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Kai-Uwe Kühn and Matilde Machado

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Kai-Uwe Kühn, University of Michigan and CEPR
Matilde Machado, Universidad Carlos III de Madrid

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Centre for Economic Policy Research
90–98 Goswell Rd, London EC1V 7RR, UK
Tel: (44 20) 7878 2900, Fax: (44 20) 7878 2999
Email: cepr@cepr.org, Website: www.cepr.org

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ABSTRACT

Bilateral Market Power and Vertical Integration in the Spanish Electricity Spot Market*

The Spanish electricity spot market is highly concentrated both on the seller and the buyer side. Furthermore, unlike electricity spot markets in other deregulated electricity systems, large buyers and sellers are typically vertically integrated. This allows both large net sellers and large net buyers to strategically influence the spot market price. We develop a supply function model of this market to analyse the impact of market power on prices and productive efficiency and use it empiricially to detect such bilateral market power. Our estimates suggest that market power has had little impact on spot market prices but that substantial productive inefficiencies may have arisen from the exercise of bilateral market power.

JEL Classification: L13, L41 and L94
Keywords: bilateral market power, electricity markets, market power test, supply function equilibirum and vertical integration

Kai-Uwe Kühn
Department of Economics
University of Michigan
611 Tappan Street
238 Lorch Hall
Ann Arbour, MI 48109
USA
Tel: (1 734) 763 5317
Fax: (1 734) 764 2769
Email: kukuhn@umich.edu

Matilde Machado
Universidad Carlos III de Madrid
Calle Madrid 126
28903 Getafe (Madrid)
SPAIN
Tel: (34 91) 624 9571
Fax: (34 91) 624 9875
Email: mmachado@eco.uc3m.es

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1 Introduction

In January 1998, the Spanish government liberalized the market for electricity generation and introduced a spot market for electricity. This followed liberalization in the UK market and was enacted almost simultaneously with liberalization in California. The basic design of this electricity spot market is similar to the previously deregulated UK market and even closer to the California electricity market. However, Spanish deregulation has been distinctive by allowing vertical integration between the generation and retailing, which had been prohibited in other deregulation experiments.[1] As a result, Spain's major electricity companies are active on both sides of the electricity spot market, selling electricity as generators and buying it from the spot market as retailers.

The Spanish experience has also been distinct from that in California or the UK because there has been no major intervention by regulators caused by concerns about excessive pricing in the spot market. In the UK concerns about market power led to forced divestitures in generation and ultimately triggered a complete re-organization of the market. In California, it is now well known, that the exercise of market power caused, or at least contributed, to the 2000-2001 electricity crisis with its associated large costs to the public. In Spain, commentators had expected that the exercise of market power would be a major issue post-deregulation (see Kühn and Regibeau, 1998, and Arocena, Kühn and Regibeau, 1999). Indeed, Spanish electricity generation was more concentrated than UK generation at the time of deregulation with the two largest firms controlling approximately 75% of generation. This high degree of concentration has remained virtually unchanged over the first few years of the deregulation experience. Nonetheless, the issue of high spot market prices due to market power has been of much less importance in Spain than in the UK or California.

We show in this paper that the absence of major concerns about excessive pricing in the spot market is most likely a consequence of vertical integration. We show that what theoretically matters for an

[1] Most deregulation experiments in fairly concentrated markets, including the UK and California, have imposed vertical separation between generation and retailing activities in the belief that these would create incentives for entry into the industry. See Arocena et al. (1999) for such an argument.

integrated firm is its net demand position at any point in time in the spot market. Since some firms will be net demanders they have an incentive to overproduce in generation in order to lower the spot market price paid on the net purchases from the spot market. Since electricity markets must net out, there will always be firms with net demand and net supply positions in the spot market. If they have similar degrees of market power, prices may not differ much from competitive prices. Indeed, prices may be higher or lower than in a perfectly competitive market. As a result it will not be apparent from average price cost margins in the industry whether substantial market power exists in the spot market. However, there may, nevertheless, be large efficiency losses because of the exercise of market power since net-demanders systematically overproduce and net-suppliers underproduce.

In this paper we analyze a supply function model to show these points formally and to develop a framework for structural estimation of competition in the Spanish electricity spot market.[2] The model shows that market power effects arise exclusively from asymmetries in upstream generation assets and downstream demand realizations. Under complete symmetry in generation cost functions and downstream demands the operation of the spot market would be efficient and marginal cost pricing would obtain.

The model allows us to test alternative models of firm behavior even in the absence of cost data: In the presence of market power an increase in exogenous downstream demand will, on average, lead to a larger net demand position and systematically more aggressive bidding. Under competition, there should be no such impact of downstream demand variations on a firm's bidding strategy. Hence a systematic impact of downstream demand on the bid quantities of individual firms will indicate the presence of market power. There should also be no impact of downstream demand on bidding behavior if the generation part of the electricity company would narrowly maximize generation profits. Indeed, only under joint (generation and retailing) profit maximizing behavior would firms act as if only net

[2] We have chosen the supply function model because it most closely resembles the true bidding structure of the market. It is therefore most appropriate for a structural estimation approach. However, it should be kept in mind that the qualitative features of the model would be retained by any other bidding model, for example the models of Harbord and von der Fehr (1993) and Mansur (2003).

demand positions mattered.

Our structural model allows us to nest the assumptions of perfect competition, supply function competition, and supply function competition with imperfect joint profit maximization between upstream and downstream units of the same firm in form of simple restrictions on parameters of the estimating equation. Our estimates, based on a sample of spot market bids from May through December 2001, clearly reject perfect competition and robustly confirm the assumption of joint profit maximization between upstream and downstream units of the same firm. The latter result is of some importance in its own right. Generation and supply companies in Spain are jointly owned but formally legally separate entities. Our analysis clearly rejects the claim often made before deregulation that legal separation would have a significant impact on the behavior of the firms.

Note that the use of a structural approach is crucial for our analysis since it allows the nesting of alternative hypotheses about the existence of market power even in the absence of information on costs, financial contracts, or information on the form of downstream negotiated retail contracts. Furthermore, the structural approach is necessary to assess the impact of market power in terms of efficiency effects since it enables us to identify and estimate the firms' marginal cost parameters. Assessing efficiency gains is particularly important given that there is two sided market power in the electricity spot market. In markets with one sided market power, an estimate of price-cost markup would give an indication of the importance of market power in the market. However, since the spot market price may not be dramatically different from the competitive price, under two-sided market power the only way to assess the importance of market power is by estimating the efficiency gains.

We do so by estimating marginal costs imposing the parameter restrictions of our supply function model. This gives us, for each firm, precise estimates of the parameters of the aggregate marginal cost function for non-hydroelectric generation plants. We show that, if the two largest firms (Iberdrola and Endesa) were to bid in their non-hydro plants at marginal cost (maintaining hydro-electrical bid functions unchanged) there would be little impact on price. However, there would be an estimated cost reduction on these assets alone in the order of magnitude of 6000 Euro an hour or 51 million Euro a year.

The use of supply function equilibrium to model behavior in electricity markets was pioneered by Green and Newbery (1992) based on the theoretical work of Klemperer and Meyer (1989) and extensions of this work to capacity constrained markets by Kühn (1991). Their work focused on calibrating alternative scenarios for electricity liberalization in generation for the UK. Supply function models of electricity markets have first been estimated by Sweeting (2002) and Wolak (2003).

We contribute to this literature by expanding on the theoretical work in Kühn and Machado (2000), which first explicitly modelled the vertical structure of the market and discussed how the presence of heterogeneous and variable degrees of vertical integration could be exploited to identify market power in the spot market. In independent work Hortacsu and Puller (2004) have used an almost identical model to that developed in Kühn and Machado (2000) to study the Texas balancing market. Their use of the theoretical model is very different, however. Their aim is not to measure market power, but instead test the deviation of actual bidding from optimal bidding behavior. This is possible in their case because they have access to actual cost data. In contrast, we use the supply function model to estimate the marginal cost functions and assess the impact of market power.

Our paper is distinct from the rest of literature by focusing on the interaction of net-suppliers and net demanders with market power in the spot market.[3] What allows us to identify the impact of market power in the presence of vertical integration in our paper is a high degree of variability of downstream demand, which leads to large effective variations in vertical integration (i.e. net demand positions). The spirit of our exercise is therefore very close to Wolfram (1998) in the sense that we are observing variations in infra marginal sales to detect the exercise of market power. She concludes that asymmetries in generation assets in the UK electricity market significantly increased prices. The

[3] Mansur (2003) also notes the different incentives of net-demanders and net-suppliers. However, the main focus of his paper is on the impact of cost non-convexities on the measurement of the degree of market power in the PJM market. For his study he uses cost data, which is not available to us.

argument that asymmetric asset distributions increase market power had previously been raised by Green and Newbery (1992). Green (1996) explicitly considered the impact of asymmetric holdings of generation assets on spot market prices in a calibration of a supply function model to data of the UK electricity market. Unfortunately, the impact of asymmetries in the distribution of generation asset on spot market prices is difficult to test empirically due to the lack of variation in the distribution of those assets across firms. In contrast to these previous studies we are focused on the effects of vertical integration. Since there is much greater variation in the demand shares and therefore in the net-demand positions of different electricity companies than there is in capacities, it is possible to identify the impact of asymmetries.

The rest of the paper is structured as follows. Section 2 describes a simple theoretical model that illustrates most of the qualitative strategic effects at play and derives the basic propositions. Section 3 describes the institutional features of the Spanish electricity market. Section 4 adapts the basic model of Section 2 to the specificities of the Spanish one day ahead electricity spot market, allowing for the existence of a significant hydroelectric generating capacity and the regulatory rules that affect bidding incentives. We also describe the data in this section. In Section 5 we discuss the estimation results and in Section 6 we measures the efficiency losses from the exercise of market power. Section 7 concludes. In the Appendix we discuss some of robustness issues and theoretical caveats that may influence the interpretation of our results.

2 An Illustrative Model

There are essentially four separate economic activities in electricity markets: generation, transmission, distribution and retailing (often called supply). Even under electricity liberalization transmission and distribution are considered natural monopoly activities and always remain regulated. These services are paid fixed per unit access prices by the retailers. Generation and retailing are considered competitive activities. While in almost all deregulatory experiments generation was immediately deregulated, retailing has generally been liberalized only gradually. The introduction of a spot market meant that generators now directly sell their electricity to retailers (see Figure 1). The latter purchase regulated transmission and distribution services as separate inputs for electricity retailing. By the rules of the spot market virtually all electricity produced has to be sold into the spot market and retailers have to purchase all their electricity from the spot market. Our analysis focuses on the interaction of generators and retailers in the spot market and its implications for the efficiency of electricity supply.

The main feature of interest of the Spanish electricity market for our analysis is that the major competitors are active both in generation and in retailing. This potentially generates market power both on the buyer and the seller side of the market. In this section we develop a simple duopoly model of supply function competition that has these characteristics. In section 4 we adapt this model to the idiosyncratic features of the Spanish electricity market. Yet, the basic mechanism driving the qualitative results of the extended model will be the same as in this illustrative model.

Every generator i is integrated into downstream retailing. Demand from his customers is given by $\theta_i D(p_i)$. We assume that the final consumer price is predetermined by contract or regulation $p_i = \bar{p}$, reflecting the fact that downstream prices are set much less frequently than spot market prices. For ease of exposition we normalize $D(\bar{p}) = 1$. The demand parameter θ_i is randomly distributed on some interval $[\underline{\theta}_i, \bar{\theta}_i]$, where we allow for $\bar{\theta}_i = \infty$. We will refer to it as the state of retailing demand for firm i. We allow θ_i to be correlated between firms. There is a set of signals about the state of retail demand of the form $\sigma_k = \theta_l + \varepsilon_k$, $k = 1, ..., K$, where l is either i or j, and $E\{\varepsilon_k\} = 0$. Each firm receives a subset of these signals denoted by I_i for firm i, which is firm i's information set. For our model the only relevant signals are those which contain private information about the rival's downstream demand. Hence, without loss of generality, we reduce the set of signals in our illustrative model to one for each firm, where the signal for firm i has the form $\sigma_i = \theta_j + \varepsilon_i$.[4] We assume that the distributions of the parameter vector (θ_i, θ_j) and the signal vector are such that the posterior for θ_i, i.e. $E\{\theta_i \mid I_j\}$ is linear

[4] Note that the signal about firm i's own demand would contain information about firm j's demand when demands are correlated. We have chosen our formulation to make the illustrative model more transparent.

in the signals observed.[5]

Firm i produces electricity with the total cost function $C_i(q_i) = c_{0i}q_i + c_{1i}\frac{q_i^2}{2}$. A firm's strategy set consists of a set of supply functions of the form $S_i(\pi; I_i)$, where S_i is increasing and differentiable in π. For any information set I_i, this function specifies how much electricity the firm is willing to produce for all possible spot market prices π.

The upstream generation market is run by a spot market operator who obtains direct information about total market demand $\theta = \theta_i + \theta_j$.[6] He also receives the supply functions submitted by the two firms. He then sets the price π^* such that the market is cleared:

$$\theta = S_i(\pi^*, I_i) + S_j(\pi^*, I_j). \tag{1}$$

An electricity generator obtains $\pi^* S_i(\pi^*, I_i) - C_i(S_i(\pi^*, I_i))$ of profits from selling electricity in the spot market. In addition he receives $(\bar{p} - \pi^*)\theta_i$ from distributing electricity to the end user for which he receives the price $\bar{p}$ and pays the spot market price π^*. Firms maximize the joint profits from generation and retailing by simultaneously submitting their supply functions to the spot market operator taking the supply function chosen by the rival as given. Each firm will, therefore, perceive that a change in their supply function will affect the equilibrium spot market price the spot market operator sets via the market clearing condition (1).

Maximizing profits over a function space is potentially a difficult problem to solve. Klemperer and Meyer (1989) have shown how to reduce such a problem by substituting in for the supply function of the firm from the market clearing condition. Then the problem can be solved by choosing an optimal price π for every realization of an uncertain parameter, provided that the optimal spot market price is monotone in the uncertain parameter. Except for the changes in incentives due to vertical integration, our model would be equivalent to that of Klemperer and Meyer (1989) if all signals were common to

[5] This implies that $E\{\theta_i \mid \theta_j\} = E\{\theta_i\} + \rho[\theta_j - E\{\theta_j\}]$, where ρ is the correlation coefficient between θ_i and θ_j.

[6] Assuming that the spot market is cleared on the basis of realized demand is a simplifying assumption allowing us to exposit the basic economic effect at play in the simplest way. In section 4 we will change this assumption to reflect the true structure of the Spanish spot market mechanism. As will be clear later, the basic mechanism is still at work in that modified model.

both players so that there would be no private information.[7]

When there are private signals a firm does not only face whatever uncertainty exists in the total demand θ (as in Klemperer and Meyer), but is also uncertain about the realization of the supply function of its rival.[8] In order to use their techniques to solve the firm's maximization problem and derive explicit equilibrium behavior, we restrict attention in this paper to the analysis of equilibria in supply functions $S_i(\pi, I_i)$ that are linear in all of their arguments:

$$S_i(\pi, I_i) = s_i^0 + s_i^1 \sigma_i + s_i \pi, \tag{2}$$

The intercept of the supply function has a deterministic component s_i^0 and one component that depends on the signal observed. The latter corresponds to the signal that is observed by firm i privately.[9]

By restricting ourselves to linear supply functions we can generate a residual demand for firm i in the spot market that depends additively on a random shock as is the case in Klemperer and Meyer (1989). This residual demand for firm i is given by:

$$\theta - S_j(\pi, I_j) = \theta - s_j^1 \left[\sigma_j - E\{\sigma_j \mid I_i\}\right] - \left\{S_j(\pi, I_j) - s_j^1 \left[\sigma_j - E\{\sigma_j \mid I_i\}\right]\right\} \tag{3}$$

Define the random variable η_i by $\eta_i \equiv \theta - s_j^1 \left[\sigma_j - E\{\sigma_j \mid I_i\}\right]$. All the uncertainty faced by i in its residual demand is captured by the random variable η_i. In other words, η_i is a sufficient statistic for the state of the spot market for firm i. For any given π we can, therefore, write the residual demand for firm i as $\eta_i - E\{S_j(\pi, I_j) \mid I_i\}$.

Note that, for a higher η_i, the residual demand curve shifts upward and the unique optimal quantity will lead to a higher equilibrium price. Because of this monotonicity we can express firm i's problem simply as maximizing profits pointwise with respect to π for every possible realization of η_i:

[7] Readers familiar with Klemperer and Meyer (1989) will note that in their model there exists no equilbrium for the case of completely inelastic demand. This is not the case in our model due to vertical integration into downstream retailing.

[8] Formally, instead of analyzing Nash equilibria in supply functions we solve for Bayesian Nash equilibria.

