of the null hypothesis. In order to check the robustness of the baseline estimation against this potential inferential problem, I allowed for arbitrary variance-covariance matrix within units. Athey and Imbens (2018) suggest that, in the context of difference in difference settings with staggered adoption, the clustered bootstrap variance estimator is conservative. I estimated the models specified in equations 3 and 4 applying fixed effects for every week of the sample and block-bootstrapping methods. The results are shown in table B7 in appendix B. The statistical significance of the coefficients and the extent of uncertainty in the inference are similar to those in the baseline estimation. This is an indication that the inference in the baseline estimation is not affected by marked biases. However, given the data's long time dimension, the results of the difference-in-differences estimations performed in this paper should be treated with caution.

The results presented in this section suggest that the baseline estimation presented in subsection 5.1 is robust to different sample alternatives and other specifications of the model. However, given the data's high number of time periods I should stress that serial correlation biases of the standard error estimates may well arise.

6 Conclusions

In this paper, I have undertaken a policy evaluation of the impact of the switch from public to private management structures of electricity generation units on the bidding strategy of firms in the Colombian wholesale electricity generation market. This empirical exercise has sought to address two goals: i) a determination of the net average impact on price bids and ii) an analysis of the coherence of the empirical evidence with the theory of incentives to exercise market power in electricity markets in a mixed oligopoly framework. I drew on daily information on bidding strategies and assumed the switch to private management of several units as being an exogenous decision in order to perform a double difference analysis, in which the public units are the control group and those switching to private management constitute the treatment group.

The positive impact of private management was found to be statistically significant for situations in which the firms faced short forward contract positions, while for those facing long positions, the results are also statistically significant, but the sign of the effect is negative, and the magnitude of the coefficients are economically relevant. These findings are intuitive with regards to the model of incentives to exercise market power in the electricity market. I analyzed the dynamics of the impact of the switch to private management on bid pricing and found that the pattern of the impacts presents a decreasing effect on days of low forward contracting and an increase on days of high forward contracting. These effects are sudden following the change of management, with high variability and no clear tendency to disappear.

Given the magnitude of the impact, the link between the marginal costs of electricity generation and time invariant factors, and the empirical evidence that contradicts the hypothesis of the better cost performance of public enterprises compared to that of private firms, these findings are suggestive of a relevant change in strategic behavior when the units are switched from public administration to private management. These findings suggest that private firms are sensitive to the incentives to exercise market power, while public enterprises are less sensitive.

This empirical finding is coherent with the mixed oligopoly theory, which in line with the assumption of welfare maximizing behavior deduces that public firms apply the marginal cost pricing rule. This is not surprising in the case of electricity generation in Colombia given that the Ministry of Energy sits on the management boards of the majority of public generation firms. The price of electricity is the subject of intense political debate and one that can have a vital impact on the welfare of consumers and the competitiveness of energy intensive industries.

However, there are alternative explanations that lie outside the scope of the present paper. Hortaçsu and Puller (2008) observed that small sellers formulate less refined bid strategies than big firms and Hortaçsu et al. (2019) found that firm size and manager education improves the sophistication of firms' strategies. Extrapolating this finding to privately and publicly managed firms, the trend towards the strategic profit maximization bids of firms that are privatized can be interpreted as a possible effect of the better bidding skills of privately managed firms. Few empirical studies to date have sought to disentangle the effects of private management in an environment of oligopolistic competition. This is understandable given that the change in management of generation units is unusual and because the number of individual units in a sample is intrinsically limited by the nature of oligopolistic market structures. Although more empirical studies of the impact of privatization on competition are necessary, the evidence presented in this paper offers clear insights regarding the changes in competitive behavior following the shift to private management.

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Appendix A Parallel trends tables

Table A5: Quadratic and Linear Trends Equality Test

	Bids		Bids Logarithms	
	Linear	Quadratic	Linear	Quadratic
Linear trend control	-0.0115	-0.142	0.0000118	-0.000465*
	(0.018)	(0.092)	(0.000)	(0.000)
Quadratic trend control		0.0000149		5.44e-08*
		(0.000)		(0.000)
Linear trend TBT	-0.0423	-0.241**	0.0000148	-0.000770***
	(0.076)	(0.078)	(0.000)	(0.000)
Quadratic trend TBT		0.0000247		9.74e-08**
		(0.000)		(0.000)
Observations	93684	93684	93684	93684
Groups	29	29	29	29
F-Statistic Ho: $\beta_1^T = \beta_1^{NT}$	0.16	0.68	0.00	1.02
P-Value	(0.70)	(0.42)	(0.98)	(0.32)
F-Statistic Ho : $\beta_2^T = \beta_2^{NT}$		0.32		1.18
P-Value		(0.58)		(0.29)

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).

Standard errors in parentheses clustered by generation unit.

