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MIXED OLIGOPOLY AND MARKET POWER MITIGATION: EVIDENCE FROM THE COLOMBIAN WHOLESALE ELECTRICITY MARKET*

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Using information on price bids in wholesale electricity pools and empirical techniques described in the literature on electricity markets, this study identifies the market power mitigation effect of public firms in the Colombian market. The results suggest that while private firms exercise less market power than is predicted by a profit-maximization model, there are marked differences between private and public firms in their exercise of unilateral market power. These findings support the hypothesis of the market power mitigation effect of public firms.

I. INTRODUCTION

A KEY CONCERN IN ANY DISCUSSION about privatization is the benefits that might accrue to society from public firms. Their advocates claim that they can be used as economic policy instruments. In mixed oligopoly markets (i.e., markets in which private and public firms compete), some economists and policy-makers argue that public enterprises are able to mitigate market power through more competitive pricing, or what I shall refer to here as *regulatory intervention*.[1]

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[1] In this article, public firms are defined as those in which national or local governments have a majority shareholding and control their management.

The mixed oligopoly literature has analyzed the strategic interaction between public and private firms in nonperfect competitive markets in order to establish, in theory, the welfare effects of privatization. Several studies employing such models have concluded that full privatization is inadvisable because it can have counter-competitive effects on the market and lead to subsequent increases in terms of deadweight loss (De Fraja and Delbono [1989]; Matsumura [1998]). These conclusions arise from the assumption that the objective function of public and mixed firms differs from that of private firms. In most cases, mixed oligopoly models assume that private firms aim to maximize profits while the objective function of public (or mixed) firms is to promote social welfare.[2]

Public firms may have objectives other than profit maximization and may even have a multiplicity of objectives (Kay and Thompson [1986]).[3] In the field, the objective function of this type of firm depends on several issues related to the government's ultimate goal and the incentives provided to their managers (Fershtman and Judd [1987]) and it is thus not possible to know *a priori* what the objective function of a public firm is.[4]

Given this ambiguity, and its obvious importance in determining the effect of private and state ownership on competition, the behavioral difference between public and private firms is a matter that merits empirical analysis.

The possibility of conducting such analyses in regulated industries has been greatly enhanced over the last three decades thanks to the improved availability of data and a diversity of market reforms. As a result of these two developments, it is now possible to empirically address the key question underpinning the mixed oligopoly model, namely: Do public and private firms behave the same when faced with equivalent incentives? An empirical analysis of differences in the way in which private and public firms exercise their market power should provide interesting insights.

[2] Traditional approaches to public firms have mainly viewed them as instruments of government policy and planning (Bös [2015]). Following this approach, the mixed oligopoly model assumes that the objective functions of public firms is to promote social welfare.

[3] According to Kay and Thompson [1986], *"Public sector managers could be expected to respond to the particular personal incentives with which they were faced. Such incentives might lead to a desire to maximize the scale of operations of the business, subject to any external financial constraint, or to seek a quiet life untroubled by changes in working practices or difficulties in labor relations, rather than to pursue a nebulous public good."*

[4] For instance, if there is political pressure from voters to decrease prices, public firms may try to mitigate market power, even applying predatory prices. Conversely, if a government is seeking to redress a fiscal deficit, its state-owned firms may try to maximize profits using market power markups as a covert form of taxation. Likewise, governments committed to a privatization program will boost a public firm's profit performance in order to increase the sale price. In addition, in the particular case of mixed firms with a government majority share, the board members have a fiduciary duty to the minority shareholders and therefore cannot ignore profit-maximization incentives. I owe this observations to an anonymous referee.

In this article, I address the strategic pricing of public and private firms from an empirical perspective in order to determine how they exercise their market power. Specifically, I extend the analysis of the incentive to exercise market power (IEMP), as proposed by McRae and Wolak [2009], to the case of two different types of firm showing disparate behavior in response to the same strategic incentives. This technique draws on information about individual bids (willingness to sell) available in the electricity markets organized as a multiproduct auction. I apply this extended methodology to the Colombian wholesale electricity market.

The case of the Colombian electricity market is appealing because market power and marked rises in wholesale electricity prices are a major concern for the Colombian authorities, consumers, and stakeholders alike. Leading industrial consumers tend to be well organized and lobby the government for energy cost reductions. At the same time, the Ministry of Energy and Mines sits on the board of several of the leading public electricity generation companies. As a result, there are potential incentives for public and mixed firms under government control to exert market power mitigation.[5]

Besides its relationship to mixed oligopoly models, this article also lies at the intersection of two other different strands in the literature: (i) Empirical studies comparing the efficiency of public and private firms, and (ii) studies estimating market power in electricity markets.

To date, empirical studies of the efficiency of public and private firms have focused primarily on differences in the performance (or productive efficiency) of public and private monopolies (La Porta and Lopez-de Silanes [1999]; Frydman *et al.* [1999]; Netter and Megginson [2001]; Bel *et al.* [2010]). One relevant exception is the study by Seim and Waldfogel [2013] which was specifically aimed at determining the goals implicit in the decisions of public enterprises. Seim and Waldfogel [2013] estimated a spatial model of demand based on information about Pennsylvania's state liquor retailing monopoly and found that the store network is very similar in size and configuration to the welfare-maximizing configuration. My research is similarly focused on disentangling the differences between the goals of public and private firms, but it differs from their study in that I analyze a situation in which private and public companies compete in the same electricity market, whereas Seim and Waldfogel [2013] investigated the goals of a public monopoly. To the best of my knowledge, the only paper to focus on the differences between

[5] It is important to clarify that, in relation to the objective function of public companies in the Colombian wholesale electricity market, in this document I try to establish how close their price responses are to the theoretical behavioral benchmarks proposed by the mixed oligopoly models. Rather than evaluating whether public companies deploy a welfare-maximizing strategy, I evaluate whether or not public companies ignore their incentives to exercise market power. Although ignoring such incentives is consistent with welfare maximization, there are other plausible theoretical benchmarks that could explain this behavior.

public and private firms competing in the same market is that by Barros and Modesto [1999], on the Portuguese banking sector.

The economic literature examining the problem of market power in electricity generation markets is extensive. However, three main groups of empirical models can be identified according to the methodological approach employed. The first of these is based on the direct or indirect estimate of Lerner indexes or markups (Wolfram [1999]; Wolak [2003]). The second group of studies seeks to determine the agents' market power, simulating the equilibrium conditions that emerge from economic models of oligopoly (Green and Newbery [1992]; Wolak [2000]; Sweeting [2007]; Hortacsu and Puller [2008]; Bushnell *et al.* [2008]). The third approach involves the use of structural econometric models to estimate functional or behavioral parameters (Wolfram [1998]; Wolak [2007]; Reguant [2014]).

Although several techniques have been proposed for estimating market power in electricity markets, few studies have attempted to distinguish differences in competitive behavior between heterogeneous types of firm. In this respect, my approach is related to the studies by Hortacsu and Puller [2008] and Hortaçsu *et al.* [2019], who examined the bidding behavior of firms in the Texas electricity spot market and found differences in the competitive strategies of large and small firms. Concerning the methodological approach, as mentioned above, my empirical implementation is similar to the estimation model proposed by McRae and Wolak [2009].

The main contribution of this article is the development of an empirical model to analyze differences between private and public firms in terms of their incentives to exercise market power in a multiunit auction framework. This methodology provides a new analytical tool that serves to clarify the effect of mixed (private-state) ownership on competition. Overall, this methodology is applicable to any multiunit, uniform price auction in which the competitors' bids and marginal costs are observable.

The empirical analysis performed here suggests that there are marked differences in the way private and public firms exercise their unilateral market power, supporting the hypothesis of the latter's market power mitigation. The results indicate that although public firms do not completely ignore their incentives to exercise market power and the private firms exercise less market power than expected of profit-maximization behavior, the former are closer to the perfect regulatory intervention benchmark. These findings are consistent with the behavioral structure of mixed oligopoly models.

Subsequently, in order to evaluate the benefits achieved due to a more moderate exercise of market power by public firms, I employ the parameters estimated in the econometric model for performing simulations of the Colombian wholesale electricity market from 2005 to 2015. I compute the *merit order effect* of the thermal units in three different counterfactual scenarios of privatization. These counterfactuals suggest that the efficiency gains from market power mitigation by public firms in the Colombian wholesale electricity market are modest.

The rest of this article is divided into five sections. Section II outlines the characteristics of the Colombian wholesale electricity market and the structural problems it presents that must be taken into account to accurately identify the behavioral parameters under study. Section III explains the theory underpinning the incentives for profit-maximizing firms to exercise unilateral market power and stresses the differences in this regard with the behavior of firms that do not act strategically. This section also describes the empirical approach adopted to identify the behavioral differences between private and public firms. Section IV presents the data and the results of applying the proposed empirical approach to this market and reports several robustness checks on multiple econometric choices. This section also discusses the counterfactual simulations. The Section V summarizes the results and presents some conclusions.

II. THE COLOMBIAN MARKET AND MIXED COMPETITION

This section outlines the principal features of the Colombian electricity generation market that distinguish it as a mixed oligopoly and describes the main elements of this market that must be taken into account when examining problems of market power.

For a market to be considered a mixed oligopoly, it must satisfy three conditions: (i) the market must be liberalized, that is, the price is determined by the competing bids made by the producers; (ii) public, private and mixed firms must compete in equal conditions, that is, there are no discrimination rules; and (iii) the conditions of competition in the market are not perfect, that is, there are high levels of concentration.

As regards the first condition, since the introduction of the Public Utilities Act (Act 142 of 1994) and the Electricity Act (Act 143 of 1994), electricity generation in Colombia has been organized as a pooled wholesale electricity market. Generators can sell their energy by means of long-term bilateral contracts with other agents or directly in the day-ahead power exchange. This exchange operates as a multiunit, uniform first-price auction, in which each generator reports a price bid (or willingness to sell) to the market operator for each generation unit. With this information, and according to demand forecasts, the market operator organizes the generation units from the cheapest to the most expensive (this arrangement is known as merit order) and defines the market clearing price (spot price) for every hour of the day. This feature demonstrates that the Colombian wholesale energy market is neither price-regulated nor a cost-based pool and that it obeys the conditions of competition among producers.

Second, with respect to the coexistence of private and public companies in the Colombian generation market, it should be noted that although the

TABLE I
MARKET SHARES IN THE COLOMBIAN ELECTRICITY MARKET–2014

Firm	Majority shareholding	Electricity generation (gWh)	%	Cumulative %
EMGESA	Private	13,691	21%	21%
EPM	Public	13,626	21%	42%
ISAGEN	Public	10,609	16%	59%
GECELCA	Public	7508	12%	71%
COLINV.	Private	6711	10%	81%
AES	Private	3982	6%	87%
GENSA	Public	2436	4%	91%
Others		5764	9%	100%
Total		64,328	100%	100%
HH				1422

Source: XM–Market Operator.

intention of the Colombian electricity sector reform in the early nineties was to promote private entrepreneurship, the activity has a high proportion of public or mixed firms under government control. It is also important to clarify that classification of generation firms into "private" and "public" categories in the Colombian electricity market is not direct because there are several firms with both private and public participation. In addition, smaller publicly-owned firms had power purchase agreements (PPAs) to buy electricity from privately-owned generation plants. For the particular application reported here, this classification was performed by unit, taking into account the category of shareholder controlling the firm that represents the unit to the market operator.[6]

Table I shows market shares in the Colombian wholesale electricity market for 2014. The second column reveals that four of the seven leading firms were state controlled in that year according to the classification criterion adopted in this study. In consonance with this information, the leading generation firms operating in Colombia during the study period presented a heterogeneous ownership structure in terms of the private or public nature of their major shareholders.

Finally, as regards the third condition, that is, the level of market competition and concentration, electricity generation activity in Colombia shows levels of concentration that correspond to a moderate oligopoly, according to the merger guidelines of the US Department of Justice. Table I presents the participation of the six leading generation companies in the Colombian generation market.

[6] It is important to consider that the entity responsible for the bidding process of a generation unit in the Colombian wholesale electricity market is the firm that represents the unit to the market operator. See the Journal's editorial web site for further details about firm's ownership in Online Appendix F. Table F25 in Online Appendix F presents the ownership features of the most important firms in the Colombian electricity generation market and Table F26 in Online Appendix F lists the generator units used in the analysis and details the corresponding ownership group and classification into public or private.

In addition to the above features, there are several other features of the Colombian wholesale electricity market that must be considered in order to accurately characterize the unilateral market power of electricity generators.

1. Colombia's generation supply is mainly produced by hydroelectric and thermoelectric resources. In the case of the country's hydro technology, it should be borne in mind that Colombia's rain regime is subject to the effects of El Niño and La Niña events. During the former, dry weather conditions have a negative impact on the contribution of hydroelectric resources, while the opposite occurs during La Niña events. In addition, the annual rain regime fluctuates between a dry season (December, January, and February) and a wet one (April, May, and June). Daily information is available on the river flows that feed the main hydro units. As for the country's thermal technology units, these are primarily gas and coal fired. The gas market in Colombia is organized as a bilateral contract scheme, and the price of Colombia's main gas well was regulated during the study period. Likewise, the fees for using the gas transport pipes are regulated according to a mixed scheme which takes into consideration capacities and volumes alike. Information is available about the heat rates of each thermoelectric plant. Table II highlights the importance of large hydro plants and thermoelectric units.
2. Most energy transactions are performed through long-term, fixed-price forward contracts. Since physical dispatch is centrally coordinated, bilateral forward contracts work as financial hedges against spot prices (Garcia and Arbelaez [2002]). Generally, information on transactions made through bilateral forward contracts is not available in markets that are organized as a multiproduct auction. An additional advantage of analyzing the case of the Colombian electricity market is that the information on sales in long-term forward contracts is available after the market closes. Thus, the net forward market position of the firms can be computed. Table III shows the total energy traded in 2013 and 2014 in the electricity generation market, distinguishing between transactions conducted through fixed-price forward contracts and direct transactions in the day-ahead energy exchange.

Table II
Generation by Type of Resource–2013 and 2014

	Generation (gWh)			
Type	December 2013	December 2014	Growth	Share 2014
Hydro	3622	3707	2%	68%
Thermal	1370	1474	8%	26%
Small units	300	305	2%	6%
Cogeneration	32	45	41%	1%
Total	5323	5531	4%	100%

Source: XM–Market Operator.

TABLE III
ENERGY SALES BY TRADE MECHANISM–2013 AND 2014

	Generation (gWh)			
	2013	2014	Growth	Share 2014
Spot market	14,949	15,507	4%	18%
Forward contracts	71,374	69,846	−2%	82%
Total	86,323	85,352	−1%	100%

Source: XM–Market Operator.

