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

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February 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.

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†We would like to thank Pedro Blás from UNESA for the data he provided us. Keywords: market power test, vertical

1 Introduction

In January 1998, the Spanish government liberalized the market for electricity generation. 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 distribution (and supply) 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 at the beginning of the liberalization period in 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.

The combination of vertical integration and regulated final supply prices makes it unclear what allocative role the spot market for generation plays in the allocation of resources (see Arocena, Kühn, and Regibeau 1999), since the established electricity companies listed in Table 1 have been the only participants on both sides of the spot market. Due to the high degree of vertical integration much of the payments made and received are effectively pure transfers between distribution/supply and generation activities of the same companies. Does market power in generation 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 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.

In this paper we show that an analysis of the existence and impact of market power in the Spanish generation spot market can be inferred from market behavior because of the systematic and varying

Quotas for the Peninsular Market	Quotas in 1999		Quotas in 2001	
	Generation	Distribution	Generation	Distribution
Endesa	45.9	41.3	50.7*	40.4*
Iberdrola	28.6	39.4	28.7	39.6
Union Fenosa	12.9	15.0	13	15.5
Hidro-Cantabrico	7.3	4.3	6.9	4.5
Other	5.3	-	0.4	-

Table 1: Average market shares for the 4 biggest Spanish Electric firms. Source: CNE annual report, HC annual report, Iberdrola annual report, UF annual report, OMEL web page. * Numbers do not include the sale of E. Viesgo by Endesa in September 2001.

degrees of vertical integration between the different electricity companies. Table 1 documents the systematic difference in market shares in generation and distribution between the major players in the market.

As can be seen from Table 1, Iberdrola is on average a net demander in the spot market while ENDESA is a net supplier both in 1999 and 2001.[1] But this means that Iberdrola has on average an incentive to act similarly to a monopsonist and overbid 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 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. Indeed, the analysis immediately implies that the entry of unintegrated supply firms in the Spanish electricity

[1] Indeed, Iberdrola is always a net-demander with the exception of one hour over the sample and Endesa is always a net-supplier (see figures 7 and 8 in the Appendix).

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 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.

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 the theoretical analysis in section 2 and incorporates the vertical integrated structure of the Spanish firms in section 3. We can estimate this model because there is significant variation in the net demand positions of firms, even on average over the day. This is Illustrated in Figure 1 where significant variation is shown to exist even for average net demand positions across the hours of the day (Figures 7 and 8 in the appendix show all the net demand positions for all periods in the sample).

We extend the basic model in section 4 to allow for the existence of an important hydroelectric generating capacity. 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 ... 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 Iberdrola's marginal assets consistently have estimated marginal costs above the spot market price while those of ENDESA always have marginal cost below the spot market price, as predicted by our model.

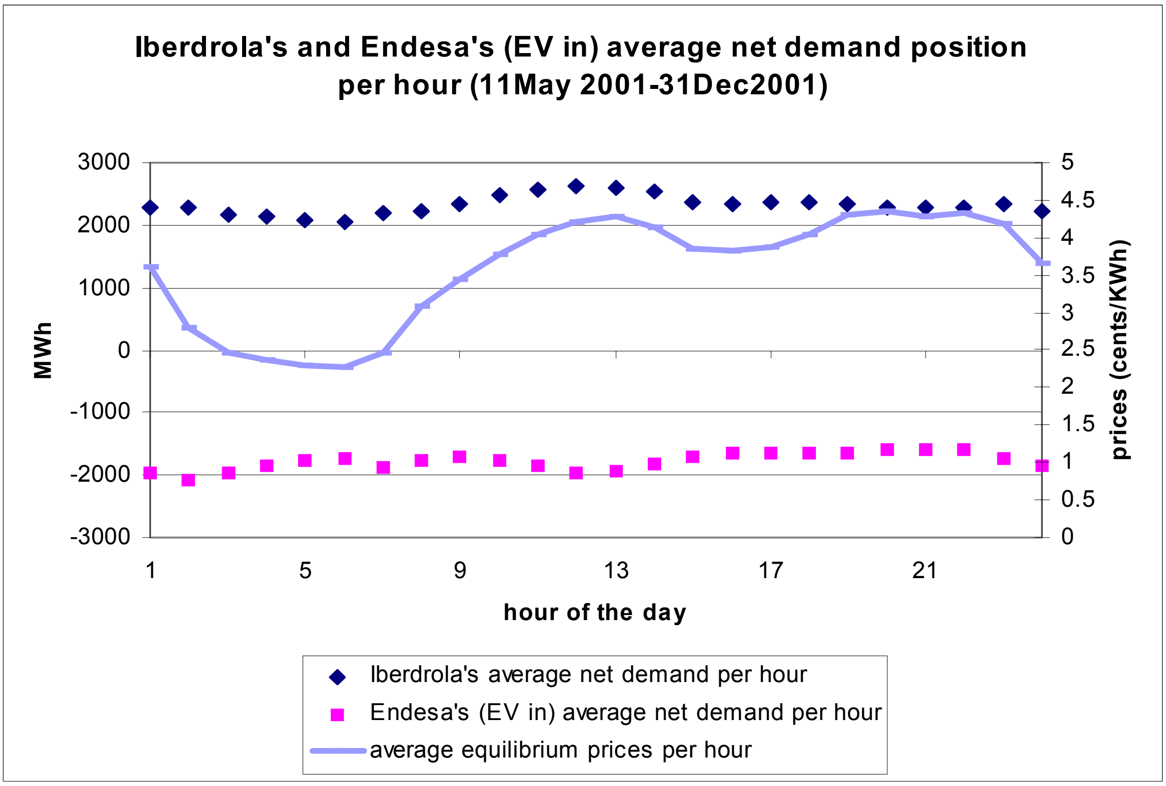
Iberdrola's and Endesa's (EV in) average net demand position per hour (11May 2001-31Dec2001)
3000
2000
1000
0
-1000
-2000
-3000
MWh
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
prices (cents/KWh)
1
5
9
13
17
21
hour of the day
Iberdrola's average net demand per hour
Endesa's (EV in) average net demand per hour
average equilibrium prices per hour

Figure 1:

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 1991, 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 on the distribution of captured consumers across generation firms 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 (see figures 5 and 6 in the Appendix) than there is in capacities. Spanish electricity companies hold a monopoly position as distribution firms in different regions of the country. Because of differences in weather patterns across regions in Spain the net demand positions of electricity companies in the spot market will change from day to day. allowing us to carefully test for the impact of heterogeneity. In a sense the spirit of the 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.

The rest of the paper is organized as follows. In section 2 the basic theoretical argument is developed. Section 3 discusses the basic ideas of implementing the model empirically, while section 4 develop a full dynamic version of the empirical model that incorporates supply function equilibrium in every period as well as the stock effects of hydroelectric supplies. Section 5 describes the data used and Section 6, we show that the basic predictions of the supply function model are borne out by the data. Section 7 concludes.

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

2 Demand Heterogeneity in a Simple Supply Function Duopoly

In this section we develop a simple duopoly model of supply function competition in a market with vertical integration into downstream supply. Every generator i is integrated into downstream distribution and has a monopoly in its distribution area i. Demand in this distribution area is given by $\theta_i D(p_i)$, where θ_i is a random demand parameter that we will refer to as the state of demand in region i. We assume that the final consumer price is regulated at $p_i = \bar{p}$. For ease of exposition we normalize $D(\bar{p}) = 1$. The state of demand in region i, θ_i, is randomly distributed on some interval $[\underline{\theta}_i, \bar{\theta}_i]$, where we allow for $\bar{\theta}_i = \infty$. We assume 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. There is a set of signals about the state of demand of the form $\sigma_k = \theta_l + \varepsilon_k$, $k = 1, ..., K$, where l is either i or j. Each firm receives a subset of these signals denoted by I_i for firm i, which is called firm i's information set. We assume that the distributions of the parameter vector (θ_i, θ_j) and the signal vector are such that all posteriors are linear in the signals observed.

The upstream generation market is run by a market operator which receives the demand needs from the agents θ_i and θ_j. From this the market operator determines total demand θ. Firm i produces electricity under the total cost function $C_i(q_i) = c_{0i}q_i + c_{1i}\frac{q_i^2}{2}$. Firms set supply functions $S_i(\pi; I_i)$, i.e. for any information set I_i, they determine a function that specifidegee-1.5326-2.304TD-0.00mi67457.1(t)-2[(pr)

taking the supply function of the competitor as given as well as the decision rule of the market operator given by (1). Note that firm i knows that given those decisions its choice of supply function will affect the spot market price π via the decision rule of the market operator.

We now show that there exists an equilibrium in linear supply functions. To construct such an equilibrium assume first that $S_j(\pi, I_j)$ is linear in all of its arguments, i.e.

$$S_j(\pi, I_j) = s_j^0 + s_j\pi + \Sigma_{k\in(I_j\cap I_i)} s_j^k \sigma_k + \Sigma_{k\in(I_j\setminus(I_j\cap I_i))} s_j^k \sigma_k. \tag{3}$$

Define $\eta_i \equiv \theta - [S_j(\pi, I_j) - E\{S_j(\pi, I_j) \mid I_i, \pi\}]$, which is the total demand in the spot market minus the component of firm j's demand that is unpredictable for firm i. Clearly, η_i is a sufficient statistic for the state of the spot market conditional on the information of firm i. By monotonicity of the strategies in π, there is then a one-to-one relationship between η_i and π. Hence, problem (2) can equivalently be expressed as:

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

Note that this can be maximized pointwise for each η_i.[3] Maximization yields the following first order condition for every π

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

where we have substituted for $\eta_i - E\{S_j(\pi, I_j) \mid I_i, \pi\}$ 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*

[3] The framework analyzed here slightly extends the standard supply function framework in which there is only aggregate uncertainty to one in which there are also private shocks. However, the procedure of analysis is standard as found in Klemperer and Meyer (1989) or Kühn (1996).

market equilibrium. Furthermore, if firm i prices on average below marginal cost if and only if it is on average a net demander.

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

Proposition 1 captures the essential strategic issue in this market. If a generator would expect to sell exactly as much into the spot market as he takes out of the spot market as a distributor, 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. However, when a firm expects to be a net supplier, then it has an incentive to hold back production slightly, because that redistributes rents from net demanders to this firm. While on all the number of units of electricity the firm distributes itself there is still only a redistribution effect, there is a positive effect on the price of the net sales leading to the standard oligopoly incentive to reduce production (or increase price). The opposite is true for net demanders. A net demander has an incentive to overproduce slightly 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.

Despite the fact that final consumer demand in our model is totally inelastic due to downstream price regulation, the interaction of oligopoly incentives for net suppliers and of oligopsony incentives for net demanders will lead to an important inefficiency in the market in the presence of significant market power: efficient units of production will be held back, while the oligopsony side of the market will induce the use of inefficient units.

The degree to which market power is a problem therefore depends on the downstream demand positions of the firms. Indeed, 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 (2) state by state would then simply generate a non-random linear supply function with slope $s_i^c = \frac{1}{c_{i1}}$. 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 how market power depends on the downstream asset distribution we can 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:

$$E\{\theta_i \mid I_i, \eta_i\} = \lambda_{i0} + \sum_{k \in I_i} \lambda_{ik}\sigma_k + \lambda_{i\eta}\eta_i \tag{6}$$

Equation (5) can therefore be written as:

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

Since (7) has to hold for any π, it has to hold for all π and hence differentiation with respect to π yields:

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

The slope of firm i's supply function in price, $S_i'(\pi, I_i)$, 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 optimal supply function of firm i will be a constant, independent of the signals received. Setting $s_i = S_i'(\pi, I_i)$ we can

solve for the equilibrium slopes of the supply functions of firms i and j from the system of equations implied by (8). This yields: [4]

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

To explain equation (9), first 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 measures the effective heterogeneity in the model. To understand this expression it is useful to first consider a special case. Suppose that θ_i and θ_j are perfectly correlated and that firms observe no private signals of demand. Then $\lambda_{i\eta}$ is simply the downstream market share of firm i and $\lambda_{i\eta} + \lambda_{j\eta} = 1$. First, consider the case of perfectly symmetric firms, i.e. $c_{i1} = c_{j1}$ and $\lambda_{i\eta} = \lambda_{j\eta}$. Then the whole expression simply collapses to $s_i = \frac{1}{c_{i1}}$, the slope of the perfectly competitive supply function. Clearly, with symmetric firms, we expect a symmetric outcome, but then every firm should have a zero net supply position in equilbirium and market power effects are irrelevant. Now consider inducing asymmetries in the demand position. Clearly the firm with the larger downstream market will have a steeper supply curve. Similarly, holding the demand side symmetric, the firm with the flatter marginal cost function will have the 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 marginal cost function will be determined by the relative size of $\frac{c_{i1}}{\lambda_{i\eta}}$. Note that even with symmetry of supply functions the competitive response to demand shocks is distorted from that of perfect competition: The firm with the lower marginal costs does not produce enough, while the firm with the higher marginal costs produces too much to accomodate a marginal increase in total demand.

Unfortunately, the interpretation in terms of $\lambda_{i\eta}$ as a market share breaks down in a more general setting. To see this, consider the extreme case in which the firm has perfect information about θ_i. In this case $\lambda_{i\eta} = 0$ although the long run market share would certainly be positive. 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. First, note that the general

[4] 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.

intuition about symmetric firms carries over when looking at average behavior:

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

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

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

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

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

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 is 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 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 Implementing the Supply Function Model Empirically

3.1 Testing the Implications of the Supply Function Model

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.

