Market Power and Vertical Integration in the Spanish Electricity Market
PRELIMINARY AND INCOMPLETE

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

December 2003

Abstract

The Spanish electricity market has two particularities: 1) the high concentration in the hands of two firms that hold around 80% of the market; 2) the high degree of vertical integration. The same firms buy from and sell electricity into a pool. We model the behavior of firms as competition in supply functions (a la Green and Newberry, 1991) taking into account both the vertical integration and the dynamic features involved in hydroelectrical generation. The different strategic effects we obtain from this model allow us to test the degree of market power of the two main firms through exogenous variations in their downstream demands that have different impact on the pool price. Our results suggest that the two largest firms in the Spanish market exercise market power.

*contact author e-mail: mmachado@eco.uc3m.es

†We particularly thank Daniel Ackerberg, Luis Cabral, and Juan Toro for comments on a previous version of the paper. Furthermore, we would like to thank Pedro Blás, Natalia Fabra, Miguel Angel Lasheras, and all participants at the 4th CEPR conference in Empirical Industrial Organization. Keywords: market power test, vertical integration, electricity markets, supply function equilibrium. JEL classification: L13,L41,L94.

1 Introduction

In January 1998, the Spanish government liberalized the market for electricity generation and introduced a spot market for electricity. By and large electricity generation must be sold in the spot market and electricity supply must be bought from the spot market at the equilibrium price. We believe, however, that the liberalization did not bring competition to this sector. There are two features that make this market a particularly interesting one to study the exercise of market power in electricity spot markets. First, the Spanish market for electricity generation is one of the most concentrated generation markets that have been liberalized. Second, all of the generation companies are vertically integrated into the retail of electricity. Because of a massive consolidation effort by the largest generating company, ENDESA, prior to liberalization, the two largest firms in the market had about 75% market share in generation and 80% market share in distribution in the beginning of 1999. As Table 1 shows, these numbers remain essentially unchanged through 2001. In addition, the supply price of electricity has remained regulated over this period of time.

Due to the high degree of vertical integration much of the payments made and received from the spot market are effectively pure transfers between retail and generation activities of the same companies. Does market power matter at all in such a setting? Can we even determine the impact of market power on spot market prices and efficiency of the use of generation assets? And is it possible to make

Market Shares in the Spot Market	Period: May - December 2001		
	Generation	total Retailing	Distribution
Endesa (E. Viesgo not considered)	45.05	38.42	38.31
Iberdrola	28.72	38.90	39.15
Union Fenosa	12.55	13.54	14.97
Hidro-Cantabrico	6.63	5.86	6.30
E. de Viesgo	3.45	0.97	1.27
Others	0.9	1.95	.002
REE (imports/exports)	2.73	0.36	0

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.

predictions about the impact of entry into liberalized supply markets on prices in the spot market? Will vertical separation increase or decrease the efficiency of market operations? All of these are important policy questions in the face of repeated attempts to reorganize the Spanish electricity market through a variety of attempts of horizontal and vertical mergers. However, they have not been formally analyzed to date.

Our aim in this paper is to test for the exercise of market power when firms are present on both sides of the market with the use of only partial information. In order to do this, we develop and estimate a structural model based on equilibrium of supply functions that accounts for the vertical integration existent in the Spanish electricity market. The use of a structural approach is essential in our case for three reasons: First, there is no public information on costs and in particular on marginal costs. Second, there is no public information on financial contracts that are "de facto" equivalently to decreases in firm's marginal cost (Wolak, 2000). Third, even if there were public information on the *relevant* marginal costs, the theoretical model is crucial to devise a test of market power in such a setting. As our model will show, when there is vertical integration, market prices below marginal cost may be consistent with the exercise of market power.

In this paper we show that an analysis of the existence and impact of market power in the Spanish spot market can be inferred from market behavior because of the systematic and varying degrees of vertical integration between the different electricity companies. Table 1 documents the systematic difference in market shares in generation and retail between the major players in the market.[1] Indeed, as can be seen from Table 1, Iberdrola is on average a net demander in the spot market while ENDESA is a net supplier in 2001. This means that Iberdrola has, on average, an incentive to act similarly to a monopsonist and overbid generation assets into the spot market in order to lower the price on the net units purchased from the market. In contrast, ENDESA has an incentive to underprovide generation

[1] It turns out that the regulation of the distribution activity in the Spanish market implies that the relevant measure of the net-demand position should take into account a different definition of downstream demand. It is still true that taking into account the "relevant" measure of downstream demand Iberdrola is most of the times a net demander and Endesa a net-supplier. This will become clear in Section 3 of the paper.

assets to the market in order to raise the price on net electricity sold to the market. With symmetric vertical integration there would of course be no marginal incentive to manipulate the spot market price. The larger the heterogeneity in vertical integration, the larger the incentives for manipulating the spot market price are. We should not expect any incentives to manipulate the spot market price iif firms were generating and supplying the same amount of electricity. We confirm this intuition in a simple supply function model. We show that net suppliers to the market will bid in the marginal generation asset at a price above marginal cost, while net demanders will bid in the marginal asset at a price below marginal cost. Asymmetric asset holdings upstream and downstream, therefore, lead to an inefficient allocation of generation assets, i.e. excessive costs of generating electricity. Preliminary results show that a more competitive benchmark i.e. where Endesa and Iberdrola bid their non-hydroelectrical units at marginal cost would lead to an increase in price of 39% and a reduction of quantity of only 4 %.

We have chosen the supply function model because it most closely resembles the true bidding structure of the market and is, therefore, most appropriate for structural estimation. However, it should be kept in mind that the qualitative features of the model would be retained by any other bidding model, for example one along the lines of Harbord and van der Fehr (199?). Using a limited data set from 2001, we show that our model matches the data patterns remarkably well. There is significant evidence of market power and firms estimated marginal costs are, most of the time, above the spot market price when net demanders and below when net suppliers, as predicted by our model.

Supply function models of electricity markets have been estimated previously by Wolak (). We are contributing to this literature by explicitly modelling the vertical structure of the market and exploiting the explanatory power of heterogeneous vertical integration for spot market outcomes. Other work on supply functions (e.g. Green and Newbery 1992, Green 1996) has focused on the application of the theoretical model to electricity markets and the calibration of alternative scenarios. Green (1996) has explicitly considered the impact of asymmetric holdings of generation assets on spot market prices. He shows that asymmetries in the distribution of generation assets between firms lead to higher prices in the spot market. His analysis is based entirely on the calibration of a supply function model to data of the UK electricity market. Unfortunately, the impact of generation asset distributions on spot market prices is difficult to test empirically due to the lack of variation in the distribution of those assets across firms[2]. Our results can be seen as the mirror image of the Green (1996) result on generation assets. However, there is much greater variation in the demand shares of different electricity companies than there is in capacities. The spirit of our exercise is also very close to Wolfram () in the sense that we are observing variations in infra marginal sales to determine the exercise of market power.

In order to test the theory and detect the exercise of market power in the Spanish electricity spot market, we develop a structural model that is based on supply function equilibrium. Section 3 describes the specificities of the Spanish electricity market. Section 4 adapts the basic model of Section 2 to the specificities of the Spanish electricity sector, importantly allowing for the existence of a significant hydroelectric generating capacity. Section 5 describes the data used and in Section 6 we show that the basic predictions of the supply function model are borne out by the data. Section 7 concludes.

2 An Illustrative Model

The main feature of interest of the Spanish electricity market for our analysis comes from the fact 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. 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. 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

[2] Wolfram (1998) is a remarkable exception.

$\theta_i D(p_i)$. We assume that the final consumer price is predetermined by contract or regulation $p_i = \bar{p}$, reflecting the idea that prices downstream are set less frequently than upstream. 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 to one for each firm, where the signal for firm i has the form $\sigma_i = \theta_j + \varepsilon_i$.[3] 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. $E\{\theta_i \mid I_i\}$ are linear in the signals observed.[4]

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 gets direct information about total market demand $\theta = \theta_i + \theta_j$.[5] 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

[3] Note, that this signal will also contain information about firm i's own demand if downstream demands are correlated. Similarly, a signal about the firm i's own demand would contain information about firm j's demand if demands were correlated. We have chosen the first formulation so that our model has an equilbrium even for independent demands.

[4] 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.

[5] 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 structre of the Spanish spot market mechanism. As it will be clear later, the basic mechanism is still at work in that modified model.

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 the uncertainty. Our model would be equivalent to theirs if all signals were common to both players so that there would be no private information.[6]

When there are private signals a firm will not only face whatever uncertainty exists in the total demand θ (as in Klemperer and Meyer), but will also be uncertain about the realization of the supply function of its rival.[7] In order to use their techniques to solve the firm's maximization problem and derive explicit equilibrium behavior, we will 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.