3. Finally, the rules of the Colombian electricity exchange market allow only one valid bid price to be made per unit for each 24-hour period. For each unit participating in the central dispatch, the bid consists of one bid price that remains valid for the entire day and 24 quantities (commercial availability), one for each hour of the day. The generators report these day-ahead bids in the market clearing period. Regardless of the fact that the market clears every hour (in order to account for differences in demand and in availability of noncentrally dispatched generation resources), the generator can only bid one price and cannot change any part of its bid during the corresponding 24-hour period. This restriction has considerable implications as regards incentives to exercise market power, as will be explained in detail in Section III(i).

III. THEORETICAL BACKGROUND AND IDENTIFICATION

III(i). *The incentives to exercise market power*

This subsection examines the theoretical background to an analysis of the IEMP of profit-maximizing and nonstrategic firms and the implications of certain features of the Colombian wholesale electricity market regarding the identification approach. The electricity market literature contains various empirical techniques for estimating market power (Green and Newbery [1992]; Wolfram [1998]; Wolfram [1999]; Borenstein *et al.* [2002]; Wolak [2003]; Bushnell *et al.* [2008]; Hortacsu and Puller [2008]; Reguant [2014]). A common element in the most relevant papers conducting analyses of this type is that the estimation strategy is based on the first order condition of the profit maximization problem. In general, these order conditions make it possible to express the optimal price or bid as the sum of a cost component plus a strategic component. Here, I adopt the model proposed by Wolak [2000] and McRae and Wolak [2009]. who have developed a methodology for estimating the IEMP based on a simple model of profit-maximizing firms that have ex-ante forward contract obligations in a residual demand setting. In this context, the IEMP is the ability to change the spot price when withdrawing output with the aim of maximizing profits. In a theoretical study, Allaz and Vila [1993] showed that when profit-maximizing firms sell a large share of their output via forward contracts with fixed prices, they have less incentive to increase prices on the spot markets.

According to McRae and Wolak [2009] model, assuming the generator has previously sold an amount of energy q^c_{ih} at a fixed price P^c_{ih} by forward contracts, the profit function of the generation firm i in the hour h can be defined by the following expression:

$$\pi_{ih} = P_h(DR_{ih})(DR_{ih} - q^c_{ih}) + P^c_{ih} q^c_{ih} - C_i(DR_{ih}),$$

where π_{ih} represents the profits of firm i in hour h in the electricity market, P_h is the spot price, DR_{ih} is the residual demand of firm i in hour h, and $C_i(DR_{ih})$ is the cost function of the firm i. From the first order condition, the following expression is obtained:

$$P_h(DR_{ih}) = \frac{\partial C_i(DR_{ih})}{\partial DR_{ih}} \underbrace{-\frac{\partial P_h(DR_{ih})}{\partial DR_{ih}}\left(DR_{ih} - q^c_{ih}\right)}_{\text{strategic element}}. \quad (1)$$

It should be borne in mind that at the point of market equilibrium, the residual demand of firm i in hour h, DR_{ih}, is equal to the total quantity produced by that firm in that hour, therefore $\frac{\partial C_i(DR_{ih})}{\partial DR_{ih}}$ is the marginal cost of firm i in hour h. This is the first term of the right-hand side of equation (1); the second is the strategic element, that is, its IEMP, which is equal to the interaction of the inverse of the slope of the residual demand curve and the firm's net position in the forward contracts market. This interaction is the optimal margin of a profit-maximizing firm. Thus, the more energy sold by the firm through fixed-price forward contracts, the less the incentive to increase the spot price. Note, however, that in cases in which the generator has an energy deficit relative to its contractual commitments, it has the IEMP by reducing, as opposed to incrementing, the spot price (McRae and Wolak [2009]).

Given the design of the Colombian wholesale electricity market, the daily bid constraint limits the generator's ability to make the precise bid that will maximize its profit function each hour. The generation firm must choose a single price in order to maximize its expected daily profits. This means it cannot bid a continuous supply function that intersects the maximum profit points, given the different realizations of the residual demand. Thus, hourly IEMPs are not necessarily the same as daily incentives.

To address this problem, I propose a daily measurement of the IEMP. This measure can be used to express the first order condition of the daily profit maximization problem as follows:[7]

[7] See Appendix A for a derivation.

$$s^*_{ijt} = c_{ijt} + \frac{-\sum_{h\in\mathscr{H}_{ijt}}\left(DR_{ith}(s_{ijt}) - q^c_{ith}\right)}{\sum_{h\in\mathscr{H}_{ijt}}\frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}}}, \tag{2}$$

where s_{ijt} is the daily bid price on day t for the energy of unit j, the asterisk highlights that this bid is optimal, c_{ijt} is the constant marginal cost of unit j, $\mathscr{H}_{ijt}$ is defined as the set of hours of day t where unit j is marginal, DR_{ith} is the residual demand of firm i that owns unit j on day t at hour h and q^c_{ih} is the energy previously sold at a fixed price by firm i on day t. The second term on the right-hand side of equation (2) is a weighted version of the inverse semi-elasticity of the residual demand. This is the IEMP of a firm that maximizes daily expected profits. I compute the daily IEMP of the firms for the daily model according to this expression.

From a behavioral perspective, strategic firms will take the IEMP into account in their pricing, whereas nonstrategic firms will not. However, what type of behavior can be expected from public firms seeking to mitigate market power? Here, the theoretical literature on mixed oligopolies offers an appealing response. Beato and Mas-Colell [1984] have demonstrated that public firms are able to restore market efficiency by applying the marginal cost pricing rule in a mixed oligopoly model in which public firms compete with private firms, where the former are welfare maximizing and the latter are profit maximizing. Hence, if public firms are implementing market power mitigation schemes, we would expect them to apply the marginal cost pricing rule, or we would at least expect the impact of the strategic element in prices to be less important for public than for private firms.

What, therefore, are our expectations regarding public firms in the specific case of Colombia? As stated in the introduction, there are potential incentives in Colombia for public and mixed firms under government control to exert market power mitigation, given the government's direct participation on the board of several of these companies and the capacity of interest groups to lobby for a reduction in electricity prices.

In sum, when private firms behave strategically, the interaction between the residual demand slope and the net financial position has an impact on price bids. In contrast, public firms have no IEMP, that is, their prices are unaffected by this interaction and are primarily explained by the marginal cost.

III(ii). *Identification strategy and estimation*

In this section, the differences in the incentives for private and public firms to exercise market power are addressed from an empirical perspective. The model presented here adopts the estimation methodology proposed by McRae and Wolak [2009], but includes the interaction between the firms' type of ownership and their IEMP. The extension of this model to establish these differences in incentives is based on expression (2) for private companies.

It is important to consider that my intention is to determine whether public and private companies respond in the same way to incentives to exercise market power, and therefore I require a strategy to test whether the supply functions of the different types of company respond in different ways to changes in the inverse semi-elasticity of residual demand. Note that the expression (2) can be interpreted as a behavioral supply function of a profit-maximizing firm, while the marginal cost pricing rule can be interpreted as a behavioral supply function of a firm that ignores its incentives to exercise market power.

Therefore, I assume that the behavioral supply of private and public companies is given by the expression:

$$p^{*}_{ijtk} = \theta c_{ijt} + \alpha_k * \widehat{IEMP}_{ijtk} + \eta_{ijtk}, \tag{3}$$

where θ is the pass-through of marginal costs, c_{ijt} represents the marginal costs, α_k is the response to incentives to exercise market power of company i that owns unit j at time t and which is of the nature k, $k \in \{public, private\}$, $\widehat{IEMP}_{ijtk}$ is the estimate of the incentives to exercise market power and finally η_{ijtk} is an idiosyncratic time variant strategic management factor not observed by the econometrician, for instance a measurement error made by the firm i in the estimates of the incentives to exercise market power.[8]

There is an endogeneity issue with the $\widehat{IEMP}_{ijtk}$ variable for two reasons:

First, both the strategic management component and the incentives to exercise market power may depend on common factors. For instance, in the case of a measurement error by the firm i, it could be the case that the bigger firms have more accurate performance in forecast tasks than the small firms and also that the bigger firms have higher incentives to exercise market power than the small ones.[9]

Second, note that the equation (2) is an equilibrium condition of a strategic interaction game. This implies that if the firm i is an important market participant, that is, it has large market power opportunities, its measurement error not only will affect its bidding program but also the bidding program of other firms and the final results of each auction. Each firms' equilibrium quantities and bids arise from the interaction between its behavioral supply function and its residual demand function; therefore, estimation of the parameter α_k implies a "reverse causality" problem.[10]

[8] Reguant [2014] notes the potential endogeneity and measurement error of the elastic strategic component (markup term) in the empirical analog of the first-order condition of a profit-maximizing firm.

[9] Hortacsu and Puller [2008] and Hortaçsu *et al.* [2019], found differences in the sophistication of the bidding strategies of large and small firms in the Texas electricity spot market.

[10] Note that the IEMP results from the expectations that various firms have about their rivals' behavior. According to the bid rules of the wholesale energy market, the competitors' bids must

In order to address this issue, it is necessary to adopt a simultaneous equations approach and instrumentalize the IEMP. According to the interpretation of McRae and Wolak [2009] the IEMP is equivalent to the inverse semi-elasticity of net residual demand (After considering the previous forward contract obligations).

As regards the stochastic components of the residual demand, these can be generated by total demand shocks (ν_t) or by shifts in the competitors' supply function (υ_{-it}). Consequently, I will model the incentive to exercise market power (IEMP) as a function of these two components, that is, $\widehat{IEMP}_{ijtk} = F(\nu_t, \upsilon_{-it})$.

It is reasonable to assume that the shocks of demand ν_t come from expected and unexpected consumer reactions which lie completely beyond the firms' control. These reactions may be a response to price changes (endogenous components) or to demand driver changes (exogenous component).[11] I will model the demand shocks as a function of expected changes to demand drivers, an elastic component which is clearly endogenous and unexpected shocks which could be exogenous or endogenous.[12]

With regard to shocks in the competitors' supply function, υ_{-it}. These shifts may be caused by foreseen changes in the costs of rival firms or by unforeseen impacts on their strategic incentives (elastic component). Because this second component depends on the strategic interaction of competing firms, poses a problem of endogeneity. I will model the shocks in the competitors' supply function as a function of the changes in rival firms' cost shifters and the endogenous (and elastic) component.

Hence, the IEMP can be expressed as a function of the endogenous (and elastic) component $\omega_i(p_t)$, the expected shocks in demand drivers z_{1t}, the changes in rival firms' cost shifters z_{2-it} and, the sum of other exogenous shocks χ_{it}, that is, $\widehat{IEMP}_{ijtk} = F(\omega_i(p_t), z_{1t}, z_{2-it}, \chi_{it})$.

I address the endogeneity problem here by performing estimates that consider instruments for the IEMP whose variation arises either from expected demand shocks z_{1t} or exclusively from the competitors' cost component z_{2-it} (both of which are uncorrelated to the idiosyncratic time variant strategic management factor η_{ijtk}).

The literature on market power estimation in an environment of differentiated products recommends using the observed characteristics of the products

be made simultaneously. Thus, for generator A to estimate its residual demand curve, it has to form an expectation about its rivals' bid prices; however, at the same time, the bid prices of these rival firms will depend on their estimates of the residual demand curves, which in turn will be dependent on their expectations regarding generator A's bid prices.

[11] The fact that consumers' reactions to demand driver changes are beyond the firms' control suggests independence of these variables, rendering them candidates for suitable instruments.

[12] The demand drivers are external shocks that shift but do not rotate the inverse function of residual demand.

supplied by rival firms in order to obtain the optimal instruments for a specific product (Berry *et al.* [1995]). By analogy, in the context of the electricity market, the instruments I have selected are variables that are uncorrelated to the rivals' elastic component but which at the same time have effects on their supply function, that is, factors associated with shifts in the costs of rival firms.[13]

Specifically, I consider three instruments:

(i) A weekend day dummy variable is used in order to capture expected demand shocks; this instrument is valid because it reasonable to assume that the weekday condition is independent of the idiosyncratic time variant strategic management factor. Likewise, the only channel through which the day of the week can affect the supply of firm *i* is through a shift in the residual demand curve. The cost shifters of electricity generation depend mainly on the technological characteristics of the units and the cost of fuels. Generally, generating companies sign long-term contracts for the supply of fuel, which do not include substantial changes in the price of the same depending on the day of the week. The above suggests that this instrument satisfies the exclusion restriction.

(ii) The inflows of the rivers feeding the rivals' main hydraulic generation units are used to account for changes in the marginal costs of the leading competitors. The independent nature of this variable is evident given its dependency on natural phenomena. Regarding the exclusion restriction, it is not expected that the inflows of the rivers feeding the reservoirs of competitors have an impact on the opportunity cost of fuel usage of the units of the firms owned by the firm *i*. Hence, shifts in residual demand constitute the only pathway through which competitors' river inflows can impact the behavioral supply function.

(iii) The competitors' full commercial availability, that is, their total generation capacity on specific days. It is important to clarify that in the Colombian wholesale electricity market, commercial availability is the quantity component of the daily bid. Firms can report only one commercial availability per unit for each hour. This availability is taken into account by the regulator in order to calculate the historical unavailability index due to forced fails. This indicator considers the observed unavailability of each generation asset, and higher levels trigger a reduction in revenue from the generation back-up scheme under Colombian law (reliability charge). Thus, generation companies do not have incentives to systematically make strategic use of commercial availability. The greatest changes in this last variable are motivated by the scheduled or unscheduled unavailability of the plants and by the highly variable contribution of smaller base-load generation units. The short-term decisions

[13] As instruments I use several rivals' cost shifters which are equivalent to drivers of the residual demand of firm *i*.

of firm i do not have an effect on its competitors' sources of variation and therefore, this variable can be considered independent. Likewise, the short-term contingencies or planned maintenance intervention of rivals' generation assets affect neither the generation technology nor the opportunity cost of fuel usage by the units owned by firm i. Hence, it is reasonable to assume that the rivals' commercial availability only affects the behavioral supply function through shifts in the residual demand.

Finally, in order to perform an estimation of the econometric model posed in expression (3), it is necessary to model the marginal cost component c_{ijt}. Marginal cost estimates of the units can be obtained from engineering formulae and the technical characteristics and prices of the observable inputs. However, there may be unit characteristics and random shocks common to all plants that are not observable to the econometrician and which have an effect on marginal costs. In addition, it is important to bear in mind that the computations performed to obtain the marginal cost estimate may contain a measurement error given that fuel costs are approximated to reference prices, and the cost per unit in actual fuel supply contracts may be different. Therefore, in this article it is assumed that the marginal costs of each unit can be expressed as the sum of the marginal cost estimate based on the technical parameters of the unit, an individual heterogeneity component and time effect common to all the units, and an exogenous disturbance term, that is, $c_{ijt} = \widehat{c}_{jt} + \mu_j + \varphi_t + \zeta_{jt}$.