First, we will extend the model to allow for more than two firms in the market. This is a straightforward extension of the model. Second, we have assumed so far that final demand was in the short run completely inelastic at a regulated price. This is an appropriate assumption for most of the Spanish market in 2001, the year of our data, since the majority of end users of electricity must be served at the regulated price. However, since deregulation at the beginning of 1998 a growing fraction of large customers (the "qualified consumers") has been allowed to contract directly with electricity producers and to bid directly in the pool. This is part of a process of a complete liberalization of supply by 2003.[5] Qualified consumers also have the option of buying electricity from a supplier ("comercializador") i.e. an agent whose business consists exclusively of buying electricity from the pool to sell it to qualified consumers and the option of buying electricity at regulated rates, which effectively generates a price cap for the contractual market. By the end of 2001, the demand bought by suppliers represented 32.1% of the total demand transacted in the daily market. [6] However, as we will show later, most of the

[5] By January 1, 2003 any consumer can become a "qualified consumer" (Real Decreto-Ley 6/2000 of 23rd of June).

[6] Source: The annual report from the grid operator (REE), 2001. The same source also states that qualified consumers ("consumidores cualificados") bought in 2001 0 GWh directly from the market, which represented also 0% of total demand. However, from public records we know that by June 2000 the number of qualified consumers was 7716 (Source: REE

qualified consumers still have inelastic demands relative to the pool price. The ones that, perhaps, have the higher demand elasticity in the market are those that write bilateral contracts with the generators but these contracts represent only a tiny fraction () of the total electricty sold in the pool. In any case, the sale of electricity through bilateral contracts takes place outside the daily market and, therefore, does not affect the pool price. Figures 2 and 3 in the appendix shows demand bidding for 3 hours of the day from distributors and suppliers belonging to the Endesa group and to Iberdrola, respectively. As we can see there is some elasticity in demand but it seems to be low. Figure 4 in the appendix is a plot of the estimated elasticities of aggregate demand per hour and for each month separately. It shows that the elasticity of demand varies across the hours of the day, i.e. is higher in the peak-demand hours, and that it grows over time, specially during the summer months. But more importantly, figure 4 shows that the estimated elasticities are never larger than 0.09 which is much inferior to the values found in the literature. [7][8]The demand pool-price elasticity in the spot market can therefore be safely approximated by zero. We will therefore maintain the assumption that end users are either individual consumers facing fixed regulated prices or contract users who's prices are fixed over the sample period.

A firm g has G groups of customers. Each $j \in G$ faces a final electricity price $p_{jt\tau}$, where t refers to the day and τ refers to the hour of the day. One of these groups is the group of customers purchasing at the regulated price, which will be the same across different days. Demand from a customer group j

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"Operación del Sistema Eléctrico, Informe 1999"), which means that qualified consumers prefer buying from suppliers or generators than bidding directly into the pool.

[7]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 (4) correspond to $\widehat{\beta} \times \frac{D(p)}{D}$ where $\widehat{\beta}$ is the estimated coefficient from the following regression:

$$\ln D(p) = \alpha - \beta \ln(\text{bid}) + u \tag{11}$$

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.

[8]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.

at time $t\tau$ is given by $D^j_{t\tau} = \theta_{jt\tau} D^j(p_{jt\tau})$ where $\theta_{jt\tau}$ is the random component of demand for group j at time $t\tau$. Total electricity demand faced by firm g is then written as $D_{gt\tau} = \sum_{j\in G} \theta_{jt\tau} D^j(p_{jt\tau})$.

In each period t in which decisions about supply functions for each $t\tau$ have to be made, firm g has signals about the $\theta_{jt\tau}$ affecting its own demand and that of its competitors as described in section 2. We denote its information set as I_{gt}. We will also allow for contracts for differences, i.e. forward contracting. There is a set of hedge contracts the firm holds, G^h. A contract $j \in G^h$ specifies the number of units D^{hj} and a fixed forward price p^h_j. The firm promises to pay the other party with which it has this contract a total amount of $(\pi - p^h_j)D^{hj}$. The total profit of firm g in period $t\tau$ is then given by:

$$E\{\sum_{j\in G} \theta_{jt\tau} D^j(p_{jt\tau}) p_{jt\tau} - \pi_{t\tau} D_{gt\tau} + \sum_{j\in G^h} D^{hj}(p^h_j - \pi_{t\tau}) + \pi_{t\tau} S_{gt\tau}(\pi_{t\tau}, I_{gt}) - C_g(S_{gt\tau}(\pi_{t\tau}, I_{gt})) \mid I_{gt}\}, \quad (12)$$

Clearly, $D_{gt\tau}$ performs the same role as θ_i in our theoretical model. The third term is new representing the possibility of (unobserved) contracts for differences. The market operator is charged with setting the price that clears the one period ahead spot market based on the demand needs stated by the firms:

$$D_{t\tau} = \sum_g S_{gt\tau}(\pi_{t\tau}, I_{gt}) \quad (13)$$

where assuming that firms report thruthfully $D_{t\tau} = \sum_g \sum_{j\in G_g} E[\theta_{jt\tau} D^j(p_{jt\tau})|I_{gt}]$. Firms maximize (12) for each τ one day in advance by choosing the supply schedule $S_{gt\tau}(\pi_{t\tau}, I_{gt})$, anticipating the market clearing mechanism (13). We maintain the assumption that C_g is quadratic and that the signals observed by the parties generate posteriors on $D_{t\tau}$ that are linear in the signals. We will again describe the behavior when rivals set linear supply functions. We can then define $\eta_g = D_{t\tau} - [\sum_{f\neq g} S_{ft\tau}(\pi_{t\tau}, I_{ft}) - \sum_{f\neq g} E\{S_{ft\tau}(\pi_{t\tau}, I_{ft}) \mid I_{gt}, \pi_{t\tau}\}]$ to be the sufficient statistic for firm g of the state of the spot market. We can then simply calculate the optimal supply function decision of firm g in the same way as in section 2. This yields the first order condition :

$$\begin{aligned} -\textstyle\sum_{j\in G^h} D^{hj} + \left[S_{gt\tau}(\pi_{t\tau}, I_{gt}) - E\{D_{gt\tau} \mid I_{gt}, \eta_{gt\tau}\}\right] \\ - \left[\pi_{t\tau} - C'_g(S_{gt\tau}(\pi_{t\tau}, I_{gt}))\right] s_{-gt\tau} = 0, \end{aligned} \quad (14)$$

where $s_{-gt\tau} = \sum_{f \neq g} S'_{ft\tau}(\pi_{t\tau}, I_{gt})$. This first order condition differs from our theoretical model only because now the aggregate slope of the supply function of rivals matters and because we include the hedge term $\sum_{j \in G^h} D^{hj}$. The latter decreases the incentive to raise price through the supply function strategy, as noted by Wolak () and Newbery (). By our linearity assumption:

$$E\{D_{gt\tau} \mid I_{gt}, \eta_{gt\tau}\} = \beta_{0g} + \beta_{1g}\eta_{gt\tau} + \sum_{k \in I_{gt}} \beta_{kg}\sigma_{gt\tau}$$

Substituting from the equilibrium condition for $\eta_{gt\tau} = \eta_g(\pi_{\tau t})$

parameter estimate on a_{2g} would yield a first indication for market power on the side of firm g. Secondly, we could test from this data whether a firm was producing above or below marginal cost to test whether the implication of the theory that a firm produces below marginal cost if and only if it is a net supplier is valid. Given the presence of hedging contracts this prediction will refer to the notional marginal cost $c_{0g} - \frac{1}{S'_{-g}} \sum_{j \in G^h} D^{hj} + c_{1g} S_{gt\tau}$. Any prediction about relative supply function slopes across the firms for which we estimate (15) can also be tested since s_{-g1} is identified and $s_{g1} - s_{f1} = s_{-f1} - s_{-g1}$. It is more problematic to recover s_{1g} directly. The term a_{1g} does not correspond to the slope of the supply function. Instead the slope of the supply function is implicitly given by $s_{1g} = a_{1g} - a_{2g}\beta_{1g} \sum_{f \neq g} s_{f1}$. The actual slope can therefore not be recovered from this simple estimation, because it depends on parameters in the conditional expectation of downstream demand of firm g.

4 The Role of Hydroelectrical Generation

The discussion about testing the model in the previous subsection has ignored the presence of hydroelectrical generation. However, in Spain hydroelectricity represents a large fraction of electricity generation (around 19% in 2001, CNE annual report). Hydroelectricity is also an important part of the total generation of the two largest firms, between 7.7 and 17% percent for Endesa and between 9 and 32% for Iberdrola (both firms use relative more hydroelectricity in the hours of high demand). We can therefore not ignore the impact of the stocks of hydroelectricty capacity in our estimation.

Let $S_{gt\tau}$ be total production of electricity by firm g and $h_{gt\tau}$ the amount of hydro generation (both in MegaWatt hours). The cost function $C_{ng}(S_{gt\tau} - h_{gt\tau})$ will denote the costs of non-hydro production of firm g. Hydroelectricity can be produced at a constant marginal cost c_h. Actual hydroelectricity costs will be implicitly determined by the shadow value of hydro stocks. The hydro stock of firm g in period $t\tau$ is denoted by $H_{gt(\tau+1)}$, which is also measured in MegaWatt hours. There will be a law of motion for the stock of hydro given by $H_{gt(\tau+1)} = H_{gt\tau} - f(h_{gt\tau}) + r_{gt\tau}$, where $f(h_{gt\tau}) = f.h_{gt\tau}$ describes how hydro stocks are converted into hydro flows and $r_{gt\tau}$ is a random change in water reserves in reservoirs

due to rain, spring snow melt, vaporization or other uses. Since in our data H and h are measured in output units of energy, i.e. MWh, we should have $f = 1$. The expected stock for the beginning of the next period conditional on one day ahead information is given by $E\{H_{gt(\tau+1)} \mid I_{t\tau}\} = H_{gt\tau} - E\{h_{gt\tau} \mid I_{t\tau}\} + E\{r_{gt\tau} \mid I_{t\tau}\}$ If firms have the same information set, then $h_{ft\tau}$ will be perfectly predicted by all firms. There may also be a perfectly predictable component of $r_{gt\tau}$. Indeed, just looking at weather and snow melt patterns, we would expect $r_{gt\tau}$ to be quite seasonal[9], just as the electricity demand pattern shows strong seasonality. As a result we cannot expect the environment to be stationary, since the shadow value of a given hydro stock will be different in different seasons. For expositional purposes we will here assume that there is stationarity in the demand and r_g series. We will discuss later, how we deal with the seasonality issue for the estimation.

We consider Markov Perfect Equilibria of the repeated supply function game. The relevant state vector for each firm is then the vector of hydro reserves $\mathbf{H}_t$ held by the firms at the beginning of period t and the vector of signals contained in I_{gt}. A Markov strategy for generator g consists of 24 pairs of functions $S_{g\tau}(\pi_{t\tau}, \mathbf{H}_{t\tau}, I_{gt})$, $h_{g\tau}(\pi_{t\tau}, \mathbf{H}_{t\tau}, I_{gt})$, which determine for every day t and every hour of the day τ the amount of total energy and hydro energy provided as a function of the hydroelectrical reserves, the price in the spot market and the information available. Firms are only allowed to set supply functions that increase in the spot market price π. The value function for firm g is denoted by $V_g(\mathbf{H}_{t\tau}, I_{gt})$, where we are not using time subscripts on V because of the stationarity assumption. In practice we will extend this to allow for some variation across time periods. Furthermore, we will make some assumptions on the change in the environment from one period to the next that will restrict the degree to which supply functions will vary in equilibrium from one period to another. Given this description of the market

[9] Note for instance the pattern of hydroelectric reserves along the year for Iberdrola and Endesa shown in figures 10 and 11 in the appendix. Although, the level of water reserves depend obviously on water usage for hydroelectricity the weather pattern contributes far more to the its pattern.

generating firms face the following dynamic programming problem:

$$\begin{array}{c} V_g(\mathbf{H}_t, I_{gt}) = \max_{\{S_{gt\tau}(\pi,\mathbf{H}_t,I_{gt})\},\{h_{gt\tau}(\pi,\mathbf{H}_t,I_{gt})\}_{\tau=1}^{24}} \\ \sum_{\tau=1}^{24} E \left\{ \begin{array}{c} \sum_{j\in J_g\cup J_g^h} \theta_{jt\tau} D_j(p_{jt\tau}(\pi_{t\tau}))(p_{jt\tau}(\pi_{t\tau}) - \pi_{t\tau}) + \pi_{t\tau} S_{gt\tau}(\pi, \mathbf{H}_t, I_{gt}) \\ -C_{g\tau}\left(S_{gt\tau}(\pi,\sigma,\mathbf{H}_t) - h_{gt\tau}(\pi,\sigma,\mathbf{H}_t)\right) - c_h h_{gt\tau}(\pi,\sigma,\mathbf{H}_t) + \delta V_g(\mathbf{H}_{t+1}, I_{gt+1}) \mid I_{gt} \end{array} \right\} \\ \text{s.t. } \sum_{g=1}^{n} S_{gt\tau}(\pi,\sigma,\mathbf{H}_{t\tau}) = \sum_{j\in J} E\{D_{jt\tau} \mid I_{jt\tau}\} \text{ for all } t\tau \\ \text{and } \; 0 \le h_{gtT} \le H_{gt} - \sum_{\tau=0}^{T-1} h_{gt\tau}, \; h_{gt0} = 0 \end{array} \tag{16}$$