[9] Note that we are making two separate linearity assumptions. First, linearity in the private signal is a standard assumptions that allows the derivation of equilibrium in Bayesian games (see for example Vives 1987, Gal-Or 1987). Second, we assume linearity in price. Given the linearity of marginal costs and demand, an equilibrium that is linear in price will be the only one robust to the support of the underlying uncertainty. The linearity assumption can always be interpreted as a local approximation.

$$\max_{\pi(\eta_i,I_i)} E\left\{E\left\{[\bar{p}-\pi]\theta_i + \pi\left[\eta_i - E\{S_j(\pi,I_j)\mid I_i\}\right] - C_i\left(\eta_i - E\left\{S_j(\pi,I_j)\mid I_i\right\}\right)\mid I_i,\eta_i\right\}\mid I_i\right\}, \tag{4}$$

Such pointwise maximization of (4) yields the following first order condition for every η_i

$$-E\{\theta_i \mid I_i,\eta_i\} + S_i(\pi,I_i) - (\pi - c_{0i} - c_{1i}S_i(\pi,I_i))s_j = 0 \tag{5}$$

where we have substituted $S_i(\pi,I_i)$ for $\eta_i - E\{S_j(\pi,I_j)\mid I_i\}$ from the equilibrium condition. From this first order condition we immediately obtain our first result:

Proposition 1 *Suppose firm j uses a linear supply function. Then, firm i in a state (I_i,η_i) will be producing at price exceeding (below) marginal cost if and only if firm i is a net supplier (net demander) of electricity in the spot market equilibrium. Furthermore, firm i prices on average below (above) marginal cost if and only if it is on average a net demander (net supplier).*

Proof. It follows directly from (5) that $S_i(\pi,I_i) - E\{\theta_i \mid I_i,\eta\} > 0 \Longleftrightarrow (\pi - c_{0i} - c_{1i}S_i(\pi,I_i)) > 0$ and the same for the reverse sign. On average net supply to the market must be equal to the unconditional expectation $E\{S_i(\pi,I_i)-\theta_i\}$. Since $E\{(\pi - c_{0i} - c_{1i}S_i(\pi,I_i))s_j\} = E\{(\pi - c_{0i} - c_{1i}S_i(\pi,I_i))\}s_j$ by the linearity of j's supply function, the same argument as before can be made for the unconditional expectations. ■

Proposition 1 captures the essential strategic issue in this market. If a generator would expect to sell exactly as much into the spot market as he takes out of the spot market as a retailer, there would be no reason at the margin to increase or decrease production to influence the price. Any marginal change in production, to the first order, will only effect a redistribution between the upstream and the downstream parts of the same business. When a firm expects to be a net supplier, then it has an incentive to hold back production, because this redistributes rents from net demanders to this firm. Holding back production results in a price increase from which the firm benefits on its net sales into the spot market. This is the standard oligopoly incentive to reduce production. The opposite is true for net demanders. A net demander has an incentive to overproduce in order to reduce the price paid on the net-purchases on the spot market. This is an oligopsony effect. It will make a net demander produce up to a point where price is below marginal cost.

The reader should note that this effect does not depend on the supply function set up. Any model of the spot market that takes vertical integration into account will have the feature that incentives are driven by the net demand positions of the firms. The supply function model has the advantage of leading to an estimating equation that has few parameters and from which we can infer the structural parameters of the model.

Despite the fact that final consumer demand in our model is totally inelastic due to predetermined downstream prices (either due to contracts or to regulation), the interaction of oligopoly incentives for net suppliers and of oligopsony incentives for net demanders will lead to an important inefficiency in generation when there is significant market power: efficient units of production will be held back, while inefficient units will be bid into the market due to the oligopsony incentive.

In the absence of market power in the electricity spot market, the downstream demand positions should not matter at all. Any firm would take the spot market price as exogenously given and not affected by its own choice of supply function. Maximizing (4) state by state would then simply generate a non-random linear supply function that has the same slope as the marginal cost curve $s_i^c = \frac{1}{c_{i1}}$. We can therefore conclude:

Proposition 2 *A firm will condition its supply function on the state of downstream demand and on signals about demand in general only if it has market power in the electricity spot market.*

To obtain more insight on the impact that the downstream distribution of retail demands has on the exercise of market power in the electricity spot market, we now analyze equilibrium behavior. We show that there exists a unique supply function equilibrium that is linear in price and the signals. To obtain such linearity in the best response of firm i to a linear supply function of firm j it is clear that we need $E\{\theta_i \mid I_i, \eta_i\}$ to be linear. But η_i is just a linear function of θ and the signals that are privately observed by j. Our assumption on the linearity of posteriors then directly implies that $E\{\theta_i \mid I_i, \eta_i\}$ takes the linear form:

$$E\{\theta_i \mid I_i, \eta_i\} = \lambda_{i0} + \lambda_{i1}\sigma_i + \lambda_{i\eta}\eta_i \tag{6}$$

Replacing η_i in equation (5) by $S_i(\pi, I_i) + E\{S_j(\pi, I_j) \mid I_i\}$ from the market clearing condition yields:

$$-E\left\{\theta_i \mid I_i, S_i(\pi, I_i) + E\{S_j(\pi, I_j) \mid I_i\}\right\} + S_i(\pi, I_i) - (\pi - c_{0i} - c_{1i}S_i(\pi, I_i))s_j = 0. \tag{7}$$

Since the first order condition (7) has to hold for every π, the first derivative of (7) must be zero. Assuming that competitors set linear supply functions (6) implies:

$$-\lambda_{i\eta}(S_i'(\pi, I_i) + s_j) + S_i'(\pi, I_i) - s_j[1 - c_{1i}S_i'(\pi, I_i)] = 0 \tag{8}$$

Equation (8) determines the slope of the supply function of firm i. Clearly, this only depends on the constants $\lambda_{i\eta}$ and c_{i1} as well as on the slope of j's supply function s_j, which we have assumed to be linear. Hence, the slope of the optimal supply function of firm i will be a constant, independent of the signals received. Setting $s_i = S_i'(\pi, I_i)$ we can solve for the equilibrium slopes of the supply functions of firms i and j from the system of equations implied by (8). This yields:[10]

$$s_i = \frac{2(\lambda_{i\eta} + \lambda_{j\eta})}{c_{i1} + c_{j1} + \lambda_{i\eta}\lambda_{j\eta}[\frac{c_{i1}}{\lambda_{i\eta}} - \frac{c_{j1}}{\lambda_{j\eta}}]} \tag{9}$$

Note that the slope of the two firms are the same up to the expression $[\frac{c_{i1}}{\lambda_{i\eta}} - \frac{c_{j1}}{\lambda_{j\eta}}]$, which determines the degree to which supply function slopes differ in equilibrium.

Note that $\lambda_{i\eta}$ will depend, via Bayesian updating, on the slope of the rival's supply function s_j. Keeping this in mind, we can gain an understanding of the implications of expression (9) by considering a limit case: Suppose that firms observe no private signals of demand, i.e. $\eta_i = \theta$ and assume that θ_i and θ_j are perfectly correlated. Then λ_{i0} and λ_{i1} in (6) are zero and $\lambda_{i\eta}$ is simply given by the downstream market share of firm i, i.e. $\lambda_{i\eta} + \lambda_{j\eta} = 1$. In this case (9) is easily interpretable. If firms

[10] Solving for s_j and replacing it in the F.O.C we can then solve for s_{0i} and s_{0j}.

are symmetric, i.e. $c_{i1} = c_{j1}$ and $\lambda_{i\eta} = \lambda_{j\eta} = \frac{1}{2}$, the whole expression collapses to $s_i = \frac{1}{c_{i1}}$, the slope of the perfectly competitive supply function. Intuitively, with completely symmetric firms, we must have a symmetric outcome. But then every firm will have a zero net supply position in equilibrium and market power effects are irrelevant. Now consider inducing an asymmetry in the demand position keeping costs symmetric. Clearly if firm i has the larger downstream market, $\lambda_{i\eta} > \lambda_{j\eta}$, firm i will have a steeper supply curve. Similarly, holding the demand side symmetric, i.e. $\lambda_{i\eta} = \lambda_{j\eta} = \frac{1}{2}$, the firm with the flatter marginal cost function will have a steeper supply function. The more efficient firm will want to expand output more strongly as a response to market shocks. Overall, we may get opposing effects from the downstream market share and the slope of the upstream cost function. Which firm has the steeper supply function will be determined by the relative size of $\frac{c_{i1}}{\lambda_{i\eta}}$. Note that even with identical slopes of the supply functions, i.e. $\frac{c_{i1}}{\lambda_{i\eta}} = \frac{c_{j1}}{\lambda_{j\eta}}$, the equilibrium response to demand shocks is distorted from that of perfect competition: For any given total production, the firm with the flatter marginal cost function does not produce enough, while the firm with the steeper marginal cost function produces too much.

Unfortunately, the interpretation in terms of $\lambda_{i\eta}$ as a market share breaks down in a more general setting with imperfect correlation or private signals. To see this, consider again the case of perfect correlation. In contrast to the previous case we now allow for private signals. In this case $\lambda_{i\eta} < \frac{\bar{\theta}_i}{\bar{\theta}}$, i.e. it falls below the average market share of firm i. The reason is that η_i is no longer a perfect signal for θ_i and Bayesian updating requires that $\lambda_{i\eta}$ falls relative to the case without private signals. It is nevertheless possible to generate some characterization results that allow one to make predictions about the relative slopes of the supply functions for different firms from observable data.

Proposition 3 shows that even in the more general settings, the general intuition about symmetric firms carries over when looking at average behavior:

Proposition 3 *Suppose firms are ex-ante symmetric in the sense that $E\{\theta_i\} = E\{\theta_j\}$, $c_{i0} = c_{j0}$, $c_{i1} = c_{j1}$, and $\lambda_{i\eta} = \lambda_{j\eta}$. Then firms are neither net suppliers nor net demanders on average and price equals on average the marginal cost of production.*

Proof. Given the assumptions of the proposition it follows that $s_{1i} = s_{1j}$ from (9). Now consider the determination of $E\{s_{i0}\}$. From (7) and (8) and the symmetry assumption we have:

$$\begin{aligned} -E\{\theta_i \mid I_i, S_i(\pi, I_i) + E\{S_j(\pi, I_j) \mid I_i\}\} - (\lambda_{\eta i}s_{1i} + \lambda_{\eta j}s_{1j})\pi \\ + [S_i(\pi, I_i) - s_{1i}\pi] \\ +(c_{0i} + c_{1i}[S_i(\pi, I_i) - s_{1i}\pi])s_{1j} = 0. \end{aligned} \tag{10}$$

Taking unconditional expectations and imposing symmetry on the slopes of the supply functions yields:

$$-E\{\theta_i\} - 2\lambda_\eta s_1 E\{\pi\} + E\{s_{i0}\} + (c_{0i} + c_{1i}E\{s_{i0}\})\, s_1 = 0$$

It follows from the assumptions stated in the proposition that $E\{s_{i0}\} = E\{s_{j0}\}$. Now note that this implies that:

$$E\{S_i(\pi, I_i)\} - E\{\theta_i\} = E\{S_j(\pi, I_j)\} - E\{\theta_j\} = -\left[E\{S_i(\pi, I_i)\} - E\{\theta_i\}\right]$$

where the first inequality follows from the symmetry of the supply functions just derived and the second follows from the market clearing condition. It then follows that $E\{S_i(\pi, I_i)\} = E\{\theta_i\}$ in equilibrium and, hence, $E\{\pi\} = E\{C_i'(S_i(\pi, I_i)\}$, by the first order condition of the firm's maximization problem. ■

This proposition does not claim that firms will always produce at marginal cost in a general setting. On the contrary, firms will, generically, be either strict net demanders or strict net suppliers for almost every realization of the demand parameters.

Proposition 3 provides a convenient benchmark to assess what would happen if we introduced some degree of asymmetry into the model. Suppose first that just the expected level of downstream demand differed between the two firms, but nothing else. Then, following the reasoning of the above proof, it is easy to show that the firm with the higher expected downstream demand will become a net-demander and will, on average, produce up to a point where marginal cost exceeds price. This means that firms with larger downstream market share will be more likely to be net demanders and to price below marginal cost. It is more difficult to relate the relative slopes of the different firms to the net demand position. But if one firm has both a lower $\frac{c_{1i}}{\lambda_{i\eta}}$ and a higher $E\{s_{0i}\}$ than the other, then it will produce below marginal cost and will be a net demander. While this does not imply that any net demander has a steeper slope of the supply function, it does seem to make it likely that net demanders will also have steeper supply functions.

3 A Description of the Spanish Electricity Market

The Spanish electricity market is highly concentrated. During the period of May-December 2001, four firms (Endesa, Iberdrola, Union Fenosa, and Hidrocantabrico) account for 92.95% of the generation sold into the spot market and 96.72 % of total electricity sold at the retailing level (see Table 1).

Market Shares in the Spot Market	Period: May - December 2001	
	Generation	total Retailing
Endesa (E. Viesgo not considered)	45.05	38.42
Iberdrola	28.72	38.90
Union Fenosa	12.55	13.54
Hidro-Cantabrico	6.63	5.86
E. de Viesgo	3.45	0.97
Others	0.9	1.95
REE (imports/exports)	2.73	0.36

Table 1: Statistics for generation, retailing and distribution sold and bought in the spot market by each of the Spanish electric firms when adding generation by co-ownwership plants according to the fraction of the plant owned.

This high degree of market concentration, particularly among the two largest firms, led to significant concerns about market power at the time of liberalization.

On the generation side there is a mixture of technologies used for power production. The most important of these are coal (33% in share of total energy consumed in 2001) and nuclear (31%). Due to geographical characteristics of the country, Spain has a high proportion of hydroelectric production (19%).[11] The role of modern CCGT technology was minimal in 2001.

Generation units belong to one of two possible regimes. Generating units in the "normal" regime

[11] Most of the remaining electricity is fuel-oil, and energy produced out of renewable sources. Source: CNE annual report for 2001.

sell all their production into the spot market.[12] Units belonging to the "special" regime (14.8% of total production in 2001) bypass the pool completely. This includes renewable and other "green" energies but also many types of cogeneration and excess sales from industrial firms generating electricity for their own use.

Electricity produced by special regime generators have to be purchased by the local distribution company in the area in which the generator is located. The distribution company has to pay the monthly average price of the daily market plus a regulated subsidy for any electricity these generators decide to sell (see Real Decreto 2818/1998). Since generators in the "special" regime are small, i.e. limited to a maximal capacity of 50MW, production decisions can be considered non-strategic.[13]

The retailing market consists of two parts. Small users of electricity like individual households have to purchase electricity at regulated retail prices from the local distribution company. Larger users of electricity ("qualified consumers") have several options: First, they can buy electricity through an intermediary (i.e. an unregulated retailer other than the local distribution company); Second, they can buy at regulated retail prices from the local distribution company. Third, they can buy electricity directly from the centralized market by placing demand bids (see figure 1). In 2001, there were no qualified consumers who made use of the latter option.[14] As part of the Spanish liberalization process, the critical consumption level determining qualified consumers has been lowered successively until it included consumers of any size at the beginning of 2003 (Real Decreto-Ley 6/2000, June 23rd). In 2001 the critical consumption level was 1 Gwh/year. At that time, unregulated retailers accounted for 32.1% of electricity purchased in the spot market.[15]

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[12] There is the possibility of writing "physical contracts" with large end users directly. The market for physical contracts represented in 2001 on average less than .5% of total electricity consumed in every hour of the day and never accounts for more than approximately 2% of the market. Physical contracts simply mean that the transaction does not go through the centralized market. However, there is an obligation to provide the amount of electricity agreed upon in the contract on the side of the generator and to take up that amount on the side of the end user.

[13] The "special" regime allows the government to subsidize certain forms of electricity production. The limit of 50MW capacity does not apply to renewable generation but since these units seem to always bid all their production there appears to be no strategic impact on the spot market price. This does not mean that there are no strategic investment decisions on these technologies but our sample period is too short for these effects to matter.

[14] Qualified consumers can also write a physical contract directly with an electricity generator (see footnote 12).

[15] Source: REE Annual Report 2001. Unregulated retailers include the retailing subsidiaries of the generation companies.

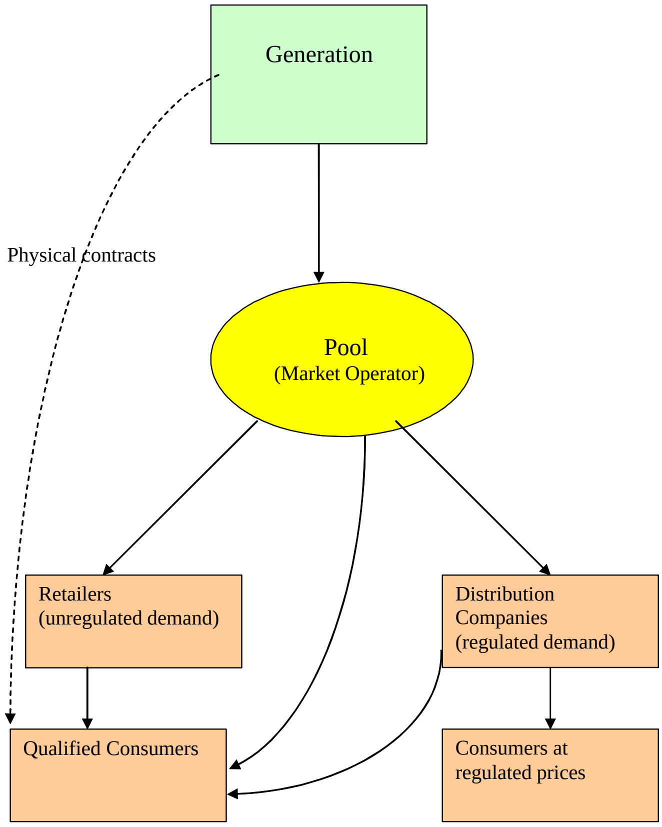

Figure 1: A Stylized Picture of the Spanish Electricity Market

The spot market (known as the “pool”) consists of a sequence of markets for and at different times of the day. The bulk of the energy (around 90% for 2001) is traded on the “daily market”. The daily market opens the day before actual production takes place. In this market firms submit, for every generating unit they control, an increasing supply function for every hour of the day. Demand in the daily market comes from demand side bids of retailers and distribution companies for each hour of the day. Bid functions must be monotonic step functions with at most 25 steps. The market operator aggregates the demand and supply functions and sets the daily market price at the lowest price at which the aggregate demand and supply functions cross. All production units offered below this price and demand bid above this price are liquidated at the equilibrium price.[16]

[16] After the market clears, the system operator will make sure that the production plan obtained from the daily market is feasible given the transmission constraints in the system. If transmission constraints are binding they are resolved by

The clearing of the "daily market", obviously, will not guarantee that the market clears in real time. For this reason firms have to submit step supply functions and step demand functions for real time market clearing. If in real time the total production cleared in the daily market falls short of realized demand, the system operator uses the supply functions to determine which firms expand production. If, in real time, committed production is in excess of realized demand, the system operator uses the demand functions to determine which firms decrease their production level. In each case the system operator determines a real time price by intersecting the bid functions with the inelastic real time demand. Marginal trades in the real time market are executed at these real time prices.[17] Our paper focuses on the operation of the "daily market". Although we are aware that there can be strategic interactions in sequential markets (see Kühn and Machado, 2000), we will ignore this possibility for the purposes of this paper.