Thus, I estimate the following two-way fixed effects linear regression model:

(4)
$$p^*_{ijt} = \beta_0 + \theta(\widehat{c}_{ijt}) + \alpha_{\text{pri}}\left(D_j^{\text{pri}} * \widehat{IEMP}_{ijt}\right) + \alpha_{\text{pub}}\left(D_j^{\text{pub}} * \widehat{IEMP}_{ijt}\right) + \mu_j + \varphi_t + \varepsilon_{it},$$

where P^*_{ijt} is the bid of firm i, for its marginal unit j on day t, $\widehat{c_{ijt}}$ is the estimate of the marginal cost of unit j on day t, $\widehat{IEMP}_{ijt}$ is the estimation of the incentive to exercise market power for a profit- maximizing firm (the empirical estimate of the second term of the left-hand side of expression (2), for company i on day t for the hours in which unit j was marginal, and D_j^{pub} is a dummy variable that takes the value of 1 when unit j is owned by a firm i under state control and 0 otherwise. D_j^{pri} is a dummy variable that takes the value of 1 when unit j is owned by a private firm i and 0 otherwise. μ_j and φ_t represent unobserved unit and time effects, respectively. The term of disturbance ε_{it} contains the unobservable exogenous disturbance term of the marginal cost and the sum of hourly idiosyncratic time variant strategic management factors, that is, $\varepsilon_{it} = \zeta_{jt} + \eta_{ijtk}$ where $\eta_{ijtk} = \sum_{h=1}^{24} \eta_{ijthk}$. β_0, θ, α_{pub}, α_{pri} are the parameters to be estimated. This model is similar to the application developed by McRae and Wolak [2009]; however, in the present article, heterogeneous effects are introduced for public and private companies.

It should be borne in mind that P_{ijt} is the price-bid of unit j when the latter is marginal. The first order condition expressed in equation (2) is not valid when unit j is not marginal. This means that the panel data only contain information about those plants that were marginal for at least one hour in the day. Likewise, in the case of the residual demand approach, the marginal price bid of firm i is equal to the spot price, that is, $p_{th} = s^*_{imt}$, if unit m is marginal in hour h. However, given the discontinuity and ladder shape of the supply and residual demand functions, this does not always occur in the real market. Therefore, there are two alternatives regarding the dependent variable of the model presented in expression (4): Either the spot price when unit i clears the market or the price bid of the marginal unit of each firm. Since a greater number of observations can be used with the latter alternative (and unit j does not need to clear the market), it can be considered the most appropriate option.

In the framework of the instrumental variables approximation, I implement several specifications of the two-way fixed effects proposed in expression (4). Note that for private companies, the inclusion of these fixed effects terms would allow them to bid prices above or below the marginal cost independent of residual demand and their contractual position, that is, for reasons independent of their IEMP. As far as public companies are concerned, the additional fixed effects would allow level-shift deviation, which implies violating the marginal cost pricing rule.[14] As I mentioned above, I interpret these fixed effects as unobservable individual heterogeneity and unobservable time effect common to all the units of the marginal cost. I assume that the unobservable, time-variant heterogeneity of the marginal cost is orthogonal to the measurement error of the IEMP, that is, $E\left[\zeta'_{jt}\eta_{ijtk}\right] = 0$.

I propose estimating the parameters α_{pub} and α_{pri} by implementing a linear generalized method of moments (GMM) model with standard errors clustered by unit. Assuming a valid and relevant set of instruments Z_{ijt}, I am able to exploit the orthogonality conditions of the instruments and the first order condition of the daily profit maximization problem presented in expression (2) in order to construct the moments conditions. The orthogonality conditions imply that:

$$E\left[Z'_{ijt}\varepsilon_{it}\right] = E\Big[Z'_{ijt}\Big[P^*_{ijt} - \theta(\widehat{c}_{ijt}) - \alpha_{\text{pri}}\left(D^{\text{pri}}_j \cdot \widehat{IEMP}_{ijt}\right) - \alpha_{\text{pub}}\left(D^{\text{pub}}_j \cdot \widehat{IEMP}_{ijt}\right) - \mu_j - \varphi_t\Big]\Big] = 0.$$

The parameters can now be estimated using the empirical analogue of these moments conditions.

[14] I owe this observation to an anonymous referee.

Finally, it is important to consider that estimation of the opportunity costs of using hydro power resources involves dynamic components that do not necessarily correspond to the first order conditions given in expression (2). For this reason, the baseline estimations presented in this article only uses data from situations in which the firms' marginal power plants use thermal technology.[15] However, the importance of hydroelectric generation in the Colombian electricity market is useful to refine the identification strategy in order to address endogeneity issues.

The econometric exercises proposed here seek empirical evidence for the impact of private and public companies' IEMP in their bid prices according to the predictions of the mixed oligopoly model. Three specific hypotheses are analyzed:

(i) *Hypothesis 1 (H1)*: Given the same incentives, the exercise of market power by state-owned and private firms differs.
(ii) *Hypothesis 2 (H2)*: Public firms (do not) exercise market power as non-strategic agents, that is, they apply the marginal cost pricing rule.
(iii) *Hypothesis 3 (H3)*: Private firms exercise market power taking into account the strategic element.

First, note that testing the null hypothesis, $\alpha_{\text{pri}} = \alpha_{\text{pub}}$ in expression (4) is consonant with the rationale that the exercise of market power by state-owned and private firms is equal given their incentives. If private firms behave as profit maximizers and public enterprises implement market power mitigation schemes, then depending on the ownership of each enterprise, the interaction of residual demand slope and net forward contract position will impact differently on their respective bidding strategies.

In the case of the second hypothesis, if public firms do not behave strategically, we would expect the parameter α_{pub} not to be statistically different from zero, that is, null hypothesis $\alpha_{\text{pub}} = 0$. If public firms exercise regulatory intervention, then their prices will be explained mainly by the marginal cost and they will not be affected by the interaction of the residual demand and the net financial position.

Finally, according to theory, if private companies behave strategically (profit maximizers), we would expect the parameter α_{pri} to be statistically significant and to present a positive sign (being very close to 1 in the case

[15] Here, it is necessary to clarify that I do not include hydro units, not only because the opportunity cost of water is difficult to estimate, but also because for hydro units, the first-order condition for this type of unit could be different from the one presented in expression (2). In the robustness check section, I present the results of the estimates including hydro units under the assumption of the same first-order condition for the different types of generation technology. The qualitative and quantitative results are similar to the baseline estimate.

of profit-maximizing firms), that is, null hypothesis $\alpha_{\text{pri}} > 0$ ($\alpha_{\text{pri}} = 1$ in the case of profit maximization). If private firms behave strategically, their IEMP has an impact on the firms' pricing. These tests are performed for each of the parameters estimated in the econometric models described above.

The parameter α can be interpreted as an indicator of whether each firm's unilateral response is consistent with unilateral profit maximization in a static model. When α is 1, the firm is maximizing its profit unilaterally in the static game, and when α is 0, the firm is ignoring its incentives to exercise market power (and potentially applying the marginal cost pricing rule). When α takes different values from 0 and 1, it can be interpreted as deviations from the benchmark of profit maximization.[16]

Deviations from stylized behavior values may be interpreted in the same way as in Hortacsu and Puller [2008] and Hortaçsu *et al.* [2019], that is, as deviations of optimization behavior unrelated to strategic reasons. Alternatively, values of α between 0 and 1 can be interpreted as evidence that the firm is offering prices as if it were facing a more elastic residual demand than is the case, for strategic reasons. Mercadal [2019] posits that when attempting to determine entry, generators do not play best response (in the static game), but act as if they were facing a more elastic residual demand (This is $\alpha < 0$).[17] On the other hand, values of the parameter α greater than 1 can be interpreted as evidence that the firm is offering prices as if it were facing a less elastic residual demand than it actually does, for strategic reasons. Mercadal [2019] suggests that, in a repeated game cooperative equilibrium, firms do not play best response, but instead behave as if they were facing a less elastic residual demand than they actually do (i.e., $\alpha > 1$).[18]

[16] It is important to clarify that the methodology proposed in this article differs from the Conduct Parameter Method used in several applications of the new empirical industrial organization (NEIO) literature. First, the conduct parameter resulting from NEIO applications is an estimate of the price-cost mark-up adjusted by the elasticity of total demand. As this is corrected for total demand, its interpretation is linked to the entire market competition model and not to individual firm behavior. On the other hand, the parameters α estimated in this article can be interpreted as a measure of the price-cost mark-up specific to each firm, given that it is adjusted by the elasticity of residual demand and the percentage of exposure to the spot price of each firm. This measure is relative to the best response of each particular firm and not with market competition model.

[17] There may be several reasons for a firm to offer prices "as if it faced" a more elastic residual demand. For example, the firm may fear regulatory intervention to reduce unilateral market exercise, so it does not exercise its full market power when the resulting price increases could arouse excessive concern in the authorities. Likewise, in the case of a public company seeking to balance consumer welfare and profits, $1 - \alpha$ could be interpreted as the importance that the firm gives to consumer welfare.

[18] Note that interpretations associated with entry deterrence, fear of regulatory intervention, and cooperative equilibrium implicitly entail scenarios of dynamic strategic interaction, namely,

The section that follows describes the methodological procedure for computing the model's variables, including the IEMP and marginal costs. Finally, the econometric method employed in the estimation is outlined and the most relevant results are presented.

IV. EMPIRICAL IMPLEMENTATION

IV(i). *Data*

The hourly and daily data for 21 firms in the Colombian wholesale electricity market were analyzed for the period 2005 to 2014. To test the three hypotheses (H1, H2, and H3) by estimating the parameters α_{pub} and α_{pri} of the model proposed in expression (4), we also need data on marginal costs and on the IEMP. Unfortunately, these variables cannot be observed directly, so we have to rely on indirect estimations.

In the case of marginal costs, an accounting approach is adopted. This is similar to the one employed in previous studies in the field of electricity markets (Green and Newbery [1992]; Wolfram [1998]; Wolfram [1999]; Borenstein and Bushnell [1999]; Borenstein *et al.* [2002]; Wolak [2000]; Fabra and Reguant [2014]). The marginal costs of thermal plants are computed, based on the technical parameters of the plants (heat rate), fuel costs, and fuel transportation costs. The data sources and more detailed information concerning the assumptions for the calculation and imputation of these costs are presented in Appendix B. It is important to bear in mind that these computations may contain a measurement error given that I approximate fuel costs to reference prices, and the cost per unit in actual fuel supply contracts may be different.

Daily marginal costs were calculated and imputed for 36 thermal plants belonging to 21 firms. Given the small differences in heat rate between publicly owned and private units, no significant differences were found in the distribution of marginal costs between public and private generation units. Panels (a) and (b) in Figure 1 present the histograms of the estimated marginal costs for private and public generation units, respectively.

As for the IEMP, recall that this incentive is related to the elasticity of residual demand. Since the Colombian wholesale electricity market allows us to observe the price bids and commercial availability of each plant as well as

a profit-maximization model subject to an incentive compatibility constraint associated with future revenues. If the incentive compatibility constraints are a function of simultaneous residual demand shocks, then the estimated α parameter may be subject to Corts [1999] criticism (i.e., α may be biased). In any event, according to the identification strategy suggested by Puller [2009], the inclusion of time fixed effects in my base line estimation allows me to address this potential inconsistent estimation issue. According to Puller [2009], theoretically, the unobserved effect related to the incentive compatibility constraint *"is equal across all firms in the collusive regime for a given period (i.e., it is not indexed by i). Although, a researcher does not have data on it, this extra term can be 'conditioned out' by including time fixed-effects"*.

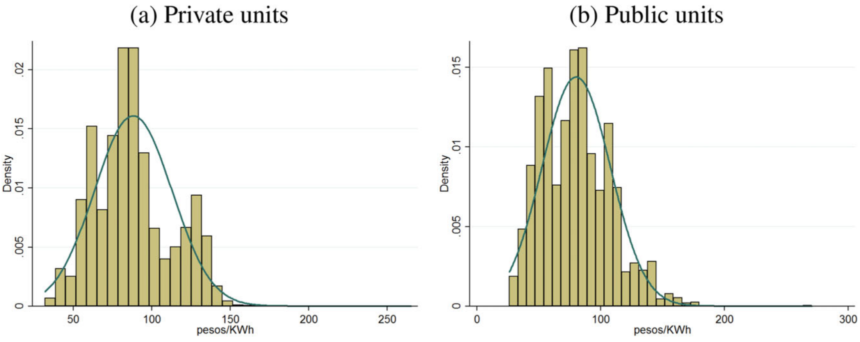

Figure 1
Estimated Marginal Costs

Source: Data from XM–Calculations and elaboration: Author.
Notes: [Colour figure can be viewed at *wileyonlinelibrary.com*]

actual electricity demand, it is possible to replicate the residual demand of each generator. The result of this exercise is a decreasing step function of residual demand in which the partial derivative is zero or indeterminate (McRae and Wolak [2009]). Therefore, to calculate the inverse net semi-elasticity of demand, an approximation must be made to the slope of this function around the market equilibrium price. Wolak [2003] suggests a nonparametric method for calculating the elasticity of residual demand using the points of the function with prices closest to—both above and below—the market equilibrium price.

As stated above, a daily version of the IEMP was computed to account for the fact that in the Colombian electricity market, generators maximize daily as opposed to hourly profits (see Section III(i)). Adopting the methodology proposed by Wolak [2003], the empirical version of the IEMP—that is, the second term on the right-hand side of equation (2)—can be computed as follows:

(5)
$$\widehat{IEMP}_{ijt} = \frac{-\sum(IG_{ith} - q^c_{ith} | \text{unit } j \text{ is marginal in hour } h)}{\sum\left(\frac{DR_{ith}(p_{th}\cdot(1+\delta)) - DR_{ith}(p_{th}\cdot(1-\delta))}{p^{\text{above}}_{th}(1+\delta) - p^{\text{below}}_{th}(1-\delta)} | \text{unit } j \text{ is marginal in hour } h\right)},$$

where $\widehat{IEMP}_{ijt}$ is the incentive to exercise market power on day t for unit j that is marginal for several hours of the day, $p^{\text{above}}_{th}(1+\delta)$ is the price of the next step in the residual demand curve above the price $p_{th}\cdot(1+\delta)$, $p^{\text{below}}_{th}(1+\delta)$ is the price of the previous step in the residual demand curve below the price

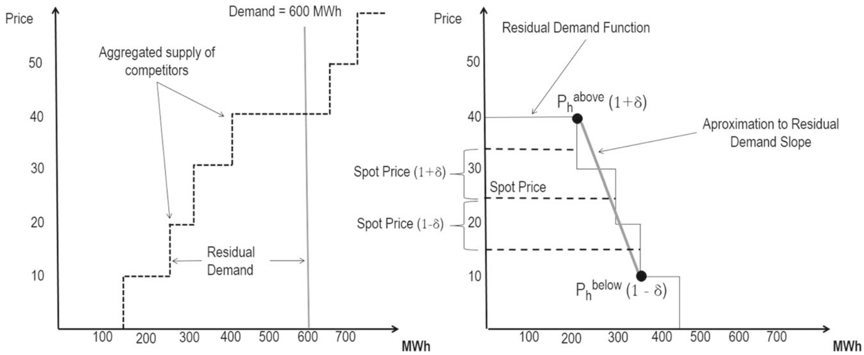

Figure 2
IEMP Calculation Technique

$p_{th} \cdot (1-\delta)$, IG_{ith} is the actual ideal generation of producer i in hour h and q^c_{ith} is the quantity of energy committed in fixed price forward contracts.[19] As stated in Section II, in the Colombian wholesale electricity market this quantity is observable ex post. Finally, I assume a parameter $\delta = 0.05$ (5%). Figure 2 illustrates this nonparametric calculation technique. Previous studies using this methodology (Wolak [2000]; McRae and Wolak [2009]) suggest that changes in δ do not have a marked effect on the outcomes. Later in this article, in the robustness checks section, I verify that the decision regarding the parameter δ does not have a critical impact on the results of the estimates. I present the estimates obtained by applying δ of 10% and 25% to compute $\widehat{IEMP}_{ijt}$.