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

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

[6] Readers familiar with Klemperer and Meyer (1989) will note that in this case there would be no equilbirium in our model since we have assumed demand to be completely inelastic with respect to π.

[7] Formally, instead of analyzing Nash equilbria in supply functions we have to look at Bayesian Nash equilbria in our model.

Define the random variable η_i by $\eta_i \equiv \theta - s_i^1 [\sigma_j - E\{\sigma_j \mid I_i\}]$. 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 $\eta_i - E\{S_j(\pi, I_j) \mid I_i\}$. Figure 1 illustrates the field of these residual demand functions generated by different η_i.

Note that, for a higher η_i, the 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 with respect to π for every possible realization of η_i:

$$\max_{\pi(\eta_i, I_i)} E\left\{E\left\{[\bar{p} - \pi]\theta_i + \pi\left[\eta_i - E\{S_j(\pi, I_j) \mid I_i\}\right] - C_i\left(\eta_i - E\left\{S_j(\pi, I_j) \mid I_i\right\}\right) \mid I_i, \eta_i\right\} \mid I_i\right\}, \qquad (3)$$

Pointwise maximization of (3) yields the following first order condition for every η_i

$$-E\{\theta_i \mid I_i, \eta_i\} + S_i(\pi, I_i) - (\pi - c_{0i} - c_{1i} S_i(\pi, I_i)) s_j = 0 \qquad (4)$$

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 marginal cost if and only if firm i is a net supplier of electricity in the spot market equilibrium. Furthermore, firm i prices on average below marginal cost if and only if it is on average a net demander.*

Proof. It follows directly from (4) 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

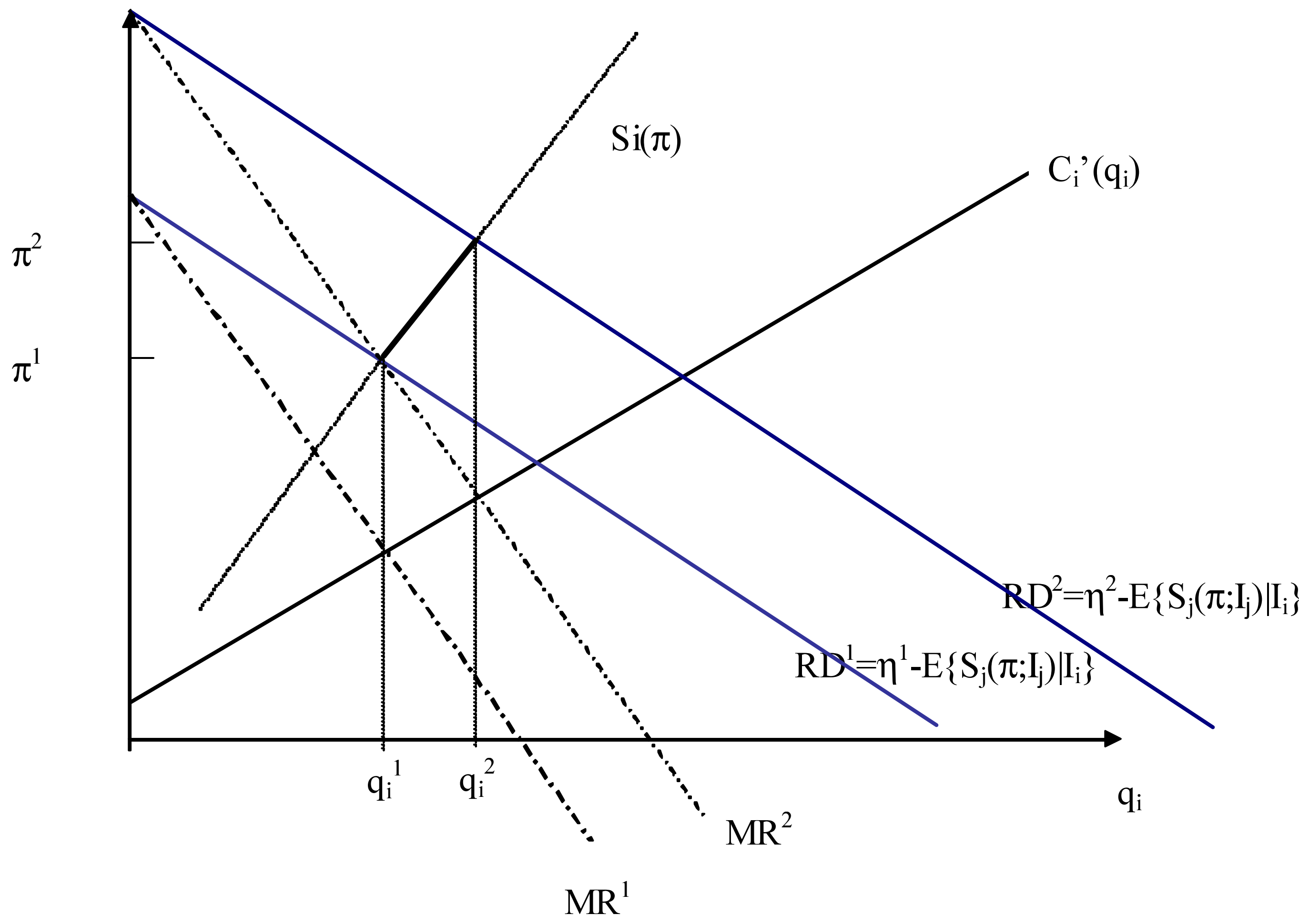

Figure 1: The derivation of the Supply function

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 come down to 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.

It should be clear to the reader that in the absence of market power in the electricity spot market, the downstream demand positions should not matter at all. The firm would take the spot market price as exogenously given and not affected by its own choice of supply function. Maximizing (**??**) state by state would then simply generate a non-random linear supply function with slope of 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:

$$E\{\theta_i \mid I_i, \eta_i\} = \lambda_{i0} + \lambda_{i1}\sigma_i + \lambda_{i\eta}\eta_i \tag{5}$$

To see this, first replace η_i in equation (4) by $S_i(\pi, I_i) + E\{S_j(\pi, I_j) \mid I_i\}$ from the market clearing condition. This yields:

$$-E\left\{\theta_i \mid I_i, S_i(\pi, I_i) + E\{S_j(\pi, I_j) \mid I_i\}\right\} + S_i(\pi, I_i) - (\pi - c_{0i} - c_{1i}S_i(\pi, I_i))s_j = 0. \tag{6}$$

Now note, that (6) has to hold for all π, so differentiation with respect to π yields:

$$-\lambda_{i\eta}(S_i'(\pi, I_i) + s_j) + S_i'(\pi, I_i) - s_j[1 - c_{1i}S_i'(\pi, I_i)] = 0 \tag{7}$$

Equation (7) 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 (7). This yields: [8]

$$s_i = \frac{2(\lambda_{i\eta} + \lambda_{j\eta})}{c_{i1} + c_{j1} + \lambda_{i\eta}\lambda_{j\eta}[\frac{c_{i1}}{\lambda_{i\eta}} - \frac{c_{j1}}{\lambda_{j\eta}}]} \tag{8}$$

Note that the slope of the two firms are the same up to the expression $[\frac{c_{i1}}{\lambda_{i\eta}} - \frac{c_{j1}}{\lambda_{j\eta}}]$. This expression determines the heterogeneity in the supply functions in equilibrium.

To understand expression 8 it is useful to first consider 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.[9] Then λ_{i0} and λ_{i1} in (5) 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 (8) is easily interpretable. If firms 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

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

[9] The reader should be aware that in the absence of private signals our model does not generate any uncertainty in the spot market. As in Klemperer and Meyer (1989) there is a continuum of equilibria in supply functions in our model in that case. However, our restriction to linear supply functions yields a unique equilbrium as has been shown by Turnbull (19??) for supply function equilbrium.

setting with imperfect correlation or private signals. To see this, consider again the case of perfect correlation. But now we allow for private signals. In this case $\lambda_{i\eta} < \frac{\theta_i}{\theta}$, 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 (8). Now consider the determination of $E\{s_{i0}\}$. From (6) and (7) and the symmetry assumption we have:

$$\begin{array}{c} -E\left\{\theta_i \mid I_i, S_i(\pi, I_i) + E\{S_j(\pi, I_j) \mid I_i\}\right\} - (\lambda_{\eta i} s_{1i} + \lambda_{\eta j} s_{1j})\pi \\ + \left[S_i(\pi, I_i) - s_{1i}\pi\right] \\ +(c_{0i} + c_{1i}[S_i(\pi, I_i) - s_{1i}\pi])s_{1j} = 0. \end{array} \tag{9}$$

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

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

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 in the generation market 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 The Spanish Electricity Market

3.1 A General Description of the Market

There are essentially four separate economic activities in electricity markets: generation, transmission, distribution and retailing (often called supply). With electricity liberalization transmission and distribution remained regulated because they are considered natural monopoly elements of the electricity system. Downstream agents can purchase transmission and distribution services at fixed per unit access prices from transmission and distribution companies.