We can then again rewrite problem (16) in such a way that we can maximize with respect to $\pi_{t\tau}$ and $h_{gt\tau}$. Then the first order condition with respect to $\pi_{t\tau}$ becomes:

$$\pi_{t\tau} = C'_{g\tau}(S_{gt\tau} - h_{gt\tau}) + \frac{1}{S'_{-gt\tau}}[S_{gt\tau} - E\{D_{gt\tau} \mid I_{gt}, \pi_{t\tau}\}] + \frac{1}{S'_{-gt\tau}} \sum_{j\in J_g^h} D_{jt\tau} p'_{jt\tau} \tag{17}$$

and an additional first order condition for the hydro production:

$$C'_{g\tau}(S_{gt\tau} - h_{gt\tau}) - c_h - \varepsilon_{hg} - \delta \frac{\partial E\{V_i(\mathbf{H}_{t+1} \mid I_{gt\tau}\}}{\partial H_{gt+1}} \le 0 \tag{18}$$

and with equality for strictly positive use of hydro (we are ignoring the possibility (for now) that $h_{gt} = H_{gt}$, because in reality we never observe the use of all hydro resources. We know that this is wrong though in the supply function context, since arbitrarily low probability of hitting the constraint would have an effect on the supply functions. However, we can see no way to do this properly and keep things tractable). We will analyze this as if hydro use was always strictly positive, so that equation (18) is satisfied as an equality. If we did not do that we would potentially loose the linear quadratic setup and would not be able to derive linear supply function equilibria and therefore no explicit solution to the problem. Expression (18) simply says that the marginal cost of using non-hydro sources has to be equal to the marginal cost of using hydro sources. Note that (18) gives us an optimal amount of hydro usage given the total electricity supplied to the market by firm g, S_g, the stock of hydro held by others in period $t+1, \mathbf{H}_{-gt+1}$, and the own maximally available stock of hydro, H_{gt}.

Let us now make the following assumptions: Let us suppose that $C'_{g\tau}(S_{gt\tau} - h_{gt\tau}) = c_{1g\tau} + c_{2g}(S_{gt\tau} - h_{gt\tau}) + \varepsilon_{cgt\tau}$. We are assuming here that hourly shifts in the cost function affect the constant term in marginal cost but not the slope. We believe this is reasonable since the primary systematic hourly shifts come in form of assets being already in or out the market. We would therefore think there is a

systematic shift downwards in the percieved constant part of marginal costs at times where many of the assets are already in the market. However, there is no reason to believe that the rankings in terms of marginal costs among the assets change systematically. (Not that this is totally satisfactory, but there is no totally satisfactory way of getting at this!).

Given these definitions we have the following relationship between hydro production and non-hydro production :

$$c_{1g\tau} + c_{2g}(S_{gt\tau} - h_{gt\tau}) + \varepsilon_{cgt\tau} - c_h - \varepsilon_{hg} - \delta \frac{\partial E\{V_i(\mathbf{H}_{t+1} \mid I_{gt\tau}\}}{\partial H_{g(t+1)}} = 0 \tag{19}$$

Note that the marginal 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. Given the assumptions the 24 first order conditions for hydro will allow us to identify the slope of the cost function in principle.

Notice that when facing estimating (18) and anything that uses the marginal of the value function, we are taking expectations over the hydro reserves and therefore hydro output of others. We are not sure how we have dealt with that before, since the estimate of hydroproduction of a rival and the actual production will not be the same. (This is in addition to the usual endogeneity problem that we will have). We therefore suggest to start estimating this by rewriting (17) as:

$$S_{gt\tau} = \frac{S'_{-g}}{1 + c_{2g}S'_{-g}} \left\{ -c_{1g\tau} - \frac{1}{S'_{-g}} \sum_{j \in J_g^h} D_{jt\tau} p'_{jt\tau} + \pi_{t\tau} + c_{2g} h_{gt\tau} + \frac{1}{S'_{-g}} E\{D_{gt\tau} \mid I_{gt}, \pi_{t\tau}\} - \varepsilon_{cgt\tau} \right\} \tag{20}$$

where we have to instrument for $\pi_{t\tau}$ and $h_{gt\tau}$. Note that the stocks do not enter this equation at all since the information about the shadow price of water to firm g is all contained in the information on h. So we would have an estimating equation:

$$S_{gt\tau} = a_{o\tau} + a_1 \pi_{t\tau} + a_2 h_{gt\tau} + a_3 E\{D_{gt\tau} \mid I_{gt}, \pi_{t\tau}\} + \zeta_{cgt\tau} \tag{21}$$

where the expectation of downstream demand enters in the same way as before. Just as in the previous section, we are able to identify a lot of interesting parameters such as c_{2g}, S'_{-g}, and the relevant intercept of the marginal cost function. There are at least three reasons for using this equation as a test of our model: 1) this is a valid estimating equation even if hydro decisions are not taken in a cost minimizing way; and 2) all the variables in the equation are taken directly from our data. In particular the quantity $E\{D_{gt\tau} \mid I_{gt}, \pi_{t\tau}\}$ can be taken to be the demand bids by the firms at the equilibrium price. 3) although there is now detailed data on the firm bids this is not needed in order to estimate (21). Note that we will need hourly dummies in this equation because the intercept can vary because of the different levels of marginal costs throughout the day. Results for equation (21) are dicussed in the next section.

In order to check the robustness of the dynamic model, we have also developed an alternative estimating equation based on hydroelecytricity production. Given (19) we can solve for $S_{gt\tau}$ to obtain:

$$S_{gt\tau} = h_{gt\tau} + \phi(\mathbf{H}_{t(\tau+1)}, h_{gt\tau}, \varepsilon_{cgt\tau} - \varepsilon_{hg}; I_{gt\tau}) \tag{22}$$

[10]where ϕ is the implied non-hydro production if firms are cost-minimizing. We can now substitute (**??**) into 17 and obtain:

$$\begin{array}{c} \pi_{t\tau} = c_h + \varepsilon_{hg} + \delta \frac{\partial E\{V_g(\mathbf{H}_{t(\tau+1)}|I_{t\tau}\}}{\partial H_{g(t+1)}} + \frac{1}{S'_{-g}} \sum_{j \in J_g^c} D_{jt\tau} p'_{jt\tau} \\ + \frac{1}{S'_{-g}} \{h_{gt\tau} + \phi(\mathbf{H}_{t(\tau+1)}, h_{gt\tau}, \varepsilon_{ng} - \varepsilon_{hg}; I_{t\tau}) - E\{D_{gt\tau} \mid I_{t\tau}, \pi_{t\tau}\}\} \end{array} \tag{23}$$

now we want to impose our assumptions on quadratic costs functions, which means that we need quadratic non-hydro costs and a quadratic value function. Under the assumption of quadratic non-hydro costs $C'_g(S_{gt\tau} - h_{gt\tau}) = c_{1g} + c_{2g}(S_{gt\tau} - h_{gt\tau})$, we have:

$$\phi(\mathbf{H}_{t(\tau+1)}, h_{gt\tau}, \varepsilon_{ng} - \varepsilon_{hg}; I_{t\tau}) = \frac{1}{c_{2g}} \left[c_{hg} - c_{1g} + \delta \frac{\partial E\{V_g(\mathbf{H}_{t(\tau+1)} \mid I_{t\tau}\}}{\partial H_{g(t+1)}} + \varepsilon_{hg} - \varepsilon_{cgt\tau} \right] \tag{24}$$

The quadratic assumption on the value function implies that:

$$\begin{aligned} V_g(\mathbf{H}_{t(\tau+1)}) &= v_0 + v_g H_{gt(\tau+1)} + v_j H_{jt(\tau+1)} \\ &\quad + \frac{1}{2} v_{gg} H^2_{gt(\tau+1)} + \frac{1}{2} v_{jj} H^2_{jt(\tau+1)} + v_{gj} H_{gt(\tau+1)} H_{jt(\tau+1)} \end{aligned} \tag{25}$$

[10]Notice that equation (22) implies a correlation of 1 between hydroelectric and non-hydroelectric generation within the firm. In the data, this correlation is 0.872 for Iberdrola and around 80.83% for Endesa (including 85% of EV). Figures 12 and 13 show that indeed Iberdrola and Endesa's total and hydroelectrical generation are very much correlated.

Differentiating with respect to $h_{gt\tau}$ gives:

$$\begin{aligned}
\frac{\partial V_g(\mathbf{H}_{t(\tau+1)})}{\partial H_{g(t+1)}} &= \left[v_g + v_{gg}H_{gt(\tau+1)} + v_{gj}H_{jt(\tau+1)}\right] \\
&= \left[v_g + v_{gg}(H_{gt\tau} - h_{gt\tau} + r_{gt\tau}) + v_{gj}(H_{jt\tau} - h_{jt\tau} + r_{jt\tau})\right] \qquad (26)
\end{aligned}$$

substituting in (23) and collecting terms we get:

$$\begin{gathered}
h_{gt\tau}[1 - \delta v_{gg}\left(\tfrac{1}{c_{2ng}} + S'_{-g}\right)] = \\
S'_{-g}\pi_{t\tau} - S'_{-g}\left[c_{hg} + \delta\left[v_g + v_{gg}H_{gt\tau} + v_{gj}H_{jt\tau}\right]\right] - \textstyle\sum_{j\in J_g^c} D_{jt\tau}p'_{jt\tau} \\
-\tfrac{1}{c_{2ng}}[c_{hg} - c_{1ng} + \delta\left[v_g + v_{gg}H_{gt\tau} + v_{gj}H_{jt\tau}\right] + E(h_{jt\tau}|I_g)\left[\delta v_{gj}\left(S'_{-g} + \tfrac{1}{c_{2ng}}\right)\right] + E\{D_{gt\tau} \mid I_{t\tau}, \pi_{t\tau}\} + \widetilde{\varsigma}_{gt\tau}
\end{gathered}$$

Dividing both sides by $[1 - \delta v_{gg}\left(\frac{1}{c_{2ng}} + S'_{-g}\right)]$ and collecting terms we get the estimating equation:

$$h_{gt\tau} = a_{g0} + a_{g1}\pi_{t\tau} + a_{g2}E\{D_{gt\tau} \mid I_{t\tau}, \pi_{t\tau}\} + a_{g3}H_{gt\tau} + a_{g4}H_{jt\tau} + a_{g5}E(h_{jt\tau}|I_g) + \varsigma_{gt\tau} \qquad (27)$$

where:

$$\begin{aligned}
a_0 &= -\frac{S'_{-g}}{[1 - \delta v_{gg}\left(\frac{1}{c_{2ng}} + S'_{-g}\right)]}\left[c_{hg} + \delta v_g + \frac{c_{hg} - c_{1ng} + \delta v_g}{S'_{-g}c_{2ng}} + \frac{1}{S'_{-g}}\sum_{j\in J_g^c} D_{jt\tau}p'_{jt\tau}\right] \\
&\quad -\frac{\delta\left[v_{gg}E\left(r_{gt\tau}|I_{gt\tau}\right) + v_{gj}E\left(r_{jt\tau}|I_{gt\tau}\right)\right]\left(\frac{1}{c_{2ng}} + S'_{-g}\right)}{[1 - \delta v_{gg}\left(\frac{1}{c_{2ng}} + S'_{-g}\right)]} = \\
&= -a_1\left[c_{hg} + \delta v_g + \frac{c_{hg} - c_{1ng} + \delta v_g}{S'_{-g}c_{2ng}} + \frac{1}{S'_{-g}}\sum_{j\in J_g^c} D_{jt\tau}p'_{jt\tau}\right] + a_3 E\left(r_{gt\tau}|I_{gt\tau}\right) + a_4 E\left(r_{jt\tau}|I_{gt\tau}\right) \\
a_1 &= \frac{S'_{-g}}{[1 - \delta v_{gg}\left(\frac{1}{c_{2ng}} + S'_{-g}\right)]} \\
a_2 &= \frac{1}{[1 - \delta v_{gg}\left(\frac{1}{c_{2ng}} + S'_{-g}\right)]} \\
a_3 &= -\frac{\delta v_{gg}\left(\frac{1}{c_{2ng}} + S'_{-g}\right)}{[1 - \delta v_{gg}\left(\frac{1}{c_{2ng}} + S'_{-g}\right)]} \\
a_4 &= \frac{v_{gj}}{v_{gg}}\hat{a}_3 \\
a_5 &= -\hat{a}_4 \\
\varsigma_{gt\tau} &= -S'_{-g}\varepsilon_{hg} - \frac{1}{c_{2ng}}(\varepsilon_{hg} - \varepsilon_{cg})
\end{aligned}$$

One of the disadvantages of using (27) over (21) is that the intercept of the marginal cost function is no longer identifiable. Note that both π and $E(h_{jt\tau}|I_g)$ are endogenous variables in this estimating equation. Conditional on finding adequate instruments, we can identify several of the relevant parametyers of the model. Alternatively we can estimate the reduced form:

$$h_{gt\tau} = \frac{a_{g0} + a_{g5}a_{j0}}{1 - a_{g5}a_{j5}} + \frac{a_{g1} + a_{g5}a_{j1}}{1 - a_{g5}a_{j5}}\pi_{t\tau} + \frac{a_{g2}}{1 - a_{g5}a_{j5}}\hat{D}_{gt\tau} + \frac{a_{g5}a_{j2}}{1 - a_{g5}a_{j5}}\hat{D}_{jt\tau} + \frac{a_{g3} + a_{g5}a_{j3}}{1 - a_{g5}a_{j5}}H_{gt\tau} + \frac{a_{g4} + a_{g5}a_{j4}}{1 - a_{g5}a_{j5}}H_{jt\tau} +$$

$$h_{jt\tau} = \frac{a_{j0} + a_{j5}a_{g0}}{1 - a_{g5}a_{j5}} + \frac{a_{j1} + a_{j5}a_{g1}}{1 - a_{g5}a_{j5}}\pi_{t\tau} + \frac{a_{j2}}{1 - a_{g5}a_{j5}}\hat{D}_{jt\tau} + \frac{a_{j5}a_{g2}}{1 - a_{g5}a_{j5}}\hat{D}_{gt\tau} + \frac{a_{j3} + a_{j5}a_{g3}}{1 - a_{g5}a_{j5}}H_{gt\tau} + \frac{a_{j4} + a_{j5}a_{g4}}{1 - a_{g5}a_{j5}}H_{jt\tau} +$$

From where the initial parameters can also be identified. For example, we can identify a_{g5} and a_{j5} from:

$$\begin{aligned} \widehat{a}_{g5} &= \frac{\frac{a_{g5}a_{j2}}{1-a_{g5}a_{j5}}}{\frac{a_{j2}}{1-a_{g5}a_{j5}}} \\ \widehat{a}_{j5} &= \frac{\frac{a_{j5}a_{g2}}{1-a_{g5}a_{j5}}}{\frac{a_{g2}}{1-a_{g5}a_{j5}}} \end{aligned} \tag{28}$$

and from these we can identify everthing else.