Information about daily price bids, hourly spot prices, hourly ideal generation and hourly sales in forward contracts—essential details to compute the IEMP—was taken from the website of the Colombian wholesale electricity market operator XM.

A shortcoming of the IEMP calculation technique presented above is that it can yield extreme values due to absolute values close to zero in the denominator of expression 5. In fact, in the sample analyzed in this article, extreme values are obtained which can reach 2.228 times the interquartile range. Panel (a) in Figure 3 presents a scatter plot for the IEMP and the margin $(P^*_{ijt} - c_{jt})$ for the total sample in which extreme outliers are present. In order to address this issue, the sample has been trimmed to exclude the observations corresponding to the 1% lowest values for the denominator of expression (5),

[19] From a supply function equilibrium approach (Klemperer and Meyer [1989]), the marginal price bid is the best response of an electricity generating firm given the actions taken by its competitors (as it sets its level of generation and the spot price). This optimal bid price is associated with an optimal generation quantity, so the residual demand of the generator in the equilibrium price should be equal to its ideal generation.

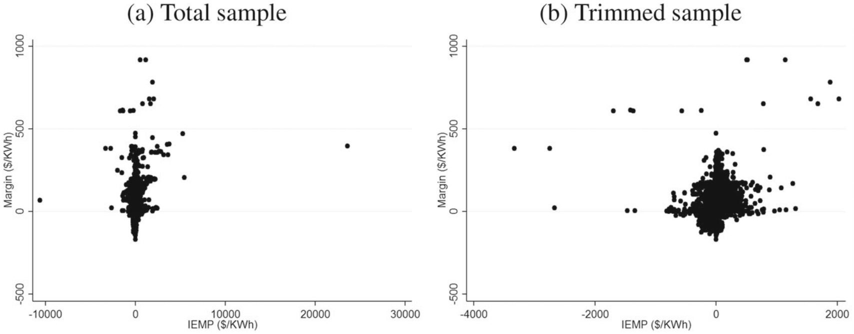

Figure 3
Sample Outliers and Trimming

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

that is, the sum of the slopes of the hourly residual demand functions. Panel (b) in Figure 3 presents an IEMP verses margin scatter plot, after trimming. In the robustness tests, several trimming percentile values are tested but they have no major impact on results.

Unlike the situation with estimated costs, some differences were found in the descriptive statistics of the IEMP for private and public companies. Figure 4 shows the distribution of the IEMP among the main public and private electricity generation companies in Colombia. Panel (a) in Figure 4 presents the box-plot excluding extreme values. In this figure, it can be seen that while private companies, on average, have incentives to exercise market power through price increases, public companies have incentives to bid prices below the marginal cost. In panels (b) and (c) in Figure 4, it can also be seen that the distribution of IEMP among private enterprises has more weight in the right tail, while that corresponding to public firms has more weight in the left tail. This occurs because, on average, a greater percentage of the energy the latter sell is committed to forward contracts.

Information about instrumental variables—including daily water inflows and hourly commercial availability—was taken from the website of the Colombian wholesale electricity market operator XM.

Finally, due to the period analyzed is long, in order to correct for inflation, all variables measured in current prices were converted to constant prices of 2014. Table IV highlights the main descriptive statistics for each of the variables included in the model.

IV(ii). *Estimation and Results*

Given marginal cost estimates for each plant and each firm's incentives to exercise market power under the assumption of profit maximization, we can

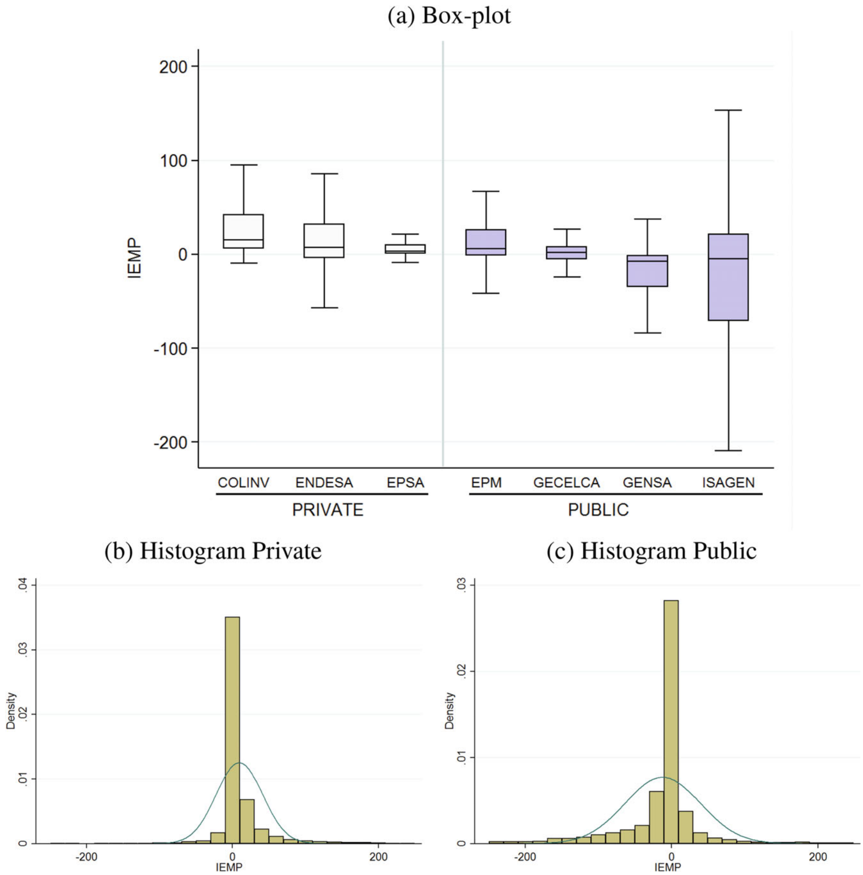

Figure 4
IEMP of Private and Public Firms

Source: Data from XM–Calculations and elaboration: Author
Notes: [Colour figure can be viewed at *wileyonlinelibrary.com*]

now estimate the econometric model of expression (4) and test the hypotheses formulated in Section III(ii).

It is important pointing that the estimates of the marginal costs presented in Section IV(i) are based on data that changes at the unit dimension (heat rates and transportation fuel costs) and the monthly dimension (fuel costs), therefore, there is limited within-month variation in this variable. The only marginal cost's within-month variation arises from fluctuations in the exchange rate. Table V presents a decomposition of the within-month versus the between *unit* × *month of the sample* variation in the marginal costs, the marginal bid, and the IEMP. This decomposition reveals that the within-month variation of the estimates of the marginal costs is negligible

TABLE IV
VARIABLES IN THE ECONOMETRIC MODEL

Variable and unit	No. Obs.	Mean	St. Dev.	Min	Max
Marginal bid ($/KWh)	19,789	119.50	61.26	27.39	999.64
Marginal cost ($/KWh)	19,789	83.86	26.09	26.28	270.73
IEMP ($/KWh)	19,789	−1.25	87.43	−3330.17	2024.58
River inflows of competitors (GWh)	19,789	96.47	44.97	9.91	394.00
Availability of competitors (GWh)	19,789	10.99	1.07	7.38	14.24
Weekend day dummy	19,789	0.24	0.43	0.00	1.00
PRIVATE					
Marginal bid ($/KWh)	10,344	120.45	65.05	27.39	999.64
Marginal cost ($/KWh)	10,344	87.17	24.06	31.88	265.19
IEMP ($/KWh)	10,344	14.00	65.70	−663.68	2024.58
River inflows of competitors (GWh)	10,344	96.70	44.01	20.84	394.00
Availability of competitors (GWh)	10,344	10.98	1.18	7.43	14.24
Weekend day dummy	10,344	0.24	0.43	0.00	1.00
PUBLIC					
Marginal bid ($/KWh)	9445	118.47	56.81	27.87	721.91
Marginal cost ($/KWh)	9445	80.23	27.70	26.28	270.73
IEMP ($/KWh)	9445	−17.95	103.71	−3330.17	1311.18
River inflows of competitors (GWh)	9445	96.22	46.00	9.91	394.00
Availability of competitors (GWh)	9445	11.00	0.95	7.38	14.00
Weekend day dummy	9445	0.24	0.43	0.00	1.00

Source: XM–Market Operator.

TABLE V
WITHIN-MONTH VERSUS THE BETWEEN *unit × month of the sample* VARIATION

Variable		Mean	Std. Dev.	Min	Max	Observations
Marginal cost	Overall	93.93	25.97	37.23	319.87	$N = 19{,}789$
	Between Unit × Month		27.60	37.40	318.53	$n = 1825$
	Within-month		2.13	54.93	151.73	
Marginal bid	Overall	133.23	63.59	32.09	1060.53	$N = 19{,}789$
	Between Unit × Month		73.48	33.03	885.29	$n = 1825$
	Within-month		20.10	−220.36	811.26	
IEMP	Overall	−1.41	98.40	−3811.90	2147.90	$N = 19{,}789$
	Between Unit × Month		114.37	−1497.75	2147.90	$n = 1825$
	Within-month		72.84	−3093.96	1375.62	

compared with the same variation of the other two variables. Thus, the inclusion of unit and month fixed effects should absorb most of the marginal cost variation and consequently, an econometric specification including two-way fixed effects without the marginal cost term would be appropriate.[20]

[20] I owe this observation to an anonymous referee. See the Journal's editorial web site for further details about the exclusion of marginal cost from both specifications 3 and 4. Table E24 in Online Appendix E shows that the exclusion of marginal cost from both the two way fixed effects model and the *unit × month of the sample* fixed effects model does not have an important impact either on the value of the coefficients or on the validity and weakness tests of the instruments. Likewise, it is observed that in these estimates the coefficient of marginal cost is not statistically significant.

Given the arguments presented in the previous paragraph, for the baseline estimations 4 specifications are proposed. The first (presented in column 1) does not include fixed effects at all and the second (presented in column 2) includes unit fixed effects. These two specifications include the marginal cost estimates as a control variable. The third and fourth specifications (presented in columns 3 and 4, respectively) exclude from the regression the marginal cost. The former of these specifications include two-way fixed effects while the latter includes *unit* × *month of the sample* fixed effects.

As stated, to address the issue of endogeneity of the IEMP, I used instrumental variable techniques. I performed a two-stage generalized method of moments (GMM2S) to estimate the two-way fixed effects model proposed in expression 4.[21] As instruments, I used the contemporary values, the quadratic transformation, and the first three lags of the variables described in Section III(ii), that is, the inflows of the rivers feeding the rival firms' reservoirs, the competitors' commercial availability, and the weekend day dummy variable.

There are two endogenous variables: the interactions $D_j^{\text{pri}}\widehat{IEMP}_{ih}$ and $D_j^{\text{pub}}\widehat{IEMP}_{ih}$. In the two-way fixed effects model, the first stage equation for these variables is:

$$\begin{aligned} D_i^{\text{owner}} \times \widehat{IEMP}_{it} = \gamma_0 &+ \sum_{k=1}^{2}\left(\pi_{k1}(z_{k-it})^2 + \pi_{k2}\left(D_i^{\text{pub}} \times (z_{k-it})^2\right)\right) \\ &+ \sum_{\tau=0}^{3}\sum_{k=1}^{2}\left(\pi_{k3}z_{k-i(t-\tau)} + \pi_{k4}\left(D_i^{\text{pub}} \times z_{k-i(t-\tau)}\right)\right) \\ &+ \gamma_1(\widehat{c_{ijt}}) + \psi_{\text{weekday}} + \mu_j + \varphi_t + \chi_{it} \end{aligned}$$

where the *owner* can be either private (*pri*) or public (*pub*), z_{1-it} is the sum of inflows of the rivers which feed the reservoirs of the major hydroelectric units of the competitors of agent i on day t measured in GWh, z_{2-it} is the sum of the commercial availability of the competitors of agent i on day t measured in GW, τ is the lag of the variables used as instruments, ψ_{weekday} is the weekend day dummy, μ_j represents unit fixed effects, and φ_t are monthly fixed effects. The results of these GMM2S estimations are shown in Table VI.[22]

[21] See the Journal's editorial web site for further details about the ordinary least squares (OLS) estimation of the model. The results are presented in Table D21 in the Online Appendix D. The coefficients from the GMM2S estimation yield values of a higher order of magnitude. This is consistent with the attenuation bias problem in the OLS estimators.