There are a number of special features of the Spanish electricity market that we need to take into account in order to adapt our basic model. The most important of these is the recovery of the so called "costs of the transition to competition" (CTCs). As part of the negotiations between the government and the incumbent generation firms before liberalization in 1998, it was agreed that generators should receive a compensation for profit losses due to the introduction of competition.[18] There has been continued discussion over the years about how much should be paid to generators and how these payments should be financed. In our sample period (i.e. May 2001 to December 2001) we have a single regime. Essentially, the profits of the distribution companies are taxed away and redistributed to generators according to percentages set by law. Retailing profits from the regulated part of the market accrue to the firm in the

replacing generating units with the cheapest units that solve the constraint. We will abstract from this issue in this paper.

[17] In addition there are six "intra day" markets that sequentially open after the daily market closes. In these markets previously made production and demand commitments can be modified over time as new information about demand and availability of generation plants arrives. Each one of these markets works technically like the daily market with the only difference that supply and demand functions can only have 5 steps. All trades are executed at the price that clears each market. However, in this market demand units can sell previously committed demands and generators can purchase electricity to reduce production commitments. The net result of the daily and intra daily markets in terms of production and demand commitments establishes the final production plan before the real time markets open.

[18] Sometimes this was justified by a stranded assets argument: Generators had made government mandated investments in generation plants under the old regime, that they argued would not be profitable in a competitive environment.

form of CTC compensation whereas profits from unregulated retailing will remain with the firm. CTCs have a big impact on the incentives of the firms when bidding on the spot market because the regulated part of the market covers 65% of total demand.[19] This is highlighted by a comparison between Table 1 and Figures 2 and 3. According to Table 1, Iberdrola is a net-demander on average and Endesa a net supplier. However, CTCs modify the effective net demand position. As can be seen from Figures 2 and 3 Endesa is now most of the time (81.5%) an effective net demander while Iberdrola frequently switches between being a net demander and a net supplier.

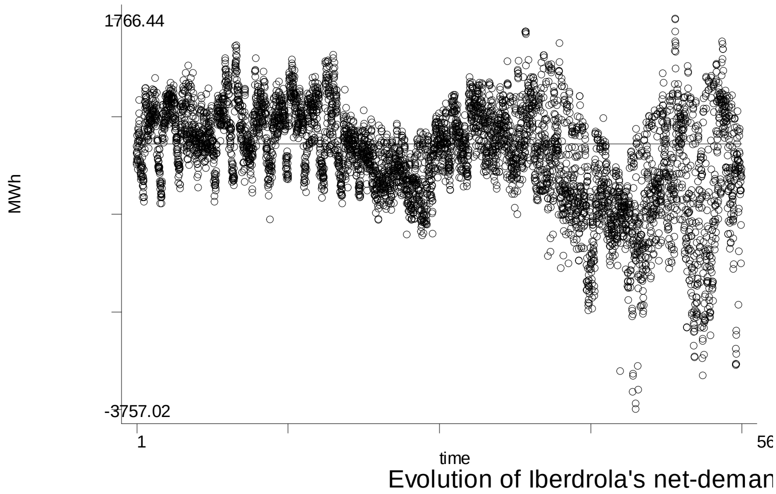

Figure 2:

[19]A further complication arising from CTCs comes from a potential direct effect on the price of the daily market. The law stipulates a maximum for the total aggregate compensation paid to generators in the form of CTCs until 2010. This amount may be reduced in the event that the annual weighted average spot market price received by firms exceeds 6 pts/Kwh. It should be clear that the impact of each day's strategy on this average must be minimal. In addition, Unda (2002, section 2) argues that given the low CTC payout to generators in 2001 and the distribution deficits in 2002, firms would not expect to recover the full stipulated amount of CTCs by 2010 in any case. For that reason an increase of the average weighted spot market price above 6 pts would not be perceived as having the effect of reducing the total amount of CTCs that would eventually be paid. Therefore, we do not model this aspect of CTCs.

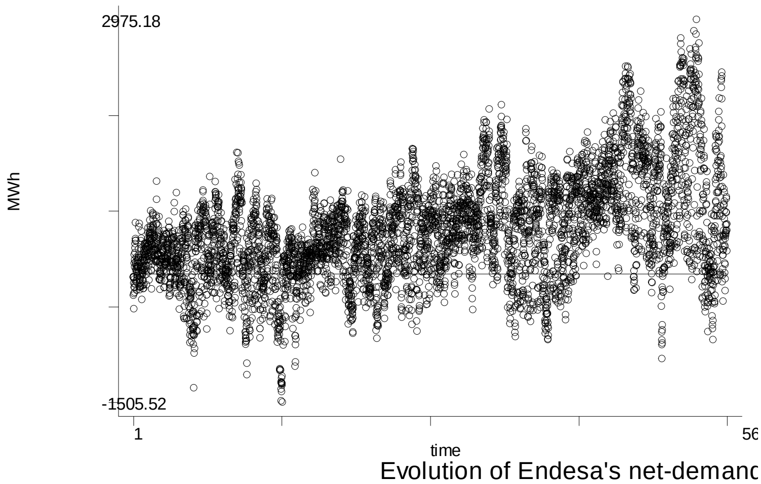

Figure 3:

Another feature of the Spanish market that cannot be ignored in the modelling is the presence of cross-ownership for some generating units. Production from jointly owned plants accounts on average for 28.6% of total production of which 90% comes from nuclear plants and 10% from non-nuclear thermal plants. The prevalence of nuclear technology in jointly owned generation plants implies that the strategic effects from jointly owned production will be small since nuclear capacity is always fully bid in as base load.

Finally, the model in the next section also deals appropriately with dynamic issues arising from hydroelectric production. In our sample, hydroelectricity represents between 7% and 17% of Endesa's hourly production and between 9% and 32% of Iberdrola's hourly production. Iberdrola uses hydroelectricity extensively as the marginal technology.

4 Implementing the Supply Function Model Empirically

In this Section, we adapt the theoretical model developed in Section 2 to the specific features of the Spanish electricity market and develop the empirical strategy that allows us to identify the structural parameters of the model from the available dataset. We proceed by separately modelling the profit terms that arise from retailing and generation.

4.1 The retailing side of the market

Firm's obtain profits from the regulated and the unregulated retail market. In the unregulated retail market, firm i has a set of customers B_i, with whom it has established retailing contracts. Each customer $b \in B_i$ faces a final electricity price $p^b_{t\tau}$, where t refers to the day and τ refers to the hour of the day. Demand from a customer b at time $t\tau$ is given by $D^b_{t\tau}(p^b_{t\tau}) = \theta_{bt\tau} D^b(p^b_{t\tau})$ where $\theta_{bt\tau}$ is the random component of demand from customer b at time $t\tau$. Total unregulated retail demand faced by firm i is then written as $D^u_{it\tau} = \sum_{b \in B_i} \theta_{bt\tau} D^b(p^b_{t\tau})$. We assume that the demands from these retailing contracts are completely inelastic in the spot market price $\pi_{t\tau}$. This assumption is obviously not exactly satisfied in the real data. However the estimated spot market demand elasticities with respect to the spot market price are never larger than 0.09.[20] In the Appendix we show that they can safely be approximated by zero and we show that our empirical tests are robust to assuming elastic demand.

In the illustrative model of section 2 we assumed that the realized demand was bid into the spot market. However, in the Spanish market, firms bid a forecast for the next day's demand into the spot market. Market clearing is based on these forecasts. Let I_{it} be the information that firm i has the day before day t. Then its expected demand from the unregulated part of the retail business will be $E\{D^u_{it\tau} \mid I_{it}\}$. We assume this demand forecast is truthfully bid into the market.[21] In addition the firm truthfully bids its expected regulated demand $E\{D^r_{it\tau} \mid I_{it}\}$ into the daily market. This part of the demand is totally inelastic due to regulation.[22]

[20] Wolfram (1999) cites that Wolak and Patrick (1997) found short run elasticities for customers that hold pool price related contracts in one the UK REC areas not bigger than 0.30. She also claims that her "calibrated" elasticity of 0.17 is within the values found in Lester D. Taylor (1975) and E. Rapahel Branch (1993). Moreover her demand estimates (using nuclear availability as an instrument for price in the demand equation, instrument which she admits is "noisy") produce a short run elasticity at the average values of 0.1. Similarly to our data, Wolfram's elasticity estimates were not very sensitive to the linear demand or constant elasticity assumptions. Finally, Mansur (2001) finds an elasticity of demand (to lag prices) of around 0.096 which he admits may be biased downwards due consumers expectations of a retroactive rebate. The low observed elasticity has led a number of authors to assume contracts that are completely inelastic relative to the spot market price (see Hortacsu and Puller, 2004, Mansur, 2003 and Wolak, 2003).

[21] We are disregarding the potential strategic incentives for demand bidding in this paper (see Kühn and Machado, 1998).

[22] In practice, the regulated demands are bid in at the maximum price allowed by the rules of the market.

The revenue of the distribution companies comes from access fees for providing the distribution service in a given geographic area and from retailing to the regulated part of the market in that area. The costs of the distribution companies consist of the distribution costs plus the costs of purchasing the electricity it sells to the regulated part of the market. Note that the profits of a distribution company are therefore largely determined by the regulated retail price and the realized prices in the pool. Whatever surplus there is, it is used to pay subsidies to the generating firms. These consist first of a subsidy for domestic coal use. What is left after the payment of the coal subsidy is distributed according to the pre set CTC percentages. This strips the distribution companies of any profits.

All distributors are owned by the four largest upstream generating companies. But since distributors are stripped of their profits, all profits arising from the regulated side of demand appear on the balance sheet as CTC compensations.[23] As a result, a firm views profits from retailing to the regulated part of the market (for any transaction in the pool) as depending on total regulated demand and not on its own regulated demand. As noted in Section 3 this changes the effective demand position of the firms.

If the share in CTCs of firm i is given by α_i, then the CTC payment generated at time $t\tau$ from the regulated demand bid into the spot market is given by:

$$\alpha_i \sum_j \left[(\bar{p} - \pi_{t\tau} - c_{jd}) E\{D^r_{jt\tau} \mid I_{jt}\} \right], \tag{11}$$

where c_{jd} are the marginal distribution costs of firm j and $\bar{p}$ is the retail price in the regulated part of the market.

Moreover, distributor j has to buy the electricity produced by generators in the special regime, $S^{ej}_{t\tau}$, in their area at the monthly average hourly price in the daily market plus a regulated subsidy and sell

[23]Since CTCs are calculated from residual profits of the distribution companies they can be negative. In this case, distribution companies are reimbursed by the generators. The pre-set CTC percentages differ in this case from a situation with positive CTCs. In the empirical part of the paper we assume that expected CTC payments at the time of decisions in the daily market are non-negative, so that there is a single set of CTC shares. At least until the end of October 2001 the aggregate distribution profit over the year was positive. However, aggregate distribution profits turn sharply negative at the end of the year. There was some discussion whether the government should cover such a deficit and, at the end of 2002 the government accepted the petition by the generators to do so. If this was anticipated in 2001, then firms may reasonably have ignored the deficit CTC payment percentages. (See CNE 2002, “Informe sobre los resultados de la liquidacion provisional n^o 10 de 2002 y verificaciones practicadas”.)

this electricity on to final customers at price $\bar{p}$.[24] Collecting terms in these payments that involve the price $\pi_{t\tau}$, the CTC payment generated in period $t\tau$ can be written as $\sum_j (\bar{p} - \pi_{t\tau} - c_{jd}) \bar{S}^{ej}_{\tau}$, where $\bar{S}^{ej}_{\tau}$ is the monthly average of production from the special regime purchased by firm j. The total CTC payment attributable to period $t\tau$ for firm i can then be written as:

$$CTC_{it\tau}(\pi_{t\tau}, I_t) = \alpha_i \sum_j \left\{ (\bar{p} - \pi_{t\tau} - c_{jd}) \left(E\{D^r_{jt\tau} \mid I_{jt}\} + \bar{S}^{ej}_{\tau} \right) + k_j \right\}, \tag{12}$$

where I_t is the vector of information sets of all firms and k_j a term that does not depend on $\pi_{t\tau}$.[25]

We will also allow for contracts for differences (or forward contracts), i.e. pure financial instruments that allow hedging the spot market risk. There is a set of hedge contracts firm i holds, B^h_i. A contract $b \in B^h_i$ specifies the number of units $D^b_{t\tau}$ and a fixed forward price $p^b_{t\tau}$. The firm promises affect the behavior of firms in the spot market (see Wolak, 2000). We do not have any data on these contracts, but they can be treated as an unobservable component of marginal cost.[26]

4.2 The Generation Side of the Market

Let $S_{it\tau}$ be total production of electricity by firm i and $h_{it\tau}$ the amount of hydroelectric generation (both in MegaWatt hours). The cost function $C_i(S_{it\tau} - h_{it\tau})$[27] denotes the costs of non-hydro production of firm i. We maintain the assumption that marginal costs are linear but now allow for an additive shock

[24] Note that the total expected demand of firm i in the regulated retail sector is given by $E\{D^r_{it\tau} \mid I_{it}\} + E\{S^{ei}_{t\tau} \mid I_{it}\}$, since downstream demand is served first by electricity from the special regime.

[25] Strictly speaking distributors profits include access fees from unregulated demand that other firms sell in firm i's distribution area as well as the payment of supply subsidies on electricity bought from generators in the special regime. From the point of view of setting supply functions in the daily market these will be seen as fixed costs, i.e. they do not interact with π, and, therefore, do not affect optimal choices. We consolidate these terms in the term k_j in order to simplify notation.

[26] As in Hortacsu and Puller (2004) these may be part of the firms' private information and thus contribute to the residual demand uncertainty.

[27] Strictly speaking, $S_{it\tau}$ should include the production from jointly owned generation plants weighted by ownership share $(\sum_{n \in P_i} \kappa_n S_n)$, where P_i represents the set of plants where firm i has a less than a 100% share and κ_n is firm $i's$ ownership share in plant n. Likewise, the production from co-owned plants would enter the cost function in the following way:

$$C_i(S_{it\tau} - h_{it\tau} - \sum_{n \in P_i} \kappa_n S_n)$$

For the moment we abstract from this because it only complicates notation. It is straightforward to include the production from co-owned plants in the analysis (see appendix). All our empirical results presented in Section 5 include the correct specification.

which is observed by the firms: $C'_{it\tau}(S_{it\tau} - h_{it\tau}) = c_{0i\tau} + c_{1i}(S_{it\tau} - h_{it\tau}) + \varepsilon_{cit\tau}$. Note, that we also assume that there can be hourly systematic shifts in the cost function that affect the constant term in marginal cost but not the slope.[28] This is a crude way of accounting for the effect of start up costs: Generating units already running will have lower perceived avoidable costs of expanding production than generating units that still have to start up. We believe that this is best captured through a shift in the constant term of marginal cost. To have an effect on the slope of marginal costs one would have to argue that the efficiency ranking of generating units systematically changes when they are in or out. While this is certainly true to some extent (e.g. nuclear has very high start up costs and very low marginal costs), those generators for which it may apply are mostly operating as base load suppliers, so that the ranking of generation units remains approximately constant throughout the day.

Autocorrelation in the shocks to costs should be expected in electricity generation. For example, autocorrelation may be due to an unobserved unavailability of some generating unit, which typically lasts for more than one hour.

Hydroelectricity can be produced at a constant marginal cost $c_{hi}+\varepsilon_{hit}$, where ε_{hit} is a random shock. The full marginal opportunity cost of hydroelectricity costs will, however, be implicitly determined by the shadow value of hydro stocks. The hydro stock, measured in units of MegaWatt hours, of firm i at the beginning of day t is denoted by H_{it}. There is a law of motion for the stock of hydro given by

$$H_{i(t+1)} = H_{it} - \sum_{\tau=1}^{24} h_{it\tau} + r_{it} \tag{13}$$

where r_{it} is the exogenous random net inflow of water reserves in units of MegaWatt hours during day t. Given that r_{it} has a predictable component, $E\{r_{it} \mid I_{it}\}$ will vary with the information firm i has. In particular, if this component is purely seasonal, I_{it} will include the information about the season. We will capture all of the non-stationarity in the environment through the common components of all the information sets I_{it}. For estimation purposes we then only have to decide what enters I_{it}.