Appendix B Robustness Checks Tables and Figures

Table B6: Placebo tests

	25% Units with placebo				50% Units with placebo				50% Units with placebo			
	(1) Bid	(2) Bid	(3) Ln (Bid)	(4) Ln (Bid)	(5) Bid	(6) Bid	(7) Ln (Bid)	(8) Ln (Bid)	(9) Bid	(10) Bid	(11) Ln (Bid)	(12) Ln (Bid)
Ch. to Pri.	-129.87**		-0.33**		-42.52		-0.12		-61.97		-0.12	
	(52.59)		(0.12)		(59.40)		(0.15)		(66.35)		(0.20)	
Ch.P./C.Low		-146.37**		-0.46**		-54.07		-0.12		0.55		0.09
		(59.41)		(0.21)		(61.13)		(0.18)		(74.44)		(0.24)
Ch.P./C.High		-45.45		-0.09		-27.66		-0.07		-66.45		-0.19
		(49.74)		(0.19)		(60.81)		(0.17)		(59.56)		(0.20)
C. Low		132.87**		0.53***		120.40**		0.48**		105.64**		0.42**
		(50.55)		(0.17)		(51.11)		(0.16)		(42.48)		(0.15)
Marginal C.	-1.98***	-1.99***	-0.01***	-0.01***	-2.18***	-2.32***	-0.01***	-0.01***	-2.28***	-2.44***	-0.01***	-0.01***
	(0.61)	(0.54)	(0.00)	(0.00)	(0.61)	(0.48)	(0.00)	(0.00)	(0.64)	(0.55)	(0.00)	(0.00)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
N	63481	62301	63481	62301	63481	62301	63481	62301	63481	62301	63481	62301
R-sq	0.47	0.44	0.49	0.48	0.47	0.43	0.49	0.47	0.47	0.43	0.49	0.47

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

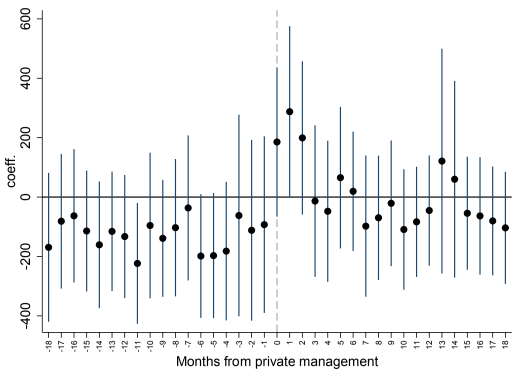
Table B7: Results using bootstrapping for standard errors

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	71.994				0.181			
	(69.694)				(0.118)			
Ch. to P.		358.752***				0.642***		
Small to big		(78.784)				(0.247)		
Ch. to P.		-4.763				0.029		
New comp.		(61.960)				(0.143)		
Ch. to P. Contracts Low			176.332*				0.381**	
			(90.780)				(0.149)	
Ch. to P. Contracts High			-189.320*				-0.453***	
			(111.140)				(0.129)	
Ch. to P. Contracts Low				419.523***				0.753**
Small to big				(109.662)				(0.318)
Ch. to P. Cont. High				-154.960				-0.329**
Small to big				(101.109)				(0.168)
Ch. to P. Contracts Low				91.204				0.285
New comp.				(103.888)				(0.237)
Ch. to P. Contracts High				-188.693				-0.532*
New comp.				(174.344)				(0.275)
Contracts Low			59.576	58.109			0.296	0.293
			(78.202)	(71.435)			(0.263)	(0.230)
Marginal Costs	-2.405**	-2.324**	-2.912***	-2.829**	-0.007***	-0.007***	-0.008***	-0.008***
	(0.963)	(0.915)	(0.906)	(1.203)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Week of the sample FE	Y	Y	Y	Y	Y	Y	Y	Y
N	90875	90875	89608	89608	90875	90875	89608	89608
R-sq	0.116	0.126	0.133	0.142	0.189	0.196	0.209	0.215
Bootstrap replications	50	50	50	50	50	50	50	50

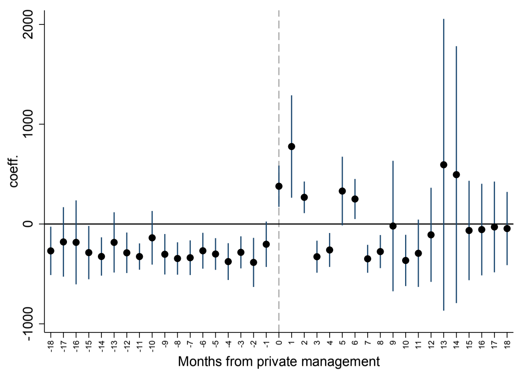
Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Figure B5: Dynamic effects - Bid as dependent variable