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 till 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.

Over the sample period, the average price per hour of the day had a tendency to increase (figure 9 in the Appendix) and the hydroelectric reserves of Iberdrola and Endesa are not constant over the sample

(figures 10 and 11). While Iberdrola builds up hydroelecric capacity until July and then let the level of reserves fall for the rest of the sample, Endesa has a more conservative policy and starts depleting its reserves only after the middle of the sample.

6 Empirical Results (preliminary)

We start by showing the results of the estimating equation:

$$S_{gt\tau} = \frac{S'_{-g}}{1 + c_{2g}S'_{-g}} \left\{ -c_{1g\tau} - \frac{1}{S'_{-g}} \sum_{j \in J_g^h} D_{jt\tau} p'_{jt\tau} + \pi_{t\tau} + c_{2g} h_{gt\tau} + \frac{1}{S'_{-g}} E\{D_{gt\tau} \mid I_{gt}, \pi_{t\tau}\} + \varepsilon_{cgt\tau} \right\} \Leftrightarrow \tag{29}$$

$$\Leftrightarrow S_{gt\tau} = a_{o\tau} + a_1 \pi_{t\tau} + a_2 h_{gt\tau} + a_3 E\{D_{gt\tau} \mid I_{gt}, \pi_{t\tau}\} + \varepsilon_{cgt\tau} \tag{30}$$

The variables $\pi_{t\tau}$ and $h_{gt\tau}$ are endogeneous since shocks to the marginal cost of non-hydro generation affect both the erquilibrium price and the decision on how much hydroelectricity to produce. To avoid biases, we have used several variables as instruments for $\pi_{t\tau}$ and $h_{gt\tau}$, which we believed are not correlated with the shocks to the firm's marginal cost. For Endesa, the best instruments are 24-hour changes in temperatures and pool prices ($\Delta\pi_{t\tau}$) as well as 48-hour lagged hydro production ($h_{EN(t-2),\tau}$). For Iberdrola, the best result is achieved with 24-hour differences in temperatures, 48-hour lagged hydro production ($h_{IB(t-2),\tau}$) and the maximum price over the entire month for each specific hour period (*pehour*).

Tables 2 and 3 show the results for Endesa and Iberdrola respectively. As we can see from the p-value on the Hausman test on table 2 the OLS results are biased. From the IV results we can tell that the coefficient on the Expected demand a_3 is always significantly positive, evidence of market power by Endesa.Moreover, the slope of the rivals' supply function $\widehat{S}'_{-g}$ is always positive and significantly different from zero. In table 2, the IV results, perhaps because of their worse precision, do not reject the null hypothesis of $a_2 + a_3 = 1$. This is quite remarkable and constitutes a robustness check on our model.

Unfortunately, the model does not identify the intercept of the rivals' supply function S_{0_g}. We decided, therefore, to use the sample average quantity bidded at zero price by Iberdrola and by all firms together except Endesa to compute the model's predicted quantity produced by the rivals as $S_{0\_g} + \widehat{S}'_{.g}\overline{\pi}$, where $\overline{\pi}$ is the average sample spot market price. The sixth to last row and the forth to last row of table 2 show the sample average hourly production by Iberdrola and by all firms except Endesa. As we can see, except for IV2, $S_{0\_g} + \widehat{S}'_{.g}\overline{\pi}$ is somewhat closer to the Iberdrola's total production than to the sum of all rivals production, an indication that Endesa sees the market very much as a duopoly. Finally, we estimate Endesa's average marginal cost. Remember that our model predicts that a net supplier such as Endesa should sell into the pool such that price is higher than its MC. Our estimate of marginal cost in the second to last row is $-\widehat{a}_0 + \left(\frac{\widehat{a}_2}{\widehat{a}_1}\right)\frac{1}{T\Gamma}\sum_{t\tau}(S_{gt\tau} - h_{gt\tau})$ i.e. the intercept of marginal cost includes the effect of the hedge contracts (which we know results in a lower MC) and that explains the negative estimates of MC. We have also checked how often was the predicted MC above the equilibrium price. The last row of shows that the equilibrium price is always larger than the estimated marginal cost except when using the OLS estimates when this only occurs in 42 % of the sample. Our impression is that the results in IV1, IV3 and IV4 are the most reliable. The sensitiveness of results to the distribution level as one of the instruments in IV2 makes us suspicious about the exogeneity of this variable.

Table 3, on the other hand, shows less promissing results. Again, the OLS results are biased and the coefficient a_3 is significantly positive implying the exercise of market power by Iberdrola. However, although the sum $a_2 + a_3$ is very close to 1 this hypothesis is either rejected (the case of OLS, IV3 and IV4) or is on the frontier of being rejected (case of IV1 and IV2) due to the lowest precision of the estimates. Furthermore, IV1 and IV2's estimates of the slope of the rival's supply function are too high as can be confirmed by the overprediction of the rival's production in the forth and sixth to last rows. Finally, our model predicts that a net-demander such as Iberdrola should produce at a marginal cost higher than the equilibrium price. The marginal cost estimates were computed similarly to the ones in table 2 and the intercept includes the term of hedge contracts. The OLS results predict that marginal cost is higher than the equilibrium price in 80% of the times. However, the IV results

Table 2: Results of the total production regression for Endesa

Endesa	OLS		IV1		IV2		IV3		IV4	
Electricity Units= MWh			IVs= $\Delta\pi_{t,\tau}$ and		IVs=current distribution		IVs=24-hour diff in .		IVs=$h_{EN(t-2),\tau}$	
Endogeneous variables=π, h_{EN}			24hour diff		of IB, and 24h. diff		temperatures		and $\Delta\pi_{t,\tau}$	
			in temperatures		in temperatures		and $h_{EN(t-2),\tau}$			
	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.
π $(\widehat{a}_1)$	10.381	0.835	20.227	3.655	72.563	10.406	27.203	14.021	19.045	2.635
h_{EN} $(\widehat{a}_2)$	0.350	0.010	0.196	0.132	0.446	0.158	0.274	0.044	0.250	0.014
ED_{EN} $(\widehat{a}_3)$	0.797	0.009	0.777	0.036	0.278	0.038	0.692	0.125	0.765	0.023
constant $(\widehat{a}_0)$	2573.77	48.28	2578.59	172.52	4378.66	126.92	2905.22	444.49	2649.4	88.73
a_2+a_3	1.147		0.972		0.723		0.966		1.015	
p-value of H0: $a_2+a_3=1$	0	*Reject*	0.794	*Accept*	0.121	*Accept*	0.688	*Accept*	0.476	*Accept*
$\widehat{S}'_{-g}=\frac{\widehat{a}_1}{\widehat{a}_3}$ (bootstrap s.d.)	13.027	1.267	26.048	5.218	261.30	58.08	39.293	23.93	24.907	4.88
$\widehat{S}'_{-g}\times\pi$	466.56		932.896		9358.47		1407.28		892.04	
nobs	5640		5610		5610		5586		5592	
R^2	0.893		0.884		0.788		0.883		0.888	
AR^2	0.893		0.884		0.787		0.882		0.888	
Hausman			9.68		571.02		178.36		172.91	
p-value Hausman test			0.0079	*END.*	0	*END.*	0	*END.*	0	*END.*
O.I. R. p-value			0.963	*Good*	0.755	*Good*	0.944	*Good*	$-$	
p-value F-test π			9.8E-113		1.7E-79	*Good*	1.7E-33	*Good*	1.7E-141	*Good*
p-value F-test h_{IB}			1.8E-06		3.2E-43	*Good*	0	*Good*	0	*Good*
$\widehat{c}_{2EN}=1/\widehat{a}_1-1/\widehat{S}'_{-g}$	0.0196		0.011		0.010		0.011		0.012	
$\widehat{c}_{2EN}=\widehat{a}_2/\widehat{a}_1$	0.0338		0.0097		0.006		0.010		0.013	
Iberdrola average hourly production	5637.928	1257.04	5637.928		5637.928		5637.928		5637.928	
Iberdrola$\overline{S}_0+\widehat{S}'_{-g}\times\overline{\pi}$	5321.8		5788.2		14214.		6262.6		5747.3	
Non-Endesa average hourly production	9728.89	1756.85	9728.89	1756.85	9728.89	1756.85	9728.89	1756.85	9728.89	1756.85
Non-Endesa $\overline{S}_0+\widehat{S}'_{-g}\times\overline{\pi}$	5993.8		6460.1		14886		6934.5		6419.3	
$\widehat{MC}$ at $\overline{(S_g-h_g)}$	38.86		-45.2		-8.16		-21.2		-27.51	
$\overline{\pi}$ (Euro/MWh)	35.81	12.90								
% times $\widehat{MC}>\pi$ (bootstrap s.d.)	58	11.4	0	27.5	0	24.4	0	14.2	0	0

predict a positive although lower percentage between 2 and 31.6%. In any case, the estimates reveal that Iberdrola behaves more as a net-demander and Endesa as a net supplier according to our model.

It turns out that the results for Iberdrola improve slightly if we include month, hour and days of the week dummies to control for shocks to the intercept of the marginal cost, as the next table shows, specially columns IV3 and IV4. For this set of IVs we do not reject the null that $a_2 + a_3 = 1$ and the estimated marginal cost is greater than the equilibrium price in 71.3 and 92.5 percent of the observations, i.e. Iberdrola behaves as a netdemander in most of the sample. The IV3 results, however, overpredict the production of the rival's. IV4 offers the best set of results. S'_{-g} i.e. the slope of the rival's supply function is estimated to be positive and in general significantly different from zero.