[22] Note that column 1 of Table VI presents a specification which is a more rigorous structural interpretation of profit-maximization restricted to one bid per day from each unit. If the marginal cost and IEMP components are measured correctly by the econometrician, under a structural interpretation of the profit-maximization model, the empirical analog of the first-order condition should not include the constant and fixed effects that do not appear in equation (2). As

TABLE VI
TWO WAY FIXED EFFECTS–GMM-RESULTS

	(1)	(2)	(3)	(4)
Private IEMP	0.60**	0.74***	0.60***	0.34***
	(0.24)	(0.09)	(0.06)	(0.08)
Public IEMP	0.14**	−0.07	0.33***	0.01
	(0.06)	(0.06)	(0.07)	(0.03)
Marginal cost	1.25***	0.30***		
	(0.05)	(0.07)		
Monthly FE	NO	NO	YES	NO
Unit FE	NO	YES	YES	NO
Unit × Month FE	NO	NO	NO	YES
No. Obs	14,836	14,836	14,836	14,633
No. clusters	32	32	32	32
Joint Sig.	504.5***	53.63***	93.78***	9.785***
Weak identification				
F first stage private	8.94	1209.16	487.7	7.27
F first stage public	15.38	22.02	44.94	4.2
K-P rk Wald F	14.48	123.8	2.360	4.205
Cragg-Donald Wald F	8.694	6.289	6.088	1.575
Overidentification				
Hansen J	23.95	19.69	20.86	18.59
p-value	0.198	0.413	0.344	0.483
Test No Diff	2.88	54.06	5.11	14.23
p-value	0.09	0.00	0.03	0.00
Test PMP	2.90	8.88	40.19	68.81
p-value	0.09	0.01	0.00	0.00

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:H_0 : $\alpha_{\text{pri}} - \alpha_{\text{soe}} = 0$ and Test PMP (Profit maximization by private firms): H_0 : $\alpha_{\text{pri}} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty-one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10% and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

In the case of H1, the results in Table VI suggest that there are marked differences between private and public firms in their respective exercise of

mentioned above, the fixed effects would allow public firms violate the marginal cost pricing rule. The orthogonality conditions of this rigorous specification can be expressed as:

$$E\left[Z'_{ijt}\varepsilon_{it}\right] = E\Big[Z'_{ijt}\Big[P^*_{ijt} - \theta(\widehat{c}_{ijt}) - \alpha_{\text{pri}}\left(D^{\text{pri}}_j \cdot \widehat{IEMP}_{ijt}\right) - \alpha_{\text{pub}}\left(D^{\text{pub}}_j \cdot \widehat{IEMP}_{ijt}\right)\Big]\Big] = 0.$$

Alternatively, in column 5 of Table CI in Appendix C, I present the results of a model in which I use the margin as the dependent variable. This entails dropping the estimation of θ and assuming it is equal to 1, so the orthogonality conditions can be written as:

$$E\left[Z'_{ijt}\varepsilon_{it}\right] = E\Big[Z'_{ijt}\Big[\underbrace{\left(P^*_{ijt} - \widehat{c}_{ijt}\right)}_{\text{Margin}} - \alpha_{\text{pri}}\left(D^{\text{pri}}_j \cdot \widehat{IEMP}_{ijt}\right) - \alpha_{\text{pub}}\left(D^{\text{pub}}_j \cdot \widehat{IEMP}_{ijt}\right)\Big]\Big] = 0.$$

unilateral market power. As expected, the coefficient for private firms is greater than that for public firms. In all specifications, the coefficient of the interaction of the IEMP with the private dummy is statistically significant at conventional levels and the magnitude of this coefficient is economically significant, positive, and greater than that one obtained for public firms. At 5% level of statistical significance, the null hypothesis corresponding to no difference in the coefficients is rejected for all specifications.

As for H2, different results are obtained depending on the particular model specification. Specifications 1 and 3 yields a positive coefficient that is both economically and statistically significant. These estimates suggest a milder exercise of market power by public firms in comparison to private. Conversely, for specifications 2 and 4 the sign of the coefficient for public firms is not statistically significant. These results support the hypothesis of regulatory intervention by public firms in the Colombian electricity market.

As for H3, the results indicate that the IEMP has an impact on the pricing strategy of private firms. The estimates in specification 1 do not allow rejection of the null hypothesis (profit-maximization behavior) at the 5% significance level.[23] Although in the other specifications there is statistical evidence to reject the null hypothesis of perfect profit-maximization behavior, the coefficient for private firms presents a positive sign and is statistically and economically significant. According to these results, private firms exercise between 34% and 74% of the market power predicted by theory.

When testing the validity of the instruments, the J-Hansen statistic suggests that the models satisfy the exclusion restriction. As for the potential weakness of the instruments, the F-statistic for each of the endogenous regressors meets the rule-of-thumb threshold of values higher than 10 for the models in columns 2 and 3. Moreover, the Cragg-Donald Wald F-statistic suggests that the GMM2S estimations presented in Table VI have a maximum bias, which would not be more than 20% for the models in columns 1 and 2, according to the criteria described by Stock and Yogo [2002]. The model in column 3 is very close to the critical value of the 20% bias and specification 4 exhibits values far below this critical value. Alternatively, the Kleibergen-Paap rk Wald F-statistic suggests that the GMM2S estimations presented in Table VI have a maximum bias, which would not be more than 5% of the bias of the OLS estimations for the model in column 2, 10% for the model in column 1 and more than 30% for the models presented in column 3 and 4, according to the same criteria (Stock and Yogo [2002]). Although several of the models presented satisfy some of the criteria for ruling out instrument weakness as a relevant issue, the results presented in Table VI should be interpreted with caution given that there is no clear consensus regarding the criteria for detecting weak instruments when the conditional homoscedasticity assumption is not valid.

[23] I performed a conventional Wald test to verify the null hypothesis: $H_0 : \alpha_{\text{pri}} = 1$ for private firms.

Given the likely existence of both unobservable individual heterogeneity and common time effects of the marginal cost explained in Section III(ii) and the results of validity and strength tests of the instruments presented in the previous paragraph, my preferred specification is the instrumental variables model with two-way fixed effects presented in column 3 in Table VI. Regarding H1 this specification indicates that there are economically and statistically significant differences in the response of public and private firms to the incentive to exercise market power. Although according to this specification public firms also respond to this incentive (H2 is rejected) and private firms deviate downward from the response expected from profit-maximization behavior, the former are closer to the benchmark of perfect regulatory intervention and the latter are closer to the benchmark of profit-maximization.

In short, the results of the econometric exercises performed here suggest that private firms in the Colombian wholesale electricity market are more responsive to their incentives to exercise market power than are public firms. The introduction of structural elements and instrumental variables reveals indications of attenuation bias in the OLS estimators. Overall, this indicates that the private ownership share of electricity generation is not neutral as regards competition.

IV(iii). *Robustness checks*

The results presented above are dependent on particular specification decisions: (i) The left hand side variable; (ii) the sample of units selected for the estimation and; (iii) the choices of different parameters in the empirical implementation. Here, several estimations of the econometric model are run to test different specifications of these alternatives. Overall, the qualitative results of the model seem to be relatively robust to the different options.

(i) *Specification of the hand side variable*: The marginal price of each generator is chosen as the left-hand side variable of the baseline econometric model. The advantage of so doing is that it is possible to obtain a coefficient for the marginal cost and to determine if its value and sign are consistent with expression 2. However, it is equally possible to employ the firm's margin as the left-hand side variable. Thus, the margin $m_{it} = P^*_{ijt} - \widehat{c}_{ijt}$ was calculated and used as the dependent variable in the econometric model. The results are summarized in Table CI in Appendix C. The model's main results remain unchanged. The coefficients of the estimates in the preferred specification (column 7) for the private and public IEMP lie within the original model's confidence interval.

(ii) *Sample of units*: Several concerns may arise regarding potential selection bias in the sample used for the baseline estimation and the criterion for classifying units as public or private.

As mentioned in Section II, around 70% of electricity in Colombia is produced from hydroelectric resources, so it makes sense to assume that the profitability of the most important companies in this market depends mainly on this type of resource. Nonetheless, in the baseline estimation presented in Section IV(ii), only observations in which the thermal units were marginal were included. This is problematic because it is possible that determination of a thermal unit as marginal is not random. This would imply that the data-generating process in circumstances in which thermal plants are marginal is particular to those circumstances and does not present a reliable general picture of the unilateral market power of private and public firms in the Colombian wholesale electricity market, that is, the baseline estimation may be subject to a potential selection bias. In order to address this concern, I performed a two-way fixed effects estimation that also included the hydro units.[24]

The results are summarized in Table CII in Appendix C. The preferred specification's main conclusions remain unchanged. Regarding the IEMP coefficients of the GMM two way fixed effects specification (column 7), for both public and private firms alike, they lie within the baseline model's confidence intervals. Although, these results should be interpreted with caution given the results of the indicators of instrument weakness and also because the overidentification test is close to the critical values for rejection of the null hypothesis.

Meanwhile, as mentioned in Section II, I classified the generation firms into "private" and "public" according to the ownership category of the shareholder controlling the firm that represents the unit to the market operator. However, it is possible that not all public firms have the same incentives. In particular, there are two types of public firm in the Colombian wholesale electricity market that might not be interested in mitigating market power.[25] In order to tackle this problem of potential incentive misalignment and selection bias, I performed the estimation

[24] The inclusion of this type of unit in the sample cannot be done at zero cost in relation to the assumptions necessary for the validity of the estimate. First, it must be assumed that the first-order condition in expression (2) is also true for both thermal and hydraulic units, excluding potential dynamic components for the latter. Second, it must be assumed that the marginal cost of thermal units and the opportunity cost of water in hydraulic units are adequately modeled by unit and time fixed effects. This robustness check is inspired in the suggestion of an anonymous referee.

[25] First, the firm EPM is the property of the municipality of Medellín. It is possible that despite being a public company, EPM could exercise unilateral market power in the national electricity market in order to extract additional profits from other regions and transfer these benefits to the citizens of Medellín. Second, some of the thermal units represented in the market by public firms are actually owned by private companies that have signed power purchase agreements (PPA) with these public firms. This type of public company may have different bid price incentives depending on whether the unit being offered is subject to a PPA or not. I owe this observation to an anonymous referee.

of the two way fixed effects model presented in Section IV(ii) excluding from the sample the units under a PPA in force and the unit owned by EPM.[26] The results for estimation of this model are presented in Table CIII in Appendix C.

The most important qualitative results of the estimation remain unchanged. Although in the GMM2S two-way fixed effects estimate, the test for no differences is not rejected at standard significance levels, the coefficient of the private IEMP is still greater than that of public IEMP. Both coefficients have the same order of magnitude as the baseline estimation and are economically and statistically significant. It is important to note that the indicators of model identification in this specification reveal evidence of instruments' weakness.

Another important aspect that must be accounted for in order to avoid selection bias is related to the mechanism of electricity generation back-up for restricted supply situations. Colombia's generation supply is heavily dependent on its hydroelectric resources in drought periods which are exacerbated by El Niño events. To guarantee supply during this phenomenon, Colombia has created a payment for power availability, known as the "reliability charge".[27]

In order to rule out the possibility that the results in the baseline estimation are caused by ignoring the potential change in incentives due to the reliability charge scheme, I performed the estimation of the two-way fixed effects specification excluding from the sample the days on which the spot price rose above the scarcity price for at least one hour.[28]

The weight of observations for which the spot price exceeds the scarcity price is modest even when only thermal units are considered. For the entire sample (including thermal and hydraulic resources), this situation occurred in 68 observations. For the sample of thermal units, it occurred in 53 observations. The number of observations eliminated by discarding the days on which the marginal price exceeded the scarcity price for at least one hour was 766 for the entire sample and 422 for the subsample of thermal units. As can be seen in Table CIV in Appendix C,

[26] Particularly, I excluded observations of the units Termocentro, Termovalle, Termoflores 1, Termobarranquilla 3, Termobarranquilla 4, Tebsa, and Paipa 4.

[27] This mechanism works as a call option, where the product of the option is the obligation to generate a specific firm energy quantity. These obligations are assigned in a long-run multiunit auction. The reference price of the call option is the spot price of the wholesale electricity market and the strike price is the scarcity price. The latter is defined by the regulator and is a reference of the variable cost of generation of the most expensive unit in the system. Note that during periods when the price rises above the scarcity price, the reliability charge imposes the production of firm energy quantities at a fixed price, just as unilateral forward contracts do. As a result, it may be that reliability charge incentives distort the IEMP in the spot market during critical El Niño events.

[28] This robustness arises from the observations of an anonymous referee.

the results of the check described above were robust and similar to the baseline estimation.

(iii) *Choices of different parameters*: In order to implement the econometric model, it is necessary to rely on particular choices of several parameters such as:

(a) The percentage by which the sample should be trimmed in order to eliminate the IEMP outliers;
(b) The lags of the instruments in the first stage of the IV estimations; and
(c) The delta (δ) parameter and the methodology for computing the incentives to exercise market power.
(d) The dimension of clusters for standard errors computation.

First, in the baseline estimation, the sample was trimmed to exclude observations corresponding to the 1% lowest values for the denominator of expression (5). Table CV in Appendix C presents the estimations when trimming observations corresponding to the 0.1% and 5% lowest values.

In the case of the GMM2S two-way fixed effects estimates, even though the coefficients of the private IEMP show lower values than the baseline estimation for both samples, they are still statistically and economically significant and also greater than the coefficient of the public IEMP. The test for no differences is not rejected at standard significance levels for the sample trimmed at 0.1% and is rejected at 10% significance level for the sample trimmed at 5%.

Second, in the baseline estimation, the first three lags of the river inflows and the commercial availability of competitors were used as instruments for the GMM2S estimations. I repeated the estimations of this model using the first two and first four lags in the instrumental variable specification. These estimations are reported in Table CVI in Appendix C, where it can be seen that they are similar to the baseline estimation. Even though in the specification with two lags the test of no differences is not rejected at standard significance levels, the coefficient of the private IEMP is still greater than that of public IEMP. Also, both coefficients have the same order of magnitude as the baseline estimation and are economically and statistically significant.

Third, it is important to verify that the results of the estimates are relatively insensitive to the computation methodology for the $\widehat{IEMP}_{ijt}$. In the baseline estimation, a delta δ parameter of 5% is set in order to take into account the price window when calculating the slope of the inverse residual demand function. In order to verify the robustness of the baseline results, the IEMP was calculated again using δ parameters of 10% and 25% and the estimations were repeated with the same baseline econometric specification. The results are shown in Table CVII in Appendix C. Although the value of the private IEMP coefficient seems to increase with the delta parameter, these econometric regressions indicate that the most important qualitative results of the baseline estimation remain unchanged.

In addition, one of the potential shortcomings of the methodology for computing the residual demand slope based on only two points along the function, as the one used for the baseline estimate, is that the estimate of the slope is highly sensitive to idiosyncratically steep or flat sections of the residual demand.[29] In order to rule out the possibility that this weak point may distort the final results, I applied a smoothing approach that has been implemented by several authors (Wolak [2003]; Wolak [2007]; Reguant [2014]) in the context of electricity auctions. This approach uses all the steps of the residual demand function to compute the slope. For a given hour of the day the derivative of the residual demand faced by a firm is approximated as follows:

$$\frac{\partial DR_{ith}\left(s^*_{ijt}\right)}{\partial s^*_{ijt}} = -\frac{1}{h}\sum_{k=1}^{K} q_{-ikt}\phi\left(\left(s^*_{ijt} - s_{-ikt}\right)/h\right),$$

where s^*_{ijt} is the marginal price of firm i in hour t, K is the number of generation units supplied by the rivals of firm i, q_{-ikt} is the quantity supplied by unit k owned by a rival in hour t and s_{-ikt} is the bid for this unit, $\phi(t)$ is the standard normal density function, and h is the smoothing parameter. I applied three different smoothing parameters: $h = 200$, $h = 400$, and $h = 800$, and used this calculation of the residual demand slope to compute the daily $\widehat{IEMP}_{ijt}$, repeating the econometric estimations.[30] As can be seen in Tables CVIII, CIX and CX in Appendix C, although in the GMM2S two-way fixed effects estimate, the test for no differences is not rejected at standard significance levels, for the three different values of the smoothing parameters, the coefficient of the private IEMP is still greater than that of public IEMP in the preferred specification.