[28] The empirical formulation will also allow for monthly shifts in the constant term.

4.3 The Firm's Maximization Problem

We consider Markov Perfect Equilibria of the repeated supply function game among n firms. We assume that hydro reserves are observable to all firms. Then the relevant state vector for each firm i is the vector of hydroelectric reserves $\mathbf{H}_t$, measured in MWh, held by the firms at the beginning of period t and the vector of signals contained in I_{it}. A Markov strategy for firm i consists of 24 pairs of functions $S_{i\tau}(\pi_{t\tau}, \mathbf{H}_{t\tau}, I_{it})$, $h_{i\tau}(\pi_{t\tau}, \mathbf{H}_{t\tau}, I_{it})$, which determine for every day t and every hour of the day τ the amount of total energy and hydroelectric energy provided as a function of the hydroelectrical reserves, the price in the spot market and the information available to firm i. The value function for firm i is denoted by $V_i(\mathbf{H}_{t\tau}, I_{it})$, where all possible non-stationarity is captured by the information set I_{it}.

As in the illustrative model we simplify the maximization problem by turning it into a problem in which firm i maximizes over the vector of spot market prices $\boldsymbol{\pi}_t$ and the 24 hydro supply functions $h_{i\tau}(\pi_{t\tau}, \mathbf{H}_{t\tau}, I_{it})$. To do this we need to maintain the assumption made in the illustrative model that rival firms set linear supply functions. As in the illustrative model we start from the market clearing condition:

$$\sum_j S_j(\pi_{t\tau}, I_{jt}) = \sum_j E\left\{D^u_{jt\tau} + D^r_{jt\tau} \mid I_{jt}\right\}$$

We define $\eta_{it\tau}$ by:

$$\eta_{it\tau} = \sum_j E\left\{D^u_{jt\tau} + D^r_{jt\tau} \mid I_{jt}\right\} - \sum_{j\neq i} \left[S_j(\pi, I_{jt}) - E\left\{S_j(\pi, I_{jt}) \mid I_{it}\right\}\right]$$

Note that in contrast to the illustrative model there would be no demand uncertainty if all private information were shared. This is because the demand quantities are determined by the demand bids and not by real time realizations of demand. The random variable η_i is simply the unanticipated part of the net demand position of competing firms. It is again a sufficient statistic for the state of the market for firm i. Residual demand is then given by:

$$S_{it\tau}(\pi, I_{it}) = \eta_{it\tau} - E\left\{S_{-it\tau}(\pi, I_t) \mid I_{it}\right\}, \tag{14}$$

where we simplify notation by using $S_{-it\tau}(\pi, I_t) = \sum_{j\neq i} E\left\{S_{jt\tau}(\pi, I_{jt}) \mid I_{it}\right\}$ and $\eta_{it\tau}$ does not depend on π when we maintain the assumption that rivals set linear supply functions. We can now state the dynamic programming problem of firm i as:

$$\begin{array}{c} V_i(\mathbf{H}_t, I_{it}) = \max_{\{\pi_{t\tau}(\eta_{it\tau},\mathbf{H}_t,I_{it})\}_{\tau=1}^{24},\{h_{it\tau}(\eta_{it\tau},\mathbf{H}_t,I_{it})\}_{\tau=1}^{24}} \\ \sum_{\tau=1}^{24} E\left\{E\{\sum_{b\in B_i\cup B_i^h}(p_{t\tau}^b - \pi_{t\tau})D_{t\tau}^b(p_{t\tau}^b) \ + CTC_i(\pi_{t\tau}, I_t)\right. \\ +\pi_{t\tau}(\eta_{it\tau} - E\{S_{-i}(\pi, I_t) \mid I_{it}\}) + \pi_{t\tau}\bar{S}_{t\tau}^{ei} \\ \left. -C_{it\tau}(\eta_{it\tau} - E\{S_{-i}(\pi, I_t) \mid I_{it}\} - h_{it\tau}) - (c_{hi} + \varepsilon_{hit})h_{it\tau} + \delta V_i(\mathbf{H}_{t+1}, I_{i(t+1)}) \mid I_{it}, \eta_{it\tau}\} \mid I_{it}\right\} \end{array} \tag{15}$$

where all decisions have to satisfy non-negativity restrictions on hydroelectric and non-hydroelectric outputs as well as on hydroelectric stocks and the law of motion of the hydroelectric stocks (13). Notice that the term $\pi_{t\tau}\bar{S}_{t\tau}^{ie}$ corresponds to the revenue from the sale of the inelastic supply of special regime energy from firm i directly into the grid. Maximizing (15) pointwise for each $\eta_{it\tau}$, yields first order conditions for $\pi_{t\tau}$ and $h_{it\tau}$.

The first order condition for $\pi_{t\tau}$ is given by:

$$\begin{array}{c} \pi_{t\tau} - C'_{i\tau}(S_{it\tau} - h_{it\tau}) + \frac{1}{S'_{-i}}\sum_{b\in B_i^h} D_{t\tau}^b(p_{t\tau}^b) \\ = \frac{1}{S'_{-i}}[S_{it\tau} + \overline{S}_{t\tau}^{ei} - E\{D_{it\tau}^u \mid I_{it}, \pi_{t\tau}\} - \alpha_i E\{\left(\sum_j E\{D_{jt\tau}^r \mid I_{jt}\} + \bar{S}_{t\tau}^{ej}\right) \mid I_{it}, \pi_{t\tau}\}], \end{array} \tag{16}$$

where we have substituted for $\eta_{it\tau}$. The first line is the effective price cost margin of firm i. It includes a term that captures the effect of financial contracts on the incentives of the firm. As is well known from the literature (see Wolak, 2000), the holding of financial contracts has the effect of reducing the effective marginal costs of generation. The expression in brackets in the second line is the equivalent of the net demand position in our illustrative model. It reflects the fact that part of the marginal effect of a price increase comes from the CTC term in downstream revenues. Note, that given these modified marginal costs and revenues it is still the case that price is above marginal costs if and only if firm i is a net supplier.

Given $\eta_{it\tau}$ and $\pi_{t\tau}$, total production of the firm is fixed and the choice of $h_{it\tau}$ is a simple cost minimization problem with the first order condition:

$$C'_{it\tau}(S_{it\tau} - h_{it\tau}) - c_{hi} - \varepsilon_{hit} - \delta \frac{\partial E\{V_i(\mathbf{H}_{t+1} \mid I_{it}\}}{\partial H_{it+1}} \leq 0, \tag{17}$$

which holds with equality for strictly positive use of hydroelectricity. In practice, there is always some use of hydroelectricity in our sample. Furthermore, the hydro stock is never fully used up. We could, therefore, safely assume that equation (17) is satisfied as an equality. Then, expression (17) simply says that the marginal cost of using non-hydroelectric sources has to be equal to the marginal cost of using hydroelectric sources. Equation (17) gives us an optimal amount of hydroelectric usage given the total electricity supplied to the market by firm i, S_i, the stock of hydroelectric resources held by others in period $t+1, \mathbf{H}_{-it+1}$, and the own maximally available stock of hydro, H_{it}. Note that the marginal (shadow) cost of hydro is perceived to be exactly the same for all hours of the day because the decision is taken one day ahead. However, there are anticipated relative cost variations over the day that will affect the relative hydro/non-hydro use.

It turns out that for our tests of the theory we can identify all the relevant parameters estimating a version of (16) only. Equation (17) could primarily help by eliminating the endogenous variable $h_{it\tau}$. However, using equation (17) simply generates new problems for the estimation. First, we are significantly more confident about the accuracy of the hydroelectricity bid data than about the reported hydroelectricity stocks: our stock data rely on some formula used by electricity companies to convert actual water reserves into MWhs. Secondly, the hydroelectricity stocks of different firms are highly correlated leading to multicollinearity problems in equations that include the shadow value of hydroelectricity. Thirdly, using the first order condition (17) would put great confidence in the ability of firms to achieve intertemporal cost minimization. In contrast, an estimate of (16) is valid even if $h_{it\tau}$ is set according to some non-optimal rule. Since there appear to be good instruments for $h_{it\tau}$ we have, therefore, opted for estimating (16) directly without using (17). Solving (16) for $S_{it\tau}$, we obtain the estimating equation:

$$S_{it\tau} = \frac{S'_{-i}}{1+c_{1i}S'_{-i}} \left\{ -c_{0it\tau} + \frac{1}{S'_{-i}} \sum_{b \in B_i^h} D^b_{t\tau} + \pi_{t\tau} + c_{1i}h_{it\tau} + \right. \tag{18}$$

$$\left. \frac{1}{S'_{-i}} E\left\{ \left[D^u_{it\tau} + \alpha_i \left(\sum_j E\{D^r_{jt\tau} \mid I_{jt}\} + \bar{S}^{ej}_{t\tau} \right) - \bar{S}^{ei}_{t\tau} \right] \mid I_{it}, \pi_{t\tau} \right\} - \varepsilon_{cit\tau} \right\}$$

In this equation $\pi_{t\tau}$ and $h_{it\tau}$ are endogenous since both will be determined partly by the shock to the marginal cost non-hydro electricity production, $\varepsilon_{cit\tau}$. Hydro stocks do not enter this equation at all because all the relevant information is contained in $h_{it\tau}$. Issues of non-stationarity arising from systematic changes in the shadow value of hydro stocks over time, therefore, do not arise in our estimation. Similarly, on the demand side, systematic seasonal or intra daily variations in aggregate demand do not matter because they are simply accommodated by moving along the supply function. The only systematic variations over time we need to worry about, therefore, come from shifts in the marginal cost function of non-hydroelectric generation. As discussed we assume all such systematic variation to arise in the constant term of the cost function.

4.4 Testing the Theory and Evaluating the Extent of Market Power

In the empirical part we do not simply want to identify the parameters of the model but also want to generate tests that can distinguish our model from plausible alternatives. The following estimating equation nests a number of relevant models that we discuss below :

$$S_{it\tau} = a_{o\tau} + a_1\pi_{t\tau} + a_2 h_{it\tau} + a_3 E\left\{ \left[D^u_{it\tau} + \alpha_i \left(\sum_j E\{D^r_{jt\tau} \mid I_{jt}\} + \bar{S}^{ej}_{t\tau} \right) - \bar{S}^{e}_{i\tau} \right] \mid I_{it}, \pi_{t\tau} \right\} +$$

$$+ a_4 \sum_{n \in P_i} \kappa_{ni} S_n + \zeta_{it\tau} \tag{19}$$

The term $\sum_{n \in P_i} \kappa_{ni} S_n$ in (19) represents production from jointly owned generation units. The parameter κ_{ni} is the ownership share of firm i in plant n and S_n is the production at that plant. As shown in the appendix, we can impose the condition $a_4 = a_2$ for all the nested models under the assumption that either firm i has control over the production of the co-owned plant or that the co-owned plants follow Cournot strategies.[29] As equation (19) shows, this condition can be tested. If $a_4 = a_2$ holds, the estimating equation (19) nests three alternative models.

First, it is consistent with perfect competition. In that case $a_3 = 0$ and $a_2 = 1$. Under perfect competition, the supply function is given by marginal costs. Downstream demand should, therefore, not matter ($a_3 = 0$). Moreover, when the supply function equals marginal costs then the firm's non-hydro supply function should not depend on hydro production ($a_2 = 1$).

The second alternative model is one where generators have market power but they maximize profits from generation alone instead of maximizing the profits of the vertically integrated firm.[30] Under this model $a_3 = 0$ but $a_2 < 1$.

The third alternative is our model, where there is market power and generators bid taking the profits of all of the integrated company into account. In this case, equation (18) implies $a_2 + a_3 = 1$ and $a_3 > 0$. Together these constraints imply that bidding behavior of the firm only depends on its net-demand position. When these constraints are satisfied, proposition 1 holds and we find that firms set price below marginal cost iff they are net-demanders and price above marginal cost iff they are net-suppliers. Having the constraint $a_2 + a_3 = 1$ hold would also make alternative explanations for $a_3 > 0$ implausible since none of those would necessarily imply that the incentives only depend on the net-demand position.

Estimating equation (19) also gives us an estimate of the degree of market power of the individual generating firms. A natural measure of market power is the inverse of the slope of the residual demand function. This can be identified for all the models we discussed above as $\frac{1}{S'_{-i}} = \frac{1-\widehat{a}_2}{\widehat{a}_1}$. It is straightforward to see that this ratio would be zero under perfect competition.

For any of the alternative models discussed above we can recover the parameters of the relevant

[29] We discuss in the appendix that this assumption appears innocuous in the case of Endesa, but could be violated in the case of Iberdrola.

[30] This is important because formally the downstream and upstream part of the business are organized as separate companies which place "independent" bids.

marginal cost function from our estimating equation as:

$$\frac{\widehat{a}_2}{\widehat{a}_1} = c_{1i} \tag{20}$$

and

$$\frac{\widehat{a}_{0\tau}}{\widehat{a}_1} = -c_{0it\tau} + \frac{1}{S'_{-i}} \sum_{b \in B_i^h} D_{t\tau}^b. \tag{21}$$

Equation (20) identifies the slope of the marginal cost function. Equation (21) identifies the constant term of the adjusted marginal cost that is relevant for the theoretical test.

There are a number of parameter restrictions which we can use as specification tests independently of the correct model. First, the coefficient on price a_1 and the coefficient on hydroelectric production a_2 should both be positive. Second, the estimated aggregate slope of the rivals' supply function S'_{-i} should be positive. Third, the model should approximate the average total production of rival firms by $\widehat{S}_{0-i} + \widehat{S}'_{-i}\overline{\pi}$, where $\overline{\pi}$ is the average spot market price and $\widehat{S}_{0-i}$ can be estimated by the average electricity bid by rivals at price zero. Fourth, the coefficient c_{1i} is overidentified under the assumption of inelastic demand. It can be obtained both by $\widehat{c}_{1i} = 1/\widehat{a}_1 - 1/\widehat{S}'_{-i}$ and $\widehat{c}_{1i} = \widehat{a}_2/\widehat{a}_1$. If the model is well specified the estimated value of c_{1i} should be (statistically) the same independently of the formula used.

4.5 The Data

We have data on supply and demand bids at the plant/unit level as well as the equilibrium price for all hours of the day from 11th of May until 31st December of 2001. This data was collected directly from the market operator web site (www.omel.es). From information collected also from OMEL's web page it is possible to obtain information about the type of generation plant (i.e. nuclear, hydroelectric) and the type of the demand bidding unit (i.e. distributor, retailer, hydroelectric pumping). We are also able to match each plant/unit with its proprietor i.e. Endesa Group, Iberdrola, Unión Fenosa, HidroCantábrico or other. We obtained temperatures for 4 hours of the day for 50 weather stations across the country from the Instituto Nacional de Meteorología (Ministerio del Ambiente).

We use the bids from the unregulated demand side of each firm at the equilibrium price as the variable $E\{D^u_{it\tau} \mid I_{it}, \pi_{t\tau}\}$ needed in our estimation. To construct the variable $\alpha_i E\left\{\sum_j E\{D^r_{jt\tau} \mid I_{jt}\} \mid I_{it}, \pi_{t\tau}\right\}$ we used the bids from the regulated demand and the CTC quotas (α_i) set by law. To construct the variables $\overline{S}^{ej}_{t\tau}$ and $\overline{S}^{ei}_{t\tau}$ that enter into equation (19) we use the realizations of the special regime energy by firm discharged into the distribution network over each calendar month.

The data on the energy sold under special regime by hour of the day was gathered in files taken directly from the OMEL's web page for the period after June 29, 2001.[31] In order to recover the two month of data since May 2001 we had to reconstruct the total special regime sales from the "programa diario base de funcionamiento" data. The "programa diario base de funcionamiento" is the plan for the next day after the daily market has cleared and after the special regime is included. By comparing this plan with the initial bids it is possible to perfectly infer the special regime sales.

There is also an issue as to the production and demand that should be counted for ENDESA. Endesa sold generation plants, distribution, and retailing assets to a new entrant (ENEL) by spinning off Electra de Viesgo during the year 2001. Ownership was transferred only in January 2002, but the decisions to create Viesgo as a separate entity, which assets to assign to this new holding, and to sell off the holding were taken at the end of April 2001 (at the beginning of our sample).[32] Electra de Viesgo was finally sold to the highest bidder ENEL in September 2001.

Once the decision to sell Viesgo had been taken, the only way the Viesgo assets entered the profit function of ENDESA was through the payment received for Viesgo from the highest bidder. If the decision taken by ENDESA on its remaining assets in the four month period May through September 2001 were not expected to affect the sales price of Viesgo, we should treat Viesgo as a separate firm

[31] The precise name of these files is: pdbf_tot_2001MMDD.xls where MM stands for the two digit month number and DD stands for the day of the month.

[32] See ENDESA press release of April 28, 2001 at www.endesa.es/index_f4.html.

when analyzing ENDESA's market behavior.