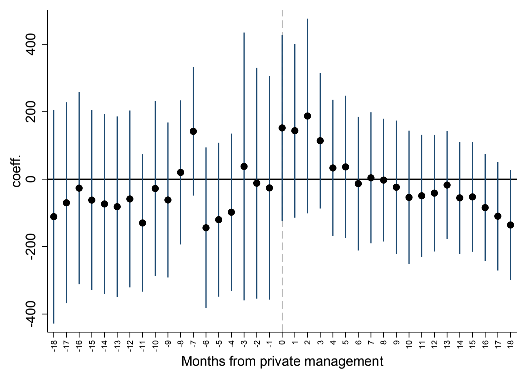
(a) All



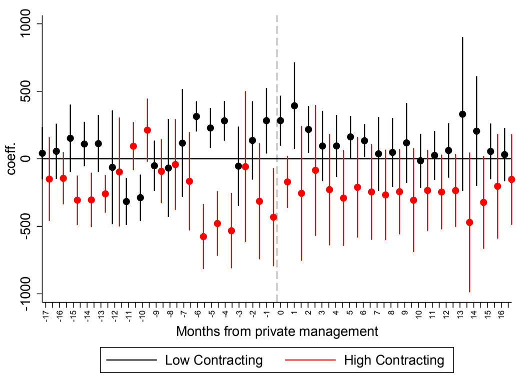
(b) Big Incumbents



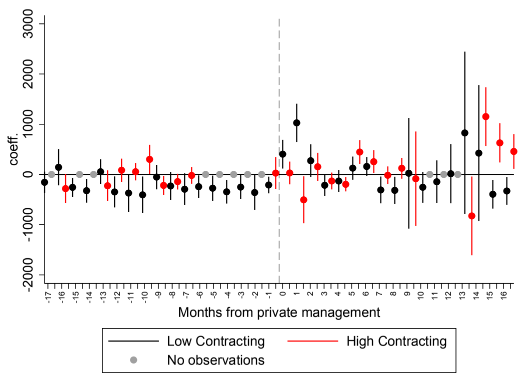
(c) New competitors



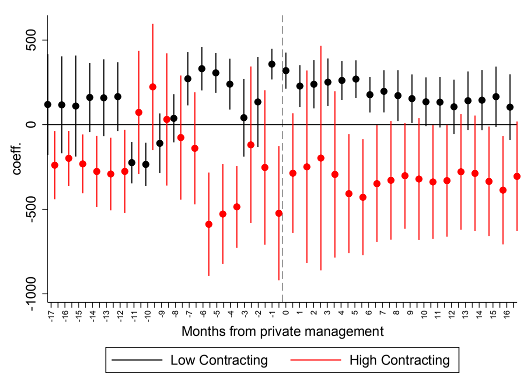
(d) All - Contracting



(e) Big Incumbents - Contracting



(f) New competitors - Contracting



Source: Data from XM - Calculations and elaboration: Author.

Appendix C Details of the Marginal cost calculus for thermal units

I computed the marginal costs of thermal plants taking account of the heat rate, fuel costs and fuel transportation costs according to the following formula:

$$\underbrace{Exchange\ R._t}_{\frac{COP\$}{US\$}} \times \Big[\underbrace{Heat\ R._i}_{\frac{MBTU}{KWh}} \times \underbrace{(Transp.\ fuel\ cost_i + Fuel\ cost_t)}_{\frac{US\$}{MBTU}}\Big] = \underbrace{Marginal\ Cost_{it}}_{\frac{COP\$}{kWh}}$$

Where *COP* are Colombian pesos, *MBTU* are one thousand of the British thermal unit, *US* are United States dollars and *KWh* is one kilowatt per hour. The heat rate is a measure of the thermal efficiency of the generation unit. It represents the quantity of fuel measured in *MBTU* necessary to generate one kilowatt per hour.The parameters of the heat rate of thermal electricity generation units were extracted from reports of the Mines and Energy Planning Unit (UPME).

In the case of gas fired units, I use as fuel cost the price of the gas from the basin Guajira which is the most important gas supply source for Colombian thermal generation. Since September 1995 Until August 2013, the Colombian Government regulated the prices of gas coming from this gas source. The regulation consist in imposing a maximum sale price of gas. This maximum price at period t, p_t, is given by the formula $p_{t-1}[index_{t-1}/index_{t-2}]$ where $index_{t-1}$ is the average of the last semester of the New York Harbor Residual Fuel Oil 1.0 % Sulfur LP Spot Price according to the series that was published by the Energy Information Administration of the United States. A period t is defined as semester and it changes 1st February and 1st August of each year [7].This price is given in *US dollars/MBTU.*

From 2006 to 2013 I applied the Guajira regulated price calculation made and published by the most important gas producer in the market (ECOPETROL) according to the regulation descrpted above and converting the resulting price *(US dollars/MBTU)*

[7] The formula was established in Act 119/2005 of CREG

to *Colombian pesos/KWh*.The exchange rate data were obtained from the Colombian Central Bank (Banco de la República). The heat rate parameters of the thermal units were extracted from the Mines and Energy Planning Unit (UPME). The fuel cost is assumed to be the price of supply from the Guajira Well. This price was regulated by the Regulatory Commission of Energy and Gas (CREG) until 2013. Since that date, a periodical market mechanism has been used to clear the price of the gas of the Guajira Well. Between 2006 and 2013, I extracted the Guajira Well price from the Regulatory acts of CREG. For the following years, the weighted average price was calculated according to the type of contract, based on information from the Gas Market Manager in Colombia (BEC). Consequently, for gas units, we take as transportation costs the sum of the fees for the use of each segment of the network necessary to transport the gas from the Guajira Well to the generation units. The fees for the use of the segment of the gas transmission network are regulated by the CREG and are published in regulatory acts (CREG 70 and 125 of 2003).

For coal fired plants, the weighted average FOB export price is calculated using information about the amount and value of thermal coal exports available in the databases of the National Statistics Institute (DANE). The price in dollars per ton was transformed to dollars per MBTU units, multiplying for a calorific value of the Colombian thermal coal of 1,370 BTU per pound (Source: Regulation 2009: 180507 Colombian Ministry of Energy and Mines). For coal transportation costs, an importation parity approach is used, which implies that they are calculated as the reference transportation fees from the importation port closest to the source of production. These fees were extracted from the System of Information of Efficient Costs for Road Freight Transportation, Transportation Ministry of Colombia.