Electricity generation is dominated by four firms: Endesa (including Electra de Viesgo), Iberdrola, Union Fenosa, and Hidrocantabrico. Smaller generators, imports, and excess power from self provision by larger industrial firms together account for only 3.6% of generation, most of this is accounted for by imports. 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 reasons, Spain has an especially high proportion of hydroelectric production (19%).[10] The role of modern CCGT technology was still minimal in 2001.

Generators have two ways of selling the electricity generated. First, there is the possibility of writing "physical contracts" with large end users directly. Second, they can sell energy into a centralized 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. 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.

The retailing market also consists of two parts. Small users of electricity like individual households can purchase electricity at regulated retail prices from the local distribution company. Larger users of electricity ("qualified consumers") have four options: First, they can buy at regulated retail prices from a local distribution company. Second, they can buy electricity directly from the centralized market. Third, they can write a physical contract directly with an electricity generator. Fourth, they can buy electricity through an intermediary (i.e. an unregulated retailer other than the local distribution company). (See graph structure of the market). As part of the Spanish liberalization process, the critical consumption level determining qualified consumers has been lowered successively until it includes everyone 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 transacted in the

[10] Source: CNE annual report for 2001.

main centralized market. There were no qualified consumers who bought electricity directly from the centralized market in 2001.[11] This means that most electricity used by qualified consumer is purchased through intermediaries.

The centralized market (known as the "pool") consists of a sequence of markets for and at different times of the day. The bulk of the energy is traded on the "daily market". The daily market opens the day before actual production takes place. In this market generators submit for every hour of the day and for every production unit it owns an increasing supply function, which is required to be a step function with at most 25 steps. Demand in the daily market comes from demand side bids of retailers (or qualified consumers) for each hour of the day. They are restricted to bid decreasing step demand functions with at most 25 steps. The market operator aggregates the demand and supply functions generated by bidding 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 will be liquidated at the equilibrium price.[12]Figure 2 is a stylized picture of the Spanish electricity market.

Since the demand function in the daily market is based on demand function bids that reflect predictions about demand on the next day, the actual quantities determined for supply will not guarantee that the market clears in real time. These quantities are only used for the liquidation of the daily market and as planning indicators by the generators and the system operator. After the daily market price is determined firms have to submit a step supply functions and a step demand function for real time market clearing. If in real time precommitted production 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 function to determine which firms decrease their production level. In each case the system operator determines a

[11] Source: REE Annual Report 2001.

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

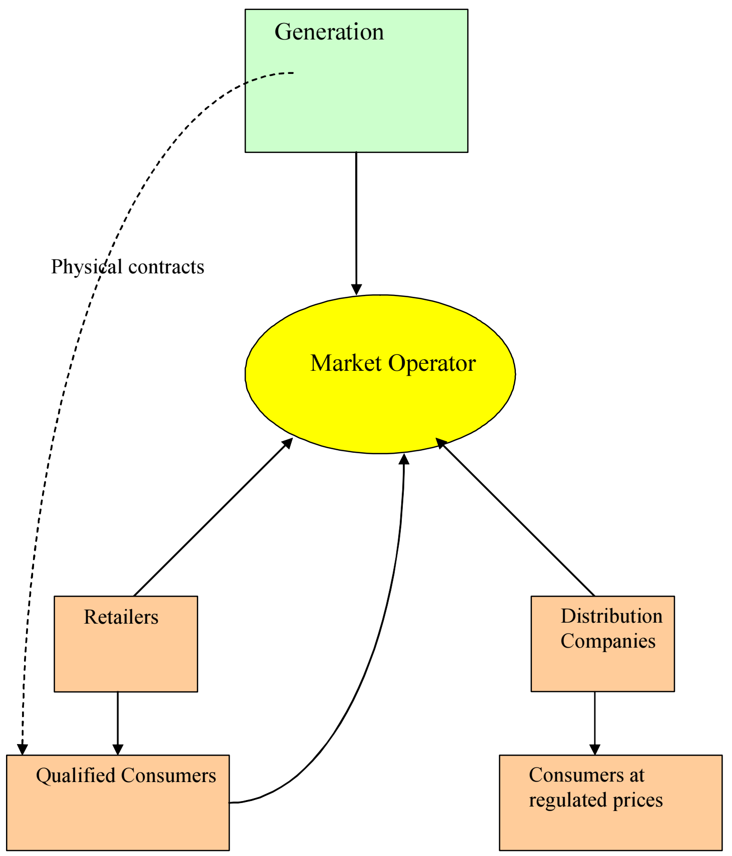

Figure 2: A stylized picture of the Spanish Electricity market

real time price by intersecting these supply (or demand) functions with the inelastic real time demand. Marginal trades in the real time market are executed at these real time prices.

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 plant arrives. Each one of these markets works technically like the daily market with the only difference that supply and demand functions bid 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.

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 1998), we will ignore this possibility for the purposes of this paper. In section 6 we briefly discuss the impact that the sequentiality of markets may have on our results.

3.2 Complications for Structural Modelling

In this subsection we discuss a number of features of the market that we will need to take into account for adapting our basic model to the Spanish market. These consist of the recovery of so called "costs of the transition to competition", the presence of cross-ownership for some generation plants, as well as the complications arising from the management of hydroelectric resources. All three of these factors have large impact on the profits of firms and therefore on their bidding behavior.

3.2.1 Costs of the Transition to Competition (CTC)

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. Sometimes this was justified by a stranded assets argument: Generators had made government mandated investments in generation plant under the old regime, that they argued would not be profitable in a competitive environment. There has been continued discussion over the years how much should 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 taken away and redistributed to generators according to pre-set percentages.

The revenue of the distribution companies comes from access fee 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 consists 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 used to pay subsidies to generating firm. 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 from 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. 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.

Since the revenue that is distributable as CTCs is calculated as a residual profit of the distribution companies it is possible that such profits are 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 paper we will generally assume that expected CTC payments at the time of decisions in the daily market are non-negative. 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. To justify our assumption further, we test it in section 5 and conclude that our assumption on expectations is consistent with the data.[13]

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, do not model this aspect of CTCs.

3.2.2 Generation in the "Special Regime"

An important part of electricity generation in Spain (14.8 % in 2001) bypasses 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 these 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). This subsidy will depend on the technology used by the generator in the special regime.

[13] See CNE (2002), "Informe sobre los resultados de la liquidacion provisional n^o 10 de 2002 y verificaciones practicadas".

Since generators in the special regime are limited to a maximal capacity of 50MW (except renewable energies), we will assume that production decisions are non-strategic. For the modelling of the daily market it would then be equivalent to consider quantities in the special regime as reducing the demand that is bid into the daily market or to treat it as supply that is bid in at a price of zero. From the point of view of firm incentives in the spot market, generators in the special regime primarily affect the amount of CTCs that can be distributed. The payment for these supplies is simply a cost for the distribution company that reduces the amount available for CTC payments.

3.2.3 Cross-Ownership of Generation Plants

The purpose of our paper is to analyze the competitive behavior at the firm level in the daily market. For this reason we are not interested in modelling supply functions at the plant level but instead at the aggregate firm level. Difficulties with this approach arise whenever some generation plants are jointly owned by two or more firms. Indeed, cross-ownership of generation plants is an important phenomenon in the Spanish electricity market. 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 precise modelling of cross-ownership will make little difference. Nuclear capacity has no impact on strategic incentives because it is always fully bid in as base load. Whether a firm has control, joint control, or no control at all over the decisions of a nuclear plant in which it has a financial interest will not matter for the bidding strategy of the plant. However, to minimize all possible contamination of our results from co-ownership effects on the non-nuclear plants, we study aggregate supply functions restricted to all plants that are 100% owned by the firms in question. Since the profit share in joint plants will enter the profit function of the firm, we have modified the analysis to allow for this effect (see the appendix).

3.2.4 The Sale of Electra de Viesgo

In addition, 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).[14] Viesgo was 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 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. However, we have also confirmed from the data that treating Viesgo as part of ENDESA does not change results significantly. If at all estimation results improve when excluding Viesgo.

3.2.5 Hydroelectric Generation

Hydroelectricity does not only represent a large fraction of electricity generation in Spain overall. It is also an important part of the total generation of the two largest firms that our analysis focuses on, Endesa (7% - 17%) and Iberdrola (9% - 32%). Especially Iberdrola uses hydroelectricity extensively as the marginal technology. Specifically, 83% of the time Iberdrola is the marginal price setter in the daily

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

market, the electricity supplied comes from a hydroelectric plant.