We consider it as highly unlikely that the supply functions bid by ENDESA in the pool over this period would have a material influence on the expected present net value of the firm to any one of the bidders. That is simply not the level of detail that investment bankers would look at when deciding on recommendations for bids. For this reason we have excluded the output from generators and retailing demand from bidding units that were assigned to Viesgo from ENDESA's supply and demand functions.

5 Empirical Results

5.1 Selection of Instruments

The estimating equation (19) poses several endogeneity issues. For all alternative models discussed in Section 4.4, the major component of the error term is the shock to the marginal cost of the non-hydro fully owned plants ($\varepsilon_{cit\tau}$). These shocks are not observed to us but are observed by the firm when making its biding decisions. We consider these shocks to be the primary source of autocorrelation in the error term. Other components of the error term can only arise through misspecification of the model. The main source could come from our treatment of cross-ownership. If the jointly owned generating units are neither controlled by the firm nor set inelastic supply functions then expected demand variables for firms with whom production is shared can appear in the error term. We will point out in our discussion below, where this will cause problems for our instruments. For Endesa we have confirmed that all jointly owned units effectively bid inelastic supply functions. For Iberdrola, in contrast, we have to assume that it controls two thermal plants it owns only to 50%. The production from these two thermal plants account on average for less than 6 percent of Iberdrola's generation and for less than 1.5 percent of the market's total production.

The variables $\pi_{t\tau}$ and $h_{it\tau}$ are clearly endogenous since shocks to the marginal cost of non-hydro generation affect both the equilibrium price and the decision on how to optimally allocate production across hydroelectric and non-hydroelectrical plants. Moreover, if Endesa or Iberdrola have control over the production of co-owned plants then shocks to marginal cost should also lead to an optimal adjustment of production between the fully owned plants and the shared plants. Where this is not the case, we should still instrument for shared production because endogeneity could be caused by firms observing signals of the marginal costs of their rivals, which would have the effect of making such decisions correlated with the error term. The variable $\sum_{n \in P_i} \kappa_n S_n$ is, therefore, also treated as endogenous.

For the spot market price we have a set of a priori excellent instruments: data on the amount of demand originating from end customers who are purchasing electricity at regulated prices, what we call regulated demand in the model, for each of the four main firms in the market. The regulatory regime leads to changes in the price of the end user at most once a year and end user prices are independent of prices in the electricity spot markets. For this reason, the regulated downstream demands can be considered exogenous. Clearly there cannot be any correlation with the marginal cost of firms. However, all of these variables are highly correlated with the spot market price as regulated demand represents around 65 % of total demand in the spot market.

From the point of view of the theory we would expect the disaggregated regulated demands to perform better as instruments for the spot price than the aggregated regulated demand. The disaggregated downstream regulated demands are likely to be correlated with the unregulated downstream demands for each of the firms. Relative movements in the downstream unregulated demand, in turn, lead to systematic movements in price because the price level is affected by relative net-demand positions. Hence, we would expect disaggregated regulated demands to contain more information about price movements than the aggregate regulated demands. The only caveat to the quality of these instruments is the possibility that misspecification of the cross-ownership model leads to correlation between the error term and a competing firm's regulated downstream demand. We discuss this possibility further below.

Finding a good instrument for hydro-production is much more difficult. The amount of hydroelectricity that a firm decides to produce depends on the relative marginal costs of hydroelectric and non-hydroelectric production. An ideal instrument would, therefore, be uncorrelated with the non-hydroelectric marginal costs, but highly correlated with the shadow costs of hydroelectric production. There does not seem to be any good contemporaneous variable that would capture this idea. For this reason, we have looked at various instruments that involve lags over decisions on hydro-electricity production. We consider a measure of the average hydro-electric production over time a preferable instrument to simple production lags in capturing variations in the shadow cost of hydro-production. This is because of the nature of relative cost variation in the production of hydro-electricity compared to the production of non-hydroelectricity. The short run marginal costs of hydro production do not appear to vary much and the overall shadow costs should not be expected to move significantly from day to day either, because they do not depend, for example, on rainfall on a specific day. Simple lags in hydro production may therefore contain more information about the previous period's non-hydro marginal costs than about the shadow costs of hydro because day to day variation in relative production would be more driven by non-hydro marginal costs which are relatively more volatile. Using an average, in contrast will smooth out day to day variations so that the averages are more driven by the slower moving variations in the shadow costs of hydroelectric production. An average would therefore be, a priori, a preferred instrument over simple lags.

The most problematic variable for our estimation is the output from units with shared ownership essentially because of its low variability over the sample. This reflects the fact that over 90 percent of the joint production from the shared units comes from nuclear plants, which always bid all their capacity as base load and, therefore, have very low variability (except for variations that are caused by shut down due to maintenance). It is, therefore, hard to obtain precise estimates of the a_4 parameter, whatever the instruments used. This problem is less severe for Iberdrola because the variability of production from shared plants is higher than Endesa's due to the jointly owned coal plants that serve peak demands inducing higher variation.

The choice of reasonable instruments for share production should then partially reflect the ownership composition of the jointly owned units. In cases where a firm does not control the joint output (and output decisions of the jointly owned units are approximately Cournot), any variable that drives the decisions of the firm that does control the output should be a reasonable instrument for the share variable. Some of our instruments for price, namely the regulated demands from rival firms should, therefore, help us identify the share coefficient in this case. For both Endesa and Iberdrola some of the jointly owned generating are controlled by rivals and bid Cournot supply functions, therefore, we expect the disaggregated regulated demands to help identify the share coefficient. This constitutes an additional argument for the use of the disaggregated regulated demands instead of the total regulated demand as instruments in the estimating equation.

On the other hand, when a firm does not control the joint output but the supply functions do not resemble Cournot strategies, problems may arise with using the regulated demands of the rivals as instruments. Joint control (in form of decisions that are reached by bargaining, for example) would inevitably mean that a term related to the downstream demand of the rival would show up in the error term. Usage of regulated demand of the rival would not be, most likely, a valid instrument in this case because of correlation with the error term. While this is not a problem for Endesa, it may be a problem for Iberdrola. Iberdrola shares two thermal plants with Unión Fenosa at 50 percent ownership and these plants do not bid Cournot supply functions. If Iberdrola does not fully control the production from these thermal plants our estimating equation would be misspecified. However, as mention above, the production from these two thermal plants is a small proportion of Iberdrola's output and, therefore, we do not think it will generate a significant bias. Nevertheless, this would imply that regulated demand from Unión Fenosa would not be a valid instrument.

Unfortunately, we have not found any instrument that would directly relate to the costs of the jointly owned units. The only other sensible instruments besides the disaggregated regulated demands available for the share variable appear to be lags of past production. Contrary to the case of hydro-electricity, there is no reason why an average should do better than straightforward lags. However, lags remain somewhat problematic due to autocorrelation that we should expect in shocks to the marginal cost term. We would expect endogeneity problems to be greater with a single day or two day lag of the variable than with a monthly average. It, therefore, seems to be much more difficult to find a good instrument. We have tried a number of instruments including lagged shared production and lagged shared nuclear production.

A further set of instruments comes from temperatures observed in different regions of Spain. These are potentially good instruments because they can be correlated with demand particularly the unregulated part of the downstream demand and, therefore, can help obtaining more precise estimates of the price and the share coefficient, a_4.[33]

This leaves us with a large set of a priori plausible instruments. As the baseline for Endesa we have chosen all the disaggregate regulated demands (dis_EG, dis_IB, dis_UF and dis_HC) and the hour-specific average of hydro production over the month (EGhphour). For Iberdrola, we have chosen the same except that we have left out the disaggregated regulated demand for Union Fenosa (dis_UF). As discussed above, the reason is due to the potential correlation between dis_UF and the error term for the case of Iberdrola due to the jointly owned thermal plants. Theoretically, our baseline should give us enough identification of the three endogenous variables in the estimating equation. Indeed, for all these regressions the instruments were (conditionally) highly correlated with the endogenous variables that they were intended to instrument for (see p-values of Wald tests in tables 2, 4 and tables 11 and 12 in the Appendix).

We tried to improve the baseline by adding as instruments other variables that satisfy our a priori criteria. First, 24-hour differences in temperatures (24-hour Δtemps) always have little impact on the point estimates of the parameters but reduce the standard deviation of the estimates. Hence, they are included in all reported regressions. One consequence of adding the temperature instruments is that the p-value of the Sargan test becomes very close to one. We believe that this is an artefact of 24-hour

[33]We construct temperatures for all hours of the day based on a weighted average of the reported temperatures of the two adjacent hours.

temperature differences being a very large set of instruments. We do not take this test to be very informative.

Second, for Iberdrola adding any of our a priori reasonable instruments for shared production, namely 48-hour lags of shared production (sharIBLL) and 48-hour lags of shared nuclear production (SN_IBLL) left the coefficients on price, hydro production and Expected demand roughly unchanged but greatly reduced the variance on the share coefficient and intercept terms (see table 4). Although, the addition of SN_IBLL or sharIBLL to the instruments set does not significantly improve the p-value of the Sargan test when temperatures are also included, the p-value of the Sargan test does significantly increase when the temperature variables are excluded from the instrument set.[34] For Endesa, all of the a priori plausible additional instruments for the share variable (e.g. sharEGLL and SN_EGLL) led to a dramatic fall in the p-value of the Sargan test and a negative point estimate for a_4. These two effects together strongly suggest that both of these instruments are correlated with the error term.

In the case of Iberdrola we also attempted to add the Union-Fenosa (dis_UF) regulated demand as an instrument. This had a dramatic impact on the p-value of the Sargan test causing it to drop below 0.05 when temperatures were not part of the instrument set. This suggests that dis_UF is strongly correlated with the error term. As discussed above this can arise because Iberdrola does not fully control generation units jointly owned with Union Fenosa. Alternatively, this correlation may be spurious because low demand periods in Union-Fenosa areas coincide with a partial shut down of a 100% owned nuclear plant of Iberdrola.

Finally, we have experimented with a variety of different average based instruments for hydroelectric production, which we report in our tables below.

In the next subsection we present the results for our estimations. The estimation method used is two-step GMM with a weighting matrix given by the Newey-West procedure allowing for a maximum of 30

[34] Due to the uninformativeness of the p-values of the Sargan test when the 24-hour difference in temperatures are part of the instrument set, we consider, this comparison to be the relevant criterium.

lags.[35,36] In the Appendix we present the results of the first step GMM (or regular IV estimates) where standard deviations have been constructed according to the Newey-West procedure. All regressions include month and hourly dummies (not shown in the tables below).

5.2 Results for Endesa

For the case of Endesa in table 2 we show four different sets of IVs. They all include the disaggregated regulated demands (dis_EG, dis_IB, dis_UF, dis_HC). Except for IV1 the 24-hour differences in temperatures are also included. The reported instrument sets primarily differ on the instruments used for hydroelectricity: IV1 and IV2 use the hour-specific average over the calendar month of own hydroelectricity bid below equilibrium price in the daily market (EGhphour). IV3 uses an hour-specific average of own hydroelectricity bids below equilibrium price in the daily market over a thirty day period around the actual date (EGmovav3). In IV4 the instrument is very similar to EGmovav3 but reduces the number of lags and forwards to 10 (EGmovav1). For all IV sets, with and without temperature related instrumental variables, the p-value of the Sargan test is extremely high giving us some confidence in our specifications.[37]

As discussed in Section 4.4 all reasonable models nested in our estimating equation should satisfy a number of minimal restrictions on the parameter: The coefficient on price a_1 as well as the coefficients on hydroelectric and shared production (a_2 and a_4) should be positive. Moreover, the estimate of the aggregate slope of the rivals' supply function $S'_{-i} = \frac{a_1}{a_3}$ should be non-negative and the two ways of identifying the slope coefficient of the marginal costs (c_{1i}) should result in similar estimates. The

[35] Robustness checks were made by increasing the number of lags to 50. Results did not change although standard deviations increased slightly.

[36] As we discuss in the Appendix, the form of autocorrelation found in both Iberdrola and Endesa's estimating equations is complex. The Newey-West procedure produces consistent estimates of the standard deviations under an unknown form of heteroskedasticity and autocorrelation.

[37] The Sargan-Hansen's test is the following:

$$\widehat{\zeta} Z'(Z'\widehat{\Omega}Z)^{-1}Z\widehat{\zeta}'\tilde{}\chi_{(s)}$$

where s are the number of overidentfying restrictions and $\widehat{\Omega}$ is the Newey-West estimation of the variance-covariance matrix of ζ.

estimated equation should also do a reasonable job in predicting the average production of rivals.

As we can see from table 2, the OLS estimates for Endesa fail several of these consistency criteria. The estimated price coefficient (a_1) is negative which is a clear sign of the endogeneity of price in this equation. The OLS estimate of the slope of the cumulative rivals' supply function and the estimates of the slope of Endesa's marginal cost, c_{1EN}, are all negative because these are identified from the price coefficient. The OLS coefficient of the share production (a_4) is also negative (although not statistically significantly different from zero) which is inconsistent with any reasonable model. Lastly, the OLS prediction of the rival's production ($= 5112.5$ MWh) is not within one standard deviation of the average rival's production of Endesa.

In contrast, our IV estimates for all instrument sets selected based on our discussion in Section 4.4, pass this basic check. The estimates of the price coefficient, the hydroelectricity and share production coefficients, the slope of the rival's supply function and the slope of Endesa's marginal cost are now always positive for all sets of instrumental variables used. These parameters are, however, not always statistically different from zero due to the large standard deviations produced by the Newey-West procedure. The estimates of the slope of the marginal cost are now not only positive but very similar for each IV set selected. The IV estimates prediction of the average production of the rivals is much better. Indeed, the estimated production is always within one standard deviation from the sample mean.

The estimates in table 2 strongly support our theoretical model relative to the other theoretical models nested in the estimation equation (19). We easily reject the competitive hypothesis since $\widehat{a}_3 > 0$ and $\widehat{a}_2 \neq 1$ and both tests are significant at the 99% confidence level. We can also discard a model where there is market power in generation but where downstream profits are not taken into account by upstream generators since $\widehat{a}_3 > 0$. In order for our theory to hold, we need $a_2 + a_3 = 1$, $a_2 = a_4$, and $a_3 > 0$. As we can see from table 2, our IV estimations always produce $\widehat{a}_2 + \widehat{a}_3 = 1$ and $\widehat{a}_3 > 0$. Both of these tests are very powerful given the high precision of the estimates.[38] With respect to the criteria $a_2 = a_4$, our test has little power since $\widehat{a}_4$ is very imprecisely estimated. We were able to increase the precision of all estimates and in particular get a more reasonable estimate of a_4 with the introduction of the temperature related variables (24h Δtemps) as instruments (compare IV1 and IV2). Nonetheless, a_4 remains quite imprecisely estimated. Unlike in the case of Iberdrola, none of the variables highly correlated with the shared production (e.g. 48-hour lag in nuclear production from shared plants) could be used as IVs because they caused negative estimates of the share coefficient and significant changes in some of the other parameters. These two effects are evidence of correlation between the instrument and the error term and, therefore, we have decided not to present these results. The imprecision of $\widehat{a}_4$ raises the question of whether the equation is identified. In order to check this, we examined the first-stage estimation to ensure that the instruments used can identify the share coefficient as well as the coefficients of the other endogenous variables.[39] The Wald test on whether the instruments are jointly zero in the first-stage regression of shared production does not reject that null in IV2-IV5. However, when 24h Δtemps are not included as part of the instrumental variable set (e.g. IV1) the p-value of the same test decreases to 0.0072 clearly rejecting the null that the instrumental variables have no explanatory power. A comparison between the IV1 and IV2 show that indeed temperature related variables help identify the share coefficient as well as other coefficients. We think the high p-value of the Wald test for the first-stage of the shared production in IV2-IV5 is partly due to the high standard deviations produced by the Newey-West procedure.

The imprecision of the estimate of a_4 makes it difficult to obtain precise estimates of marginal costs. This can be seen at the bottom of table 2 where we show the average value of the *relevant* estimated marginal costs over the sample period. All point estimates are consistent with the theory in the sense

[38] Table 2 also reports the percentage of the time that the estimated model predicts that price is above marginal cost given that the firm is a net-supplier and that price is below marginal costs conditional on the firm being a net supplier. When the restrictions $a_1 + a_2 = 1$ and $a_2 = a_4$ are imposed this must always be true. However, relatively small deviations of estimates from satisfying these constraints can move these percentages considerably. Our tests on the parameter restrictions implies that the hypothesis of an exact correspondence to the theory cannot be rejected.

[39] The standard deviations of the first-stage regressions presented in table 11 in the Appendix are computed using the Newey-West procedure since the residuals are autocorrelated.

that Endesa, as an a net-demander on average (81.5% of all hours in our sample), should have average marginal cost above the average price of 35.2 Euros/MWh. However, unless the parameter constraint $a_2 = a_4$ is imposed the variance of the estimated average marginal cost is so large that the point estimate does not appear very meaningful.

For the purposes of estimating marginal cost we feel, however, that it is fully justified to impose $a_2 = a_4$. As explained in the appendix, the restriction will hold in theory when the bid functions submitted by plants co-owned by Endesa are Cournot (i.e. vertical) supply functions. We have verified in the data that this is indeed the case. We have also verified for all specifications of our instrument sets that imposing $a_2 = a_4$ does not change the parameter estimates. However, it always reduces the standard deviations considerably, especially for the time dummies and constant term (see an example in table 3, which reproduces IV2 from table 2 in its first column and shows the estimation results when we impose each of the theoretical restrictions separately). High variance in the constant term and the time dummies is the cause for high variance of marginal cost estimates in the unrestricted model. We are therefore very comfortable to impose this restriction in order to obtain a precise estimate of marginal cost for our numerical assessment of efficiency losses due to market power.

Although the estimates of rival production are, for all IV estimations presented, well within a standard deviation of true production (in contrast to OLS), we appear to systematically underestimate the rival's production level by roughly 1000 MWh.[40] It is not clear what may be causing this difference. But note, that we obtain our estimate of the intercept $\hat{S}_{0-i}$ of the rivals' aggregate supply function by a separate procedure, namely the sample average of the amount bid in by the rivals at zero price.

[40] In the computations of the rivals' production we do not account for the production coming from plants where Endesa has a share.

Table 2: Results of the total production regression for Endesa, using month and hour dummies, 2-step GMM

Endesa (Viesgo out) –	OLS		IV1- IVs used		IV2- IVs used:		IV3- IVs used:		IV4- IVs used:	
Electricity Units= MWh			EGhpmean,		EGhpmean,dis_EG,		EGmovav3,dis_EG,		EGmovav1,dis_EG,	
Endogenous var=π, h_{EN},			dis_EG,dis_IB,		dis_IB,dis_UF,		dis_IB,dis_UF,		dis_IB,dis_UF,	
and *shared_firms*			dis_UF,dis_HC		dis_HC, 24hΔtemps		dis_HC, 24hΔtemps		dis_HC, 24hΔtemps	
	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.
π ($\widehat{a}_1$)	-18.40	3.17	14.75	11.44	12.35	9.60	18.30	10.27	13.53	9.86
h_{EN} ($\widehat{a}_2$)	0.513	0.039	0.523	0.059	0.514	0.052	0.569	0.061	0.588	0.063
Shared_plants ($\widehat{a}_4$)	-0.056	0.223	1.093	1.114	0.421	0.790	0.747	0.792	0.538	0.817
ED_{EN} ($\widehat{a}_3$)	0.754	0.036	0.490	0.103	0.519	0.085	0.463	0.083	0.492	0.086
constant ($\widehat{a}_0$)	1846	609	273.6	2665	1870.5	1908	1458.0	1982	1808.9	2010
$a_2 + a_3$	1.267		1.014		1.033		1.031		1.080	
p-value of H0: $a_2 + a_3 = 1$	$2.80E-18$		0.877		0.662		0.706		0.295	
p-value of H0: $a_2 = a_4$	0.011		0.600		0.903		0.817		0.950	
$\widehat{S}'_{-EN} = \frac{\widehat{a}_1}{\widehat{a}_3}$ (s.d.)	-24.41	3.42	30.08	29.31	23.82	22.14	39.56	28.72	27.51	24.48
$\widehat{S}'_{-EN} \times \overline{\pi}$	-874.10		1077.42		853.0		1416.88		985.28	
nobs	5640		5640		5610		4920		5160	
AR^2	0.921		0.891		0.900		0.898		0.903	
Sargan test p-value			0.923		0.999998		0.899		0.966	
p-value Wald test π			$8.85E-07$		0.00016		$6.21E-05$		$1.29E-05$	
p-value Wald test h_{EN}			$1.77E-100$		$5.11E-109$		$9.88E-131$		$7.27E-102$	
p-value Wald test Shared_plants			0.0072		0.330		0.405		0.500	
$\widehat{c}_{1EN} = 1/\widehat{a}_1 - 1/\widehat{S}'_{-EN}$	-0.013	0.004	0.035	0.020	0.039	0.024	0.029	0.013	0.038	0.022
$\widehat{c}_{1EN} = \widehat{a}_2/\widehat{a}_1$	-0.028	0.006	0.036	0.027	0.042	0.032	0.031	0.018	0.043	0.031
Non-Endesa average product.	8041	1971	8041	1971	8041	1971	8041	1971	8041	1971
Non-Endesa $\overline{S}_{-0} + \widehat{S}'_{-EN} \times \overline{\pi}$	5112.5		7064.0		6839.57		7403.45		6971.85	
average $\widehat{MC}$	-37.75	32.29	157.0	187.2	46.99	156.9	80.11	115.4	66.56	153.1
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} > \pi$ if net-demand.	0		100		80.04		100		100	
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} < \pi$ if net-supplier	99.81		0		100		0.76		43.34	

5.3 Results for Iberdrola

For the case of Iberdrola in table 4 we also show four different sets of IVs. They all include the disaggregated regulated demands of Endesa, Iberdrola and Hidro-Cantabrico (dis_EG, dis_IB, dis_HC). As explained in Section 4.4 we leave the regulated demand from Unión Fenosa out of the IV set because of evidence of correlation with the residuals. All IV sets in table 4 include as well an instrument related to hydroelectricity produced. IV1, IV2 and IV3 use the hour-specific average over the calendar month of own hydroelectricity bid below equilibrium price in the daily market (IBhphour) while IV4 uses 20-day hour specific moving average of future hydroelectricity bid below market price (IBmovav4). All except IV1 also include 48-hour lag nuclear production from shared plants weighted by ownership as an additional IV (SN_IBLL).[41] Finally IV1, IV3 and IV4 include 24-hour differences in temperatures in some regions of Spain. The p-value of the Sargan test is always high including for IV2 where 24-hour differences in temperatures are not used as IVs.

[41] 48-hour lag of total production from shared plants weighted by ownership (sharIBLL) gives very similar results.

Table 3: Results of the IV2 regression for Endesa with restrictons on the parameters, 2-step GMM

Endesa	No restrictions		$a_2 + a_3 = 1$		$a_2 = a_4$		$a_2 + a_3 = 1,\ a_2 = a_4$	
	IV2		IV2		IV2		IV2	
	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.
π ($\widehat{a}_1$)	12.35	9.60	16.20	3.85	12.74	9.26	16.22	3.79
h_{EN} ($\widehat{a}_2$)	0.514	0.052	–	–	0.517	0.048	–	–
Shared_firms ($\widehat{a}_4$)	0.421	0.790	0.483	0.792	–	–	–	–
ED_{EN} ($\widehat{a}_3$)	0.519	0.085	0.499	0.053	0.513	0.075	0.489	0.047
constant ($\widehat{a}_0$)	1870.5	1908.4	1870.6	1952.9	1647.0	413.7	1801.0	177.78
$a_2 + a_3$	1.033		–		1.030		–	
p-value of H0: $a_2 + a_3 = 1$	0.662		–		0.678		–	
p-value of H0: $a_2 = a_4$	0.903		–		–		–	
$\widehat{c}_{1EN} = 1/\widehat{a}_1 - 1/\widehat{S}'_{-EN}$	0.039	0.024	0.031	0.005	0.038	0.022	0.031	0.005
$\widehat{c}_{1EN} = \widehat{a}_2/\widehat{a}_1$	0.042	0.032	–	–	0.041	0.029	–	–
Sargan p-value	0.999998		0.9999993		0.9999995		0.9999998	
Non-Endesa average hourly production	8041.2	1970.7	8041.2	1970.7	8041.2	1970.7	8041.2	1970.7
Non-Endesa $\overline{S}_{-0} + \widehat{S}'_{-EN} \times \overline{\pi}$	6839.57		7171.4		6875.5		7174.78	
$\widehat{MC}$ at $\overline{(S_{EN} - h_{EN} - shared\_firms)}$	46.99	156.85	46.69	122.40	64.92	44.03	51.05	5.09
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} > \pi$ if net demander	80.04		88.34		100		100	
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} < \pi$ if net supplier	100		100		53.73		100	

OLS estimates for Iberdrola are not as obviously biased as the ones for Endesa. All coefficient estimates are positive including the price coefficient, the slope of the rivals' aggregate supply function, and the estimates of the marginal cost slope. The two estimates of the slope of the marginal cost are also not statistically different from each other. The IV estimates also conform with these basic checks on the parameter estimates. Moreover, the two ways of identifying the slope of the marginal cost parameter render virtually the same value for all IV sets. Both OLS and IV estimates predict rivals' average production within a standard deviation of the true value. OLS considerably underpredicts the true value while all IV estimates with the exception of IV4, significantly overpredict rivals' production.

As in the case of Endesa, the IV estimates can easily reject the competitive framework since $\widehat{a}_3 > 0$ and $\widehat{a}_2 \neq 1$ with 99% confidence level. Because $\widehat{a}_3 > 0$ we know that generators take into account the downstream demand in their strategies. Finally, the nulls $\widehat{a}_2 + \widehat{a}_3 = 1$ and $\widehat{a}_2 = \widehat{a}_4$ cannot be rejected which together with $\widehat{a}_3 > 0$ implies we cannot reject our model, i.e. we cannot reject the hypothesis that all that matters for the exercise of market power is firms' net-demand position. Notice that although in IV1 we do not include any instrument specifically related to the shared production, the precision of $\widehat{a}_4$ is higher than for Endesa. This is likely due to the higher variance of Iberdrola shared production relative to Endesa's. When we further include SN_IBLL in the IV set, the precision of $\widehat{a}_4$ increases although the parameter's point estimate is now farther away from $\widehat{a}_2$. This increase in precision reflects the high correlation between SN_IBLL and the shared production as is reflected in the decrease of the p-value of the Wald test in the first-stage regression.

Iberdrola is slightly more often a net-supplier (54.5% of the times) than a net-demander. The theory predicts that the average marginal cost should be slightly below the average price (35.2 Euros/MWh). The estimates at the bottom of table 4 support the theory (for all IVs) but, although not as large as in the case of Endesa, the standard deviation is still large. The sum of estimated parameters $\widehat{a}_2 + \widehat{a}_3$ always has a point estimate very close to 1 and is very precisely estimated. This further confirms the theory in the sense that Iberdrola clearly takes retailing profits fully into account when deciding on the bidding strategy for its generation units. The fact that we estimate Iberdrola to almost always have a price above marginal cost is clearly caused by the estimated difference between $\widehat{a}_2$ and $\widehat{a}_4$. This becomes evident from table 5. There we show, for the case of IV1, that once we impose the restriction $a_2 = a_4$ the theory predicts the actual behavior 100 percent of the time price above marginal cost when Iberdrola is a net-supplier and 81.5 percent of the times price below marginal cost when Iberdrola is a net-demander. Imposing the restriction $a_2 = a_4$ hardly changes other parameter estimates so that we feel confortable imposing it. Notice that similarly to the case of Endesa the standard deviation of the average estimated marginal cost dramatically improves. The value of average estimated marginal cost increase to 34.01 Euros/MWh, a value just below the average price as the theory would predict. In the last column of table 5, once $a_2 + a_3 = 1$ is also imposed, we obtain even higher precision of the estimated marginal cost with no significant change in its value.

It should be noticed how precisely the slope parameter of the marginal cost function is estimated and how little it varies across different instrument sets. Note also, that the two ways of identifying the slope of the marginal cost function generates the same estimate for almost all IV sets. The reason appears to be that Iberdrola's downstream demand is literally inelastic as assumed in the model.

Finally, it should be mentioned that across all IV specifications Endesa is estimated to have a steeper supply function slope than Iberdrola. We showed in the theory section that the firm that is more of a

Table 4: Results of the total production regression for Iberdrola, using month and hour dummies, 2-step GMM

Iberdrola	OLS		IV1- IVs used:		IV2- IVs used:		IV3-IVs used:		IV4-IVs used:	
Electricity Units= MWh			IBhphour,dis_EG,		IBhphour		IBhphour,dis_EG,		IBmovav4,dis_EG,	
Endogenous var= π, h_{IB},			dis_IB,dis_HC,		dis_EG, dis_IB		dis_IB,24hΔtemps		dis_IB,24hΔtemps	
and *shared_firms*			24hΔtemps		dis_HC, SN_IBLL		dis_HC,SN_IBLL		dis_HC, SN_IBLL	
	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.	coef.	Nws.d
π ($\widehat{a}_1$)	16.38	2.44	28.32	4.72	27.85	5.16	28.61	4.72	21.19	5.26
h_{IB} ($\widehat{a}_2$)	0.771	0.039	0.793	0.040	0.790	0.043	0.791	0.040	0.756	0.039
Shared_firms ($\widehat{a}_4$)	0.907	0.155	0.683	0.414	0.554	0.208	0.597	0.173	0.516	0.164
ED_{IB} ($\widehat{a}_3$)	0.302	0.031	0.206	0.046	0.218	0.045	0.210	0.043	0.262	0.047
constant ($\widehat{a}_0$)	132.2	326.1	753.2	795.9	980.7	422.0	904.2	349.1	1049.8	326.8
$a_2 + a_3$	1.073		0.999		1.008		1.001		1.018	
p-value of H0: $a_2 + a_3 = 1$	0.035		0.982		0.888		0.985		0.743	
p-value of H0: $a_2 = a_4$	0.348		0.790		0.236		0.244		0.120	
									0.152	
$\widehat{S}'_{-IB} = \frac{\widehat{a}_1}{\widehat{a}_3}$ (s.d.)	54.16	11.11	137.38	46.98	127.95	45.32	136.29	45.11	81.01	32.23
									2901.45	
nobs	5640		5610		5592		5586		5112	
AR^2	0.934		0.930		0.930		0.929		0.930	
Sargan test p-value	–		0.9999		0.730		0.9999		0.998	
p-value Wald π	–		$2.08E-44$		$2.91E-44$		$4.57E-44$		$1.38E-40$	
p-value Wald h_{IB}	–		$1.45E-129$		$1.77E-135$		$1.76E-137$		$4.61E-104$	
p-value Wald Shared_firms	–		0.343		$1.77E-18$		$3.30E-24$		$3.09E-26$	
$\widehat{c}_{1IB} = 1/\widehat{a}_1 - 1/\widehat{S}'_{-IB}$	0.043	0.006	0.028	0.004	0.028	0.004	0.028	0.004	0.035	0.007
$\widehat{c}_{1IB} = \widehat{a}_2/\widehat{a}_1$	0.047	0.008	0.028	0.006	0.028	0.006	0.028	0.005	0.036	0.010
Non-Iberdrola average production	11082	1944	11082	1944	11082	1944	11082	1944	11082	1944
Non-Iberdrola $\overline{S}_{-0} + \widehat{S}'_{-IB} \times \overline{\pi}$	9910.0		12890.40		12552.6		12851.5		10871.63	
Average $\widehat{MC}$	76.92	26.12	26.38	29.00	17.61	15.14	20.51	12.21	12.71	15.25
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} > \pi$ if net demander	100		2.38		0		0		0.04	
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} < \pi$ if net supplier	0		100		100		100		100	

Table 5: Results of the IV1 regression for Iberdrola with restrictons on the parameters, 2-step GMM

Iberdrola	No restrictions		$a_2 + a_3 = 1$		$a_2 = a_4$		$a_2 + a_3 = 1$, $a_2 = a_4$	
	IV1		IV1		IV1		IV1	
	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.
π ($\widehat{a}_1$)	28.32	4.720	28.23	2.38	28.30	4.69	27.78	1.72
h_{IB} ($\widehat{a}_2$)	0.793	0.040	–	–	0.793	0.040	–	–
Shared_firms ($\widehat{a}_4$)	0.683	0.414	0.681	0.400	–	–	–	–
ED_{IB} ($\widehat{a}_3$)	0.206	0.046	0.207	0.033	0.201	0.041	0.204	0.031
constant ($\widehat{a}_0$)	753.20	795.93	756.42	782.63	543.30	135.83	530.60	76.52
$a_2 + a_3$	0.999		–		0.9940		–	
p-value of H0: $a_2 + a_3 = 1$	0.982		–		0.907		–	
p-value of H0: $a_2 = a_4$	0.790		–		–		–	
$\widehat{c}_{1IB} = 1/\widehat{a}_1 - 1/\widehat{S}'_{-IB}$	0.028	0.004	0.028	0.003	0.028	0.0039	0.029	0.002
$\widehat{c}_{1IB} = \widehat{a}_2/\widehat{a}_1$	0.028	0.006	–	–	0.028	0.0055	–	–
Sargan p-value	0.9999		0.99995		0.99996		0.99998	
Non-Iberdrola average hourly production	11082.2	1943.5	11082.2	1943.5	11082.2	1943.5	11082.2	1943.5
Non-Iberdrola $\overline{S}_{-0} + \widehat{S}'_{-IB} \times \overline{\pi}$	12890.40		12857.89		13003.59		12837.14	
$\widehat{MC}$ at $\overline{(S_{IB} - h_{IB} - shared\_firms)}$	26.38	29.00	26.28	28.73	34.01	6.04	34.72	0.628
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} > \pi$ if net demander	2.38		2.34		85.85		100	
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} < \pi$ if net supplier	100		100		100		100	

net demander should be expected to have the steeper supply function. This is clearly the case in our data.

6 The Impact of Market Power on the Efficiency of the Spanish Electricity Spot Market

In this section we use the estimated marginal cost parameters from the model in which all parameter constraints of the theory are imposed to compute a lower bound to the efficiency losses due to the exercise of market power. For this exercise we take total production for every hour in our sample as given. Then we calculate gains that would accrue from shifting non-hydro production optimally between Endesa's and Iberdrola's 100% owned plants, keeping all other production amounts (i.e. those of hydro-production, shared production and of competitors) fixed. This exercise clearly gives a lower bound to the efficiency losses from market power, because it corresponds to a constrained industry cost minimization problem.