The next table shows all possible combinations of $\widehat{S}_{-IB} - \widehat{S}_{-EN} = (\widehat{S_{EN} - S_{IB}})$ using the values from tables 2 and 4. The most reliable results are in rows IV1, IV3 and IV4 and in column IV4. In general, with the exception of the IV2 estimates for Endesa, Endesa's supply function is steeper although

Table 3: Results of the total production regression for Iberdrola

Iberdrola	OLS		IV1		IV2		IV3		IV4	
Electricity Units= MWh			IVs=pmaxweek, and		IVs=IBhphour, and		IVs=$h_{IB(t-2),\tau}$,$\Delta\pi_{t,\tau}$		IVs=$h_{IB(t-2),\tau}$,	
Endogeneous variables=π, h_{IB}			24hour diff		24-hour diff in .		and 24-hour diff in .		and $\Delta\pi_{t,\tau}$	
			in temperatures		temperatures		temperatures			
	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.
π (a_1)	23.79	0.747	33.954	1.794	40.741	10.680	33.275	1.514	32.779	1.551
h_{IB} (a_2)	0.67	0.010	0.762	0.088	0.707	0.048	0.685	0.017	0.680	0.018
ED_{IB} (a_3)	0.26	0.008	0.146	0.036	0.123	0.057	0.188	0.018	0.194	0.018
constant (a_0)	1755.5	43.34	2204.40	199.40	2217.12	136.79	2001.00	74.86	1977.68	77.13
$a_2 + a_3$	0.936		0.908		0.830		0.873		0.874	
p-value of H0: $a_2 + a_3 = 1$	0	*Reject*	0.091	*Reject?*	0.093	*Reject?*	0	*Reject*	0	*Reject*
$S'_{-g} = \frac{a_1}{a_3}$ (bootstrap s.d.)	90.13	6.03	232.59	71.25	330.40	668.19	176.94	27.31	168.88	26.89
$S'_{-g} \times \pi$	3228.05		8330.15		11833.45		6336.98		6048.40	
nobs	5640		5610		5610		5586		5592	
R^2	0.883		0.877		0.8718		0.879		0.880	
AR^2	0.883		0.877		0.8718		0.879		0.880	
Hausman			126.71		57.58		111.19		107.09	
p-value			0	*END.*	0	*END.*	0	*END.*	0	*END.*
O.I. R. p-value			0.994	*Good*	0.996	*Good*	0.991	*Good*	–	
p-value F-test π			0		$1.05E-36$		0		0	
p-value F-test h_{IB}			$1.96E-19$		0		0		0	
$c_{2EN} = 1/a_1 - 1/S'_{-g}$	0.031		0.025		0.022		0.024		0.025	
$c_{2EN} = a_2/a_1$	0.028		0.022		0.017		0.021		0.021	
Endesa average hourly production	9766.4	1436.94	9766.4	1436.94	9766.4	1436.94	9766.4	1436.94	9766.4	1436.94
Endesa$S_0 + S'_{-g} \times \overline{\pi}$	10647.		15749.		19252.		13756.		13467.	
Non-Iberdrola average hourly production	13857.4	1990.25	13857.4	1990.25	13857.4	1990.25	13857.4	1990.25	13857.4	1990.25
Non Iberdrola $S_0 + S'_{-g} \times \overline{\pi}$	11148		16250.0		19753		14257		13968.	
$\widehat{MC}$ at $\overline{(S_g - h_g)}$	46.22		30.40		19.33		27.38		27.85	
$\overline{\pi}$ (Euro/MWh)	35.81	12.90								
% times $\widehat{MC} > \pi$ (bootstrap s.d.)	80	5.99	31.6	18.2	2	33.2	22.2	6.98	23.4	7.22

Table 4: Results of the total production regression for Iberdrola including month, hour and days of the week dummies

Iberdrola	OLS		IV1		IV2		IV3		IV4	
Electricity Units= MWh			IVs=pmaxweek,		IVs=24-hour diff		IVs=pmaxweek		Ivs=pehour,$h_{IB(t-2),\tau}$	
Endogeneous variables=π, h_{IB}			and 24hour diff		in temperatures		and $h_{IB(t-2),\tau}$		and 24-hour diff	
Including Month and hour dummies			in temperatures						in temperatures	
all days of the week	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.
π	13.76	0.76	27.83	2.01	23.35	9.136	27.595	1.897	22.154	3.985
h_{IB}	0.758	0.010	0.395	0.070	0.419	0.084	0.850	0.029	0.843	0.027
ED_{IB}	0.267	0.009	0.331	0.033	0.353	0.055	0.122	0.022	0.165	0.029
constant	1710.2	59.32	1338.7	161.83	1258.7	224.75	2292.44	106.28	2136.02	124.75
a_2+a_3	1.025		0.726		0.772		0.972		1.007	
p-value of H0: $a_2 + a_3 = 1$	0.013	*Reject*	0	*Reject*	0.026	*Reject*	0.166	*Accept*	0.845	*Accept*
$S'_{-g} = \frac{a_1}{a_3}$ (bootstrap s.d.)	51.55	4.86	84.062	14.82	66.12	35.44	226.50	83.34	134.69	74.07
$S'_{-g}\times\pi$	1846.3		3010.7		2368.2		8112.21		4823.96	
nobs	5634		5605		5605		5588		5574	
R^2	0.932		0.913		0.916		0.926		0.929	
AR^2	0.931		0.912		0.916		0.925		0.928	
Hausman			92.14		24.23		75.54		27.57	
p-value			0	*END.*	0	*END.*	0	*END.*	0	*END.*
O.I. R. p-value			0.639		0.270	*o.k.*	–		0.904	*Good*
p-value F-test π			$2.60E-232$		$2.53E-08$		$8.89E-233$		$1.57E-43$	
p-value F-test h_{IB}			$2.79E-20$		$1.33E-20$		$9.05E-159$		$7.10E-179$	
$c_{2EN}= 1/a_1 - 1/S'_{-g}$	0.053		0.024		0.028		0.032		0.038	
$c_{2EN}= a_2/a_1$	0.055		0.014		0.018		0.031		0.038	
Endesa average hourly production	9766.4	1436.9	9766.43	1436.9	9766.43	1436.9	9766.43	1436.94	9766.43	1436.94
Endesa$S_0 + S'_{-g} \times \pi$	9265.1		10429.		9786.9		15531.		12243.	
Non-Iberdrola average hourly production	13857.4	1990.3	13857.4	1990.3	13857.4	1990.25	13857.4	1990.25	13857.4	1990.25
Non Iberdrola $S_0 + S'_{-g} \times \pi$	9766.2		10931.		10288.		16032.		12744.	
$\widehat{MC}$ at $\overline{(S_g - h_g)}$	90.73		7.73		15.75		40.35		54.89	
$\overline{\pi}$ (Euro/MWh)	35.81	12.90								
% times $\widehat{MC} > \pi$ (bootstrap s.d.)	98.9	0.68	0.2	5.2	6.1	39.2	71.3	17.5	92.5	17.6

Table 5: Estimated SEN-SIB, Boostrap s.d. from 1000 replications

$EN \backslash IB$	OLS	IV1	IV2	IV3	IV4
OLS	38.524 (5.06)	71.035 (14.89)	53.093 (35.57)	213.47 (83.16)	121.66 (73.96)
IV1	25.503 (7.28)	58.014 (15.83)	40.072 (36.29)	200.45 (83.41)	108.64 (74.15)
IV2	−209.75 (57.65)	−177.24 (58.98)	−195.18 (67.98)	−34.8 (97.31)	−126.61 (92.90)
IV3	12.258 (24.42)	44.769 (28.59)	26.827 (44.84)	187.21 (85.91)	95.397 (78.93)
IV4	26.644 (6.97)	59.155 (15.65)	41.213 (36.43)	201.59 (83.18)	109.78 (74.09)

its is hard to conclude that this difference is significantly different from zero due to the low precision of estimates.

The results for the hydro equation:

$$h_{gt\tau} = a_0 + a_1\pi_{t\tau} + a_2 E\{D_{gt\tau} \mid I_{t\tau}, \pi_{t\tau}\} + a_3 H_{gt\tau} + a_4 H_{jt\tau} + a_5 E(h_{jt\tau}|I_g) + \varsigma_{gt\tau} \tag{31}$$

are shown in the next two tables. Again they show evidence of market power, as can be see by the positive and significant coefficient on the expected demand. Furthermore, the values of the slope of the rivals' bid function $\widehat{S}'_{-g}$ are similar to the values obtained in the previous tables. The sensitivity of the results to the introduction of the firm's current distribution levels as an instrumental variable (IV3 in table 6 and 7) leads us to think that, just as in the case of IV2 in table 2, this variable may in fact be correlated with the error term although the OIR test is not invalidated. Remarkably, the null hypothesis that $H_0 : a_4 = -a_5$ is not rejected by none of the IV estimates while it is strongly rejected by the OLS estimates. Part of this positive result is due to the less precise estimates obtained with instrumental variables but also if we look at the estimates of a_4 and a_5 we see that specially a_5 (the coefficient on one of the endogeneous variables) is very different under IV. The estimated slope of the rival's supply function S'_{-g} is always positive but the large standard errors make it just significantly different from zero in IV2 and IV4 in table 6 and in IV2 and IV3 in table 7. Unfortunately, the hydro equations do

Table 6: Results of the hydro regression for Endesa

Endesa	OLS		IV1		IV2		IV3		IV4	
Electricity Units= MWh			pmaxweek,IBhpd_1		24-hour diff in .		IB current distribution,		24 hour diff in	
With Month dummies			EdUFd_1L,24h diff		temperatures		24-hour diff in		distribution a	
Endogenous variables:			in temperatures				temperatures		24-hour diff in t	
π, h_{IB}	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	
π (a_1)	1.433	0.786	18.23	3.30	15.57	6.84	29.73	5.16	10.20	4
ED_{EN} (a_2)	0.354	0.0082	0.340	0.014	0.320	0.04	0.212	0.023	0.355	0
H_{EN} (a_3)	0.0004	0.00009	0.0003	0.0001	0.0004	0.0001	0.0004	0.0001	0.0003	0
H_{IB} (a_4)	0.0003	0.00006	0.0005	0.00005	0.0005	0.00008	0.0005	0.00008	0.0004	0.
h_{IB} (a_5)	0.125	0.010	-0.074	0.049	-0.003	0.088	-0.0037	0.094	0.0073	0
constant (a_0)	-4758.0	248.2	-6128.78	423.77	-5657.8	645.94	-5784.7	691.89	-5549.7	63
$\widehat{S}'_{-g}$ (boostrap s.d.)	4.05	2.56	53.54	9.66	48.66	26.99	140.04	21.66	28.71	1
$\widehat{S}'_{-g} \times \overline{\pi}$	145.041		1917.44		1742.89		5015.67		1028.29	
$p-value\ H_0 : a_4 = -a_5$	0	*Reject*	0.139	*Accept*	0.980	*Accept*	0.972	*Accept*	0.929	*A*
nobs	5640		5586		5610		5610		5610	
R^2	0.8088		0.7854		0.7949		0.7636		0.8013	
AR^2	0.8084		0.7849		0.7945		0.7631		0.8009	
Hausman			33.86		4.71		231.15		2.94	
p-value			0	End.	0.0947	End.	0	End.	0.2301	No
O.I. R. p-value			0.670		0.8898		0.595		0.829	
p-value F-test π			0		$4.33E-08$		$6.33E-144$		$5.08E-32$	
p-value F-test h_{IB}			$1.25E-150$		$2.19E-15$		$8.56E-159$		$8.02E-31$	
Iberdrola average hourly product.	5637.93	1257.04	5637.93	1257.04	5637.93	1257.04	5637.93	1257.04	5637.93	12
Iberdrola$\overline{S}_0 + \widehat{S}'_{-g} \times \overline{\pi}$	5000.3		6772.7		6598.2		9871.0		5883.6	
Non-Endesa average hourly product.	9728.89		9728.89		9728.89		9728.89		9728.89	
Non-Endesa $\overline{S}_0 + \widehat{S}'_{-g} \times \overline{\pi}$	5672.3		7444.7		7270.1		10543.		6555.5	

not allow identification of the parameters of the cost function so from these results we could not test the prediction that a net supplier should produce at price above marginal cost and a net demander at price below marginal cost.

Finally, table 8 compute the difference in slopes $S_{EN} - S_{IB}$. Due to the large standard deviations most of these results are not conclusive except for those in column IV1 where we get that with the exception of row IV3, which, as we explained above, is not a good set of IVs, the difference is significantly positive, i.e. Endesa's supply function is steeper.

We have also performed some informal tests of our hypotheis that higher net demand position will give incentives to both Endesa and Iberdrola to bid more quantity to the pool, i.e. biding at lower price. For this we estimated the bid functions for Iberdrola and Endesa and included the inelastic part of their demand in the regressors. If firms were simply bidding at marginal costs then the coefficient on the inelastic demand should be zero. It turned out that this coefficient was consistently negative and statistically different from zero.

Table 7: Results of the hydro regression for Iberdrola

Iberdrola	OLS		IV1		IV2		IV3	
Electricity Units= MWh			pmaxweek,EGhpd_1		24-hour diff in .		EG current distribution,	
Endogeneous variables= π, h_{EN}			24h diff		temperatures		24-hour diff in	
			in temperatures				temperatures	
	estimate	s.d.	estimate	s.d.	estimate	s.d.	estimate	s.d.
π (a_1)	0.727	1.112	27.64	3.54	31.84	14.82	43.04	14.14
ED_{IB} (a_2)	0.381	0.011	0.3159	0.0215	0.297	0.097	0.120	0.040
H_{EN} (a_4)	-0.00087	0.00004	-0.0007	0.00005	-0.0007	0.0001	-0.00069	0.0001
H_{IB} (a_3)	0.00020	0.00002	0.00033	0.00003	0.0003	0.00008	0.00028	0.00007
h_{EN} (a_5)	0.344	0.019	0.0085	0.082	-0.0217	0.217	0.230	0.183
constant (a_0)	-1097.73	97.82	-2385.81	341.94	-2497.86	888.78	-1401.97	720.87
S'_{-g} (boostrap s.d.)	1.905	3.91	87.47	14.37	107.05	112.30	357.57	219.81
$S'_{-g} \times \pi$	68.24		3132.92		3834.18		12806.3	
$p - value\ H_0 : a_4 = -a_5$	0	*Reject*	0.924	*Accept*	0.9178	*Accept*	0.208	*Accept*
nobs	5640		5610		5610		5610	
R^2	0.6241		0.5722		0.557		0.5291	
AR^2	0.6238		0.5718		0.5566		0.5287	
Hausman			91.7		5.79		112.1	
p-value			0		0.0554		0	
O.I. R. p-value			0.889		0.843		0.729	
p-value F-test π			0		0.0008		$1.48E-102$	
p-value F-test h_{IB}			$2.49E-154$		$5.80E-06$		$3.63E-189$	
Endesa average hourly production	9766.434	1436.936	9766.434	1436.936	9766.434	1436.936	9766.434	1436.936
Endesa$S_0 + S'_{-g} \times \pi$	7487.0		10552.		11253.		20225.	
Non-Iberdrola average hourly production	13857.4		13857.4		13857.4		13857.4	
Endesa$S_0 + S'_{-g} \times \pi$	7988.2		11053.		11754.		20726.	