Finally, some concerns may arise regarding the calculation of standard errors given the low number of clusters (32) used in the baseline estimation. Due to the relevance of this issue for the test of no differences between the Private IEMP and Public IEMP coefficients, it is important to check the robustness of the inference in different clustering alternatives.

Abadie *et al.* [2017] discuss the motivations for using different cluster alternatives. These authors argue that there are two potential

[29] This robustness check arises from the suggestion of an anonymous referee.

[30] I use these values of the smoothing parameter h because the standard deviation of the bids of the units participating in the market in the study period is around 400.

motivations: When the sampling is done by clusters and when the assignment of the treatment is done by clusters. In this particular application, I consider that the second case applies. This entails that the relevant intraclass correlation to take into account regarding the standard error calculation is that relative to the units.

These authors also argue that for the case in which the fixed effects are included in the regression at the cluster level, in which it is expected that there is no heterogeneity in the treatment effects, it is not necessary to adjust the standard errors for the clusters once fixed effects are included. According to this and given the exhaustive inclusion of monthly fixed effects in the model it is not necessary to include the time dimension as a cluster for standard errors calculation.

In any case, Table CXI in Appendix C presents several estimations of the two-way-fixed-effects model and the *unit* × *month of the sample* fixed effects model using alternative cluster specifications for standard errors calculation. These estimations considers different one-dimensional cluster alternatives that are plausible: *unit* × *Niño event*, *unit* × *month of the year* and *unit* × *month of the sample*. It is possible to appreciate that regarding the inference of the tests of differences between the Private IEMP and Public IEMP coefficients, the inclusion of a greater number of clusters does not have important effects.

IV(iv). *Efficiency gains from market power mitigation*

An important question that arises from the hypothesis of market power mitigation behavior by public companies is what level of efficiency gains is achieved due to public companies responding less to the incentives to exercise market power than private firms?[31]

In this article, it has been assumed that the total demand for electricity is inelastic. This implies that losses in consumer surplus are transferred to a larger producer surplus and hence the deadweight losses arise from the supply side. In this context, it is possible to identify two sources of potential efficiency gains. The first consists of the *rival's incentive effect*. This arises because the supply of prices with market power mitigation by public companies implies that private companies are faced with flatter residual demand curves. On the other hand, it is also possible to identify a *merit order effect*. This originates from the efficiency gains that result from the displacement of higher-cost plants owned by private companies as a consequence of public companies bidding at more competitive prices. Despite the importance of these effects, the calculation of each of these components presents several difficulties.

[31] This subsection arises from the suggestion of an anonymous referee.

Regarding the *rival's incentive effect*, once the counterfactual of a public company that exercise market power like a private is added, then in order to perform a complete calculation of the companies' response it would be necessary to calculate the new equilibrium under this counterfactual. To perform this task, it may be necessary to assume an oligopolistic competition model and a functional form for the marginal costs of the firms, an exercise that goes beyond the scope of this article.

In relation to the *merit order effect*, it is necessary to have estimates of the marginal costs in order to build the competitive supply of public and private firms and calculate the generation costs both in equilibrium with market power mitigation and in the counterfactual equilibrium in which the public company exercises market power like a private. As mentioned above, there are estimates of the marginal costs of thermal units but not for hydro plants. Therefore, there is no choice but to make some kind of assumption regarding the marginal cost of the water units. In the context of this subsection of the article, it will be assumed that all the firms bid the marginal costs of water units. This allows the results of the calculations to be interpreted as a lower bound of the *merit order effect*.

To calculate the *merit order effect*, the following steps were adopted:

1. First, three counterfactual scenarios of privatization of a number of companies owned by central government are constructed.

   – In the first counterfactual scenario, it is assumed that the ISAGEN company was privately owned from 2005 to 2015.
   – In the second counterfactual scenario, it is assumed that the ISAGEN and GECELCA companies formed a single synthetic firm and that this firm was privately owned from 2005 to 2015.
   – In the third counterfactual scenario, it is assumed that the companies ISAGEN, GECELCA, and GENSA comprise a single synthetic firm and that this firm was privately owned from 2005 to 2015.

2. Second, the residual demand curve and the total cost curve of the synthetic company are constructed for each hour of the day. Water resources are assumed to be being bet at the marginal cost.
3. Third, each firm's profits are calculated as the income obtained at each point of residual demand minus the accumulated costs at the corresponding level of production. To calculate the profit function, two cases arise:

   – The profits that the firm would obtain if it did not have energy committed in forward contracts.
   – The profits that the firm would obtain according to the forward contracts observed in the sample.

The prices and quantities in the residual demand that maximize profits in each scenario and case are found. This allows calculating the incentive to exercise market power in the point of profit maximization of the synthetic firm.

4. Fourth, the supply curve for the case when the synthetic firm bids like a public firm is constructed. The bidding prices of the thermal units are replaced by bidding prices equal to the sum of the marginal costs and the product of the estimate of α_{pub} (0.33) and the incentive to exercise market power calculated in the previous step. Here it is also assumed that the bidding prices of the water units reflect their marginal cost. Subsequently, the market power mitigation equilibrium is found and the generation quantities and electricity generation costs corresponding to this equilibrium are computed.
5. Fifth, the supply curve for the case when the synthetic firm bids like a private firm is constructed. The bidding prices of the thermal units are replaced by bidding prices equal to the sum of the marginal costs and the product of the estimate of α_{pri} (0.60) and the incentive to exercises market power calculated in step three. The same assumption about water units costs is adopted. Subsequently, the no mitigation equilibrium is found and the generation quantities and costs corresponding to this equilibrium are computed.
6. Sixth, for each counterfactual scenario and each case of specification of the profit function (with and without contracts) the generation costs of the no mitigation equilibrium are compared with those resulting from the market power mitigation equilibrium.

The results of applying this methodology in scenario 1 are presented in Table VII, those corresponding to scenario 2 are presented in Table VIII, and those corresponding to scenario 3 are presented in Table IX. These tables present the daily average of total generation cost in the equilibrium of market power mitigation and the estimated efficiency loss that would arise if the synthetic firm bid as a private company.

In the case in which the counterfactual company does not have energy committed in contracts, the impact in the first scenario (ISAGEN private) varies between 0.06% and 0.27% of the cost of a nonprivatization situation, an effect that seems quite modest if we consider that ISAGEN is among the three most important firms in the electricity generation market in Colombia. The explanation for this is that the ISAGEN company only has one thermal unit (Termocentro) and the model presented above only captures the effect of the merit order of thermal units. In the second (GECELA and ISAGEN private) and third scenarios (GECELA, GECELCA, and GENSA private), more important effects are observed that vary between 0.5% and 2.15% for the second case and 0.76% and 2.53% for the third.

TABLE VII
EFFICIENCY GAINS OF MARKET POWER MITIGATION: SCENARIO 1

	Millions of Colombian pesos					
	No forward C.			With forward C.		
Year	Total cost MP Mitigation	Efficiency loss	Efficiency loss %	Total cost MP Mitigation	Efficiency loss	Efficiency loss %
2005	6271.13	13.73	0.22%	6266.72	0.38	0.01%
2006	6494.35	18.49	0.27%	6482.11	2.22	0.04%
2007	7247.36	16.74	0.23%	7240.59	0.85	0.01%
2008	7463.00	16.27	0.23%	7451.88	4.97	0.07%
2009	11,158.73	8.02	0.08%	11,156.20	0.57	0.01%
2010	11,270.95	13.61	0.15%	11,266.89	2.82	0.04%
2011	7477.96	16.23	0.21%	7469.99	3.51	0.05%
2012	11,285.84	6.82	0.06%	11,283.38	1.13	0.01%
2013	15,633.23	15.21	0.11%	15,630.58	0.73	0.01%
2014	17,874.01	20.82	0.14%	17,870.88	0.12	0.00%

TABLE VIII
EFFICIENCY GAINS OF MARKET POWER MITIGATION: SCENARIO 2

	Millions of Colombian pesos					
	No forward C.			With forward C.		
Year	Total cost MP mitigation	Efficiency loss	Efficiency loss %	Total cost MP mitigation	Efficiency loss	Efficiency loss %
2005	5636.12	128.87	2.15%	5496.63	37.89	0.65%
2006	6360.21	103.04	1.35%	6213.38	46.30	0.62%
2007	6834.04	113.45	1.59%	6673.34	31.03	0.45%
2008	7224.34	78.91	1.10%	7061.86	41.77	0.62%
2009	10,923.72	105.79	1.00%	10,760.50	49.47	0.49%
2010	11,147.23	156.18	1.32%	11,049.94	52.15	0.46%
2011	7327.93	64.51	0.81%	7251.20	16.32	0.24%
2012	10,993.97	71.20	0.50%	10,949.05	13.88	0.11%
2013	15,287.56	247.18	1.59%	15,153.11	36.25	0.28%
2014	17,736.64	337.66	2.09%	17,617.84	35.39	0.23%

This variation seems to be explained to some extent by fluctuations in water resources caused by El Niño and La Niña phenomena. In 2011, significantly lower generation costs were observed, which coincided with the abundance of water resources generated by a fairly intense La Niña phenomenon. On the other hand, higher generation costs were observed in 2014. One explanation for this may be that November and December of this year witnessed the start of the worst El Niño phenomenon observed in a decade.

In the case in which the counterfactual company has energy committed in forward contracts according to the quantities observed in the sample, the efficiency gains by the merit order effect in the three scenarios considered is negligible. In the first it varies from 0.03% to 0.18%, in the second from 0.08% to 0.36%, and in the third from 0.06% to 0.34%.

TABLE IX
EFFICIENCY GAINS OF MARKET POWER MITIGATION: SCENARIO 3

Millions of Colombian pesos						
	No forward C.			With forward C.		
Year	Total cost MP mitigation	Efficiency loss	Efficiency loss %	Total cost MP Mitigation	Efficiency loss	Efficiency loss %
2005	5679.30	148.21	2.45%	5485.97	54.89	0.92%
2006	6421.47	131.42	1.69%	6233.74	63.91	0.86%
2007	6893.41	148.96	2.06%	6668.02	46.59	0.67%
2008	7269.16	86.59	1.17%	7059.17	56.96	0.83%
2009	11,076.21	123.54	1.14%	10,825.75	75.48	0.71%
2010	11,274.55	196.75	1.62%	11,154.81	80.40	0.67%
2011	7331.47	60.59	0.76%	7247.17	18.00	0.26%
2012	11,022.34	84.30	0.59%	10,950.91	19.80	0.16%
2013	15,429.18	332.50	2.12%	15,186.27	59.95	0.43%
2014	18,157.54	418.88	2.53%	17,962.91	96.21	0.50%

As in the previous case, this result can be partially explained by the fact that the proposed methodology only captures the merit order effect of thermal units. However, the difference in results between the first and second cases shows that levels of forward contracts play a determining role in the possibilities of mitigating market power in the spot electricity market.

As mentioned above, it is possible that a company that intends to mitigate market power applies this policy in deciding its forward contractual positions, thus conditioning how much potential market power it has in the short-term market. In the case that considers the observed forward contracts levels, the results suggest that given the forward contracting position of public firms, there are no major differences between the equilibrium that would be obtained from profit maximization and application of the marginal cost pricing rule. This can happen because public companies have signed contracts in such a way that they have little incentive to exercise market power in the spot market. Of course, this interpretation is based on the strong assumption that the firms used to construct the counterfactual scenario bid their water resources according to their marginal costs.

In my opinion, given that the evidence presented in Section IV(iii) suggests that public companies exert market power mitigation in the short-term market, it is quite possible that these same companies are also exerting such mitigation in the forward contract market. This leads me to consider that the efficiency gains from market power mitigation behavior in the Colombian spot electricity generation market are modest.

V. CONCLUSIONS

In this study, bid price information for the Colombian electricity market has been used to understand differences in the way in which private and public firms exercise market power. Here, the methodology developed by McRae and

Wolak [2009] has been extended to include firms that do not price strategically. A new interpretation is proposed of the impact of incentives to exercise market power on prices in an attempt to obtain evidence of the profit-maximizing behavior of private firms and the adoption of the marginal cost pricing rule by public firms.

Estimations of the semi-elasticity of demand combined with contracting information suggest that the generators analyzed—both public and private—had incentives to exercise market power in association with profit-maximization behavior. An econometric analysis was conducted to find statistical evidence of: (i) differences in the impact of incentives to exercise market power on the bids and prices of public and private firms; (ii) the nonexercise of market power by public companies; and (iii) the exercise of market power by private firms consistent with profit-maximization behavior. Based on the outcomes of these econometric estimations, three main conclusions can be drawn. First, marked differences exist in the way in which private and public firms exercise unilateral market power: Specifically, private generators in the Colombian market are more responsive to IEMP than are public firms. Second, public firms do not exercise perfect regulatory intervention in the Colombian electricity markets–that is, they are also responsive to IEMP. Third, private firms are less responsive to IEMP than expected of profit-maximization behavior.

Afterward, I build simulations of the Colombian wholesale electricity market under three counterfactual scenarios of privatization and computed the*merit order effect* resulting from the more moderate exercise of market power by public firms in this market. These experiments yield negligible estimates of the generation total costs savings arising from the *merit order effect*. The above suggests that the benefits due to public companies responding less to the incentives to exercise market power than private firms are modest.

These findings suggest that the ownership regime of firms in Colombia's electricity industry is not neutral as regards the exercise of market power. Moreover, the outcomes reported have important implications for the regulation of electricity markets and the privatization of state-owned firms. First, besides increasing competition, there would appear to be an alternative way to achieve efficiency, namely, the mitigation of market power by public companies. Likewise, regulators need to recognize the nature of ownership within the market they are designing and determine whether public companies implement market power mitigation strategies. Second, the absence of neutrality in the exercise of market power implies that privatization has indirect effects on market competitiveness. This means the government should take into account the possible anti-competitive effects that privatization might have and include these undesirable costs in their assessment of the sales operation of state-owned generation units.

APPENDIX A

DERIVATION OF THE DAILY VERSION OF THE IEMP

The problem the generator faces is that of designing a set of daily bids $S_{it} = \{s_{i1t}, s_{i2t}, \dots, s_{ijt}, \dots, s_{iNt}\}$, where s_{ijt} is the daily bid price on day t for the energy of unit j, owned by firm i and N is the number of units that this firm i is able to bid. These bids are ordered from lowest to highest, so that they maximize the expected daily profit π_{it}, which is the sum of the hourly profits π_{ith}. If we adopt a residual demand approach, in which the competitors' bids are given, the generator should choose the bids that clear the market in the 24 hour of day t, constrained by the capacity of its own units and the market clearing price rules. Let $\pi_{it}(S_{it})$ be the daily profits of firm i on day t; let DR_{ith} be the residual demand of firm i on day t at hour h; and, let S_{it} be the set of bids made by firm i during day t. When considering forward contracts, the profit maximization problem of the firm can be stated as:

$$\max_{S_{it}} \pi_{it}(S_{it}) = \max_{S_{it}} \left[\sum_{h=1}^{24} \left(p_{th} \left(DR_{ith}(S_{it}) \right) \left(DR_{ith}(S_{it}) - q^c_{ith} \right) \right) + \sum_{h=1}^{24} p^c_{ith} q^c_{ith} - \sum_{h=1}^{24} C_{it} \left(DR_{ith}(S_{it}) \right) \right].$$

Subject to capacity constraints and non-negativity conditions:[32]

$$0 \le q_{jith} \le \overline{q_{ji}}.$$

If the restrictions are not binding, the first order conditions of this problem are:[33]

$$\sum_{h=1}^{24} \left[\frac{\partial p_{th}}{\partial s_{ijt}} \left(DR_{ith}(S_{it}) - q^c_{ith} \right) \right] + \sum_{h=1}^{24} p_{th} \left(DR_{ith}(S_{it}) \right) \frac{\partial DR_{ith}(S_{it})}{\partial s_{ijt}} - \sum_{h=1}^{24} \frac{\partial C_{it} \left(DR_{ith}(S_{it}) \right)}{\partial DR_{ith}} \frac{\partial DR_{ith}(S_{it})}{\partial s_{ijt}} = 0$$

Given the residual demand approach and the market clearing price rule, the equilibrium price of the market (or marginal price) is $p_{th} = min(s_{i1t}, s_{i2t}, \dots, s_{ijt}, \dots, s_{iNt})$

[32] In the equilibrium the residual demand of firm i is equal to the total production of electricity of firm i, $DR_{ith}(s_j ith) = \sum_{j=1}^{m} q_{jith}$, where the units 1 to m are the units that produce electricity, that is, the units 1 to m have bids lower or equal to the marginal price and the units $(m+1)$ to N have bids higher than the marginal cost, hence, the former are called to produce electricity while the latter not. That is the way by which q_{ijth} is implicitly included in the objective function.

[33] Note that I am interested in the units that are marginal (the equilibrium bid of the firm). We have to assume that around the equilibrium there are not capacity constraints. This is not reasonable when the marginal unit is the most expensive and it is operating at full capacity. An empirical indicator of this is the percentage of observations in which the firms are operating at full capacity. In the sample considering only marginal thermal units, in about 3.5% of the observations the firm is operating at full capacity. After repeating the econometric estimations excluding these observations from the sample, the basic results of the baseline estimation hold.

(the index j orders the units owned by firm i from the cheaper to the most expensive), such that:

$$DR_{ith}(s_{imt}) = \sum_{j=1}^{m} q_{ijt},$$

where the marginal unit is the mth most expensive unit owned by firm i. Once the units of firm i are ordered by merit, the above condition means that the spot price is equal to the bid of the generator's marginal unit, $p_{th} = s_{imt}$, if plant m clears the market in hour h. This in turn implies that $\frac{\partial p_{th}}{\partial s_{imt}} = 1$. In addition, in line with previous studies in the literature (Reguant [2014]), I assume that the residual demand of hour t is a function of the bid of unit m that is marginal in this hour h, but not of the bids of the other units. This implies that the derivative of the residual demand of hour h with respect to the bids of the plants that are not marginal in that hour is equal to zero, that is, $\frac{\partial DR_{ith}(s_{imt})}{\partial s_{ijt}} = 0$ where $m \neq j$ and that the derivative of the price of hour h with respect to the bids of the plants that are not marginal in that hour is equal to zero that is, $\frac{\partial p_{th}}{\partial s_{ijt}} = 0$, if unit j is not marginal.

Note that the set of potential bids that the generator is able to bet is limited by the daily bid constraint. If the day has 24 periods with different residual demands, the generator owns N units, and $N < 24$, then in at least $24 - N$ periods the generator will not be able to choose the exact bid that clears the market in the profit-maximizing point of each hour. In fact, the generator is compelled to clear the market with the bid of one unit, let s_{imt}, for several hours of the day. Hence, if unit m is marginal in hours h and h+k, this means that $p_{th} = p_{t(h+k)}$. In this way, every hour can be linked to a marginal plant m. Considering all of the above, if $\mathscr{H}_{ijt}$ is defined as the set of hours of day t where unit j is marginal (and unit j is owned by firm i), the first order condition can be expressed as:

$$\sum_{h\in\mathscr{H}_{ijt}} \left(DR_{ith}(s_{ijt}) - q^{c}_{ith}\right) + s_{ijt} \sum_{h\in\mathscr{H}_{ijt}} \frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}} - \sum_{h\in\mathscr{H}_{ijt}} \frac{\partial C_{it}}{\partial DR_{ith}} \frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}} = 0.$$

The optimal bids for unit j s^{*}_{ijt} for a private firm should be such that:

$$s^{*}_{ijt} = \frac{\sum_{h\in\mathscr{H}_{ijt}} \frac{\partial C_{it}}{\partial DR_{ith}} \frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}} - \sum_{h\in\mathscr{H}_{ijt}} \left(DR_{ith}(s_{ijt}) - q^{c}_{ith}\right)}{\sum_{h\in\mathscr{H}_{ijt}} \frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}}}.$$

If we assume the marginal cost of unit j to be constant during day t, the optimal bid of a daily profit-maximizing firm can be expressed s^{*}_{ijt} as:

$$s^{*}_{ijt} = c_{ijt} + \frac{-\sum_{h\in\mathscr{H}_{ijt}} \left(DR_{ith}(s_{ijt}) - q^{c}_{ith}\right)}{\sum_{h\in\mathscr{H}_{ijt}} \frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}}}.$$

APPENDIX B

DETAILS OF THE MARGINAL COST CALCULUS FOR THERMAL UNITS

The marginal costs of thermal plants were computed based on the heat rate, fuel costs, and fuel transportation costs according to the following formula:

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

where *COP* are Colombian pesos, *MBTU* are one thousand 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 published the Mines and Energy Planning Unit (UPME).

In the case of gas-fired units, the fuel cost is based on the price of gas from the Guajira Basin, which is the most important gas supply source for Colombian thermal generation. From September 1995 to August 2013, the Colombian Government regulated the price of gas obtained from this source by imposing a maximum sale price for 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 US Energy Information Administration. A period t is defined as a semester and it changes on the 1st February and 1st August of each year.[34] This price is given in *US dollars/MBTU*.

From 2005 to 2013, I applied the Guajira regulated price calculation published by the most important gas producer in the market (ECOPETROL) and converted the resulting price *(US dollars/MBTU)* to *Colombian pesos/KWh*. The exchange rate data was obtained from the Colombian Central Bank (Banco de la República). For the years after 2013, the weighted average gas price was calculated according to type of contract, based on information about wholesale gas transactions listed on the web page of the Gas Market Operator in Colombia (BEC).

Consequently, for gas-fired units, transportation costs were calculated as the sum of the fees for use of each segment of the gas transmission network necessary to transport the gas from the Guajira well to the respective generation units. These fees are regulated by the CREG and are published in regulatory acts (CREG 70 and 125 of 2003).

As regards coal-fired units, given that Colombia is a net exporter of coal, I used the FOB export price of thermal coal available in the Colombian Mines and Energy Planning Unit (UPME) databases. The price in *dollars per ton* was converted into *dollars per MBTU* units, multiplying by a calorific value of Colombian thermal coal of 1,370 *btu per pound* (*Source*: regulation 2009 180507 Colombian Ministry of Energy and Mines). To compute coal transportation costs, I used an import parity approach.

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

According to this criterion, transportation costs are estimated as the fee in *COP per ton* for road freight transportation from the closest importation port to the location of the generation unit. These fees were extracted from information provided by the Columbian Ministry of Transport on efficient road freight transportation costs.

APPENDIX C

ROBUSTNESS CHECK TABLES

TABLE CI
ESTIMATION USING MARGIN AS DEPENDENT VARIABLE

	OLS				GMM2S			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Private IEMP	0.33***	0.17***	0.17***	0.07	1.76***	0.49***	0.64***	0.31***
	(0.08)	(0.06)	(0.06)	(0.05)	(0.19)	(0.08)	(0.05)	(0.06)
Public IEMP	−0.03	−0.03	−0.03	−0.02***	−1.89***	−0.24***	0.28***	0.01
	(0.02)	(0.03)	(0.02)	(0.01)	(0.34)	(0.07)	(0.06)	(0.05)
Monthly FE	NO	NO	YES	NO	NO	NO	YES	NO
Unit FE	NO	YES	YES	NO	NO	YES	YES	NO
Unit × Month FE	NO	NO	NO	YES	NO	NO	NO	YES
No. Obs	19,789	19,789	19,789	19,578	14,836	14,836	14,836	14,633
No. clusters	32	32	32	32	32	32	32	32
Joint Sig.	9.590***	142.1***	4.297***	11.31***	58.69***	32.35***	98.35***	13.53***
Weak identification								
F first stage private					8.35	26,092.05	487.7	7.27
F first stage public					11.42	2.03	44.94	4.2
K-P rk Wald F					11.44	6121	2.360	4.205
Cragg-Donald Wald F					24.45	6.897	6.088	1.575
Overidentification								
Hansen J					28.27	19.48	19.79	19.48
p-value					0.0785	0.426	0.407	0.427
Test No Diff	19.18	9.66	10.64	3.64	88.95	63.96	22.24	15.54
p-value	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00
Test PMP	71.07	182.93	216.70	324.59	16.81	38.51	53.60	138.95
p-value	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{\text{pri}} - \alpha_{\text{soe}} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{\text{pri}} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10%, and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

TABLE CII
ESTIMATION INCLUDING HYDRO UNITS

	OLS				GMM2S			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Private IEMP	0.38***	0.09**	0.08**	0.02	4.88***	−0.23**	0.63***	−0.05**
	(0.09)	(0.04)	(0.04)	(0.01)	(0.27)	(0.10)	(0.11)	(0.02)
Public IEMP	0.02	−0.03***	−0.01	−0.01*	3.74***	−2.20***	0.19*	−0.17**
	(0.03)	(0.01)	(0.01)	(0.01)	(0.29)	(0.33)	(0.10)	(0.07)
Monthly FE	NO	NO	YES	NO	NO	NO	YES	NO
Unit FE	NO	YES	YES	NO	NO	YES	YES	NO
Unit × Month FE	NO	NO	NO	YES	NO	NO	NO	YES
No. Obs	52,154	52,154	52,154	51,876	40,544	40,544	40,544	40,225
No. clusters	53	53	53	53	53	53	53	53
Joint Sig.	9.134***	203.3***	940,820***	2.665***	273.7***	25.13***	24.76***	6.953***
Weak identification								
F first stage private					5.62	6.77	5.37	1.39
F first stage public					4.58	1.54	2.97	1.2
K-P rk Wald F					4.569	1.439	2.519	1.196
Cragg-Donald Wald F					46.95	4.453	3.640	0.922
Overidentification								
Hansen J					31.36	29.30	32.24	25.48
p-value					0.0368	0.0614	0.0294	0.145
Test No Diff	13.61	6.69	5.55	3.82	7.46	31.94	6.17	2.97
p-value	0.00	0.01	0.02	0.06	0.01	0.00	0.02	0.09
Test PMP	47.00	476.83	553.16	4565.57	205.41	154.20	11.49	2366.20
p-value	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{pri} - \alpha_{soe} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{pri} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10%, and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

TABLE CIII
ESTIMATION EXCLUDING EPM AND PPA

	OLS				GMM2S			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Private IEMP	0.27***	0.15***	0.15***	0.02	1.22**	0.16	0.55***	0.34***
	(0.07)	(0.06)	(0.05)	(0.01)	(0.49)	(0.20)	(0.16)	(0.13)
Public IEMP	0.00	−0.02*	−0.02*	−0.03***	−0.41	0.07	0.37***	0.01
	(0.03)	(0.01)	(0.01)	(0.01)	(0.50)	(0.06)	(0.07)	(0.03)
Marginal cost	1.21***	0.39***			1.08***	0.31***		
	(0.14)	(0.15)			(0.10)	(0.11)		
Monthly FE	NO	NO	YES	NO	NO	NO	YES	NO
Unit FE	NO	YES	YES	NO	NO	YES	YES	NO
Unit × Month FE	NO	NO	NO	YES	NO	NO	NO	YES
No. Obs	15,888	14,984	14,984	14,828	11,991	11,344	11,344	11,207
No. clusters	78	72	72	70	76	70	70	66
Joint Sig.	48.75***	5.772***	5.692***	7.554***	137.1***	5.825***	23.22***	3.622**
Weak identification								
F first stage private					3.75	1.51	2.32	1.55
F first stage public					3.35	2.41	3.94	4.02
K-P rk Wald F					3.401	1.435	2.343	3.630
Cragg-Donald Wald F					11.86	1.002	2.249	2.807
Overidentification								
Hansen J					25.63	28.66	24.53	24.06
p-value					0.141	0.0716	0.177	0.194
Test no diff	10.97	8.94	9.21	9.00	3.96	0.21	1.07	7.10
p-value	0.00	0.00	0.00	0.00	0.05	0.65	0.30	0.01
Test PMP	107.59	235.03	255.80	4381.89	0.21	17.75	7.62	27.06
p-value	0.00	0.00	0.00	0.00	.65	0.00	0.01	0.00

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{pri} - \alpha_{soe} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{pri} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10%, and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

TABLE CIV
ESTIMATION EXCLUDING OBSERVATIONS DURING RELIABILITY CHARGE

	OLS				GMM2S			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Private IEMP	0.16*	0.18***	0.05**	0.02	0.73***	0.65***	0.59***	0.34***
	(0.08)	(0.06)	(0.02)	(0.01)	(0.25)	(0.10)	(0.05)	(0.08)
Public IEMP	0.06	−0.04	0.01	−0.00	0.02	−0.04	0.33***	−0.04
	(0.04)	(0.03)	(0.01)	(0.01)	(0.03)	(0.05)	(0.08)	(0.06)
Marginal cost	1.28***	0.56***			1.19***	0.32***		
	(0.19)	(0.20)			(0.05)	(0.06)		
Monthly FE	NO	NO	YES	NO	NO	NO	YES	NO
Unit FE	NO	YES	YES	NO	NO	YES	YES	NO
Unit × Month FE	NO	NO	NO	YES	NO	NO	NO	YES
No. Obs	19,450	19,789	19,450	19,243	14,636	14,636	14,636	14,431
No. clusters	32	32	32	32	32	32	32	32
Joint Sig.	25.63***	133.4***	5.445***	1.128	574.6***	53.60***	102.8***	8.514***
Weak identification								
F first stage private					6.46	925.95	420.75	7.28
F first stage public					10.47	24.44	27.53	2.38
K-P rk Wald F					10.74	41.24	3.418	2.429
Cragg-Donald Wald F					8.366	6.326	5.897	1.535
Overidentification								
Hansen J					25.51	19.35	20.71	18.46
p-value					0.144	0.434	0.353	0.492
Test No Diff	1.07	10.91	2.94	1.62	7.02	32.54	5.31	12.88
p-value	0.31	0.00	0.09	0.21	0.01	0.00	0.03	0.00
Test PMP	109.64	177.98	2092.05	4412.83	1.19	12.12	59.09	61.96
p-value	0.00	0.00	0.00	0.00	0.28	0.00	0.00	0.00

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test no diff: $H_0 : \alpha_{\text{pri}} - \alpha_{\text{soe}} = 0$ and test PMP (profit maximization by private firms): $H_0 : \alpha_{\text{pri}} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10%, and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

TABLE CV
TRIMMING PERCENTAGES

	Sample trimmed at 0.1%				Sample Trimmed at 5%			
	OLS		GMM2S		OLS		GMM2S	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Private IEMP	0.20***	0.13***	0.37***	0.39***	0.34***	0.23***	3.31***	0.37***
	(0.05)	(0.04)	(0.07)	(0.07)	(0.11)	(0.08)	(0.70)	(0.12)
Public IEMP	−0.03	−0.04**	1.03***	0.28***	0.15	0.04**	−1.23***	0.15
	(0.03)	(0.02)	(0.14)	(0.06)	(0.09)	(0.02)	(0.22)	(0.11)
Marginal cost	1.29***		1.35***		1.24***		0.96***	
	(0.19)		(0.05)		(0.19)		(0.09)	
Monthly F.E.	NO	YES	NO	YES	NO	YES	NO	YES
Unit F.E.	NO	YES	NO	YES	NO	YES	NO	YES
No. Obs	20215	20215	15032	15032	18199	18199	13873	13873
No. clusters	32	32	32	32	32	32	32	32
Joint Sig.	37.44***	1.823**	331.7***	134.7***	19.89***	3.569***	415.3***	4.542**
Weak identification								
F first stage private			12.13	202.37			69.54	586.13
F first stage public			3.22	26.58			3.56	9.8
K-P rk Wald F			3.988	17.13			5.487	49.52
Cragg-Donald Wald F			5.773	2.819			6.218	5.996
Overidentification								
Hansen J			21.88	22.88			25.74	20.48
p-value			0.290	0.243			0.137	0.366
Test No Diff	11.77	15.26	16.08	0.87	1.99	5.86	37.70	3.70
p-value	0.00	0.00	0.00	0.36	0.17	0.02	0.00	0.06
Test PMP	211.92	439.28	93.76	85.71	35.64	94.82	10.79	25.39
p-value	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{\text{pri}} - \alpha_{\text{soe}} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{\text{pri}} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10%, and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

TABLE CVI
GMM2S ESTIMATION WITH 2 AND 4 LAGS

	2 First Lags		4 First Lags	
	(1)	(2)	(3)	(4)
Private IEMP	0.60**	0.57***	0.67***	0.63***
	(0.24)	(0.09)	(0.16)	(0.04)
Public IEMP	0.36**	0.33**	−0.17***	0.14***
	(0.16)	(0.15)	(0.05)	(0.04)
Marginal cost	1.26***		1.15***	
	(0.06)		(0.03)	
Monthly F.E.	NO	YES	NO	YES
Unit F.E.	NO	YES	NO	YES
No. Obs	16404	16404	13420	13420
No. clusters	32	32	32	32
Joint Sig.	289.5***	53.34***	1014***	144.7***
Weak Identification				
F first stage private	8.13	141.05	86.83	1001.19
F first stage public	2.79	45.1	271.62	16.32
K-P rk Wald F	4.606	1.931	107.2	20.13
Cragg-Donald Wald F	10.77	6.802	7.648	5.270
Overidentification				
Hansen J	23.10	19.39	27.40	25.08
p-value	0.0820	0.197	0.239	0.346
Test No Diff	0.55	1.35	26.00	58.37
p-value	0.46	0.25	0.03	0.00
Test PMP	2.72	24.57	4.47	80.89
p-value	0.10	0.00	0.00	0.00

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{\text{pri}} - \alpha_{\text{soe}} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{\text{pri}} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10%, and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

TABLE CVII
DELTA PARAMETER 10% AND 25%

	$\delta = 10\%$				$\delta = 25\%$			
	OLS		GMM2S		OLS		GMM2S	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Private IEMP	0.35***	0.24***	1.33***	0.66***	0.44***	0.28***	2.19***	0.84***
	(0.10)	(0.07)	(0.41)	(0.10)	(0.15)	(0.10)	(0.79)	(0.16)
Public IEMP	0.00	−0.04	−0.79**	0.41***	−0.00	−0.07	−1.69***	0.65***
	(0.04)	(0.03)	(0.36)	(0.13)	(0.11)	(0.10)	(0.29)	(0.14)
Marginal Cost	1.27***		1.12***		1.27***		1.09***	
	(0.18)		(0.06)		(0.18)		(0.09)	
Monthly F.E.	NO	YES	NO	YES	NO	YES	NO	YES
Unit F.E.	NO	YES	NO	YES	NO	YES	NO	YES
No. Obs	19,771	19,771	14,818	14,818	19,771	19,771	14,840	14,840
No. clusters	32	32	32	32	32	32	32	32
Joint Sig.	30.96***	5.97***	1146***	52.89***	27.38***	1.984**	858.2***	24.81***
Weak identification								
F first stage private			28.14	1601.69			25.55	435.34
F first stage public			14.92	24.88			4.74	27.61
K-P rk Wald F			6.384	1.600			4.936	11.10
Cragg-Donald Wald F			7.545	6.432			7.399	8.309
Overidentification								
Hansen J			25.64	20.56			26.64	24.71
p-value			0.141	0.362			0.113	0.170
Test No Diff	8.55	12.67	11.73	1.39	5.20	6.95	19.00	0.74
p-value	0.00	0.00	0.00	0.25	0.00	0.01	0.00	0.32
Test PMP	39.57	104.40	0.64	10.98	13.33	55.27	2.26	1.01
p-value	0.00	0.00	0.42	0.00	0.02	0.00	0.13	0.40

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{\text{pri}} - \alpha_{\text{soe}} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{\text{pri}} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10%, and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

TABLE CVIII
KERNEL-SMOOTHED APPROACH $h = 200$

	OLS				GMM2S			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Private IEMP	0.87***	0.55***	0.53***	0.39	1.29***	1.32***	0.96***	1.24***
	(0.25)	(0.13)	(0.12)	(0.26)	(0.20)	(0.08)	(0.11)	(0.21)
Public IEMP	0.28	−0.29	−0.27	−0.19***	8.20***	1.54*	0.86**	0.30***
	(0.36)	(0.24)	(0.23)	(0.06)	(0.77)	(0.77)	(0.37)	(0.11)
Marginal cost	1.23***	0.52***			1.25***	0.54***		
	(0.18)	(0.19)			(0.03)	(0.08)		
Monthly FE	NO	NO	YES	NO	NO	NO	YES	NO
Unit FE	NO	YES	YES	NO	NO	YES	YES	NO
Unit × Month FE	NO	NO	NO	YES	NO	NO	NO	YES
No. Obs	19,207	19,207	19,207	18,997	14,771	14,771	14,771	14,569
No. clusters	32	32	32	32	32	32	32	32
Joint Sig.	31.04***	19.82***	25.21***	5.886***	895.6***	423.1***	40.66***	20.62***
Weak identification								
F first stage private					33.93	3682.27	1430.64	3.14
F first stage public					10.77	36.67	14.42	22.9
K-P rk Wald F					8.657	5.747	9.425	3.308
Cragg-Donald Wald F					38.80	4.650	6.993	4.761
Overidentification								
Hansen J					24.46	22.21	23.06	20.56
p-value					0.179	0.274	0.235	0.362
Test No Diff	1.55	9.47	9.45	4.50	66.33	0.09	0.06	16.58
p-value	0.21	0.00	0.00	0.04	0.00	0.76	0.81	0.00
Test PMP	0.29	12.13	16.69	5.34	2.02	17.75	0.14	1.28
p-value	0.59	0.00	0.00	0.03	0.15	0.00	0.71	0.27

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{\text{pri}} - \alpha_{\text{soe}} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{\text{pri}} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10%, and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

TABLE CIX
KERNEL-SMOOTHED APPROACH $h = 400$

	OLS				GMM2S			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Private IEMP	0.58***	0.22**	0.19**	0.09	0.72***	0.73***	0.54***	0.71***
	(0.22)	(0.10)	(0.09)	(0.08)	(0.10)	(0.05)	(0.06)	(0.12)
Public IEMP	0.44***	−0.04	−0.01	−0.07	4.48***	0.63	0.46**	0.16**
	(0.15)	(0.11)	(0.10)	(0.05)	(0.37)	(0.47)	(0.20)	(0.06)
Marginal cost	1.24***	0.57***			1.25***	0.57***		
	(0.18)	(0.20)			(0.03)	(0.08)		
Monthly FE	NO	NO	YES	NO	N0	NO	YES	NO
Unit FE	NO	YES	YES	NO	N0	YES	YES	NO
Unit × Month FE	NO	NO	NO	YES	NO	NO	NO	YES
No. Obs	19,207	19,207	19,207	18,997	14,771	14,771	14,771	14,569
No. Clusters	32	32	32	32	32	32	32	32
Joint Sig.	29.47***	31.99***	8.007***	1.413	1499***	445.7***	39.14***	20.57***
Weak identification								
F first stage private					33.27	3949.23	1226.37	2.49
F first stage public					10.19	40.83	14.78	22.89
K-P rk Wald F					9.396	5.290	7.901	2.756
Cragg-Donald Wald F					42.80	5.047	7.540	4.273
Overidentification								
Hansen J					23.37	21.50	22.73	20.41
p-value					0.221	0.310	0.249	0.370
Test No Diff	0.21	2.71	2.37	2.65	92.67	0.06	0.16	17.52
p-value	0.64	0.10	0.12	0.11	0.00	0.81	0.69	0.02
Test PMP	3.53	57.46	73.23	134.88	7.46	29.88	53.79	6.25
p-value	0.06	0.00	0.00	0.00	0.01	0.00	0.00	0.00

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{\text{pri}} - \alpha_{\text{soe}} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{\text{pri}} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10%, and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

TABLE CX
KERNEL-SMOOTHED APPROACH $h = 800$

	OLS				GMM2S			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Private IEMP	0.29**	0.07**	0.06**	0.01	0.39***	0.38***	0.29***	0.37***
	(0.12)	(0.03)	(0.03)	(0.01)	(0.05)	(0.03)	(0.03)	(0.06)
Public IEMP	0.25***	−0.01	0.00	−0.03	2.38***	0.26	0.24**	0.08**
	(0.08)	(0.06)	(0.05)	(0.03)	(0.19)	(0.26)	(0.11)	(0.03)
Marginal cost	1.24***	0.58***			1.25***	0.59***		
	(0.18)	(0.21)		(0.03)	(0.09)			
Monthly FE	NO	NO	YES	NO	NO	NO	YES	NO
Unit FE	NO	YES	YES	NO	NO	YES	YES	NO
Unit × Month FE	NO	NO	NO	YES	NO	NO	NO	YES
No. Obs	19207	19207	19207	18997	14771	14771	14771	14569
No. clusters	32	32	32	32	32	32	32	32
Joint Sig.	30.04***	42.85***	2.94***	1.255	2072***	501.4***	39.48***	20.72***
Weak identification								
F first stage private					32.2	4281.9	1105.97	2.31
F first stage public					8.91	43.95	13.73	24.27
Cragg-Donald Wald F					44.95	5.237	7.849	4.178
Overidentification								
Hansen J					23.38	20.94	22.57	20.36
p-value					0.221	0.340	0.257	0.373
Test No Diff	0.04	1.54	0.97	2.10	111.66	0.25	0.17	18.21
p-value	0.84	0.21	0.33	0.16	0.00	0.62	0.68	0.00
Test PMP	38.25	789.15	1143.49	9488.31	146.37	485.86	469.21	103.38
p-value	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{\text{pri}} - \alpha_{\text{soe}} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{\text{pri}} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10%, and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

TABLE CXI
CLUSTER ALTERNATIVES

	TWFE				Unit × M. Sample			
Cluster by	Unit (1)	Unit × Niño (2)	Unit × M. Year (3)	Unit × M. Sample (4)	Unit (5)	Unit × Niño (6)	Unit × M. Year (7)	Unit × M. Sample (8)
Private IEMP	0.60***	0.63***	0.61***	0.62***	0.34***	0.26**	0.22**	0.22**
	(0.06)	(0.12)	(0.13)	(0.13)	(0.08)	(0.11)	(0.10)	(0.09)
Public IEMP	0.33***	0.05	0.04	0.04	0.01	−0.08	−0.13*	−0.11
	(0.07)	(0.12)	(0.11)	(0.12)	(0.03)	(0.08)	(0.08)	(0.08)
M. Sample FE	YES	YES	YES	YES	NO	NO	NO	NO
Unit FE	YES	YES	YES	YES	NO	NO	NO	NO
Unit × M. Sample FE	NO	NO	NO	NO	YES	YES	YES	YES
No. Obs	14,836	14,836	14,836	14,836	14,633	14,633	14,633	14,633
No. clusters	32	91	346	1537	32	87	330	1334
Joint Sig.	93.78	14.40	12.15	12.44	9.785	4.089	4.639	4.427
Weak identification								
F first stage private	487.7	3.82	2.62	3.17	7.27	1.52	1.18	1.13
F first stage public	44.94	2.31	1.89	1.75	4.2	0.97	0.99	0.95
K-P rk Wald F	2.360	1.956	2.135	2.067	4.205	0.976	0.993	0.951
Cragg-Donald Wald F	6.088	6.075	6.075	6.075	1.575	1.575	1.575	1.575
Overidentification								
Hansen J	20.86	25.60	36.14	41.32	18.59	24.21	20.63	23.34
p-value	0.34	0.14	0.01	0.00	0.48	0.19	0.36	0.22
Test No Diff	5.11	9.41	9.65	10.57	14.23	8.04	9.25	8.60
p-value	0.03	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Test PMP	40.19	9.05	9.62	9.36	68.81	47.54	60.89	71.37
p-value	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Notes: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{pri} - \alpha_{soe} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{pri} = 1$. The test statistics for weak identification are the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04, and 6.10 for 5%, 10%, and 20% maximal IV relative bias, respectively, according to Stock and Yogo [2002].

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