The most important aspect of hydroelectric generators is that the capacity of the generator depends on the stock of water stored in a reservoir. This stock will be influenced by exogenous inflows such as snow melt and rain fall, exogenous outflows like evaporation, as well as endogenous production decisions. Depending on the stock of water available and the anticipated rainfall pattern in the future, the shadow cost of using water will vary during the year. Any reasonable model of the Spanish market, therefore, has to incorporate the dynamics of water reserves for hydroelectric plants.

An additional complication in modelling the dynamics of water reserves arises because exogenous inflows into and outflows out of water stocks are non-stationary. We have taken a simple approach to dealing with this problem by making the simplifying assumption that the mean of the netflow distribution of water changes monthly. Together with the other assumptions on the model this can be interpreted as simple shifts in capacity.

4 Implementing the Supply Function Model Empirically

In this Section, we adapt the theoretical model developed previously to the specific features of the Spanish electricity market and develop the main empirical strategy that allows us to identify crucial parameters in the model with the use of the available dataset. We separately model the profit terms that arise from retailing and generation to account for the idiosyncrasies of the Spanish market described in the previous section. The major issue on the retailing side is the contribution of CTCs in firm revenues. The major issue on the generation side is the modelling of the dynamic aspect of hydroelectric generation.

4.1 The retailing side of the market

We separately model a firm's 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 therefore 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. Figure **??** shows that the estimated elasticities are never larger than 0.09 which is much inferior to the values found in the literature. The demand pool-price elasticity in the spot market can therefore safely be approximated by zero.[15][16] We discuss the robustness of our results to an explicit modeling of elastic demand in section 6.

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 of the next days demand into the spot market and 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.[17] In addition the

[15] The demand elasticties were estimated assuming the demand has an inelastic and an elastic components as follows: $D = \overline{D} + D(\pi)$. We first estimated the elasticity of demand assuming the elastic part $D(\pi)$ was linear. The elasticity patterns are different across months i.e. seem to be higher in May-July and lower afterwards but the values are low with a maximum at 0.096.

We have also estimated the demand elasticity assuming that the elastic component has constant elasticty. The numbers reported in (**??**) correspond to $\widehat{\beta} \times \frac{D(p)}{D}$ where $\widehat{\beta}$ is the estimated coefficient from the following regression:

$$\ln D(p) = \alpha - \beta \ln(\text{bid}) + u \tag{10}$$

Finally, we have also added hourly demands horizontally to obtain an aggreage daily demand. We estimated demand elasticities for each month and the maximum value obtained was just below 0.05 for the month of August.

[16] Wolfram (AER 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.

[17] We are disregarding the potential strategic incentives for demand bidding in this paper. The issues arising with such

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.

As explained in section 3 profits from the regulated retail business only accrue to the firm in the form of its share of CTC payments. If the share in CTCs of firm i is given by α_i, then the CTC payment generated at time $t\tau$ from the demand bid into the spot market is given by:

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

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 this electricity on to final customers at price $\bar{p}$. [18] Collecting terms in these payments that involve the price $\pi_{t\tau}$, the CTC payment generated in period $t\tau$ can be written as $(\bar{p} - \pi_{t\tau} - c_{jd}) \sum_j \bar{S}^{ej}_{t\tau}$, where $\bar{S}^{ej}_{t\tau}$ 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:

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

where I_t is the vector of information sets of all firms and k_j a term that does not depend on $\pi_{t\tau}$.[19]

We will also allow for contracts for differences (or forward contracts), i.e. pure financial instruments that allow to hedge 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 the behavior of firms in the spot market (see Wolak 200?). However, we do not have any data on these contracts.

strategic demand bidding are discussed in section 6.

[18] 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.

[19] Strictly speaking distributors profits include access fees from unregulated demand that other firms sell in firm j'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 and therefore do not affect optimal choices. We consolidate these terms in the term k_j in order to simplify notation.

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). $S_{it\tau}$ includes the production from jointly owned generation plants weighted by ownership share. The cost function $C_i(S_{it\tau} - h_{it\tau})$ 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: $C'_{it\tau}(S_{it\tau} - h_{it\tau}) = c_{0i\tau} + c_{1i}(S_{it\tau} - h_{it\tau}) + \varepsilon_{cit\tau}$. 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. 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 in any case, so that the ranking remains constant.

Hydroelectricity can be produced at a constant marginal cost $c_{hi} + \varepsilon_{hit}$, where ε_{hit} is a random shock. Actual hydroelectricity costs will 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

$$H_{i(t+1)} = H_{it} - \sum_{\tau=1}^{24} h_{it\tau} + r_{it} \tag{11}$$

where r_{it} is the exogenous random net inflow of water reserves in units of MegaWatt hours. 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}.

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 $\mathbf{H}_t$ 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:

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

Note that in contrast to the illustrative model there is no common demand element to the definition of η_i. This is because the demand quantities are determined by the demand bids. 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:

$$S_{it\tau}(\pi, I_{it}) = \eta_{it\tau} - E\left\{S_{-it\tau}(\pi, I_t) \mid I_{it}\right\}, \tag{12}$$

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:

$$
\begin{array}{c}
V_i(\mathbf{H}_t, I_{it}) = \max_{\{\pi_{t\tau}(\eta_{it\tau},\mathbf{H}_t,I_{it})\}_{\tau=1}^{24},\{h_{gt\tau}(\eta_{it\tau},\mathbf{H}_t,I_{it})\}_{\tau=1}^{24}} \\
\sum_{\tau=1}^{24} E\left\{E\{\sum_{b\in B_i\cup B_i^h}(p_{t\tau}^b-\pi_{t\tau})D_{t\tau}^b(p_{t\tau}^b)\ +CTC_i(\pi_{t\tau},I_t)\right. \\
\pi_{t\tau}(\eta_{it\tau}-E\{S_{-i}(\pi,I_t)\mid I_{it}\})+\pi_{t\tau}\bar{S}_{t\tau}^{ei} \\
-C_{it\tau}(\eta_{it\tau}-E\{S_{-i}(\pi,I_t)\mid I_{it}\}-h_{it\tau})-(c_{hi}+\varepsilon_{hit})h_{it\tau}+\delta V_i(\mathbf{H}_{t+1},I_{i(t+1)})\mid I_{it},\eta_{it\tau}\}\mid I_{it}\}
\end{array}
\tag{13}
$$

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 (11). 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 (13) 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:

$$
\begin{array}{c}
\pi_{t\tau}-C_{i\tau}'(S_{it\tau}-h_{it\tau})+\frac{1}{S_{-i}'}\sum_{b\in B_i^h}D_{t\tau}^b(p_{t\tau}^b) \\
=\frac{1}{S_{-i}'}[S_{it\tau}+\overline{S}_{t\tau}^{ei}-E\{D_{it\tau}^u\mid I_{it},\pi_{t\tau}\}-\alpha_i E\{\left(\sum_j E\{D_{jt\tau}^r\mid I_{jt}\}+\bar{S}_{t\tau}^{ej}\right)\mid I_{it},\pi_{t\tau}\}],
\end{array}
\tag{14}
$$

where we have substituted back 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

$$C'_{it\tau}(S_{it\tau} - h_{it\tau}) - c_{hi} - \varepsilon_{hit} - \delta \frac{\partial E\{V_i(\mathbf{H}_{t+1} \mid I_{it\tau}\}}{\partial H_{it+1}} \leq 0 \tag{15}$$

which holds with equality for strictly positive use of hydroelectricity. In reality 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 (15) is satisfied as an equality. Then expression (15) simply says that the marginal cost of using non-hydroelectric sources has to be equal to the marginal cost of using hydroelectric sources. Note that (15) 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. But there are anticipated 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 (14). Equation (15) could, therefore, primarily help by eliminating the endogenous variable $h_{it\tau}$. However, this simply generates new problems for the estimation. First, we can be significantly more confident in the accuracy of the hydroelectricity production data than in the reported hydroelectricity stocks, since the first are measured directly while the second 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 a significant multicollinearity problem in equations that include the shadow value of hydroelectricity. Thirdly, using the first order condition (14) puts great confidence in the ability of firms to actually achieve intertemporal cost minimization. An estimate of (14) 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 (14) directly and not using (15). Solving (14) for $S_{it\tau}$, we obtain the estimating equation:

$$S_{it\tau} = \frac{S'_{-i}}{1+c_{1i}S'_{-i}}\left\{-c_{0it\tau} + \frac{1}{S'_{-i}}\sum_{b\in B_i^h} D^b_{t\tau} + \pi_{t\tau} + c_{1i}h_{it\tau} + \right. \tag{16}$$

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

In this equation $\pi_{t\tau}$ and $h_{it\tau}$ are endogenous since both will be determined partly by the shock to 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

We want to test the prediction that there is significant two-sided market power with the estimating equation:

$$S_{it\tau} = a_{o\tau} + a_1\pi_{t\tau} + a_2h_{it\tau} + a_3E\left\{\left[D^u_{it\tau} + \alpha_i\left(\sum_j E\{D^r_{jt\tau} \mid I_{jt}\} + \bar{S}^{ej}_{t\tau}\right) - \bar{S}^{e}_{i\tau}\right] \mid I_{it}, \pi_{t\tau}\right\} + \zeta_{it\tau} \tag{17}$$

The simplest test of market power is that coefficient a_3 is strictly positive and significantly different

$$\frac{a_2}{a_1} = c_{1i}$$

and

$$\frac{a_{0\tau}}{a_1} = -c_{0it\tau} + \frac{1}{S'_{-i}} \sum_{b \in B_i^h} D_{t\tau}^b.$$

The first identifies the slope of the marginal cost function. The second identifies the constant term of the adjusted marginal cost that is relevant for the theoretical test. This information allows us to directly test whether conditional on a net demand or supply position price is below or exceeds marginal cost. A clear pattern would provide strong evidence that both oligopoly and oligopsony forces are important to understand the impact of market power in the daily market. Finally, we can also identify S'_{-i}. Since $S'_i - S'_j = S'_{-j} - S'_{-i}$ this also gives us an estimate for the difference in slope of the supply function of the firms we are estimating. With the information about average marginal cost and average net demand position we obtain from the data, we can test whether the sign of this difference is consistent with the theory.

The theory also imposes a number of parameter restrictions that we can use as additional specification test. First, coefficient on price a_1 and the coefficient on hydroelectric production should both be positive. Second, the coefficients a_2 and a_3 should add up to1. Third, the coefficient c_{1i} is overidentified. 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. Fourth, the estimated aggregate slope of the rivals' supply function S'_{-i} should be positive. Fifth, 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 bided by rivals at price zero. We will see that the model does remarkably well on all of these tests.

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 May until December 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, supplier, pumping). We are also able to match each plant/unit with its proprietor i.e. Endesa Group, Iberdrola, Unión Fenosa, HidroCantábrico or Other. UNESA provided us with the daily hydroelectrical reserves by firm. We obtained temperatures for 4 hours a day for 50 weather stations across the country from the INM (Ministerio del Ambiente). The temperature data was crucial for the construction of valid instruments for the regressions in the next section.

We take a practical approach and use the bids from the unregulated demand side of each firm conditional on the equilibrium price as the variable $E\{D^u_{it\tau} \mid I_{it}, \pi_{t\tau}\}$ needed in our estimation. Moreover, we used the realized regulated demand to construct the variable $\alpha_i E\left\{\sum_j E\{D^r_{jt\tau} \mid I_{jt}\} \mid I_{it}, \pi_{t\tau}\right\}$.

The data on the total energy sold under special regime by hour of the day was gathered in files taken directly files posted in the OMEL web page for the period after June 29, 2001.[20] 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.

5 Empirical Results (preliminary)

We start by showing the results of the estimating equation:

[20] 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.

$$S_{it\tau} = a_{o\tau i} + a_{1i}\pi_{t\tau} + a_{2i}h_{it\tau} + a_{3i} \left[E\{D^{r}_{it\tau} \mid I_{it}, \pi_{t\tau}\} + \alpha_i E\left\{ \left(\sum_j E\{D^{r}_{jt\tau} \mid I_{jt}\} + \bar{S}^{ej}_{t\tau} \right) \mid I_{it} \right\} \right] + a_{4i} \sum_{n \in P_i} \kappa_n S_n + \zeta \tag{18}$$

where $\sum_{n \in P_i} \kappa_n S_n$ is the weighted by ownership share of all electricity produced in plants partly owned by firm i and $a_{4i} = -\frac{c_{1i}S'_{-i}}{1+c_{1i}S'_{-i}}$ (see appendix).

The variables $\pi_{t\tau}$ and $h_{it\tau}$ are clearly endogeneous since shocks to the marginal cost of non-hydro generation affect both the equilibrium price and the decision on how much hydroelectricity to produce. Moreover, if Endesa or Iberdrola have some control over the production of co-owned plants then shocks to marginal cost plants leads to a rearrangement of production between the 100% controled plants and the shared plants. We, therefore, treat the variable $\sum_{n \in P_i} \kappa_n S_n$ as endogeneous. We have used several variables as instruments for $\pi_{t\tau}$ and $h_{it\tau}$ and $\sum_{n \in P_i} \kappa_n S_n$ which we believed are not correlated with the shocks to the firm's marginal cost. Some instruments are more correlated to price, some to hydroelectricity and some to $\sum_{n \in P_i} \kappa_n S_n$. We made sure that the isntruments used were enough correlated with the endogeneous variables so that the equation was indeed identified. The instruments used that are closer correlated to price are: 1) realized aggregate regulated demand of electricity (totdis); 2) firm specific realized regulated demand, dis_EG, dis_IB, dis_HC, dis_UF from Endesa, Iberdrola, Hidrocantabrico and Unión Fenosa. 3) current production of Unión Fenosa (UF_p); 4) 24-hour changes in temperatures. The instruments that were more correlated to hydroelectricity of Endesa and Iberdrola respectively were: 5) Endesa monthly average hydroelectricity bidded into the pool regardless of whether it is dispached or not (EGhphour). 6) Iberdrola's monthly average production of hydroelectricity, i.e. only quantities bidded in below the equilibrium pool price. It was much harder to find proper instruments for the Endesa and Iberdrola's shares of production from co-owned plants. For the Endesa case, we could not find a perfect instrument instead we relied on the instruments that were more correlated to price and hydroelectricity and they did a reasonably good job. For Iberdrola, the 24-hour lagged quantity of $\sum_{n \in P_i} \kappa_n S_n$ as well as Iberdrola's monthly average share of nuclear production in shared plants seem good and valid instruments.

Apart from the structural restrictions described in the previous section we should add $a_{4i} = a_{2i}$ i.e the coefficient on the hydroelectricity production should equal the coefficient on the firm's share of the production coming from the co-owned plants $\sum_{n \in P_i} \kappa_n S_n$. Below we will show the OLS and IV results with and without imposing this restriction.

The tables below present the results for Endesa and Iberdrola separately that best matched the predictions from the theoretical model. All specifications for Endesa and Iberdrola control for month and hourly dummies. [21] We comment first the results obtained for Endesa and then the results obtained for Iberdrola.

Tables 2 and 3 present the best results obtained for Endesa without and with the restriction $a_{4i} = a_{2i}$, respectively. Let's start by describing the results obtained from table 2. First, notice that, in contrast with the IV columns, the OLS column shows a negative price coefficient which is a clear evidence of endogeneity. Furthermore, the OLS results reject all the structural null hypothesis: $a_{2i} + a_{3i} = 1$, $a_{4i} = a_{2i}$, and $a_{2i} + a_{4i} = 1$. The OLS estimate of the slope of the cummulative rivals' supply function and the estimates of the slope of Endesa's marginal cost, c_{1i}, are all negative. The estimated average production of rival firms (= 5112.5 MW) is far further from the sample average than the IV estimate. On the contrary, for all instrumental variables used, the coefficient on price is positive and the structural null hypothesis on the parameters $a_{2i} + a_{3i} = 1$, $a_{4i} = a_{2i}$, and $a_{2i} + a_{4i} = 1$ are not rejected, which is quite remarkable. Notice however that a_{4i}, the coefficient on the share of production coming from co-owned plants, is not vbery precisely estimated in any of the IV columns and this is partly the reason why the restrictions on this parameter are easier not rejected. The reason why a_{4i} is not precisely estimated is because, although the instruments in use do a good job in the first-stage regression, we could not find an instrument that was directly correlated with it and not with the ressiduals. Furthermore, because the price coefficient is now positive, the estimated slope of the rival's supply function is now also positive

[21] The results are incomplete in this version of the paper, among other things we plan to add tests of serial correlation.

and significantly different from zero. Another robustness test is given by the comparison of the two different estimates of the slope of the marginal cost, c_{1EN}, which is overidentified in this model. In the OLS column the two estimates obtained are not only negative but very different from each other. The IV estimates, on the contrary, are not only positive but very similar (we still do not have confidence interval on these). The low p-values of the Hausman test in the tables below shows that there is evidence of endogeneity of the variables π, h_{EN}, and $\sum_{n \in P_i} \kappa_n S_n$. The p-values of the over-identification restriction test[22] are not very high, meaning that there is still some correlation with the residuals, but high enough to have confidence in the results, specially because all the instruments are strongly correlated with the endogeneous variables as the low p-values on the F-tests of the first-stage regressions indicate. Of all the sets of instruments chosen, IV2 is the one that does worse. IV1, IV3 and IV4 are very similar. The theoretical model predicts that a firm's marginal cost should be above price when the firm is a net demander and below price when the firm is a net supplier. Endesa is a net demander 81.5% of the times. The average price in the sample is 35.2 Euros/MWh, so Endesa's estimated average marginal cost is above price as it would be expected from a firm that is more frequently a net-demander than a net-supplier. In any case, it is possible that our estimate of the marginal costs is biased upward since the estimates conform much better with the predicted behavior when a net-demander (except for IV2, 100% of times the estimated marginal cost is above price) than they do when a net-supplier. IV4, however, does remarkably well at predicting the theoretical results from the model both when the firm is a net-demander and a net-supplier. Lastly, although the predicted average value of the rival's production[23] is closer to the sample average, we still underestimate the rival's production level by roughly 1000 MW. The reason probably lies in the estimate of the intercept S_{0-i} of the rival's aggregate supply function. $\widehat{S}_{0-i}$ is the sample average of the amount bidded in by the rivals at zero price. Something that we need to check is if Endesa rivals bid any amount at prices very close to zero that can account for this differencial.

[22]The OIR test used here is the one proposed by Hausman (see Greene, 3rd edition, page 617).

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

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

Endesa (Viesgo out) –	OLS		IV1		IV2		IV3		IV4	
Electricity Units= MWh			IVs=EGhphour,		IVs=EGhphour		IVs=EGhphour,UF_p		IVs=EGhphour,UF_p	
End. var= $\pi, h_{EN}, shared\_firms$			24Δtmp, dis_EG,		24Δtmp, dis_IB,		24Δtmp, dis_EG,		24Δtmp, totdis,	
Month and hour dummies			dis_IB,dis_UF,dis_HC		dis_UF,dis_HC		dis_IB,dis_UF,dis_HC		dis_IB,dis_HC	
without weekend days	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.
π ($\widehat{a}_1$)	-18.40	0.802	12.95	3.70	9.79	3.90	13.19	2.94	12.89	2.98
h_{EN} ($\widehat{a}_2$)	0.513	0.015	0.490	0.034	0.470	0.034	0.490	0.034	0.489	0.034
Shared_firms ($\widehat{a}_4$)	-0.056	0.055	0.474	0.299	0.092	0.341	0.483	0.288	0.461	0.291
ED_{EN} ($\widehat{a}_3$)	0.754	0.009	0.521	0.031	0.556	0.034	0.519	0.025	0.522	0.026
constant ($\widehat{a}_0$)	1845.7	149.0	1724.9	724.0	2539.14	801.4	1712.4	715.89	1754.0	719.83
$a_2 + a_3$	1.267		1.011		1.026		1.009		1.011	
p-value of H0: $a_2 + a_3 = 1$	0		0.777		0.499		0.791		0.753	
p-value of H0: $a_2 = a_4$	0		0.956		0.258		0.979		0.922	
p-value of H0: $a_3 + a_4 = 1$	0		0.985		0.276		0.996		0.951	
$\widehat{S}'_{-EN} = \frac{\widehat{a}_1}{\widehat{a}_3}$ (delta method s.d.)	-24.41	0.893	24.88	8.47	17.61	8.02	25.43	6.77	24.72	6.80
$\widehat{S}'_{-EN} \times \pi$	-874.10		890.93		630.80		910.93		885.24	
nobs	5640		5610		5610		5610		5610	
AR^2	0.921		0.899		0.904		0.898		0.899	
p-value Hausman test			0		0		0		0	
O.I. R. p-value			0.319		0.469		0.381		0.335	
p-value F-test π			$4.67E-65$		$1.44E-61$		$1.34E-105$		$1.28E-102$	
p-value F-test h_{EN}			0.0		0.0		0.0		0.0	
p-value F-test Shared_firms			$1.88E-45$		$3.13E-37$		$1.30E-46$		$2.51E-46$	
$\widehat{c}_{1EN} = 1/\widehat{a}_1 - 1/\widehat{S}'_{-EN}$	-0.013		0.037		0.045		0.036		0.037	
$\widehat{c}_{1EN} = \widehat{a}_2/\widehat{a}_1$	-0.028		0.038		0.048		0.037		0.038	
Non-Endesa average hourly production	8041.2	1970.7	8041.2	1970.7	8041.2	1970.7	8041.2	1970.7	8041.2	1970.7
Non-Endesa $\overline{S}_{-0} + \widehat{S}'_{-EN} \times \overline{\pi}$	5112.5		6877.5		6617.37		6897.50		6871.80	
$\widehat{MC}$ at $(S_{EN} - h_{EN} - shared\_firms)$	-37.75		60.7		-11.91		60.52		58.27	
% $\widehat{MC} > \pi$ if net demander(b.s.d.)	0		100		11.75		100		100	
% $\widehat{MC} < \pi$ if net supplier(b.s.d.)	99.81		74.52		100		71.93		90.04	

Table 3 presents the estimation under the same specification as table 2 when the restriction $a_{4i} = a_{2i}$ is included. Results do not change much except for OLS and IV2. All coefficients are now estimated with higher precision than before, especially the constant term, and the values of the OIR test are slighty higher than in table 2. The results from IV2 are now much closer to the ones from the other columns.

Lastly, table 4 shows Endesa's estimated values of the CTC share α. This is done by estimating separate coefficients for the regulated and unregulated part of the Expected demand as it is easily seen in the estimating equation equation 18. The true value of α is 0.5036 and this was the value used in the estimations presented in tables 2 and 3. The estimated values of α are slightly above the true value granting in fact a rejection of the true value for most specifications with the exception of the sets of IVs IV3 and IV4 where the true value of α is just not rejected.

Next, we show the results for Iberdrola. Table 5 shows results without imposing the restriction

Table 3: Results of the total production regression for Endesa, using month and hour dummies

Endesa (Viesgo out)	OLS		IV1		IV2		IV3		IV4	
Electricity Units= MWh			IVs=EGhphour,		IVs=EGhphour		IVs=EGhphour,UF_p		IVs=EGhphour,UF_p	
End. variables=π, h_{EN}			24Δtmp, dis_EG,		24Δtmp, dis_IB,		24Δtmp, dis_EG,		24Δtmp, totdis,	
Month and hour dummies			dis_IB,dis_UF,dis_HC		dis_UF,dis_HC		dis_IB,dis_UF,dis_HC		dis_IB,dis_HC	
without weekend days	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.
π ($\widehat{a}_1$)	-18.14	0.809	13.00	3.59	11.50	3.65	13.20	2.92	12.93	2.96
h_{EN}+Shared_firms ($\widehat{a}_2$)	0.48	0.015	0.490	0.034	0.477	0.034	0.490	0.034	0.489	0.034
ED_{EN} ($\widehat{a}_3$)	0.749	0.009	0.520	0.028	0.535	0.029	0.518	0.024	0.521	0.024
constant ($\widehat{a}_0$)	487.9	64.5	1686.00	164.64	1651.5	164.16	1694.2	141.12	1685.16	142.16
$a_2 + a_3$	1.23		1.010		1.011		1.01		1.01	
p-value of H0: $a_2 + a_3 = 1$	0		0.778		0.758		0.791		0.763	
$\widehat{S'}_{-EN} = \frac{\widehat{a}_1}{\widehat{a}_3}$ (delta method s.d.)	-24.20	0.91	25.01	8.16	21.51	7.92	25.46	6.70	24.82	6.74
$\widehat{S'}_{-EN} \times \overline{\pi}$	-866.76		895.60		770.29		911.82		888.96	
nobs	5640		5610		5610		5610		5610	
AR^2	0.919		0.899		0.901		0.898		0.899	
p-value Hausman test			0		0		0		0	
O.I. R. p-value			0.378		0.474		0.442		0.394	
p-value F-test π			$4.67E-65$		$1.44E-61$		$1.34E-105$		$1.28E-102$	
p-value F-test (h_{EN} + $shared\_firms$)			0.0		$1.10E-296$		0.0		0.0	
$\widehat{c}_{1EN} = 1/\widehat{a}_1 - 1/\widehat{S'}_{-EN}$	-0.014		0.037		0.040		0.036		0.037	
$\widehat{c}_{1EN} = \widehat{a}_2/\widehat{a}_1$	-0.027		0.038		0.041		0.037		0.038	
Non-Endesa average hourly production	8041.2	1970.7	8041.2	1970.7	8041.2	1970.7	8041.2	1970.7	8041.2	1970.7
Non-Endesa $\overline{S}_{-0}+\widehat{S'}_{-EN}\times\overline{\pi}$	5119.8		6882.17		6756.86		6898.39		6875.53	
$\widehat{MC}$ at ($S_{EN} - h_{EN} - shared\_firms$)	-103.7		63.43		68.43		61.86		63.40	
% $\widehat{MC} > \pi$ if net demander(b.s.d.)	0		100		100		100		100	
% $\widehat{MC} < \pi$ if net supplier(b.s.d.)	100		58.43		56.32		64.66		60.15	

Table 4: Estimated values of the CTC cuota

Iberdrola	OLS	IV1	IV2	IV3	IV4
α - table 2	0.5904	0.5658	0.5714	0.5371	0.5394
p-value H0: $\alpha = 0.5036$	0	0.0171	0.0173	0.1322	0.1173
α - table 3	0.5993	0.5658	0.5714	0.5357	0.5376
p-value H0: $\alpha = 0.5036$	0	0.0172	0.0175	0.1403	0.1282

that $a_{4i} = a_{2i}$ and table 6 shows the results for the same specification after imposing the restriction. The first thing to notice in Iberdrola's results is that the OLS estimates are not as bad as the ones for Endesa. The OLS price coefficient is positive and so is the slope of the rivals' aggregate supply function and the marginal cost estimates. Furthermore, the sum $a_{2i} + a_{3i}$ although significantly different from 1 is fairly close to one. However, the OLS results do not predict the right behavior when Iberdrola is a net-supplier, which happens 54.5% of the time, and the average estimated marginal cost is too high. The IV estimates of the hydro coefficient are only slightly higher than the OLS estimates but the coefficient on the Expected downstream demand is much smaller so that the value of $a_{2i}+a_{3i}$ is now much closer to unity and the restriction is never rejected. The restriction that $a_{4i} = a_{2i}$ is also not rejected in IV2 and IV4 and it is borderline for IV1 and IV3. In the case of IV3 the test $a_{4i} = a_{2i}$ has little power given the large standard deviation of the a_{4i} estimate. In fact, although the average nuclear production over the month is highly correlated with the share of production from the co-owned plants (correlation coefficient = 0.54), it performs very poorly in first stage regression i.e. its conditional correlation with the share of production coming from coowned firms is not statistically different from zero. IBhphour and totdis also perform poorly in the first stage rehgression meaning that the the identification of the equation hinges on the correlation between the 24-hour changes in temperature and the share of production from co-owned plants, and this correlation is small. The Hausman test (done together for the three endogenous variables) indicates that these variables are endogenous and that IV estimation should be used instead of OLS. The over-identification restrictions test again is not incredibly high but high enough to grant that the correlation between IVs and residuals is not important. The sets of IVs used are very strongly correlated with the endogenous variables as the miniscule p-values of the first-stage regression show. Finally, the two estimates of the slope of the marginal cost are very similar which is another robustness test on the estimates. Iberdrola is slightly more often a net-supplier so the estimated average marginal cost should be slightly below the average price of 35.82 Euros/MWh. In fact this only happens for IV1 and IV4. IV3 estimate of the average of marginal cost is as bad as the IV estimate and we think this is biased upwards. Contrary to the OLS results, the IV results overestimate the rivals' average production by quite a lot. The only exception is IV2 where the difference is smaller. The reason why the results for Iberdrola are worse than the results for Endesa may have to do with the nature of the co-owned plants in the case of Iberdrola. As explained in the appendix, if Iberdrola does not have control over the non-nuclear co-owned plants (Iberdrola owns 50% of Aceca plant and Unión Fenosa owns another 50%) then the hypothesis of cost-minimization across plants does not hold and an extra term show up in the error term. The test of $a_{4i} + a_{3i} = 1$ should also be a test of the control hypothesis and this holds for IV2 although only marginally for the other sets of IVs.

Table 6 reestimates the equation imposing the restriction that $a_{4i} = a_{2i}$. The coefficient estimates are very similar, the biggest difference happening with IV3 perhaps where results improve siubstancially. In general, imposing the restriction brought about an increase in the estimated average marginal cost, a worsening of the overidentification restructions but a better fit to the average production by rivals. Finally, table 7 estimates the CTCs cuotas for Iberdrola by separating the coefficient from the regulated from the unregulated part of the demand. OLS and IV1 estimated $\alpha' s$ are significantly different from the true CTC share of 0.2463, in fact IV1 estimated α is negative and would only make sense if Iberdrola expected to pay rather than receive CTCs. In constrast, for the other IVs, the estimated CTC's cuotas are closer to the true value particularly when the restriction $a_{4i} = a_{2i}$ is imposed.

Finally, we plan to present results where the restriction $a_{2i} + a_{3i} = 1$ is imposed in order to increase efficiency. This restriction is perhaps our most robust as the tables for Endesa and Iberdrola show and we are confident that some of our tests will improve once we take this restriction into account.

5.1 Comparison with the benchmark case

We construct a benchmark case where Endesa and Iberdrola produce a competitively amount of non-hydroelectrical energy coming from 100% ownership plants. We assume, for simplicity, that the hydroelectrical bid functions from Endesa and Iberdrola remain constant as well as the production of all other firms including the plants co-owned by Endesa and Iberdrola. We take the estimated marginal

Table 5: Results of the total production regression for Iberdrola, using month and hour dummies

Iberdrola	OLS		IV1		IV2		IV3		IV4	
Electricity Units= MWh			IVs=shareIBL		IVs=shareIBL		IVs=SN_IBm		IVs=shareIBL,	
End. var=$\pi, h_{IB}, shared\_firms$			IBhphour,		IBhphour,24Δtmp,		IBhphour,24Δtmp,		24Δtmp,IBhphour,	
Month and hour dummies			dis_IB		totdis		totdis		dis_HC	
without weekend days	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.
π ($\widehat{a}_1$)	16.38	0.705	29.56	1.807	24.27	1.548	24.08	1.57	29.187	2.408
h_{IB} ($\widehat{a}_2$)	0.771	0.010	0.779	0.027	0.800	0.025	0.800	0.025	0.778	0.026
Shared_firms ($\widehat{a}_4$)	0.907	0.034	0.696	0.060	0.766	0.054	1.269	0.249	0.698	0.059
ED_{IB} ($\widehat{a}_3$)	0.302	0.009	0.202	0.014	0.229	0.014	0.204	0.019	0.205	0.018
constant ($\widehat{a}_0$)	132.21	74.29	731.65	111.78	558.33	102.00	-386.78	468.60	728.57	119.76
$a_2 + a_3$	1.073		0.981		1.029		1.004		0.983	
p-value of H0: $a_2 + a_3 = 1$	0		0.430		0.146		0.868		0.514	
p-value of H0: $a_2 = a_4$	0		0.067		0.425		0.058		0.083	
p-value of H0: $a_3 + a_4 = 1$	0		0.071		0.923		0.046		0.108	
$\widehat{S}'_{-IB} = \frac{\widehat{a}_1}{\widehat{a}_3}$ (delta method s.d.)	54.16	3.29	146.15	15.04	105.78	10.79	117.93	14.30	142.63	21.74
$\widehat{S}'_{-IB} \times \overline{\pi}$	1939.81		5234.54		3788.62		4223.78		5108.14	
nobs	5640		5616		5610		5610		5610	
AR^2	0.934		0.929		0.932		0.931		0.930	
p-value Hausman test			0		0		0		0	
O.I. R. p-value			$-$		0.491		0.788		0.516	
p-value F-test π			0		0		0		$1.70E-145$	
p-value F-test h_{IB}			0		0		$1.57E-225$		$1.72E-301$	
p-value F-test Shared_firms			0		0		$2.78E-13$		0	
$\widehat{c}_{1IB} = 1/\widehat{a}_1 - 1/\widehat{S}'_{-IB}$	0.043		0.027		0.032		0.033		0.027	
$\widehat{c}_{1IB} = \widehat{a}_2/\widehat{a}_1$	0.047		0.026		0.033		0.033		0.027	
Non-Iberdrola average hourly production	11082.2	1943.5	11082.2	1943.5	11082.2	1943.5	11082.2	1943.5	11082.2	1943.5
Non-Endesa $\overline{S}_{-0} + \widehat{S}'_{-IB} \times \overline{\pi}$	9910.0		13204.7		11758.8		12194.0		13078.3	
$\widehat{MC}$ at $\overline{(S_{IB} - h_{IB} - shared\_firms)}$	76.92		25.01		38.43		76.57		25.36	
% $\widehat{MC} > \pi$ if net demander(b.s.d.)	100		1.21		100		100		1.67	
% $\widehat{MC} < \pi$ if net supplier(b.s.d.)	0		100		57.26		0		100	

Table 6: Results of the total production regression for Iberdrola, using month and hour dummies

Iberdrola	OLS		IV1		IV2		IV3		IV4	
Electricity Units= MWh			IVs=shareIBL,		IVs=shareIBL,		IVs=SN_IBm,		IVs=shareIBL,	
End. variables=π, h_{IB}			IBhphour,		IBhphour, 24Δtmp,		IBhphour, 24Δtmp,		24Δtmp,IBhphour,	
Month and hour dummies			dis_IB		totdis		totdis		dis_HC	
without weekend days	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.
π ($\widehat{a}_1$)	16.73	0.702	28.38	1.68	23.92	1.48	24.48	1.54	27.378	2.153
h_{IB}+Shared_firms ($\widehat{a}_2$)	0.770	0.010	0.795	0.026	0.804	0.024	0.798	0.024	0.791	0.024
ED_{IB} ($\widehat{a}_3$)	0.308	0.009	0.198	0.014	0.228	0.014	0.227	0.014	0.208	0.018
constant ($\widehat{a}_0$)	392.59	40.68	551.16	52.61	487.05	49.35	498.35	50.17	545.25	55.75
$a_2 + a_3$	1.077		0.992		1.032		1.025		0.998	
p-value of H0: $a_2 + a_3 = 1$	0		0.754		0.104		0.222		0.952	
$\widehat{S}'_{-IB} = \frac{\widehat{a}_1}{\widehat{a}_3}$ (delta method s.d.)	54.36	3.24	143.12	15.00	104.97	10.76	107.94	11.12	131.84	19.49
$\widehat{S}'_{-IB} \times \pi$	1946.91		5125.70		3759.54		3865.96		4721.75	
nobs	5640		5616		5610		5610		5610	
AR^2	0.934		0.93		0.932		0.932		0.931	
p-value Hausman test (df=2)			0		0		0		0	
O.I. R. p-value			0.219		0.536		0.603		0.365	
p-value F-test π			0		0		0		$1.70E-145$	
p-value F-test (h_{IB} + $shared\_firms$)			$1.04E-284$		$1.01E-248$		$7.07E-246$		$8.95E-228$	
$\widehat{c}_{1IB} = 1/\widehat{a}_1 - 1/\widehat{S}'_{-IB}$	0.041		0.028		0.032		0.032		0.029	
$\widehat{c}_{1IB} = \widehat{a}_2/\widehat{a}_1$	0.046		0.028		0.034		0.033		0.029	
Non-Endesa average hourly production	11082.2	1943.5	11082.2	1943.5	11082.2	1943.5	11082.2	1943.5	11082.2	1943.5
Non-Endesa $\overline{S}_0 + \widehat{S}'_{-IB} \times \overline{\pi}$	9917.1		13095.9		11729.7		11836.1		12691.93	
$\widehat{MC}$ at $\overline{(S_{IB} - h_{IB} - shared\_firms)}$	60.19		33.17		42.20		40.36		34.23	
% $\widehat{MC} > \pi$ if net demander(b.s.d.)	100		73.87		100		100		94.63	
% $\widehat{MC} < \pi$ if net supplier(b.s.d.)	3.19		100		22.53		37.27		100	

Table 7: Estimated values of the CTC cuota

Iberdrola	OLS	IV1	IV2	IV3	IV4
α - table 5	0.391	-1.510	0.088	0.054	0.151
p-value H0: $\alpha = 0.2463$	0	0	0.278	0.257	0.460
α - table 6	0.384	-0.759	0.199	0.0014	0.238
p-value H0: $\alpha = 0.2463$	0	0	0.636	0.1195	0.932

costs from the IV4 column for Endesa and IV2 column for Iberdrola when restrictions are not imposed. The average price obtained in this benchmark equilibrium is roughly 39 percent higher than the average sample price. In the new equilibrium the non-hydroelectric 100% owned plants from Endesa and Iberdrola originate a concentration ratio of 0.301 in contrast with a larger concentration ratio of 0.395 in the sample. Moreover, Endesa reduced its share of non-hydroelectricity production in its 100% owned plants from 27.6% in the sample to 22.5% in the competitive benchmark. Iberdrola, surprisingly perhaps, also reduces market share from 11.9% in the sample to 7.6% in the competitive case. The rise in price has certaninly to do with the reduction in the production from the traditional net-demander, Endesa, which was certainly overproducing to keep prices low in the sample.

The average total supply per hour in the *competitive* benchmark is 19466.72 MWh production compared with the 20351.02 MWh in the sample, a decrease of only 4 percent. The low response in quantity and the high response in price should be of no surprise in a situation where demand is really very inelastic. Our model predicts exactly this that there is a redistribution to the less efficient firms (i.e. the net-demanders) in order to keep prices down.

6 Conclusion

Indeed, the analysis immediately implies that the entry of unintegrated supply firms in the Spanish electricity market should lead to an increase in the electricity spot market price, since generating firms will overall shift towards being more 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. If the market power story that theory suggests were valid, it may in fact not be a good idea to enforce vertical disintegration in liberalized electricity generation markets.

References

[1] Arocena, Pablo, Kühn, Kai-Uwe and Regibeau, Pierre (1999): *Regulatory reform in the Spanish electricity industry: a missed opportunity for competition*, Energy Policy, Vol. 27 (7), 387-399.

[2] Borenstein, Severin and James Bushnell (1998): *An Empirical Analysis of the Potential for Market Power in California's Electricity Industry*, NBER Working Paper Series 6463.

[3] Frankena, Mark W. (1997): *Market Power in the Spanish Electric Power Industry*, CSEN, Madrid Spain.

[4] Green, Richard J. (1996):"Increasing Competition in the British Electricity Spot Market," The Journal of Industrial Economics vol 44, No. 2, June 1996, pp 205-216.

[5] Green, Richard J. and Newbery, David M. (1992): *competition in the British Electricity Spot Market* in Journal of Political Economy, 1992, vol 100 n^o 5.

[6] Klemperer, Paul D. and Meyer, Margaret A. (1989): "Supply Function Equilibria in Oligopoly under Uncertainty," Econometrica, vol 57, No. 6 pp 1243-1277.

[7] Kühn, Kai-Uwe, and Pierre Regibeau (1998): "¿Ha llegado la Competencia? Un Análisis Económico de la Reforma del Sector Eléctrico en España," Informes de IAE (CSIC).

[8] Hendricks, Kenneth and Power, Robert H (1989): *Collusion in Auctions* in Annales d'Economie et de Statistique N^o 15/16.

[9] Wolak, Frank A. (2000): *An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market.* Mimeo.

[10] Wolfram, Catherine D. (1998): " Strategic bidding in a multiunit auction: an empirical analysis of bids to supply electricity in england and Wales," RAND Journal of Economics, Vol. 29 No. 4, Winter 1998, pp 703-725.

[11] Wolfram, Catherine D. (1999): *Measuring Duopoly Power in the British Electricity Spot Market,* American Economic Review, September 1999.

[12] Green, Richard and Newbery, David M. (1997): *Competition in the Electricity Industry in England and Wales,* Oxford Review of Economic Policy, vol. 13, N^o 1.

7 Appendix

7.1 Co-ownership

As mentioned in Section 3 co-ownership of generation plant 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 contractas 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, $S_j(\pi, I_{tj})$, the maximization problem for firm i can be written as:

$$\underset{\pi(\eta_{it\tau},I_{it})}{Max} E\left\{E\left\{(\bar{p}-\pi)D_{it\tau}(\bar{p})+\pi(\eta_i-S_j(\pi,I_{jt})-S_l(\pi,I_{lt}))-C(\eta_i-S_j(\pi,I_{-it})-S_l(\pi,I_{lt}))\right.\right. \tag{19}$$
$$\left.\left.+\alpha_l[\pi S_l(\pi,I_{lt})-C_l(S_l(\pi,I_{lt}))]\mid \eta_{it\tau},I_{it}\right\}\mid I_{it}\right\}$$

The first order condition is:

$$-E\{D_{it\tau}(\bar{p}) \quad | \quad I_{it}\}]+S_i(\pi,I_{it})+\alpha_l E\{S_l(\pi,I_{lt})\mid I_{it}\}-(\pi-C'(S_i(\pi,I_{it}))S_j' \tag{20}$$
$$+S_l'\left[-\pi(1-\alpha_l)+C'(S_i(\pi_{t\tau},I_{it}))-C_l'(S_l(\pi,I_{lt}))\right].$$

Note, that the second line in the first order condition (20) 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 (20) is zero for all firms in our sample. We will discuss below how we can test whether this assumption causes any porblems in the estimation.

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

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

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

$$\hat{S}_i(\pi, I_{-it}) = \frac{1}{1+S_j' c_{1i}} \left\{-S_j' c_{0i} + S_j' \pi + E\{D_{it\tau}(\bar{p}) \mid I_{it}\}\right\} + S_j' c_{1i} \alpha_l E\{S_l(\pi, I_{lt}) \mid I_{it}\} - \varepsilon_{it\tau}\} \tag{21}$$

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 hydro 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 is 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 endogneous and correlated with the error in the estimating equation. This is the same issue as with hydro-electricity, so that we would have to instrument 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 issue we have to address is what the consequences are 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 if the assumption of Iberdrola control on 50% co-owned plants is invalid. Then the second term in (20) 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 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 $S_j' c_{i1}$. 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.

7.2 Estimates of aggregate demand elasticity