Table 8: Estimated SEN-SIB from hydro regressions, Boostrap s.d. from 1000 replications

$EN\backslash IB$	OLS	IV1	IV2	IV3
OLS	-2.145 (4.97)	83.42 (14.65)	103.0 (112.3)	353.52 (220.0)
IV1	-51.635 (10.80)	33.93 (16.33)	53.51 (112.2)	304.03 (219.9)
IV2	-46.755 (27.18)	38.81 (30.06)	58.39 (114.1)	308.91 (221.0)
IV3	-138.14 (22.09)	-52.57 (25.57)	-32.99 (112.8)	217.53 (220.2)
IV4	-26.805 (16.86)	58.76 (21.37)	78.34 (112.5)	328.86 (219.8)

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7 Data appendix

Figures 2 and 3 show the demand bids by firms belonging to the Endesa group and Iberdrola respectively in three hours of the day: Figure 4 shows the estimated demand elasticities estimated separately per

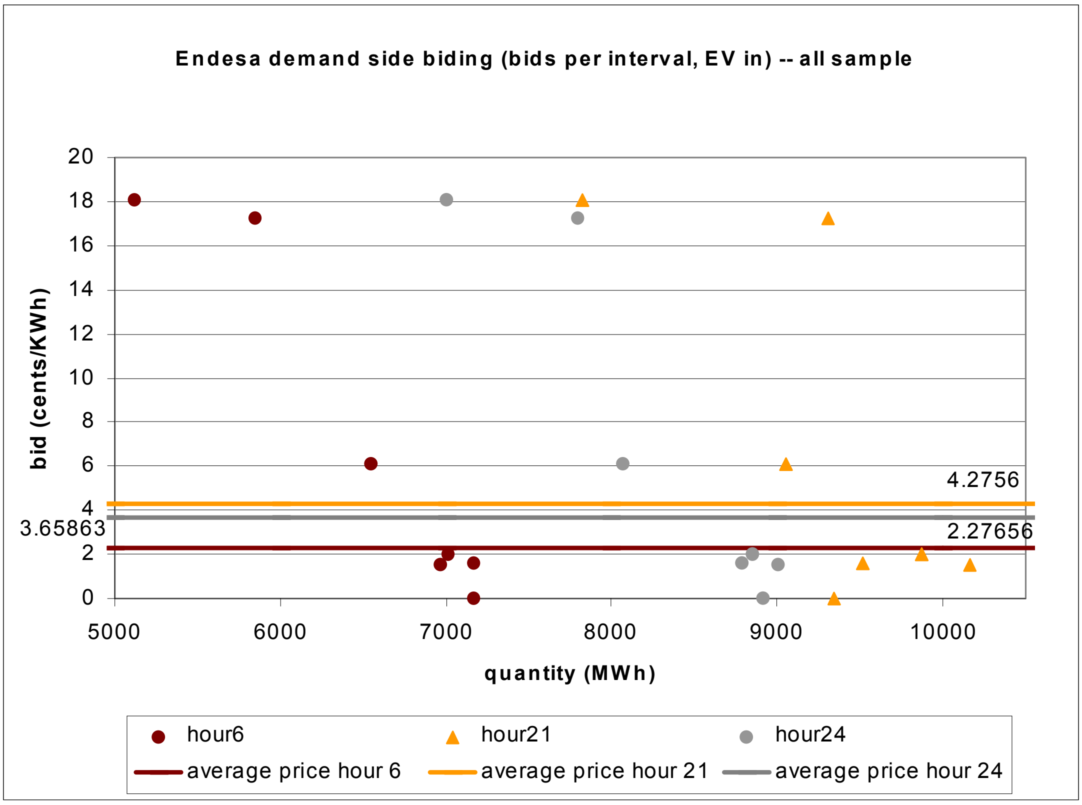


Figure 2:

hour and month.

Figures 5-8 show the patterns of netdemand and netsupply for Iberdrola and Endesa. Both firms

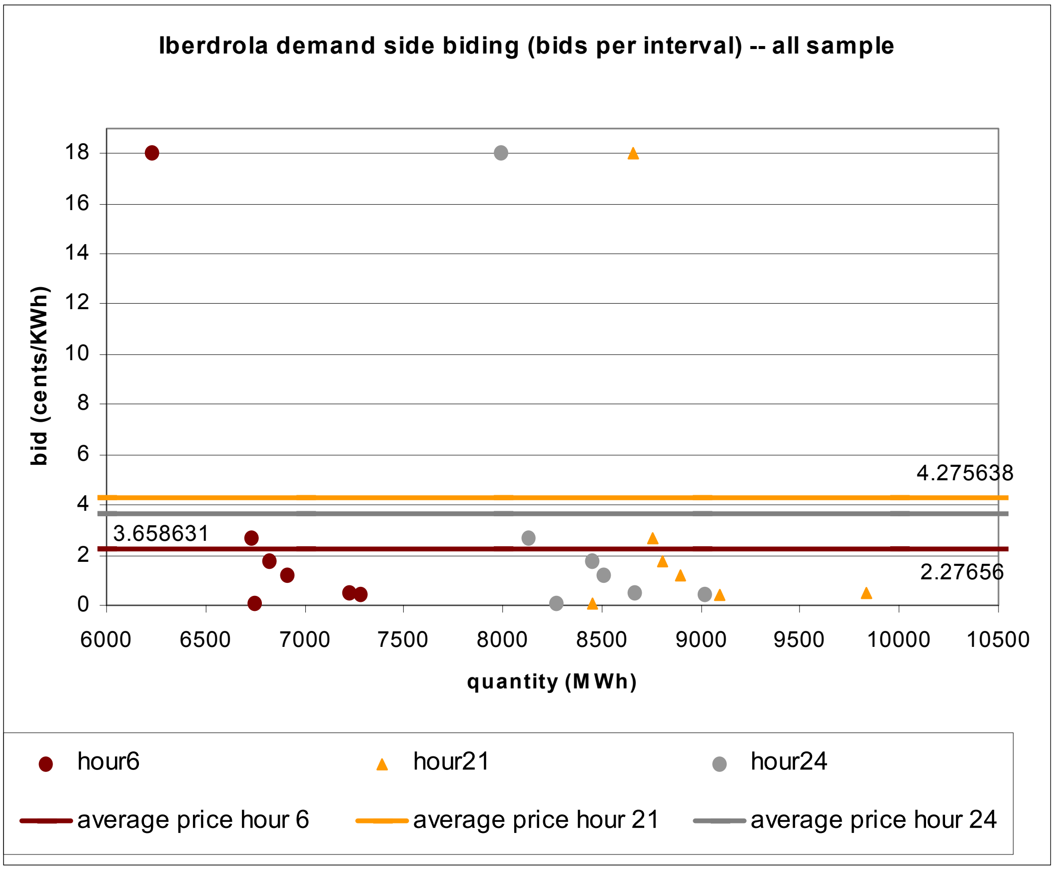

Iberdrola demand side biding (bids per interval) -- all sample
bid (cents/KWh)
18
16
14
12
10
8
6
4
2
0
4.275638
3.658631
2.27656
6000
6500
7000
7500
8000
8500
9000
9500
10000
10500
quantity (MWh)
hour6
hour21
hour24
average price hour 6
average price hour 21
average price hour 24

Figure 3:

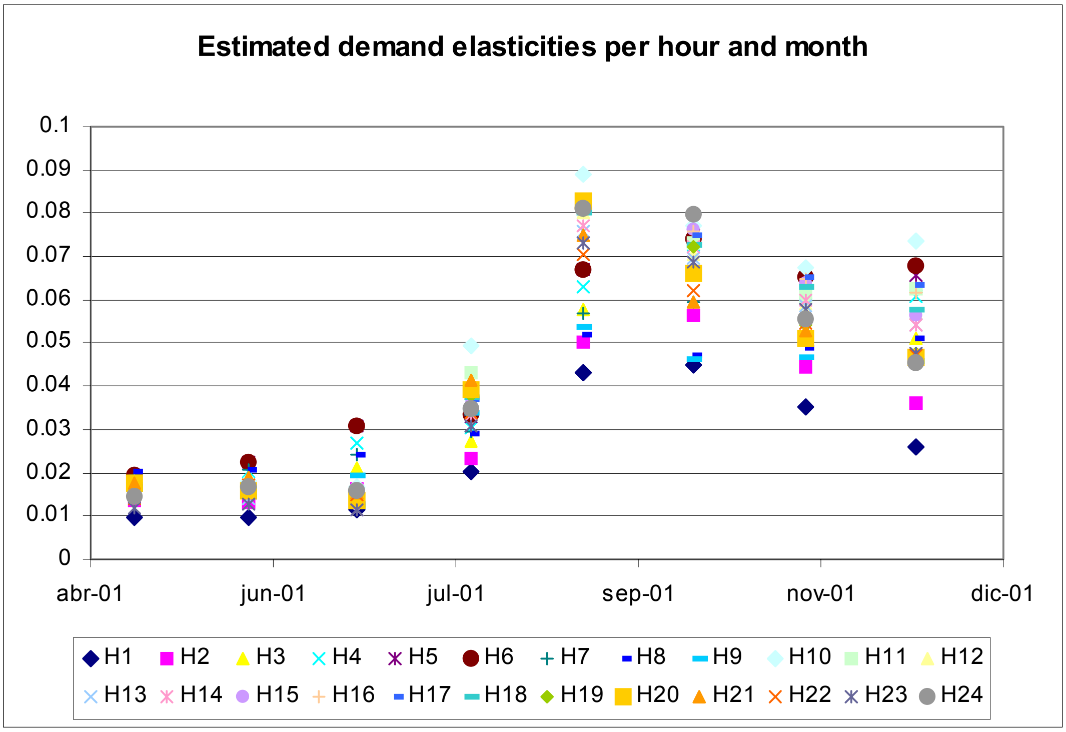

Estimated demand elasticities per hour and month
0.1
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
abr-01
jun-01
jul-01
sep-01
nov-01
dic-01
H1 H2 H3 H4 H5 H6 H7 H8 H9 H10 H11 H12
H13 H14 H15 H16 H17 H18 H19 H20 H21 H22 H23 H24

Figure 4:

show a lot of variance in the net demand positions even for the same hour of the day over the months. Nevertheless, Endesa is always a net-supplier and Iberdrola a net-demander (the latter with the exception of one data point):

Figures 10 and 11 show that reserves vary a lot along the year for both Endesa and Iberdrola although the pattern of evolution is not the same (partly due to different strategies in the productionj of hydroelectricity).

The strong correlation (predicted from our model) between the total generation and the hydro generation is seen in the figures 12 and 13:

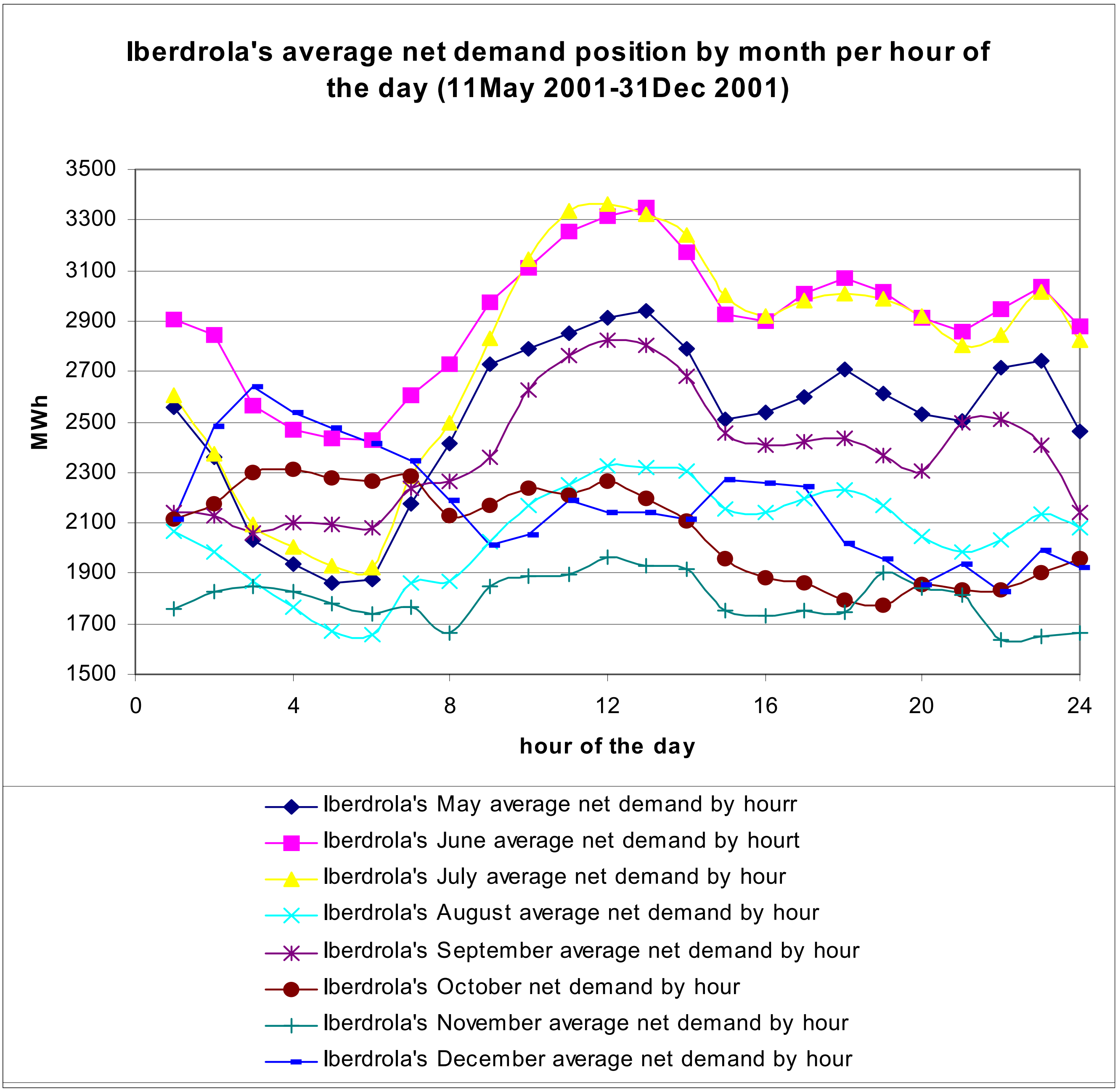
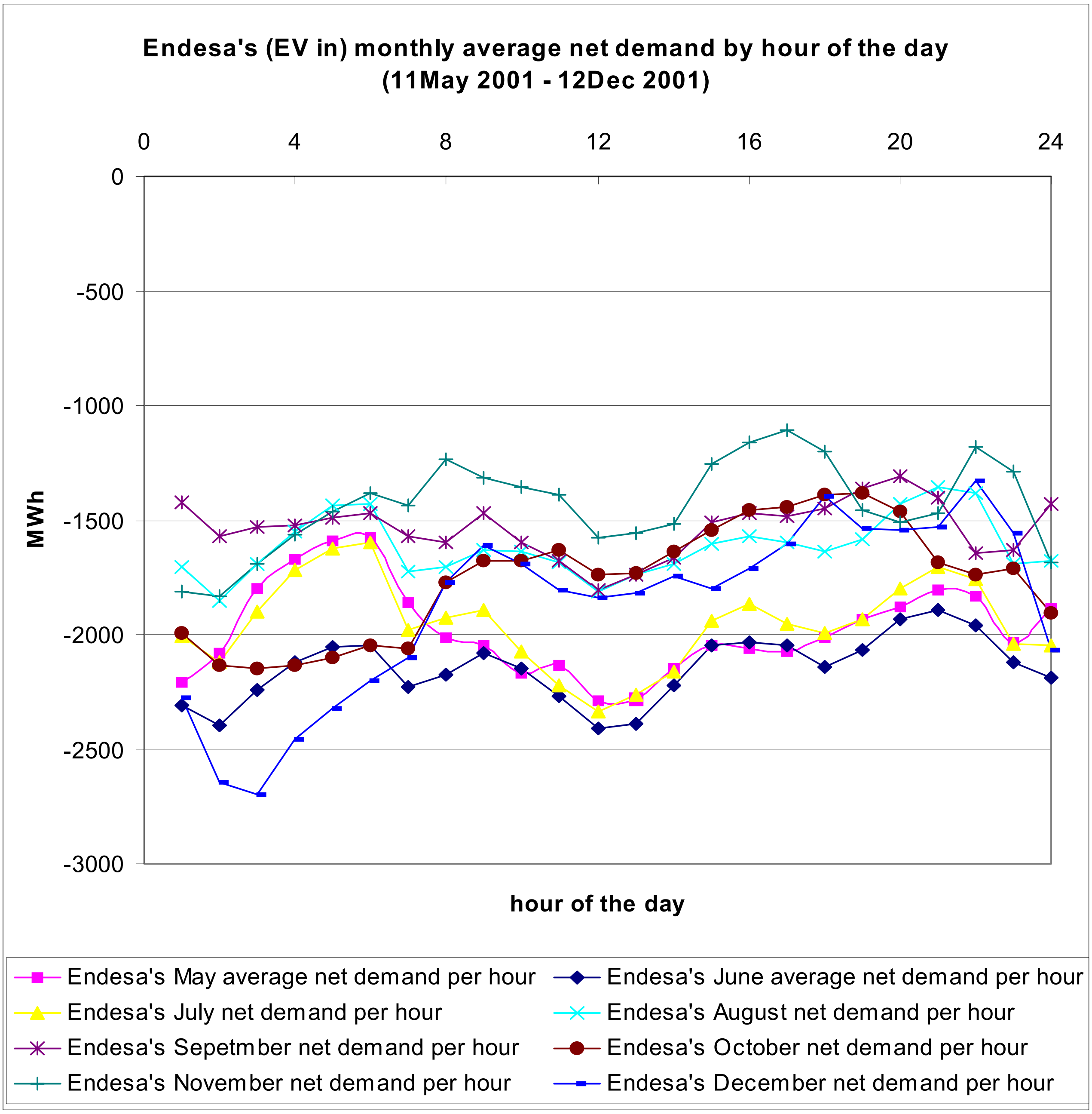

Iberdrola's average net demand position by month per hour of the day (11May 2001-31Dec 2001)
3500
3300
3100
2900
2700
2500
2300
2100
1900
1700
1500
MWh
0
4
8
12
16
20
24
hour of the day
Iberdrola's May average net demand by hourr
Iberdrola's June average net demand by hourt
Iberdrola's July average net demand by hour
Iberdrola's August average net demand by hour
Iberdrola's September average net demand by hour
Iberdrola's October net demand by hour
Iberdrola's November average net demand by hour
Iberdrola's December average net demand by hour

Figure 5:



Endesa's (EV in) monthly average net demand by hour of the day
(11May 2001 - 12Dec 2001)
0
4
8
12
16
20
24
0
-500
-1000
-1500
-2000
-2500
-3000
MWh
hour of the day
Endesa's May average net demand per hour
Endesa's June average net demand per hour
Endesa's July net demand per hour
Endesa's August net demand per hour
Endesa's Sepetmber net demand per hour
Endesa's October net demand per hour
Endesa's November net demand per hour
Endesa's December net demand per hour

Figure 6:

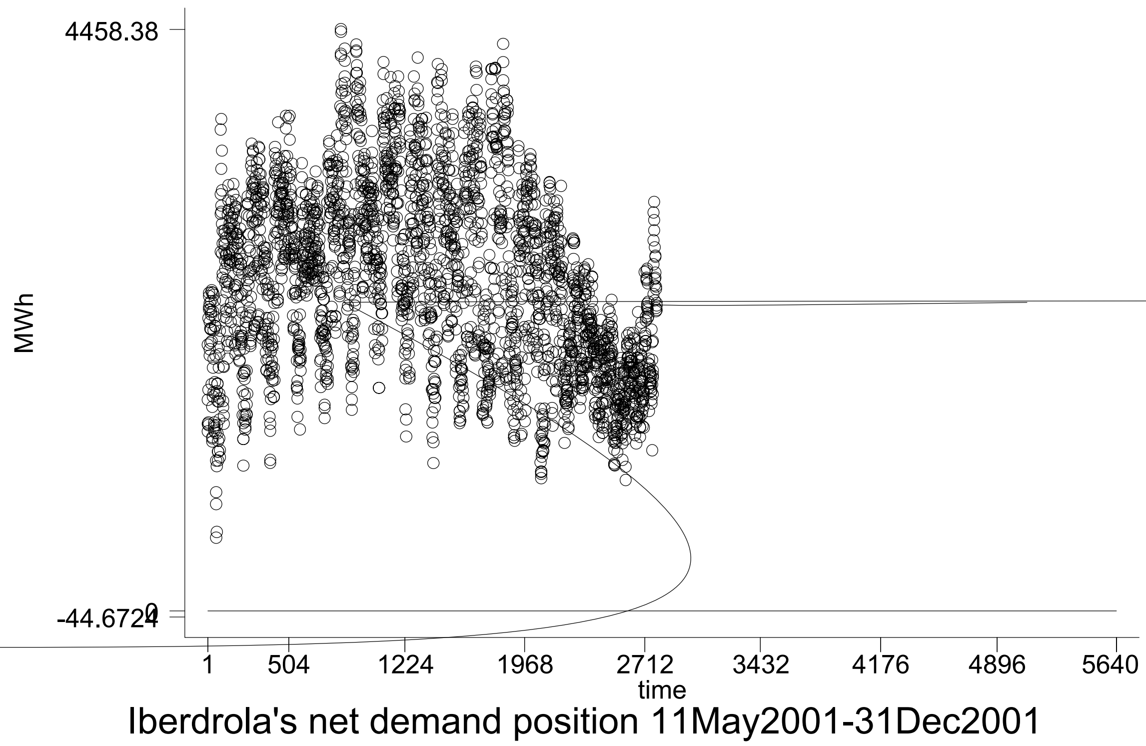

4458.38
-44.6724
0
MWh
1
504
1224
1968
2712
3432
4176
4896
5640
time
Iberdrola's net demand position 11May2001-31Dec2001

Figure 7:

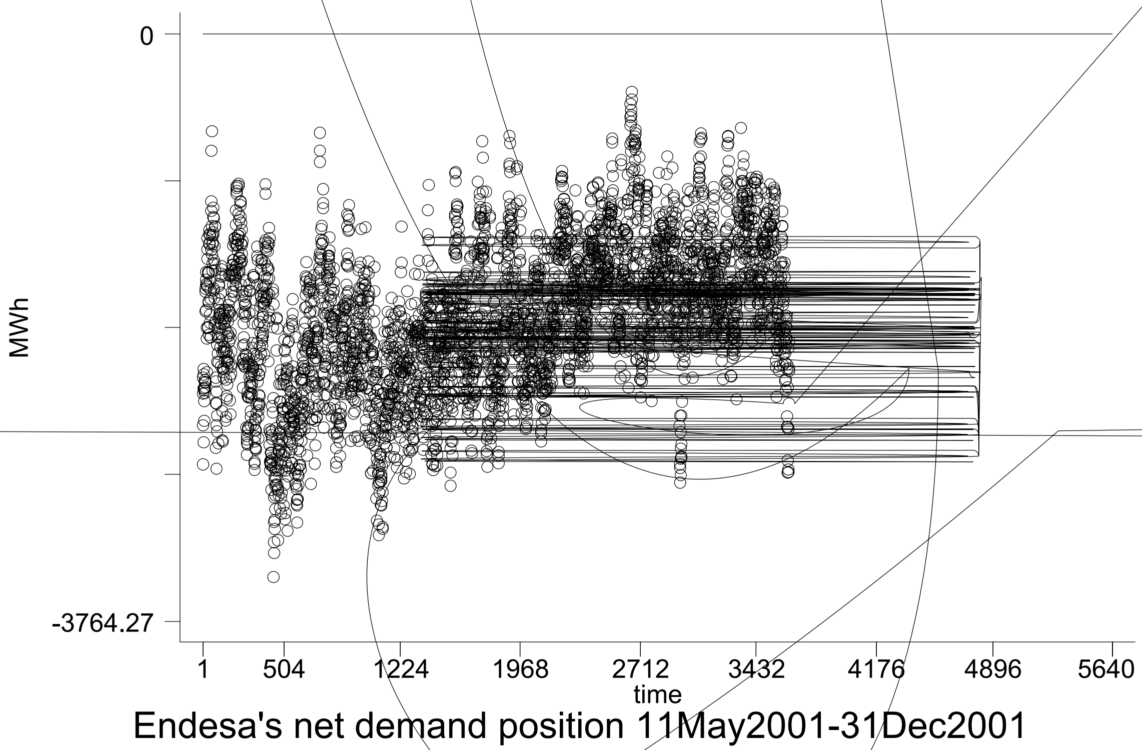
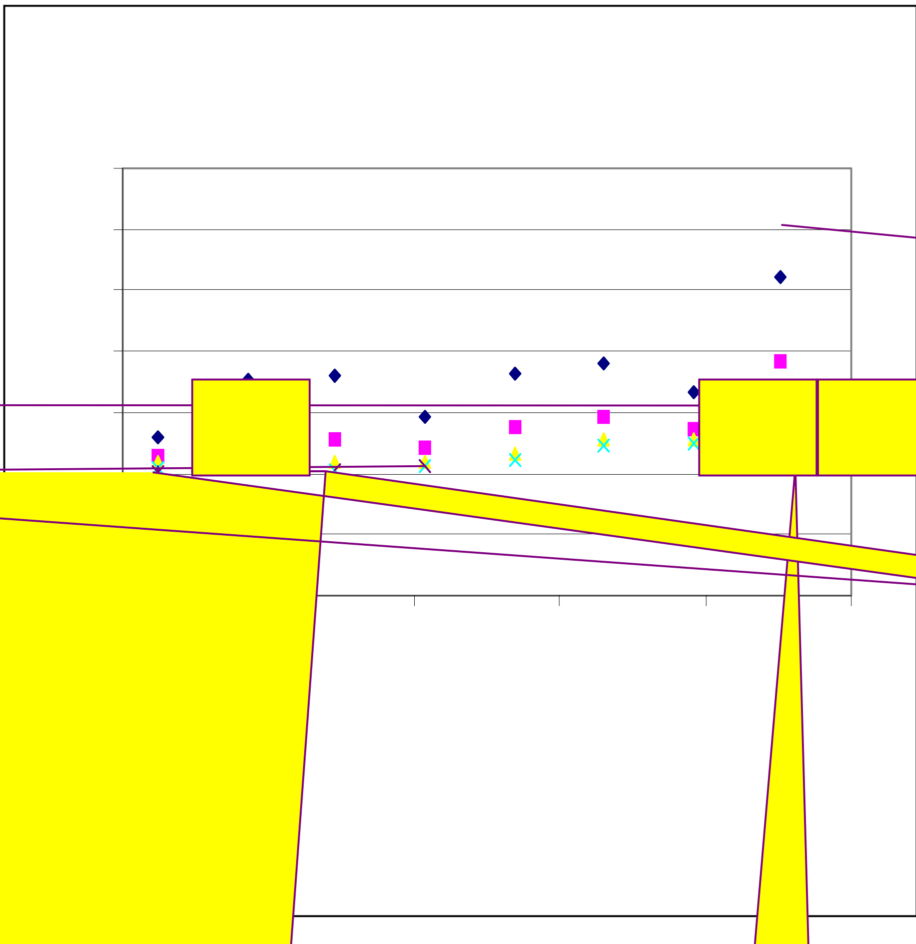