We have seen that the average marginal cost of Endesa is considerably higher than that of Iberdrola. This implies that relative to the constrained industry cost minimization problem we consider, Endesa will on average overproduce and Iberdrola will underproduce. Table 6 presents the average efficiency gain per hour in our sample period from reallocating production according to the constrained cost minimum. The estimates depend on the IV sets used to compute the marginal cost parameters. They range from 3372.6 Euros with IV4 for Endesa and IV3 for Iberdrola to 6932 Euros with IV1 for Endesa and IV4 for Iberdrola. This corresponds to a total cost saving over the 8 months sample ranging from $19,021,662$ to $39,095,046$ Euros. Note from table 6 that the relatively great range of estimates is due to the relatively large impact of IV choice for Endesa, reflecting the fact that our estimates for Iberdrola are much more robust to IV choice. Note also that the standard deviations for the estimates are large.[42]

[42] Standard errors in tables 6, 7 and 8 were computed under the assumption that the error terms from Iberdrola and Endesa estimating equations are independent, in other words, assuming that the coefficient estimates of both equations are not related. The computation of standard errors involved taking 10000 draws from the asymtpotic distribution of the parameter estimates of equation 19 for both Endesa and Iberdrola when $a_2 = a_4$ and $a_2 + a_3 = 1$ are imposed i.e. a normal distribution $N(\widehat{a}, \widehat{\sum})$ where $\widehat{a}$ are the 2-step GMM estimates of equation and $\widehat{\sum}$ its estimated covariance matrix..

Table 6: Average hourly efficiency gains (Euros) from redistribution of production between IB and EG*

Iberdrola⟶	IV1		IV2		IV3		IV4	
Endesa⇂	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.
IV1	6708	13071	6720	13064	6703	13085	6932	12940
IV2	6343	5099	6353	5093	6336	5108	6577	5069
IV3	3740	2701	3745	2697	3727	2702	4041	2758
IV4	3387	3103	3392	3099	3373	3106	3695	3138

To deal with the large variance of the estimates and to give an impression of the relative importance of such cost reductions to the firms, tables 7 and 8 present the cost reduction as a percentage of joint total costs and of joint revenues, respectively. The standard deviations remain large but as percentage of total costs of the firms the numbers becomes statistically significantly different from zero for most IV sets. More importantly, the point estimates underline the fact that these are indeed economically significant numbers: they range from 11.5% to 33.8% as a percentage of total non-hydro costs of the two firms and from .93% to 1.92% of the total revenue of the two firms. These should be considered economically quite relevant numbers given that these are based on lower bound estimates. Given that over production by Endesa could crowd out considerable hydro production by Iberdrola, a more careful assessment of the efficiency losses due to market power could be considerably higher. However, such an assessment would also require an estimate of the social shadow costs of hydroelectric production conditional on the observed production path.

Table 7: Average efficiency gains as percentage of costs

Iberdrola⟶	IV1		IV2		IV3		IV4	
Endesa⇂	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.
IV1	26.4	5.65	16.8	2.65	28.9	222.1	19.2	26.93
IV2	21.8	7.29	14.2	5.15	13.0	76.9	14.5	13.44
IV3	15.2	1.74	18.7	15.39	33.8	11.88	13.9	3.81
IV4	19.5	26.40	11.5	35.69	23.7	10.21	13.9	111.9

The highest standard deviations occur for Endesa IV1. This is the IV set with the highest standard deviation of the raw parameter estimates $\widehat{a}$ so that for some draws the optimal reallocation of production between Endesa and Iberdrola involved negative quantities (this was the case when estimated marginal costs of one of the firms were negative which made it optimal for the other firm to produce negative quantities). Of course optimal quantitiy reallocations were truncated in these cases. If instead of truncating the optimal quantities we left these draws out of the computation of the standard deviations, the standard deviations for Endesa IV1 would have been slightly higher but similar in magnitude to those of Endesa IV2.

Table 8: Efficiency gains as percentage of non-hydro fully-owned generation revenues

Iberdrola⟶	IV1		IV2		IV3		IV4	
Endesa↓	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.
IV1	1.86	3.66	1.86	3.65	1.85	3.66	1.92	3.61
IV2	1.75	1.42	1.76	1.42	1.75	1.42	1.82	1.41
IV3	1.03	0.75	1.03	0.75	1.03	0.75	1.12	0.76
IV4	0.94	0.86	0.94	0.86	0.93	0.86	1.02	0.87

A slightly different but closely related benchmark shows that a switch to competitive behavior would allow the realization of cost reduction benefits in the order of magnitude indicated above, but that there would be virtually no price effect. To see this consider a hypothetical situation in which only the 100% owned generation units of Endesa and Iberdrola would switch to setting competitive supply functions while all other supply functions (including the hydroelectric supply functions of Endesa and Iberdrola) would remain unchanged. There are two differences to the previous benchmark. First, since we are not taking prices as fixed, we will move along the supply functions of those units whose bidding behavior we have assumed unchanged. Second, since there is some elasticity to the actual demand there can be a small change in deadweight loss due to the price change.

We use for this exercise the estimated marginal cost functions from the IV2 estimation for Endesa and the IV3 estimation for Iberdrola when restrictions are imposed. There is a very small effect on prices. The ratio between the price obtained in this benchmark and the sample price is on average 0.996. Since under market power there is less pass through of marginal cost changes than under perfect competition we should also see an increase in the variance when we go to our partially competitive benchmark. Indeed, table 9 shows that the average prices over the sample period are very similar although the standard deviation is higher in the benchmark case. The equilibrium price ranges from $[5.8, 121.1]$ in the benchmark case while it varies only between $[14.5, 113.3]$ in the sample.

Since the price changes so little there is only a small change in total output and only a small change in production by generating units whose supply functions we have fixed. Hence, the efficiency gains from the restricted switch to competitive behavior will induce efficiency gains of the order of magnitude of

Table 9: Statistics relating the benchmark case with the sample

	Benchmark		Sample	
	average	s.d.	average	s.d.
price	35.96	14.24	35.82	12.90
weighted price	37.68	–	37.44	–
Iberdrola quota	12.31	2.85	11.87	2.18
Endesa quota	25.77	4.09	27.65	2.93
Total Supply	20144	2971.2	20326	3056.9
IB supply from 100% non-hydro	2494	778	2414	592
IB total supply	5540	967	5937	1262
EG supply from 100% non-hydro	5151	857	5604	893
EG total supply	8541	1038	9219	1200

Table 10: Statistics relating the benchmark case with the sample

	Production from 100% owned in Benchmark relative to the sample			
	Endesa		Iberdrola	
Net demand position in the sample	Increase (%)	decrease (%)	Increase (%)	Decrease (%)
net-demand	1.28	98.72	21.03	78.97
net-supply	85.06	14.94	83.50	16.50

our restricted cost minimization exercise but generate virtually no significant change in the price level. This shows that in markets with bilateral market power and vertical integration we have to estimate efficiency losses from market power to get any reasonable first cut at the importance of market power.

Finally, the theory tells us that the benchmark should bring about an increase in production in periods when firms were net-suppliers in the sample and a reduction in production in periods when firms were net-demanders. Unfortunately, we cannot test the theory on the firms' total production since our benchmark takes as given the bids from hydroelectric plants and jointly owned plants. Therefore, we will limit our analysis to the production of the non-hydro 100% owned plants. Table 10 shows the percentage of time the production from non-hydroelectric 100% owned plants increased or decreased in the benchmark case relative to the sample in periods when the firms are net-demanders and net-suppliers in the sample. As we can see, Endesa decreased production in 98% of the hours where it was a net-demander while Iberdrola decreased production only in 78% of these periods. On the other hand, Endesa increased production in 85% of the hours where it was a net-supplier and Iberdrola increased production in 83% of these periods. Overall, in the benchmark case, Iberdrola increases (slightly) the average production from its 100% non-hydro plants relative to the sample while Endesa decreases its production. This was to be expected given that Endesa was on average a net-demander and, therefore, overproduced and Iberdrola was (slightly) more often a net-supplier and, therefore, underproduced in the sample. Moreover, the impact of Endesa's strategy in the market price is large. 96 percent of the times where the benchmark's price is higher than the sample price correspond to situations where Endesa is a net-demander in the sample. This is consistent with our theory that net-demanders will bid in order to lower the equilibrium price in the pool. Once this incentive disappears, the price will rise.

7 Conclusion

In this paper we have developed a supply function model for an electricity spot market with vertically integrated generation and retailing firms. We have estimated this model on the basis of data from the Spanish electricity spot market. The data fits the model surprisingly well. The data clearly rejects that the market is competitive and confirms the theory that bidding by generation units should only depend on the net-demand position of the integrated firm in the spot market. Firms that are net demanders will overproduce while net sellers will underproduce. While the spot market price may not be very much affected by the existence of market power, we show that the efficiency losses due to misallocation of generation assets have to be considered the major efficiency loss in this type of electricity markets. Using cost estimates derived from our model's parameters we confirm that these effects are economically significant in the Spanish electricity market.

Methodologically we have shown that a simple linear supply function model can be used to analyze market power in electricity spot markets with vertical integration. As we have shown this appears a fairly robust approach for detecting market power and assessing the degree to which firms act as a single entity. All that is needed to identify market power is then a significant variability in the net demand functions of such firms.

Our paper also explains that despite the strong market power in the Spanish electricity industry, concerns about price gouging have not been as important in Spain as they have been in the UK and California deregulation experience. Our model shows that this is the case because vertical integration and market power on both sides of the market prevent prices to go as far above or below the market price as would be the case with one sided market power. This does not imply that the efficiency losses in the Spanish market should be considered smaller than those that were generated in the British spot market before the market mechanism was changed. However, the analysis does indicate that very large losses due to downstream bankruptcy as in California can be avoided by allowing vertical integration between generation and retailing in electricity markets.

Our approach could be extended to estimate equilibrium behavior for the whole market to explicitly compare the performance of the vertically integrated industry to one with full vertical disintegration. While the theory predicts that with very inelastic demand, spot market prices should rise, such a move may nevertheless be efficiency enhancing since the incentives for reallocation of production between firms that is the primary cause for efficiency losses due to market power in this model disappears. This analysis would, however, have been beyond the scope of this paper.

The analysis also points to a number of predictions for the Spanish electricity spot markets that are of relevance for future market developments. First, the analysis immediately implies that the entry of unintegrated retailing firms anticipated with the complete liberalization of downstream retailing should lead to an increase in the electricity spot market price, since generating firms will overall shift towards being stronger net suppliers as they loose supply market share to the entrants. Perhaps surprisingly, this does not mean that the price increase induces inefficiencies. Indeed, when the spot market demand is extremely inelastic, as is still the case in electricity markets in the absence of real time pricing, the presence of net demanders will dominate leading to pricing below the competitive price. However, as demonstrated in California, the price may rise sufficiently that it is infeasible for unintegrated companies to profitably enter electricity supply markets.

Second, our analysis has revealed an important impact of the way the Costs of Transition to Competition (CTCs) affect the incentives of the firms operating in the spot market. When the period in which CTCs are paid ends, Endesa's incentives will likely become those of a strong net supplier and those of Iberdrola of a moderate net demander. This may imply a significant increase in spot market prices. However, the efficiency effects of such a move may very well be positive because they move production away from Endesa to Iberdrola. Our approach can be extended to estimate the effect of abolishing CTC payments. As for some of the other policy experiments suggested above it would be necessary to estimate the supply functions for all the firms in the market, which could be done in the same way as in this paper.

The main stumbling block for this and other policy experiments lies in the fact that supply function slopes in a private information model like ours depend on the parameters of the distributions of the underlying uncertainty and private signals observed by the firms. These distributions change endogenously with the policy experiment. Since the development of techniques to identify the relevant underlying parameters was beyond the scope of this paper we have left a numerical evaluation of these policy experiments that could in principle be done in our framework for future work.

The contribution of our paper to the policy debate is to highlight that such issues exist in the first place and that market power remains an important concern in the Spanish electricity spot market. It appears that the absence of dramatic price surges in the Spanish market has created the incorrect impression that there are no market power reasons that make a reform of the market mechanism in Spain necessary.

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8 Appendix

8.1 Co-ownership

As mentioned in Section 3 co-ownership of generation plants is an important aspect of the Spanish electricity industry. Here we show how to adapt the estimation framework developed in section 4 to account for co-ownership. The identification of the structural parameters of the model is unaffected by the presence of co-ownership of generation plants.

To keep notation to a minimum our analysis here focuses on a model without hydroelectric production. We also assume that there is only unregulated retailing and no special regime and that there is only one plant in which firm i has joint ownership. To simplify exposition we also assume that all retail contracts specify retail price $\bar{p}$. The extension to the full model we estimate is straightforward. Denote by S_i the production of plants owned entirely by firm i and $C(S_i)$ the cost function of production from plants completely owned. Let l be a jointly owned plant with an ownership share of firm i given by α_l. Production by plant l is denoted S_l and the cost of the plant is $C_l(S_l)$. For any given supply functions chosen for plant l, $S_l(\pi, I_{il})$ and all other plants not co-owned by i, $S_{-i}(\pi, I_{t-i})$, the maximization problem for firm i can be written as:

$$\underset{\pi(\eta_{it\tau}, I_{it})}{Max} E\{E\{(\bar{p}-\pi)D_{it\tau}(\bar{p}) + \pi(\eta_i - S_{-i}(\pi, I_{-it}) - S_l(\pi, I_{lt})) - C(\eta_i - S_{-i}(\pi, I_{-it}) - S_l(\pi, I_{lt})) \tag{22}$$
$$+\alpha_l[\pi S_l(\pi, I_{lt}) - C_l(S_l(\pi, I_{lt}))] \mid \eta_{it\tau}, I_{it}\} \mid I_{it}\}$$

The first order condition is:

$$-E\{D_{it\tau}(\bar{p}) \quad | \quad I_{it}\}] + S_i(\pi, I_{it}) + \alpha_l E\{S_l(\pi, I_{lt}) \mid I_{it}\} - (\pi - C'(S_i(\pi, I_{it}))S'_{-i} \qquad (23)$$
$$+S'_l\left[-\pi(1-\alpha_l) + C'(S_i(\pi_{t\tau}, I_{it})) - \alpha_l C'_l(S_l(\pi, I_{lt}))\right] = 0$$

Note, that the second line in the first order condition (23) is zero in two cases. First, if firm i has control over the jointly owned plant it will cost minimize across the production of all plant. Then the term in brackets is zero because margins must be equalized across plants for a firm that has control, i.e.

$$\pi - C'(S_i(\pi_{t\tau}, I_{it})) = \alpha_l[\pi - C'_l(S_l(\pi, I_{lt}))].$$

Second, the term is also zero if firm i does not have control but the strategy of plant l is a completely inelastic supply function (a Cournot strategy). This is true for all nuclear plants, which make up the bulk of the co-owned generation plants. Furthermore, we have verified in the data that this is also approximately true for all non-nuclear plants that are partially owned by Endesa. The condition fails for two traditional coal based thermal plants for Iberdrola. Iberdrola owns these at 50%. We will assume for the purposes of the estimation that Iberdrola controls the decisions of these plants so that the last term in (23) is zero for all firms in our sample.

Given that co-owned plants either are controlled or are bid in with Cournot strategies the first order condition on price reduces to:

$$-E\{D_{it\tau}(\bar{p}) \mid I_{it}\} + \hat{S}_i(\pi, I_{it}) - (\pi - C'(\hat{S}_i(\pi, I_{it}) - \alpha_l E\{S_l(\pi, I_{lt}) \mid I_{it}\})S'_{-i} = 0 \qquad (24)$$

where $\hat{S}_i = S_i + \alpha_l S_l$, and an estimating equation:

$$\hat{S}_i(\pi, I_{-it}) = \frac{1}{1 + S'_{-i}c_{1i}}\left\{-S'_{-i}c_{0i} + S'_{-i}\pi + E\{D_{it\tau}(\bar{p}) \mid I_{it}\}\right\} + S'_{-i}c_{1i}\alpha_l E\{S_l(\pi, I_{lt}) \mid I_{it}\} - \varepsilon_{it\tau}\} \quad (25)$$

This is an estimating equation where there is ownership weighted expected output on the left hand side. Expected output from jointly owned plants enters on the right hand side in exactly the same way hydroelectric production does in the estimating equation developed in the paper. Note that all parameters relevant to our analysis can still be identified.

To estimate we will assume that $E\{S_l(\pi, I_{lt}) \mid I_{it}\} = S_l(\pi, I_{lt})$. This, in essence assumes that a co-owner of a plant will be assumed to know the supply function plant l bids at the time it makes its decision. Even if this were not true, the estimation error would not introduce a bias in the estimates we obtain.

Another issue that arises is that the output chosen by co-owned plants is endogenous and correlated with the error in the estimating equation. This is the same issue as with hydroelectricity, so that we would have to use instrumental variables for these outputs. Note, however, that the largest proportion of these outputs can be taken as being exogenous since nuclear plants are always bid in up to capacity.

The more serious issues we have to address are: what happens when Cournot strategies for some of the co-owned plants are not as good an approximation to the true supply function as we think; and what happens if the assumption that Iberdrola controls the 50% co-owned plants is invalid. Then the second term in (23) would appear in the error term of the estimating equation. To the extent that price appears in the error term this is not especially problematic because we are instrumenting for price in any case. However, the marginal cost difference may be correlated with the downstream demand position given that the marginal cost difference will be determined by net demand positions of different plants. However, we can test for this problem easily. If our assumptions are wrong, the coefficient on $\alpha_l S_l$ will exceed $S'_{-i} c_{i1}$. This would show up in that the coefficients on $\alpha_l S_l$ and on downstream demand would not add up to 1. Hence, we can test in the data, whether our assumptions are violated or not.

8.2 First-Stage Estimates

Tables 11 and 12 show some of the first-stage regressions for Endesa and Iberdrola, respectively.

8.3 1-step GMM estimates

Tables 13 and 14 show the regular IV estimates or 1-step GMM where standard deviations were computed using the Newey-West procedure with maximum of 30 lags for Endesa and Iberdrola, respectively.

Table 11: Results of the first-stage estimation of IV2, using month and hour dummies

Endesa (Viesgo out) –	First-Stage Regression IV2					
	Dep. variable= π		Dep. variable= h_{EN}		Dep. variable= *Share*	
	coef.	NWs.d	coef.	NWs.d	coef.	NWs.d
dis_EG	0.0011	0.00069	0.0791	0.0244	0.0236	0.0130
dis_IB	0.0032	0.00075	-0.0221	0.0270	-0.0248	0.0158
dis_UF	0.0027	0.00097	0.0162	0.0403	0.0216	0.0195
dis_HC	0.0019	0.00805	-0.3501	0.3252	-0.4517	0.1641
EGhpmean	-0.0025	0.00077	0.7318	0.0402	-0.0188	0.0107
24-hour Δ tmps	*yes*		*yes*		*yes*	
ED_EN	0.0049	0.0004	0.198	0.018	0.0304	0.0076
month dummies	*yes*		*yes*		*yes*	
hour dummies	*yes*		*yes*		*yes*	
R2	0.823		0.877		0.534	
AR2	0.822		0.875		0.530	
obs	5610		5610		5610	
Wald test	54.03		582.03		24.33	
p-value Wald test	0.0002		$5.11E-109$		0.330	

Table 12: Results of the first-stage estimation of IV2, using month and hour dummies

Iberdrola –	First-Stage Regression IV1						First-Stage Regression IV3					
	Dep. variable		Dep. variable		Dep. variable		Dep. variable		Dep. variable		Dep. variable	
	π		h_{IB}		*Shared prod.*		π		h_{IB}		*Shared prod.*	
	coef.	NWs.d	coef.	NWs.d	coef.	NWs.d	coef.	NWs.d	coef.	NWs.d	coef.	NWs.d
dis_EG	0.0022	0.0007	-0.099	0.066	0.045	0.019	0.006	0.0007	0.264	0.046	0.0004	0.015
dis_IB	0.0062	0.0007	0.261	0.048	$-5.8E-05$	0.019	0.002	0.0007	-0.051	0.062	0.014	0.015
dis_HC	0.0160	0.0082	0.688	0.909	-0.894	0.248	0.016	0.0084	0.080	0.802	-0.543	0.179
IBhphour	-0.0028	0.0007	0.632	0.049	0.013	0.014	-0.003	0.0007	0.626	0.047	0.017	0.012
SN_IBLL	–		–		–		0.001	0.0023	-1.104	0.250	0.695	0.092
24-hourΔtmps	*yes*		*yes*		*yes*		*yes*		*yes*		*yes*	
ED_IB	0.0036	0.0004	0.383	0.031	0.048	0.012	0.0036	0.0004	0.386	0.029	0.046	0.011
month dummies	*yes*		*yes*		*yes*		*yes*		*yes*		*yes*	
hour dummies	*yes*		*yes*		*yes*		*yes*		*yes*		*yes*	
R2	0.815		0.778		0.436		0.815		0.798		0.670	
AR2	0.814		0.776		0.431		0.813		0.796		0.667	
obs	5610		5610		5610		5586		5586		5586	
Wald test	266.37		676.14		23.02		267.45		717.27		166.63	
p-value Wald	$2.08E-44$		$1.45E-129$		0.343		$4.57E-44$		$1.76E-137$		$3.30E-24$	

9 An extension of our basic model with elastic demand

Suppose we maintain all the assumptions in our model, except that the unregulated demand is generated by a downward sloping demand function. Assume that for firm i this is $\theta_i - b_i\pi$. (We assume that the lowest θ_i realization is way below the π that would choke off all demand. In our data set we could think of the highest price they are allowed to bid (or effectively bid), $\bar{\pi}$ and think of $D_i(\bar{\pi}) = \theta_i - b_i\bar{\pi}$ as the inelastic part of the demand). Aggregate demand in the spot market is: $\theta - b\pi = \sum_i \theta_i - \left(\sum_i b_i\right)\pi$. Suppressing all issues of regulated demands and costs of transition to competition, we can write down the maximization problem for firm i as:

Table 13: IV results of the total production regression for Endesa, using month and hour dummies

Endesa (Viesgo out) –	IV1-IVs used		IV2-IVs used:		IV3- IVs used:		IV4- IVs used:	
Electricity Units= MWh	EGhpmean,		EGhpmean,		EGmovav3		EGmovav1	
Endogenous var= π, h_{EN},	dis_EG,dis_IB,		dis_EG,dis_IB,dis_UF,		dis_EG,dis_IB,dis_UF,		dis_EG,dis_IB,dis_UF,	
and *shared_firms*	dis_UF,dis_HC		dis_HC, 24hΔtemps		dis_HC, 24hΔtemps		dis_HC, 24hΔtemps	
	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.
π ($\widehat{a}_1$)	14.53	11.45	11.44	10.40	19.12	10.99	14.74	10.57
h_{EN} ($\widehat{a}_2$)	0.527	0.060	0.522	0.058	0.577	0.069	0.589	0.071
Shared_plants ($\widehat{a}_4$)	1.024	1.131	0.433	0.877	0.915	0.874	0.714	0.910
ED_{EN} ($\widehat{a}_3$)	0.490	0.103	0.524	0.093	0.453	0.092	0.478	0.095
constant ($\widehat{a}_0$)	460.2	2718.0	1790.6	2110.8	970.0	2161.1	1401.6	2214.0
$a_2 + a_3$	1.017		1.046		1.030		1.067	
p-value of H0: $a_2 + a_3 = 1$	0.849		0.572		0.736		0.420	
p-value of H0: $a_2 = a_4$	0.653		0.917		0.691		0.887	
p-value of H0: $a_3 + a_4 = 1$	0.634		0.959		0.664		0.826	
$\widehat{S}'_{-EN} = \frac{\widehat{a}_1}{\widehat{a}_3}$ (s.d.)	29.68	29.29	21.82	23.46	42.24	32.14	30.83	27.83
$\widehat{S}'_{-EN} \times \overline{\pi}$	1062.82		781.56		1512.77		1104.19	
nobs	5640		5610		4920		5160	
AR^2	0.892		0.901		0.895		0.901	
Sargan test p-value	0.893		0.999989		0.771		0.918	
p-value Wald test π	$8.85E-07$		0.0002		$6.21E-05$		$1.29E-05$	
p-value Wald test h_{EN}	$1.77E-100$		$5.11E-109$		$9.88E-131$		$7.27E-102$	
p-value Wald test Shared_plants	0.0072		0.330		0.405		0.4997	
$\widehat{c}_{1EN} = 1/\widehat{a}_1 - 1/\widehat{S}'_{-EN}$	0.035	0.021	0.042	0.030	0.029	0.012	0.035	0.020
$\widehat{c}_{1EN} = \widehat{a}_2/\widehat{a}_1$	0.036	0.028	0.046	0.041	0.030	0.018	0.040	0.028
Non-Endesa average product.	8041	1971	8041	1971	8041	1971	8041	1971
Non-Endesa $\overline{S}_{-0} + \widehat{S}'_{-EN} \times \overline{\pi}$	7000.3		6768.13		7499.34		7090.76	
average $\widehat{MC}$	146.56	190.71	53.52	186.88	99.17	122.48	91.54	156.47
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} > \pi$ if net-demander	100		90.22		100		100	
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} < \pi$ if net-supplier	0		99.32		0		1.16	

$$\max_{\pi(\eta_i, I_i)} E\left\{ E\left\{ [\bar{p} - \pi]D_i(\pi) + \pi\left[\eta_i + D_i(\pi) - \sum_{j\neq i} E\{S_j(\pi, I_j) - D_{-i}(\pi) \mid I_i\}\right]\right.\right.$$

$$\left.\left. -C_i\left(\eta_i + D_i(\pi) - \sum_{j\neq i} E\{S_j(\pi, I_j) - D_{-i}(\pi) \mid I_i\} - h_{it\tau}\right) - c_{hi}h_{it\tau} + \delta V_i(\mathbf{H}_{t+1}, I_{i(t+1)}) \mid I_i, \eta_i \right\} \mid I_i \right\}$$

where $\eta_i = \sum_{j\neq i}\{S_j(\pi, I_j) - D_{-i}(\pi)\} - \sum_{j\neq i} E\{S_j(\pi, I_j) - D_{-i}(\pi) \mid I_i\}$.

The first order condition becomes:

$$-D_i(\pi) + S_i(\pi, I_i) - [\bar{p} - \pi]b_i - [\pi - C_i'](s_{-i} + b) = 0$$

or:

$$S_i(\pi, I_i) = \frac{1}{1 + c_{i1}(s_{-i} + b)}\{-c_{io}(s_{-i} + b) + b_i\bar{p} + (s_{-i} + b_{-i})\pi + c_{i1}(s_{-i} + b)h_i + D_i(\pi)\} \tag{26}$$

giving the estimating equation:

$$S_i(\pi, I_i) = a_0 + a_1\pi + a_2 h_i + a_3 D_i + \zeta_i \tag{27}$$

Table 14: IV results of the total production regression for Iberdrola, using month and hour dummies

Iberdrola	IV1- IVs used:		IV2- IVs used:		IV3 - IVs used:		IV4- IVs used:	
Electricity Units= MWh	IBhphour		IBhphour		IBhphour,dis_EG,		IBmovav4,dis_EG,	
Endogenous var=π, h_{IB},	dis_EG, dis_IB		dis_EG, dis_IB		dis_IB,24hΔtemps		dis_IB,24hΔtemps	
and *shared_firms*	dis_HC,24hΔtemps		dis_HC, SN_IBLL		dis_HC,SN_IBLL		dis_HC, SN_IBLL	
	coef.	NWs.d.	coef.	NWs.d.	coef.	NWs.d.	coef.	Nws.d
π ($\widehat{a}_1$)	28.32	5.13	27.92	5.23	28.15	5.23	23.57	5.89
h_{IB} ($\widehat{a}_2$)	0.795	0.048	0.799	0.049	0.799	0.051	0.744	0.045
Shared_firms ($\widehat{a}_4$)	0.669	0.469	0.566	0.212	0.582	0.202	0.519	0.189
ED_{IB} ($\widehat{a}_3$)	0.204	0.051	0.213	0.046	0.210	0.046	0.255	0.051
constant ($\widehat{a}_0$)	792.4	894.0	963.7	424.4	943.5	413.7	1041.5	391.8
$a_2 + a_3$	0.999		1.012		1.008		0.999	
p-value of H0: $a_2 + a_3 = 1$	0.988		0.835		0.889		0.986	
p-value of H0: $a_2 = a_4$	0.785		0.243		0.261		0.211	
p-value of H0: $a_3 + a_4 = 1$	0.778		0.283		0.295		0.222	
$\widehat{S}'_{-IB} = \frac{\widehat{a}_1}{\widehat{a}_3}$ (s.d.)	138.60	51.42	130.97	47.04	134.26	48.51	92.35	38.52
$\widehat{S}'_{-IB} \times \overline{\pi}$	4963.9		4690.9		4808.4		3307.4	
nobs	5610		5592		5586		5112	
AR^2	0.930		0.929		0.929		0.929	
Sargan test p-value	0.9997		0.594		0.9995		0.990	
p-value Wald π	$2.08E-44$		$2.91E-44$		$4.57E-44$		$1.38E-40$	
p-value Wald h_{IB}	$1.45E-129$		$1.77E-135$		$1.76E-137$		$4.61E-104$	
p-value Wald Shared_firms	0.343		$1.77E-18$		$3.30E-24$		$3.09E-26$	
$\widehat{c}_{1IB} = 1/\widehat{a}_1 - 1/\widehat{S}'_{-IB}$	0.028	0.004	0.028	0.005	0.028	0.004	0.032	0.007
$\widehat{c}_{1IB} = \widehat{a}_2/\widehat{a}_1$	0.028	0.006	0.029	0.007	0.028	0.006	0.032	0.009
Non-Iberdrola average production	11082	1944	11082	1944	11082	1944	11082	1944
Non-Iberdrola $\overline{S}_{-0} + \widehat{S}'_{-IB} \times \overline{\pi}$	12934.1		12661.1		12778.6		11277.6	
Average $\widehat{MC}$	25.08	32.71	19.59	17.39	20.15	16.89	13.01	18.16
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} > \pi$ if net demander	1.17		0		0		0	
% $\widehat{MC} + \widehat{\varepsilon}_{ct\tau} < \pi$ if net supplier	100		100		100		100	

We identify:

$$s_{-i} + b_{-i} = \frac{a_1}{a_3} \tag{28}$$

and

$$c_{i1} \frac{(s_{-i} + b)}{s_{-i} + b_{-i}} = \frac{a_2}{a_1} \tag{29}$$

We get that:

$$\frac{1}{a_1} - \frac{1}{s_{-i} + b_{-i}} = \frac{1 - a_3}{a_1} = \frac{a_2}{a_1} \tag{30}$$

So we get again that there are two approaches to identify $c_{i1} \frac{(s_{-i}+b)}{s_{-i}+b_{-i}}$ (which comes of course from the theoretical restriction on the parameters on D_i and h_i. It follows that the estimation in Section 5 generates an upward bias for the slope of the marginal cost function given by:

$$\frac{a_2}{a_1} - c_{i1} = c_{i1} \left[\frac{b_i}{s_{-i} + b_{-i}} \right] = c_{i1} \frac{a_3}{a_1} b_i > 0 \tag{31}$$

There is also a bias in the interpretation of the constant coefficient in marginal costs that we estimate:

$$
\begin{aligned}
-\frac{a_0}{a_1} &= c_{i0}\frac{(s_{-i}+b)}{s_{-i}+b_{-i}} - \frac{\bar{p}b_i}{s_{-i}+b_{-i}} \\
&= c_{i0} - \frac{b_i}{s_{-i}+b_{-i}}(\bar{p}-c_{i0}) \qquad (32)
\end{aligned}
$$

This one will be downward biased given that $(\bar{p}-c_{i0})>0$ can be expected. Again, for small b_i, this error will be small.

How does it affect our predictions concerning net demand and supply positions and pricing below or above marginal cost? Note that from the first order condition:

$$D_i(\pi) - S_i(\pi, I_i) = -[\pi - \frac{s_{-i}+b}{s_{-i}+b_{-i}}(c_{i0}+c_{i1}(S_i-h_i)) - \frac{b_i}{s_{-i}+b_{-i}}\bar{p}](s_{-i}+b_{-i}) \qquad (33)$$

Substituting the parameters from the estimating regression we get:

$$D_i(\pi) - S_i(\pi, I_i) = -[\pi - (-\frac{a_0}{a_1} + \frac{a_2}{a_1}(S_i-h_i))] \qquad (34)$$

which is exactly the same as before. This means that the core test of the theory is independent of the biases in estimating the marginal cost parameters, because the appropriately modified marginal cost term that would be relevant for the prediction relies on the same coefficient estimates.This means that while our estimates of the marginal cost parameters may be biased, this bias is irrelevant for the test of our theory.We want to run exactly the same regression when we have slope in the demand functions.

However, to estimate the parameters of the marginal cost function, we need to estimate the coefficients b_i and b_{-i} for Endesa and Iberdrola. We have done this from the data on demand bids using the linear demand specification of the model, allowing for monthly and hourly shifts in the intercept. It turns out that $b_i = 0$ for Iberdrola which means our estimates for Iberdrola in Section 5 are unbiased but this is not true for Endesa. For Endesa the estimated b_i is 13.28 and $b_{-i} = 1.80$ which means that Endesa's marginal costs parameters are biased. Table 10 shows the impact of allowing for demand slope on our estimates for one one selected instrument set. Although the slope in the case of Endesa is lower, as expected, the impact on average marginal cost is minimal.

Table 15: Marginal costs after correcting for existence of elasticity

	$a_2 + a_3 = 1$, $a_2 = a_4$		$a_2 + a_3 = 1$, $a_2 = a_4$	
	Endesa		Iberdrola	
	IV2		IV1	
	estimate	NWs.d.	estimate	NWs.d.
$\widehat{c}_{1i} = 1/\widehat{a}_1 - 1/\widehat{S}'_{-i}$	0.031	0.005	0.029	0.002
corrected slope	0.024	0.004	0.029	0.002
average intercept	-125.47		-34.49	
average intercept corrected	-82.89		-34.49	
$\widehat{MC}$ at $\overline{(S_i - h_i - shared\_firms)}$	51.05	5.09	34.72	0.628
$\widehat{MC}$ at $\overline{(S_i - h_i - shared\_firms)}$ corrected	52.72	6.15	34.72	0.628