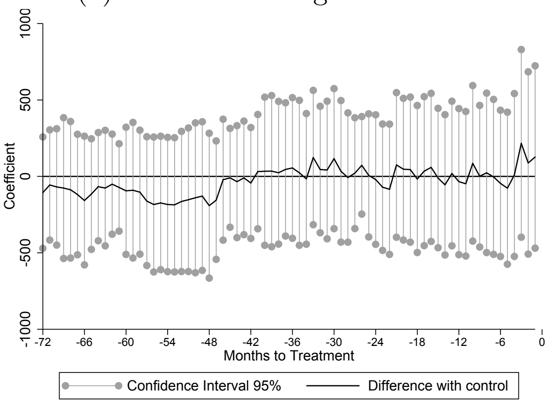
Private management and strategic bidding behavior in electricity markets: Evidence from Colombia

Online Appendix

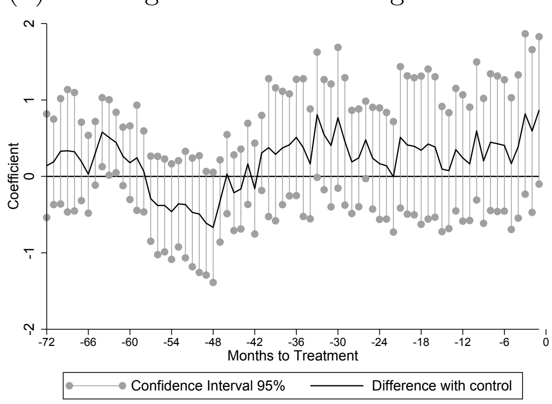
Appendix D Robustness Checks Tables and Figures

Figure D6: Parallel trends alternative control groups

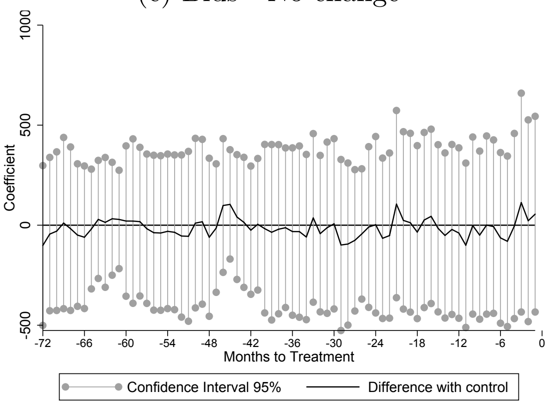
(a) Bids - Central government



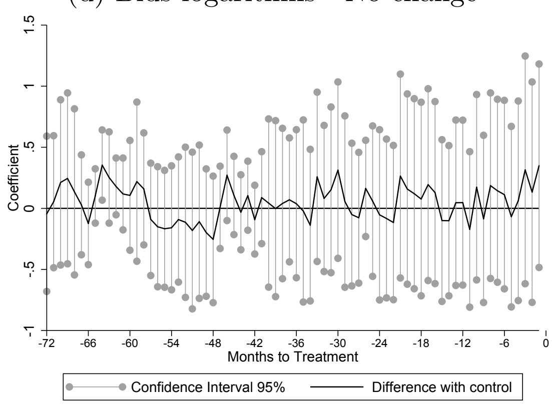
(b) Bids logarithms - Central government



(c) Bids - No change



(d) Bids logarithms - No change



Source: Data from XM - Calculations and elaboration: Author.

Table D8: Random Effects estimator

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Ch. to Pr.	86.17				0.18			
	(67.23)				(0.12)			
Ch.to Pr.		354.85***				0.64***		
Small to big		(57.92)				(0.12)		
Ch. to Pr.		-4.89				0.03		
New comp.		(51.93)				(0.11)		
Ch.P./C.Low			128.66				0.38**	
			(104.17)				(0.15)	
Ch.P./C.High			-54.59				-0.45***	
			(88.35)				(0.14)	
Ch.P./C.Low				132.76				0.74***
Small to big				(132.99)				(0.13)
Ch.P./C.High				-18.04				-0.33**
Small to big				(90.33)				(0.13)
Ch.P./C.Low				118.46				0.28
New comp.				(115.27)				(0.21)
Ch.P./C.High				-80.23				-0.53**
New comp.				(143.38)				(0.25)
Contracts			-133.16	-133.45			0.27	0.269
Low			(158.97)	(159.83)			(0.20)	(0.19)
Marginal	-2.39***	-2.30***	-1.33	-1.32	-0.01***	-0.01***	-0.01***	-0.01***
Cost	(0.83)	(0.86)	(1.32)	(1.39)	(0.00)	(0.00)	(0.00)	(0.00)
Fuel gas	376.11**	377.64**	346.59**	349.61**	1.40***	1.407***	1.412***	1.427***
	(156.13)	(163.97)	(152.77)	(157.57)	(0.40)	(0.41)	(0.41)	(0.43)
AGC	-171.32**	-150.10**	-148.85***	-146.26**	-0.50**	-0.47**	-0.53**	-0.50**
	(71.69)	(70.19)	(54.96)	(57.13)	(0.23)	(0.22)	(0.23)	(0.22)
Installed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Capacity	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Forward C.	-0.03	-0.06**	-0.03	-0.03	-0.00**	-0.00**	-0.00	-0.00
2005/2006	(0.02)	(0.03)	(0.03)	(0.03)	(0.00)	(0.00)	(0.00)	(0.00)
Energy	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00
critical	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Every Week FE	Y	Y	Y	Y	Y	Y	Y	Y
N	90875	90875	89608	89608	90875	90875	89608	89608

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table D9: Prais-Winsten estimator

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Ch. to Pr.	78.29***				0.12***			
	(22.92)				(0.03)			
Ch. to P.		107.01***				0.12***		
Small to big		(37.80)				(0.04)		
Ch. to P.		42.27**				0.11***		
New comp.		(17.38)				(0.04)		
Ch.P./C.Low			115.32***				0.19***	
			(22.15)				(0.03)	
Ch.P./C.High			-73.44***				-0.11***	
			(15.89)				(0.02)	
Ch.P./C.Low				134.80***				0.17***
Small to big				(34.51)				(0.04)
Ch.P./C.High				-74.64***				-0.10***
Small to big				(16.60)				(0.02)
Ch.P./C.Low				67.12***				0.27***
New comp.				(16.17)				(0.03)
Ch.P./C.High				-29.37				-0.25***
New comp.				(24.73)				(0.05)
Contracts			5.95	5.92			0.05***	0.05***
Low			(5.41)	(5.40)			(0.02)	(0.02)
Marginal	0.19*	0.24**	-0.42***	-0.36***	0.00***	0.00***	0.00	-0.00
Costs	(0.113)	(0.11)	(0.11)	(0.12)	(0.00)	(0.00)	(0.00)	(0.00)
Fuel gas	184.94***	185.59***	247.65***	246.17***	0.80***	0.80***	1.00***	1.01***
	(15.46)	(15.35)	(15.26)	(15.19)	(0.03)	(0.03)	(0.03)	(0.03)
AGC	-162.18***	-157.61***	-154.35***	-149.62***	-0.41***	-0.41***	-0.39***	-0.39***
	(11.31)	(10.66)	(10.43)	(10.01)	(0.03)	(0.03)	(0.03)	(0.03)
Installed	0.00	0.00	0.00***	0.00***	0.00***	0.00***	0.00***	0.00***
Capacity	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Forward C.	-0.04***	-0.05***	-0.03***	-0.05***	-0.00***	-0.00***	-0.00***	-0.00***
2005/2006	(0.01)	(0.01)	(0.01)	(0.01)	(0.00)	(0.00)	(0.00)	(0.00)
Energy	-0.00***	-0.00***	-0.00***	-0.00***	-0.00***	-0.00***	-0.00***	-0.00***
critical	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Every week FE	Y	Y	Y	Y	Y	Y	Y	Y
N	90875	90875	89608	89608	90875	90875	89608	89608
R-sq	0.03	0.03	0.04	0.04	0.07	0.07	0.11	0.11

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table D10: Estimation without applying the PSM

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	73.208				0.186			
	(69.707)				(0.118)			
Ch. to P.		365.519***				0.684***		
Small to big		(55.270)				(0.100)		
Ch. to P.		-19.830				0.027		
New comp.		(54.827)				(0.105)		
Ch. to P. Contracts Low			148.654*				0.340**	
			(82.025)				(0.147)	
Ch. to P. Contracts High			-173.705*				-0.405**	
			(98.398)				(0.147)	
Ch. to P. Contracts Low				408.231***				0.735***
Small to big				(86.260)				(0.126)
Ch. to P. Cont. High				-143.152				-0.297*
Small to big				(85.029)				(0.148)
Ch. to P. Cont. Low				58.670				0.232
New comp.				(88.800)				(0.203)
Ch. to P. Cont. High				-163.268				-0.456*
New comp.				(170.931)				(0.255)
Contracts Low			96.168**	89.026**			0.413***	0.401***
			(39.726)	(38.388)			(0.118)	(0.116)
Marginal Costs	-2.046**	-1.968**	-2.415***	-2.328**	-0.006***	-0.006***	-0.007***	-0.007***
	(0.768)	(0.805)	(0.856)	(0.929)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	108406	108406	107139	107139	108406	108406	107139	107139
R-sq	0.359	0.367	0.355	0.362	0.516	0.520	0.516	0.519

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table D11: Estimation PSM with pooled data panel

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	86.730				0.183			
	(68.794)				(0.119)			
Ch. to P. Small to big		358.829***				0.642***		
		(59.207)				(0.117)		
Ch. to P. New comp.		-4.622				0.029		
		(53.015)				(0.111)		
Ch. to P. Contracts Low			177.047*				0.383**	
			(86.567)				(0.154)	
Ch. to P. Contracts High			-190.515*				-0.457***	
			(100.656)				(0.148)	
Ch. to P. Contracts Low Small to big				419.910***				0.754***
				(83.434)				(0.128)
Ch. to P. Cont. High Small to big				-155.918*				-0.332**
				(80.508)				(0.137)
Ch. to P. Contracts Low New comp.				91.690				0.287
				(98.139)				(0.217)
Ch. to P. Contracts High New comp.				-189.404				-0.535**
				(174.820)				(0.255)
Contracts Low			61.590	60.105			0.302	0.299
			(67.995)	(60.679)			(0.196)	(0.185)
Marginal Costs	-2.414***	-2.332**	-2.926***	-2.841**	-0.007***	-0.007***	-0.008***	-0.008***
	(0.846)	(0.882)	(0.933)	(1.013)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	90874	90874	89607	89607	90874	90874	89607	89607
R-sq	0.360	0.368	0.357	0.364	0.556	0.560	0.556	0.559

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table D12: Estimation with PSM - Near Neighbor

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	71.994				0.181			
	(69.694)				(0.118)			
Ch. to P.		365.383***				0.684***		
Small to big		(55.480)				(0.101)		
Ch. to P.		-21.316				0.022		
New comp.		(54.600)				(0.104)		
Ch. to P. Contracts Low			147.349*				0.336**	
			(82.010)				(0.146)	
Ch. to P. Contracts High			-172.541*				-0.401**	
			(98.245)				(0.147)	
Ch. to P. Contracts Low				408.943***				0.738***
Small to big				(86.449)				(0.126)
Ch. to P. Cont. High				-142.992				-0.297*
Small to big				(84.760)				(0.148)
Ch. to P. Contracts Low				56.172				0.223
New comp.				(88.013)				(0.200)
Ch. to P. Contracts High				-160.750				-0.447*
New comp.				(170.694)				(0.254)
Contracts Low			89.227**	82.424**			0.388***	0.376***
			(39.003)	(37.680)			(0.117)	(0.115)
Marginal Costs	-2.023**	-1.946**	-2.390***	-2.302**	-0.006***	-0.006***	-0.007***	-0.007***
	(0.765)	(0.802)	(0.854)	(0.926)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	109137	109137	107857	107857	109137	109137	107857	107857
R-sq	0.359	0.367	0.354	0.361	0.515	0.519	0.514	0.518

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table D13: Alternative Control 1 - Central government

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	222.243**				0.410***			
	(90.650)				(0.123)			
Ch. to P. Small to big		456.831***				0.827***		
		(74.215)				(0.145)		
Ch. to P. New comp.		75.179				0.148		
		(116.992)				(0.183)		
Ch. to P. Contracts Low			318.121***				0.613***	
			(69.675)				(0.098)	
Ch. to P. Contracts High			-214.278*				-0.510***	
			(109.074)				(0.168)	
Ch. to P. Contracts Low Small to big				497.912***				0.894***
				(93.132)				(0.158)
Ch. to P. Cont. High Small to big				-146.487*				-0.312*
				(81.511)				(0.153)
Ch. to P. Contracts Low New comp.				210.892*				0.513*
				(112.433)				(0.240)
Ch. to P. Contracts High New comp.				-238.542				-0.673**
				(187.987)				(0.300)
Contracts Low			17.765	22.307			0.220	0.225
			(88.782)	(70.214)			(0.207)	(0.178)
Marginal Costs	-1.655	-1.680	-2.232*	-2.254	-0.005***	-0.006***	-0.007***	-0.007***
	(0.978)	(1.154)	(1.158)	(1.325)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	54422	54422	54355	54355	54422	54422	54355	54355
R-sq	0.295	0.305	0.303	0.311	0.457	0.464	0.469	0.474

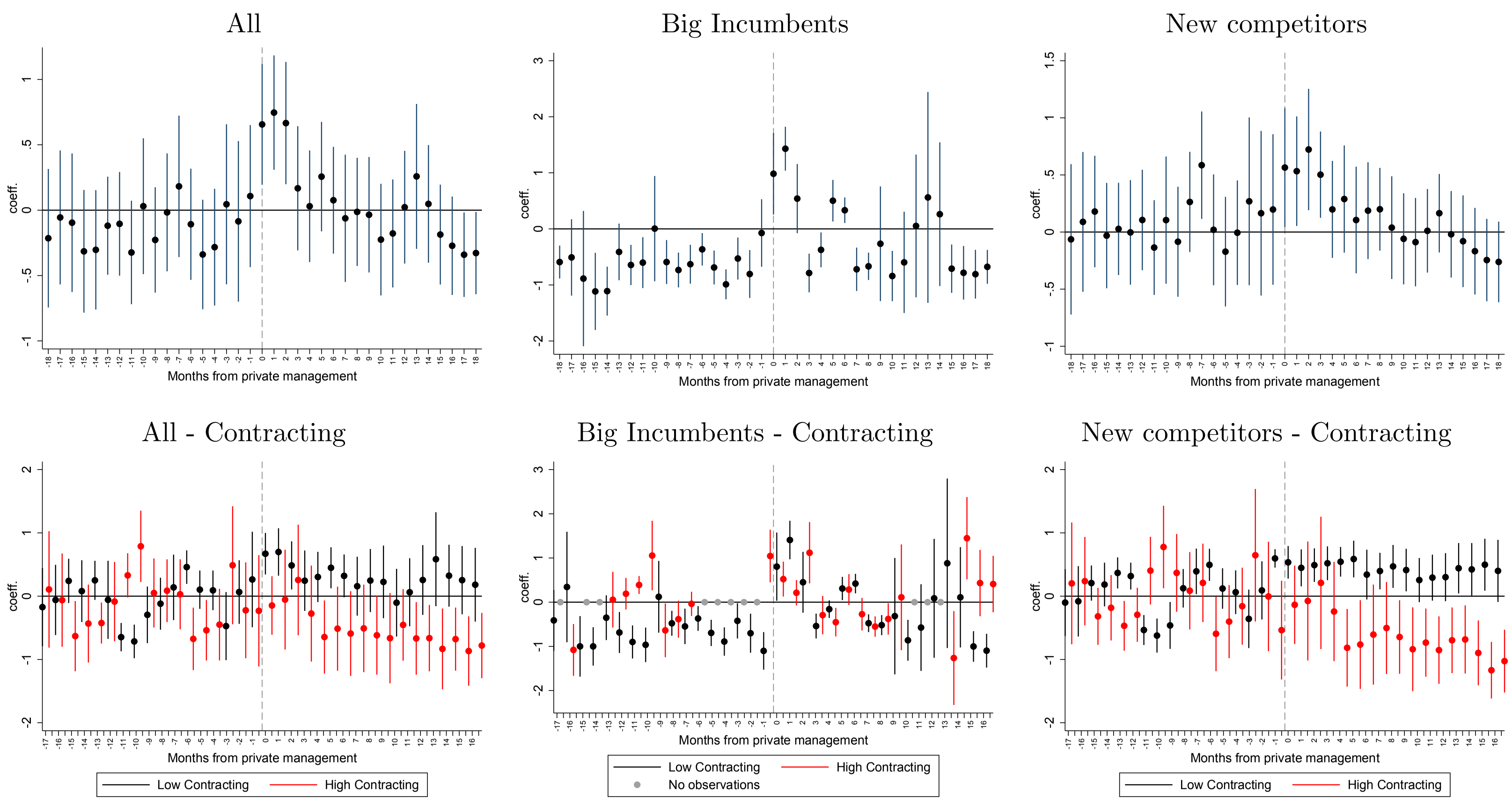
Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table D14: Alternative Control 2 - No change in property

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	141.435*				0.212*			
	(70.925)				(0.119)			
Ch. to P. Small to big		387.983***				0.666***		
		(35.540)				(0.081)		
Ch. to P. New comp.		69.098				0.079		
		(71.631)				(0.119)		
Ch. to P. Contracts Low			211.000***				0.356**	
			(71.373)				(0.143)	
Ch. to P. Contracts High			-153.576*				-0.336**	
			(85.110)				(0.134)	
Ch. to P. Contracts Low Small to big				427.343***				0.730***
				(42.280)				(0.092)
Ch. to P. Cont. High. Small to big				-123.529*				-0.254**
				(67.859)				(0.114)
Ch. to P. Contracts Low New comp.				141.986				0.251
				(86.355)				(0.201)
Ch. to P. Contracts High New comp.				-147.849				-0.359
				(151.421)				(0.248)
Contracts Low			107.341**	104.491**			0.412***	0.407***
			(47.592)	(46.311)			(0.106)	(0.104)
Marginal Costs	-1.885**	-1.865**	-2.043***	-2.018**	-0.005***	-0.005***	-0.005***	-0.005***
	(0.735)	(0.748)	(0.755)	(0.771)	(0.001)	(0.001)	(0.001)	(0.001)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	167696	167696	165914	165914	167696	167696	165914	165914
R-sq	0.445	0.447	0.448	0.450	0.598	0.600	0.600	0.602

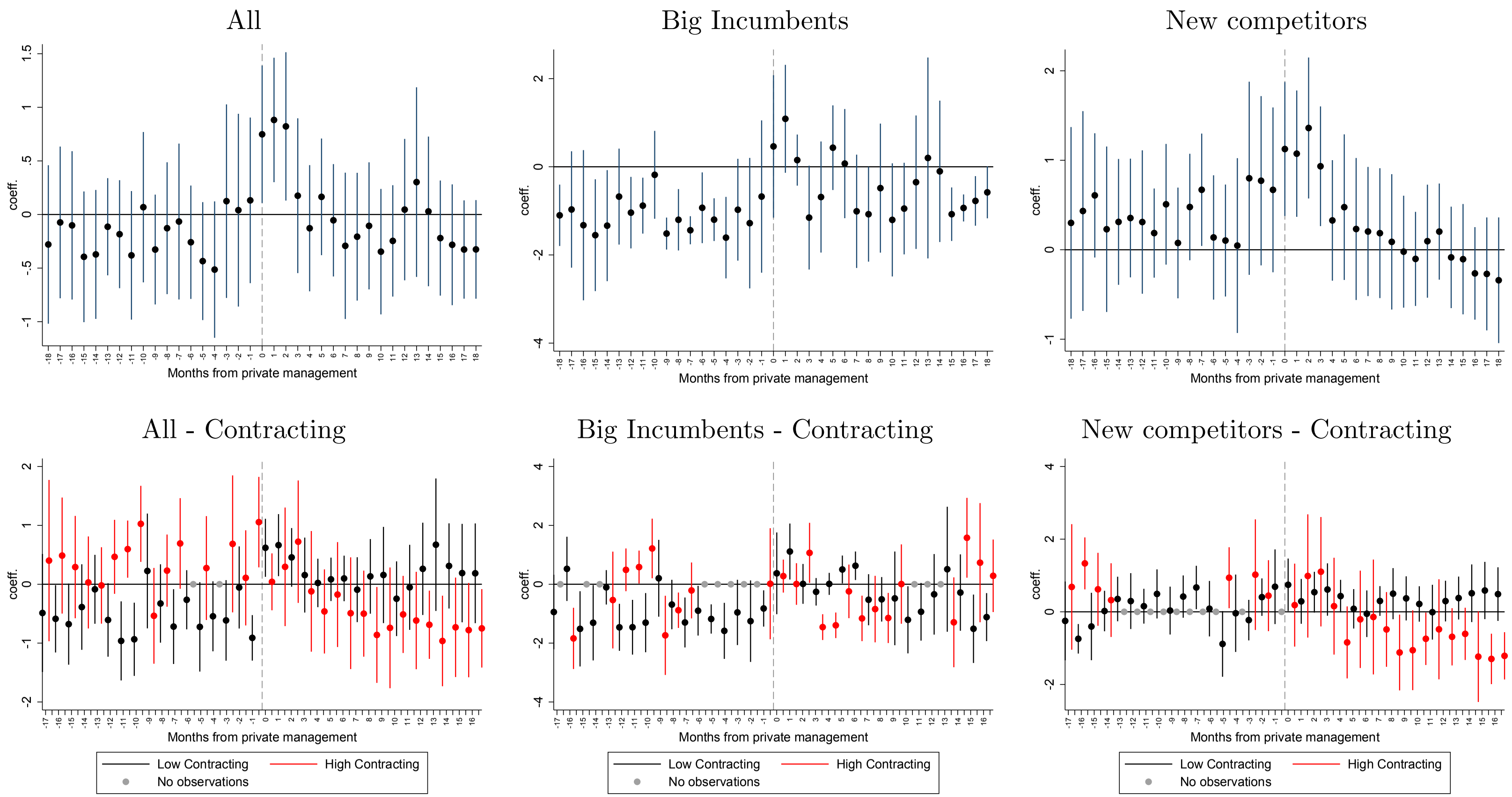
Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Figure D7: Dynamic effects - PSM No applied



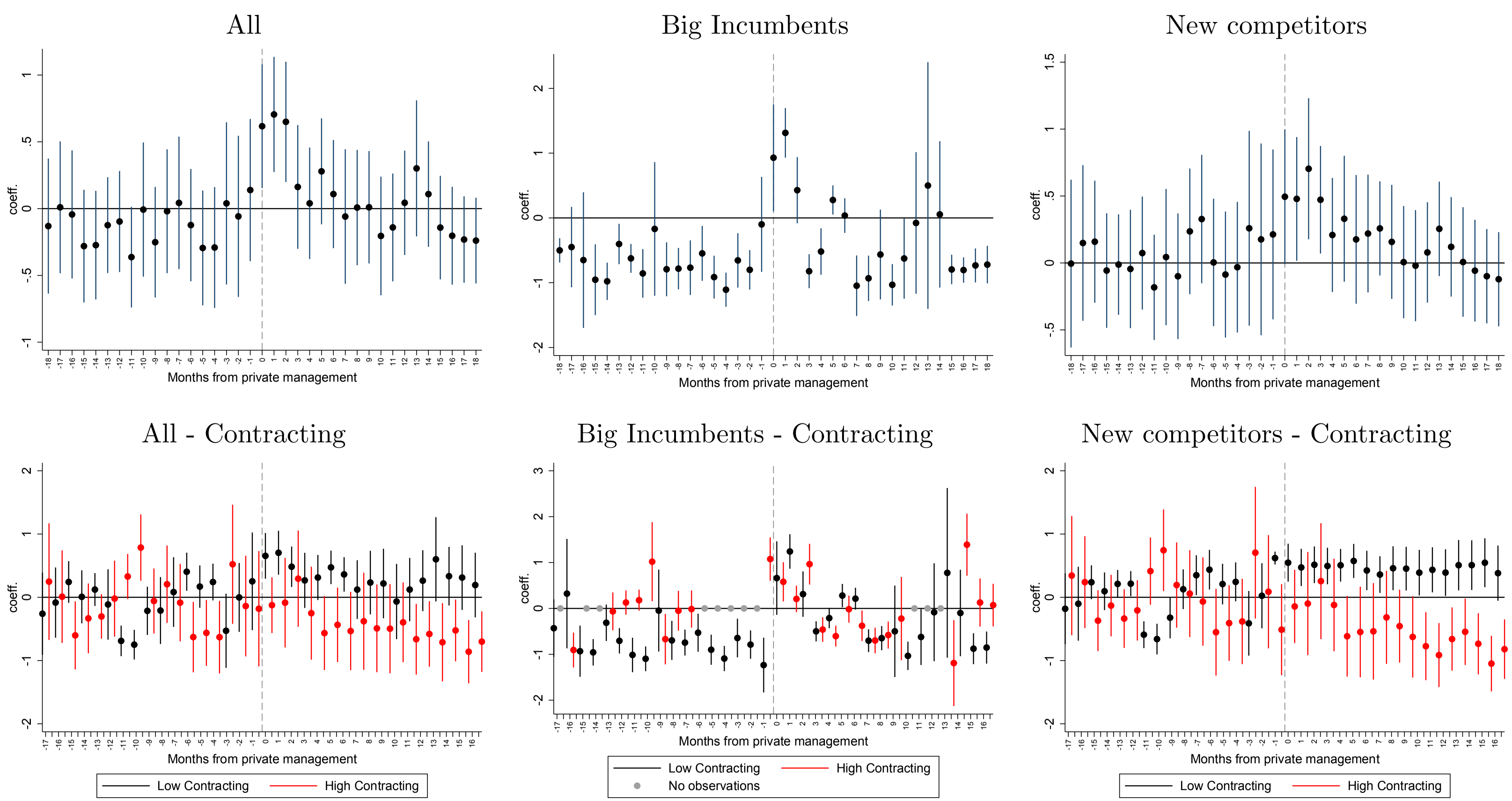
Source: Data from XM - Calculations and elaboration: Author.

Figure D8: Dynamic effects - Alternative Control 1 - Central Government



Source: Data from XM - Calculations and elaboration: Author.

Figure D9: Dynamic effects - Alternative Control 2 - No change in property



Source: Data from XM - Calculations and elaboration: Author.

UBIREA
Institut de Recerca en Economia Aplicada Regional i Pública
Research Institute of Applied Economics
Universitat de Barcelona
Av. Diagonal, 690 • 08034 Barcelona

WEBSITE: www.ub.edu/irea/ • **CONTACT:** irea@ub.edu