0
-3764.27
MWh
1
504
1224
1968
2712
3432
4176
4896
5640
time
Endesa's net demand position 11May2001-31Dec2001

Figure 8:



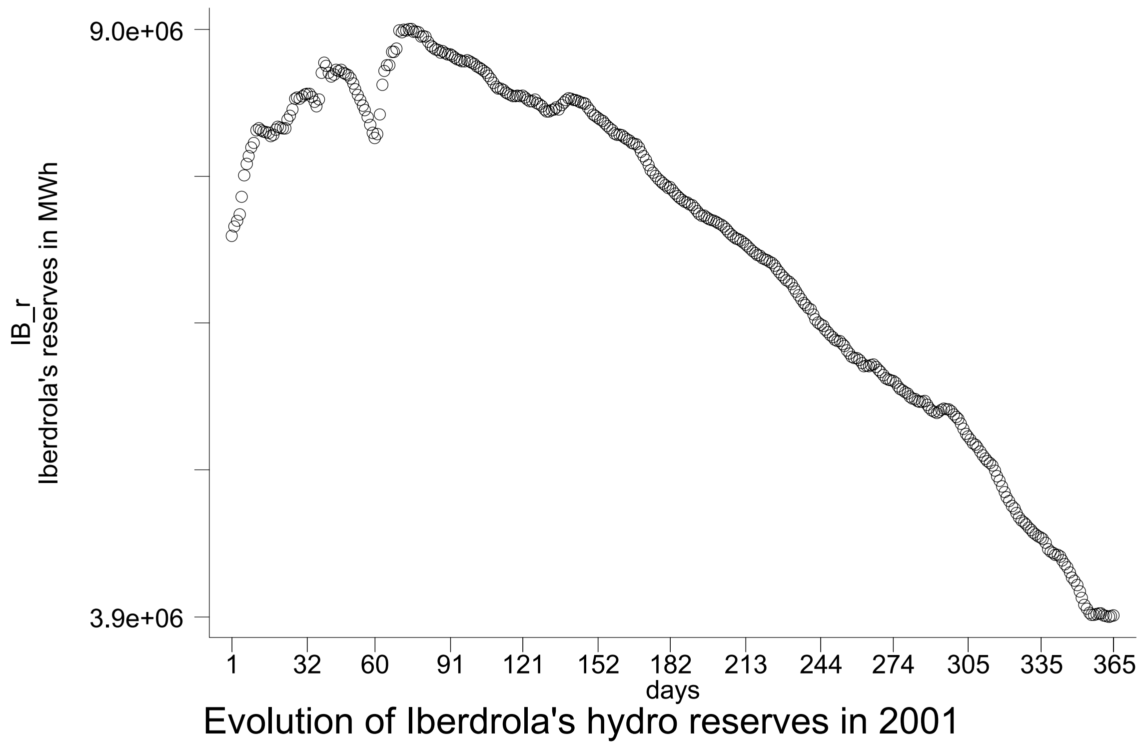

9.0e+06
3.9e+06
IB_r
Iberdrola's reserves in MWh
1
32
60
91
121
152
182
213
244
274
305
335
365
days
Evolution of Iberdrola's hydro reserves in 2001

Figure 10:

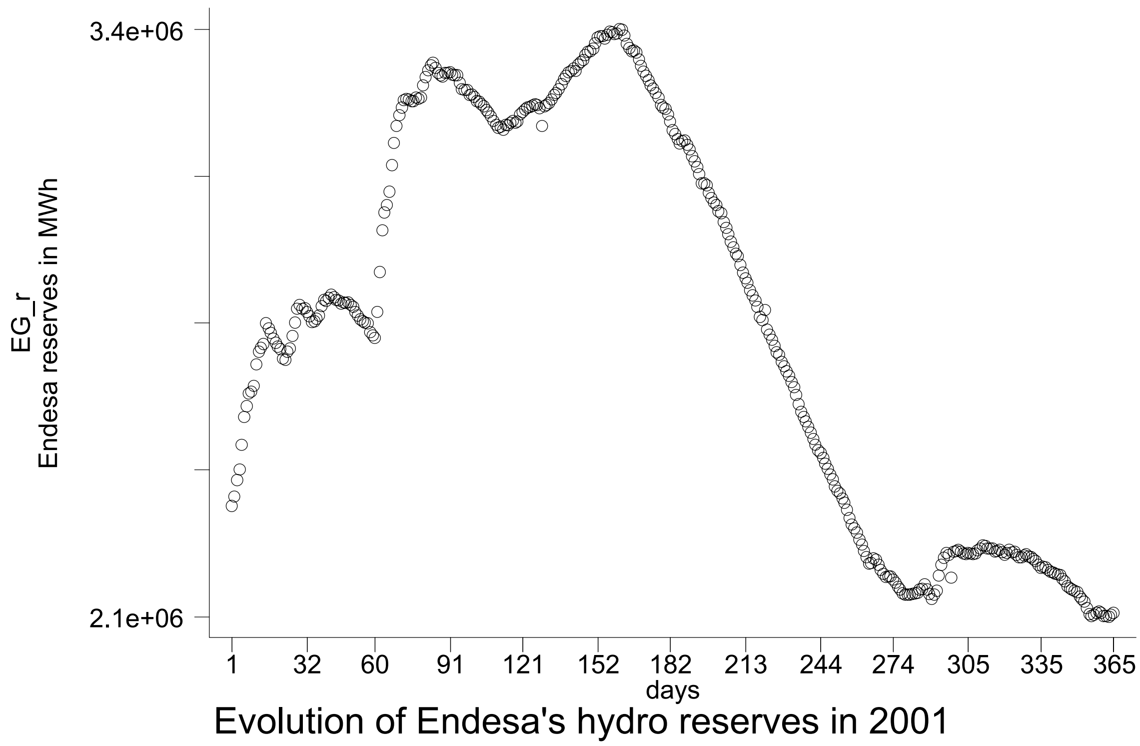

3.4e+06
2.1e+06
EG_r
Endesa reserves in MWh
1
32
60
91
121
152
182
213
244
274
305
335
365
days
Evolution of Endesa's hydro reserves in 2001

Figure 11:

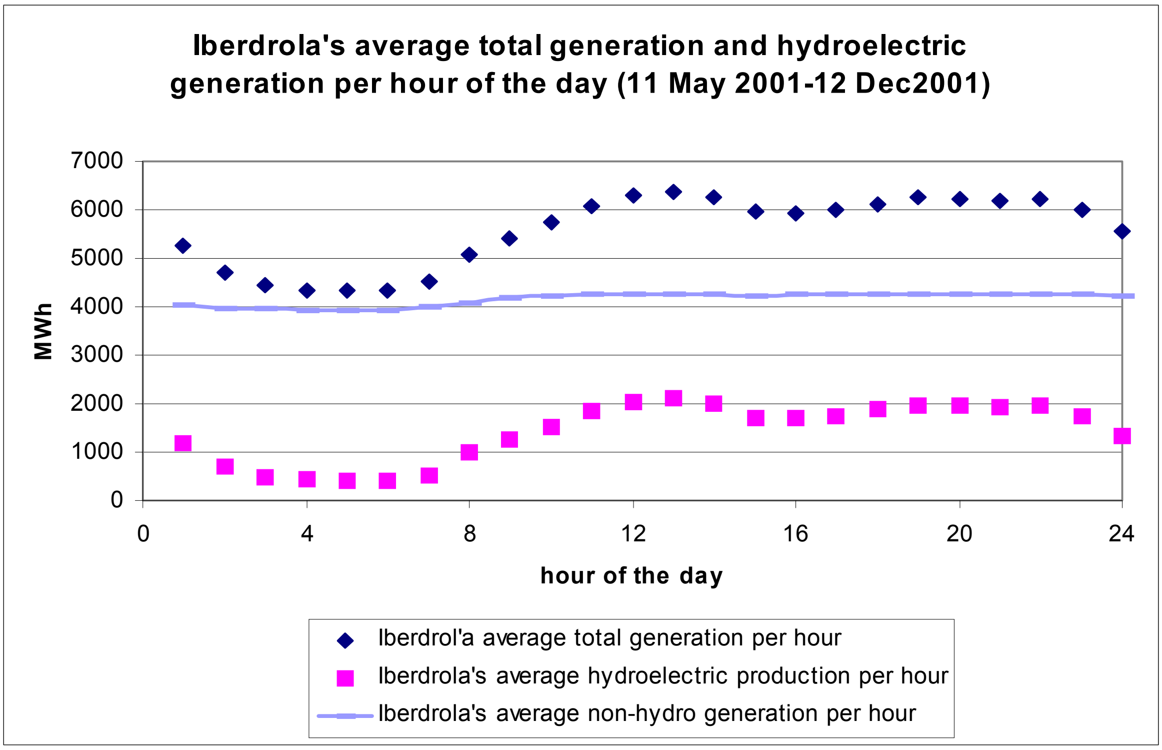

Iberdrola's average total generation and hydroelectric generation per hour of the day (11 May 2001-12 Dec2001)
MWh
7000
6000
5000
4000
3000
2000
1000
0
0
4
8
12
16
20
24
hour of the day
Iberdrol'a average total generation per hour
Iberdrola's average hydroelectric production per hour
Iberdrola's average non-hydro generation per hour

Figure 12:

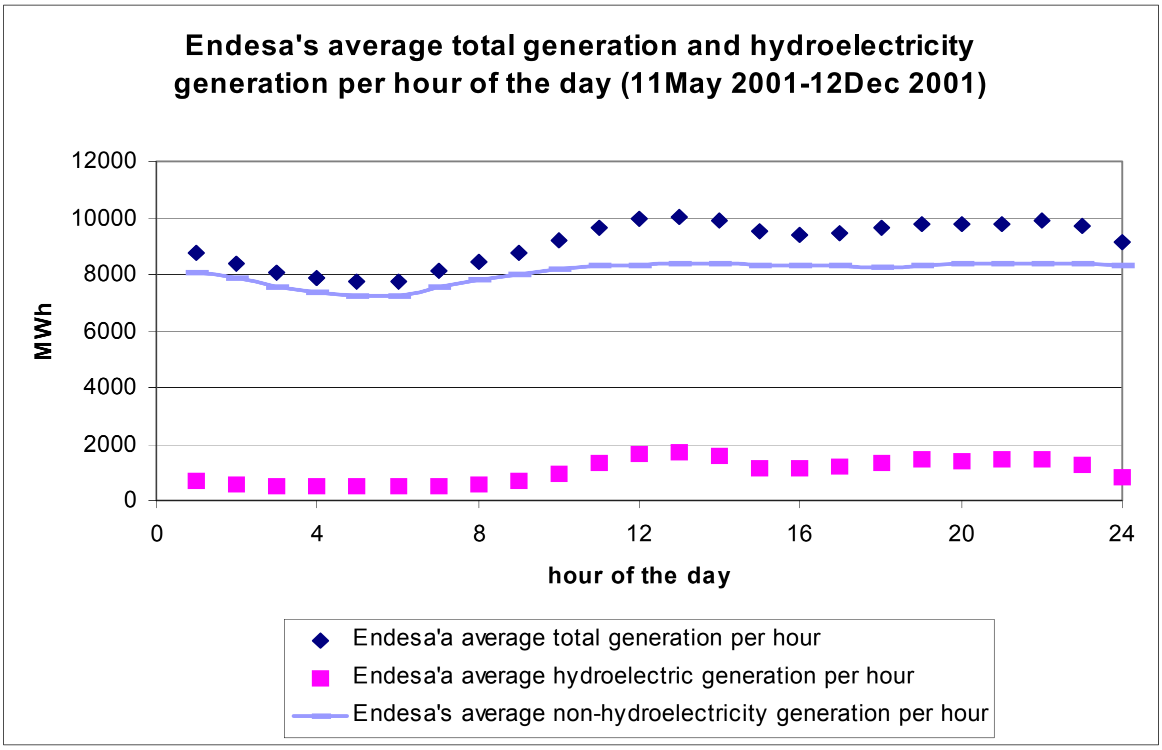

Endesa's average total generation and hydroelectricity generation per hour of the day (11May 2001-12Dec 2001)
MWh
12000
10000
8000
6000
4000
2000
0
0
4
8
12
16
20
24
hour of the day
Endesa'a average total generation per hour
Endesa'a average hydroelectric generation per hour
Endesa's average non-hydroelectricity generation per hour

Figure 13: