

# ESTIMATING MARGINAL COSTS AND MARKET POWER IN THE ITALIAN ELECTRICITY AUCTIONS

BRUNO BOSCO, LUCIA PARISIO, AND MATTEO PELAGATTI

**ABSTRACT.** In this paper we examine the bidding behaviour of firm competing in the Italian wholesale electricity market where generators submit hourly supply schedule to sell power. We describe the institutional characteristics of the Italian market and derive generators' equilibrium bidding functions. We also discuss the main empirical strategies followed by the recent econometrical literature to obtain estimates of (unobservable) optimal bids. Then, we use individual bid data, quantity volumes and other control variables to compare actual bidding behaviour to theoretical benchmarks of profit maximization. We obtain estimates of generators' costs to be used in conjunction with hourly market equilibrium prices to derive some measures of the extent of market power in the Italian electricity sector and of its exploitation by firms.

**JEL codes:** D24, L13, L41, L94, L98.

**Keywords:** Bidding behaviour in Electricity markets; Estimates of optimal bid functions; Measures of market power.

## 1. INTRODUCTION

In the last twenty years electricity markets have been significantly reshaped all around the world. Previous vertically integrated enterprises, generally owned by the state, have been split in separated autonomous (generally private) entities each entitled to carry on a specific activity roughly corresponding to single productive segments of the previous integrated firms (basically, generation, transportation, delivery and retail). The physical electricity network has been structured as an autonomous organization (either an Agency or a private company) that sells to generators the usage of the transmission capacity. In turn, generators compete for the wholesale supply of bulk electricity on newly created electricity auctions where a market coordinator supervise the demand-supply matching. These auctions normally work as single price competitive markets and operate on hour/daily frequency on the basis of both supply and demand merit orders. The general expectation that has inspired these vast reforms was that technological advances in the generation sector may allow several generators to play the competitive game among them and offer electricity at nearly competitive prices. Previous state owned firms were generally subjected to a cost-plus

---

*Date:* February 19th, 2010.

Bruno Bosco ([bruno.bosco@unimib.it](mailto:bruno.bosco@unimib.it)), Lucia Parisio ([lucia.parisio@unimib.it](mailto:lucia.parisio@unimib.it)), Dipartimento dei Sistemi giuridici ed economici, Università degli Studi di Milano-Bicocca, Via Ateneo Nuovo 1, 20126 Milano, Italy.

Matteo Pelagatti ([matteo.pelagatti@unimib.it](mailto:matteo.pelagatti@unimib.it)), Dipartimento di Statistica, Università degli Studi di Milano-Bicocca, Via Ateneo Nuovo 1, 20126 Milano, Italy.

regulation which implied that, up to a certain point and under some limitations, the final consumers were bearing the risk of any cost increase (fuel, transportation, delivery costs, and so on). Hence, the creation of wholesale electricity auctions represented a means to reduce the extent of the costs pass-through because the necessity to compete for despatching in the auction should moderate the price increase brought about by cost increase more effectively than any politically inspired regulation. Several studies, however, show that generators still earn significant extra-profits and have large extents of market power to exploit. At the same time other studies show that in many cases generators might obtain even higher profits if they acted more aggressively on the markets, i.e. if they posted supply bids higher than the actual ones and yet below the price ceiling limits fixed by regulation authorities. Then, strong market power exists but apparently it is not always fully exploited. The correct estimation of the price-cost margins has therefore become a crucial element in the overall evaluation of the impact of the above mentioned reforms on the efficiency of the electricity markets and welfare.

In this paper we pursue a twofold purpose. On the one hand we try and estimate price-cost margins and Lerner Indexes for a large sample of Italian generators competing in the Italian electricity auction during four years (2005-2006-2007-2008) in order to evaluate the existence and the extent of market power in that period and to explain it on the basis of some characteristics of the Italian market (level and regional distribution of demand, regional location and capacity of generators, grid congestion, etc.). On the other hand we evaluate the way in which the dynamics of costs' components (fuel price above all) affect generation costs and final electricity prices. By testing for a possible differential impact of, say, a gas price increase on costs and prices, we test for the hypothesis that electricity auctions smooth costs increase ( i.e. limit the extent to which cost increases are transferred to prices) and then somehow protect consumers from avoidable price increases through the simple force of competition among generators and without direct state intervention. In order to do so we recover hourly generation cost from supply bids and residual demand elasticity and compute Lerner Index accordingly. This permits the estimation of the magnitude of market power, its evolution over time and its distribution across firms and regions. Then we use the series of calculated costs and equilibrium price to estimate the elasticity of the two series to fuel price variations and present inference of the above mentioned "smoothing attitude" of electricity auctions.

The paper is organized as follows. In section 2 we briefly discuss the theoretical modelling of electricity auctions and the main issues raised by the empirical estimation of costs and market power. Section 3 contains a description of the Italian electricity auction (auction rules and structural characteristics of the generation sector) as well as the main properties of the generation process of the data used in this paper. In section 4 we present a share-auction model of bidding behavior from which we derive explicit relations between prices, costs and residual demand elasticities that will be used in the empirical part of the paper. Section 5 contains the estimated values of marginal costs and Lerner indexes for the Italian market and section 6

includes the estimated elasticities of generation costs and equilibrium prices to Brent price. Section 7 briefly concludes.

## 2. MODELLING BIDDING BEHAVIOR IN ELECTRICITY AUCTIONS

There is a growing body of literature that analyses electricity markets on both a theoretical and an empirical point of view. Wholesale electricity markets can be modeled as multi-unit auctions where multiple identical objects are bought/sold and demand/supply is not restricted to a single unit. From the theoretical point of view, the analysis concentrates mainly on the properties of the market design (various possible auction formats) and on the strategic behavior of auction participants, whereas the main focus of applied researchers is on the estimation of firms' market power.

From a theoretical point of view, like other cases of auctions for identical and divisible objects – such as Treasury Bills – electricity auctions are often analyzed as quota or share auctions. Ausubel and Cramton (2002), following the line of research first introduced by Wilson (1979), found that when multiple units are sold simultaneously under the uniform price rule, buyers have an incentive to “shade” their demand (reduce their valuation) for all units following the first. In this manner they optimally trade-off a lower probability of winning on the last units against savings on all units bought. Electricity markets, in which the majority of sellers own a number of generating units, show the same type of incentives on the supply side because overbidding on the last units increases the revenues for all the inframarginal units despatched in equilibrium. Von der Fehr and Harbord (1993) were the first to apply this approach to electricity auctions in a model of complete information about opponents' costs. Many researchers have implemented and refined this model<sup>1</sup> which – after the work of Crespo (2001) – became known with the name of Bid Function Equilibria (BFE). BFE, combining complete information with a discrete action space for bidders, predicts asymmetric bidding behavior for bidders: the price setter inflates his bid to raise the equilibrium price, whereas the other firms have a Nash equilibrium response which equates bids at marginal costs. This is easy to understand since in a multi-unit auction with uniform price rule a high price is a public good. A similar (bid shading) result was obtained by Parisio et al (2003; 2008) who relaxed the assumption of costs common knowledge and derived equilibrium bid functions in both isolated and interconnected electricity markets showing that the extent of the bid shading, and therefore the mark-up, depends among other things upon the endowments of generation capacity of each multi-plant firms.

The empirical analysis of electricity auctions is conducted following two intersecting lines of research. On the one hand, following the literature on the econometrics of auction data pioneered by Guerre et al. (2000), researchers aim at recovering the marginal cost functions (valuations) of firms from bid data, under the assumption that each bidder is acting optimally against the distribution of the bids of the opponents. Guerre et al. (2000)

---

<sup>1</sup>For example, Brunekreft (2001), Garcia-Diaz and Marin (2003), Fabra (2003), Fabra, von der Fehr and Harbord (2006).

suggest a non-parametric (indirect) approach based on the fact that the distribution of the (unknown) bidders' valuations is uniquely identified by the distribution of observed bids. Using the first order conditions for the optimal bid functions, a sample of pseudo-valuations can be obtained for a given set of  $N$  bidders observed in a series of  $L$  auctions. Other authors estimate market power (Lerner Index, price-cost markup and the like) of electricity firms under the assumptions that costs are known to the researcher. Some other studies follow a combination of both approaches. However, the multi-unit dimension of the electricity auctions poses econometric problems stronger than those of the above mentioned single-unit case. In particular, the interpretation of data generated in equilibrium in the multi-unit case is more troublesome even when the econometrician can observe the equilibrium distribution of all bids (Athey et al, 2006). Crawford et al. (2007) test the predictions of BFE using data on bid functions submitted into the England and Wales spot market from 1993 to 1995. They found strong support to the prediction of asymmetric bidding behavior between the price setter and the non-price setters; the mark-up increases with the amount of inframarginal capacity sold by firms and this effect is more pronounced for the price-setter. All together Crawford et al. (2007) found that the estimated bid function for the price setter has a lower intercept and a steeper slope than the ones of non-price setters.

Hortaçsu and Puller (2007) characterize the bidding behavior of electricity generators within the theoretical framework of Wilson's share auction. Before them, Wolak (2003) used a similar model of optimal bidding behavior to recover cost function estimates for electricity generation in the Australian National Electricity Market. He shows that under the assumption of firm-level profit maximization, it is possible to estimate the level of marginal cost implied by a given equilibrium price and quantity. Observed bid data can be used to compute directly the Lerner Index of market power.

Another line of applied research, starting from the work of Wolfram (1999), estimates the extent of market power in electricity markets measuring the price-cost margins earned by firms. This approach differs from the auction approach since marginal costs of firms are assumed to be known. Mark-ups are calculated using data of equilibrium prices in the British Pool and marginal costs of the suppliers which are recovered using information on fuel costs and from an industry survey. Results indicate that prices are higher than marginal costs but firms do not fully exploit profit opportunities predicted by most theoretical models for the case of duopolists facing inelastic demand.

The finding that firms fail to exploit the full extent of market power in electricity markets is a quite common result in the applied literature. One possible explanation of this suboptimal behavior relies on the fact that firms may be vertically integrated which means that they may be active on both sides of the auction. Considering the two-sided wholesale Spanish spot electricity market where integrated firms can be either net demanders or net suppliers (since they can sell electricity as generators and simultaneously buy it as dealers to resell it in the retail market), Kühn et al. (2004) postulate that if the firms have similar degree of market power, prices may not differ much

from perfect competition. In the reality prices can differ from competitive price but – due to the above mentioned possible net position of the firms steaming from vertical integration – average price-cost margins will not inform about the existence of substantial market power in the spot market since bids will depend on the net demand position of the integrated firms in that market. Net demanders will overproduce while net sellers will underproduce. Although this may not significantly affect spot prices and market power, yet it can induce a misallocation of the generation assets which in turn may produce an efficiency loss. To estimate market power they follow a structural approach and estimate a encompassing but parsimonious supply function model with vertical integration in which the operation of firms as both seller and buyer was taken into account. Cost parameters were indirectly recovered from this estimation and used with inverse elasticity estimates for market power evaluation. They conclude that market power is quite pervasive in the Spanish spot market but vertical integration and market power on both sides of the market prevent prices to go as far above or below the market price as would be the case with one sided market power. Other explanations might be sought by looking at the physical limitation of the grid. The flow of electricity across zones is limited by the (known) physical capacity of the interconnection and this in turn imposes a (known) ceiling to the quantity that can be exported. If ask bids posted by generators are used to price the transportation capacity across zones bid moderation might be a rational choice particularly on the part of those generators that are located near frequently congested zones.

### 3. THE ITALIAN MARKET

In this section we present the data generating process of Italian electricity prices. First we introduce the main characteristics of the Italian electricity industry and then we will analyze the market rules of the Italian wholesale electricity market (IPEX). Our data analysis will refer mainly to our sample period (2005-2008).

IPEX started its operations in April 2004 with bidders acting on the supply side only. The demand side of the market became active since January 2005. Since then the participation<sup>2</sup> in the MGP markedly increased: in the year 2008 there have been 81 operators on the supply side and 91 operators on the demand side. In the same year, the volume of energy exchanged on the MGP amounted at 232 TWh with a liquidity rate<sup>3</sup> of the 69%.

The total energy production comes from different technologies/fuels employed: the Italian industry is characterized by an high quota of thermal production (around 80% for all the sample period) which includes technologies based on oil, gas and carbon. Hydro production amounts at 15% but it is mainly concentrated in the North Zone whereas the South Zone shows a productive mix more concentrated on thermal (90.2%) than on hydro (6.2%) with some increasing share of wind production (3.5%). Finally both islands,

---

<sup>2</sup>Data are taken from the last report published by the GME in 2009, “Annual report 2008”.

<sup>3</sup>The liquidity rate is the ratio of the value of electricity traded in the power exchange and the total traded value.

Sardinia and Sicily, show a productive mix more concentrated on thermal technologies: 91.6% in Sicily (of which 69.1 on CCGT) and 91.4% in Sardinia (of which 51.3% from carbon and 38% from CCGT). Hydro production has a low share in both islands but wind production is growing considerably, having attracted new investments in the last years. Figure 1 summarizes the production data for the Italian electricity sector.

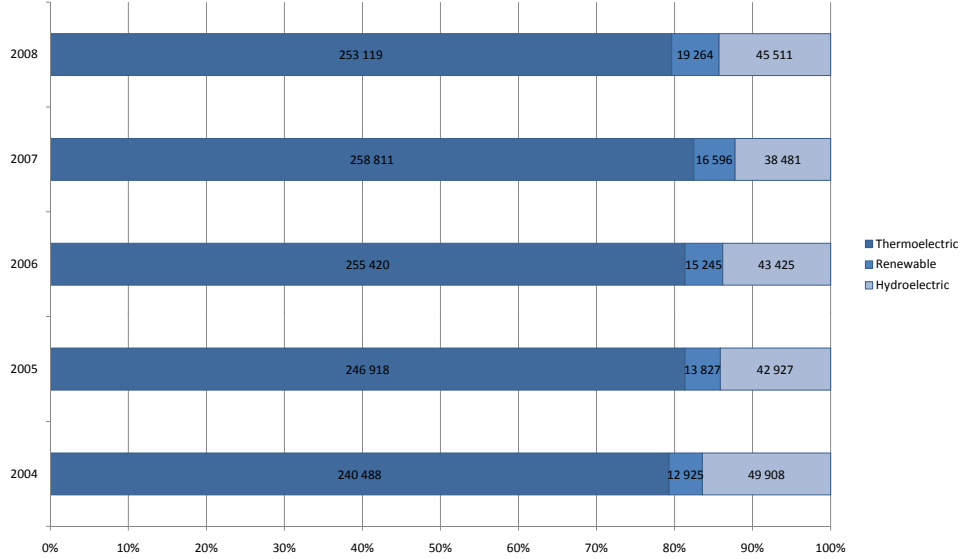


FIGURE 1. Production by font (GWh)

Before liberalization the Italian electricity industry was dominated by a state-owned monopolist (ENEL) that controlled all the stages of activity, from generation to final sale. By the time the sector was opened to competition a portion of generation capacity previously controlled by ENEL has been sold to newcomers with the intention of creating a more levelled playing field. In Figure 2 we present data on market share for years 2007 and 2008.

The increased competition in the IPEX did not have much influence on wholesale prices. On the contrary, electricity prices showed an increasing trend during our sample period. Table 1 reports annual averages for different time slots like peak, off-peak, holidays, etc.

	2008	2007	2006	2005
Total	86.99	70.99	74.75	58.59
Week day	91.06	76.48	81.43	64.98
Peak	114.38	104.90	108.73	87.80
Off peak	67.75	48.06	54.12	42.15
Holidays	77.88	58.58	60.25	44.33

TABLE 1. Mean wholesale electricity prices (Euros)

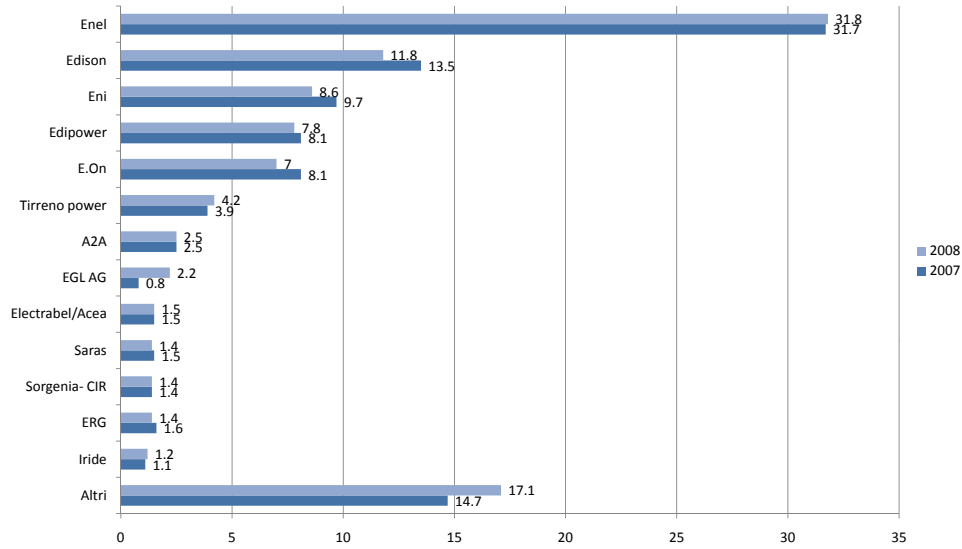


FIGURE 2. Market shares of electricity producers

The comparison between the Italian market and other European markets show that there exists a significant gap between Italian prices and other European prices, as it can be evaluated from Figure 3. We notice that the French and the German markets (Powernext and EEX respectively) generated prices which are very close both in levels and in their dynamics.

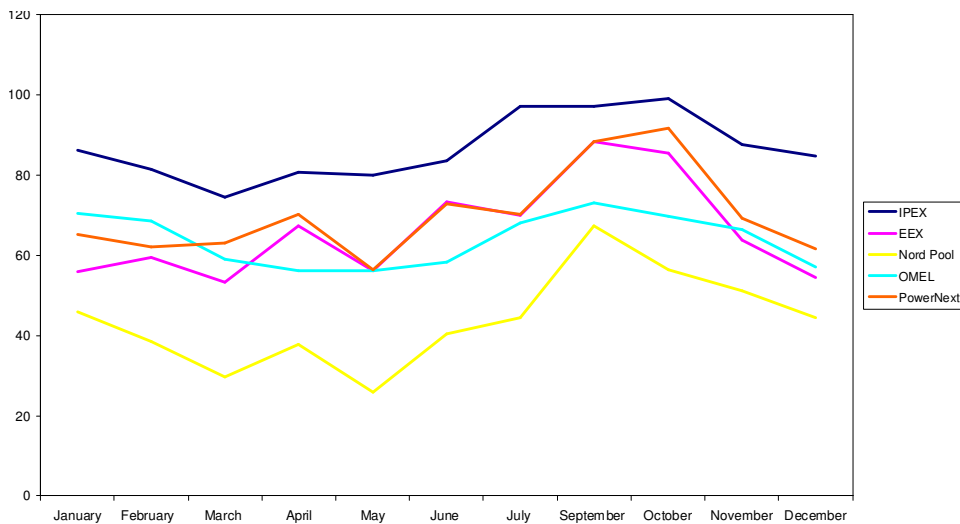


FIGURE 3. European Wholesale Prices 2008

The IPEX is composed by a day-ahead market (MGP), an Infra-day market and an ancillary services market (MSD). MGP operates as a daily competitive market where hourly price-quantity bids are submitted by generators and by buyers. The market operator (GME) orders bids according to a cost reducing merit order for supply and in a willingness to pay order for

demand. The market equilibrium is calculated in the intersection of supply and the demand. The resulting equilibrium price (SMP) is paid to all despatched suppliers. When MGP determines an equilibrium price and a corresponding equilibrium quantity that are compatible with the capacity constraints of the transmission grid – both “nationally” and locally – the wholesale electricity trade is completed. On the contrary, if the volume of the electricity flow determined in the MGP exceeds the physical limits of the grid and in some areas congestions occur, a new determination of zonal prices must be obtained in order to eliminate congestion in those areas. To this end the GME uses the bids submitted at the MGP by the generators located in the congested areas to compute a specific merit order valid for those zones. Then he allows a flow of electricity in and out of those zones within the limits given by the transmission capacity and determines a specific zonal equilibrium.

As a result of the above possible “reopening” of zonal markets the final equilibrium price in these zones might (and frequently does) diverge from that determined in the MGP for the same hour of the day. Therefore, when generators submit a supply bid in the MGP they know that their bid accomplishes – explicitly or implicitly – a twofold scope. On the one hand, the bid determines the position of their plant(s) in the MGP merit order and the quantity of electricity that he should supply at the equilibrium price. On the other hand, the bid might contribute to the definition of a zonal merit order in the geographical area where the generator operates if that area should be congested. This implies that even bids exceeding the MGP equilibrium price might become useful zonal supply bids if demand is high in their zone and there is an outflow of electricity (“export” to other connected zones) priced at the equilibrium price determined in the exporting zone where they operate. Conversely, bids at or below the MGP equilibrium price might not necessarily ensure dispatching to generators located in the importing zones. Summing up, we say that each bidder bids only once (in the MGP market) but that bid is worth twice: is an MGP bid and a potential zonal bid.

Two main considerations are in order. Bidding in the MGP market at a price above the equilibrium does not necessarily imply exclusion from production since some or all of those bidders who have bid above the equilibrium might reenter the game and sell in the zonal market at a zonal price above the MGP equilibrium price. This opportunity is known in advance and may affect the bidding strategy of all those who are active in the MGP market and particularly of those generators that are located nearly frequently congested zones. However, the flow of electricity across zones is limited by the (known) physical capacity of the interconnection and this in turn imposes a (known) ceiling to the quantity that can be exported. To some extent this ceiling imposes a rationing on supply side and limits the number of bidders located in the exporting zones who might be despatched to supply in the importing zones.



## 4. A SIMPLE MODEL

We assume that  $N$  bidders compete in a day-ahead market with hourly bids continuously mapping supplied quantity levels  $q$ , taken from open intervals, into a price codomain  $P_i$ . We indicate the price codomain as  $P = \{p_-, p^+\} = \cup_{\forall i} P_i$ .  $P$  is common knowledge. Before bidding to supply day-ahead power, each bidder has entered a contract arrangement for a quantity  $\bar{Y}_i$  (a private information) to be supplied to some buyer at a predetermined price  $\bar{p}_i \in P$ . Net day-ahead supply on the day-head market is then  $S_i(p, \bar{Y}_i)$ . Each bidder has costs given by  $C_i(q)$ .

Total demand is  $\hat{D}(p) = D(p) + \varepsilon$ , where  $\varepsilon$  is a stochastic shift component. For the moment we assume that there are no potential congestion problems among zones (transmission capacity is very high) and therefore there is a single national market that will have a single national equilibrium price.

Calling  $p^E$  the equilibrium price (uniform price to be paid to all bidders called into operation) one can write the equilibrium condition as follows:

$$\sum_{i=1}^{i=N} S_i(p^E, \bar{Y}_i) = \hat{D}(p^E)$$

and consequently the ex-post profit of each despatched bidder is

$$\pi_i = S_i(p^E, \bar{Y}_i)p^E - C_i(S_i(p^E, \bar{Y}_i)) - \underbrace{(p^E - \bar{p}_i) \bar{Y}_i}_A$$

where  $A \geq 0$  is profit foregone in the auction because of the existing contract price and  $A < 0$  is a profit realized outside the auction (capital gain on a contract). From the perspective of bidder  $i$  the realization of that profit is subjected to two sources of uncertainty:  $\varepsilon$  and  $\bar{Y}_{\forall j \neq i}$ . Following Hortag̃su and Puller (2007) we define a subjective probability measure over the realization of the market clearing price conditional on  $\bar{Y}_i$  and its supply schedule  $\hat{S}_i(p)$  under the assumption that the competitors are playing their equilibrium bid strategies  $S_j(p, \bar{Y}_j) \forall j \neq i \in N$ :

$$\begin{aligned} H^i(p, \hat{S}_i(p); \bar{Y}_i) &\equiv \Pr \left\{ p^E \leq p \mid \bar{Y}_i, \hat{S}_i(p, \bar{Y}_i) \right\} \\ &= \Pr \left\{ \sum_{\forall j \neq i} S_j(p, \bar{Y}_j) + \hat{S}_i(p, \bar{Y}_i) \geq D(p) + \varepsilon \mid \bar{Y}_i, \hat{S}_i(p) \right\} \end{aligned}$$

Calling  $F(., .)$  the joint distribution of  $\varepsilon$  and  $\bar{Y}_{\forall j \neq i}$  conditional on  $\bar{Y}_i$  the above probability is

$$H^i(p, \hat{S}_i(p); \bar{Y}_i) = \int_{\varepsilon \times \bar{Y}_{\forall j \neq i}} \left( S_j(p, \bar{Y}_j) + \hat{S}_i(p, \bar{Y}_i) \geq D(p) + \varepsilon \right) dF(\varepsilon, \bar{Y}_{\forall j \neq i} \mid \bar{Y}_i)$$

Therefore the bidder's problem is

$$(1) \quad \max_{\hat{S}_i(p)} \int_P \left[ p \hat{S}_i(p) - C_i(\hat{S}_i(p)) - (p - \bar{p}_i) \bar{Y}_i \right] dH^i(p, \hat{S}_i(p); \bar{Y}_i)$$

and the optimal  $S_i^*(p)$  is such that.

$$(2) \quad p_i = C_i'(S_i^*(p)) + (S_i^*(p) - \bar{Y}_i) \frac{H_S^i(p, S_i^*(p); \bar{Y}_i)}{H_p^i(p, S_i^*(p); \bar{Y}_i)}$$

The numerator measures the shift in the probability distribution of the market clearing price due to a change in the supply of bidder  $i$  and the denominator is the density of  $H$ . Hortaçsu and Puller (2007) assume that the supply function  $S_i(p, \bar{Y}_i)$ , which indicates the quantity supplied by bidder  $i$  at a price  $p$ , given contract position  $\bar{Y}_i$ , is a continuously increasing differentiable function which is additively separable in its two arguments. In this manner it is possible to derive a manageable expression for the probability ratio in (2), which on the whole becomes:

$$(3) \quad p_i = C'_i(S_i^*(p)) + \frac{(S_i^*(p) - \bar{Y}_i)}{\frac{\partial}{\partial p} \sum_{\forall j \neq i \in N} S_j(p)}$$

where  $\sum_{\forall j \neq i \in N} S_j(p) = RD_i(p)$  is the residual demand facing bidder  $i$ . In what follows  $\frac{\partial}{\partial p} \sum_{\forall j \neq i \in N} S_j(p) \equiv RD'(p)_i$ .

Under the assumption that supplies are additively separable in prices, Hortaçsu and Puller (2007, appendix B) use (3) and information about marginal costs  $C'$  to calculate the (unobserved) contract position of bidder  $i$ , since  $(S_i^*(p) - \bar{Y}_i) = 0$  implies  $p_i = C'_i(S_i^*(p))$ , then  $\bar{Y}_i$  is the level of quantity at which the supply function intersect the marginal cost function. Then, they are able to calculate the ex-post optimal supply function of firm  $i$  and to compare it with the actual supply function submitted.

Our approach on the contrary, uses information about contracts to obtain estimates of marginal costs and the implied Lerner Index of market power like in Wolak (2003).

Let  $Q_i^*(p)$  indicates the quantity net of contracts submitted by firm  $i$  at price  $p$  in equilibrium, then

$$(4) \quad \hat{C}'_i(S_i^*(p)) = p + \frac{Q_i^*(p)}{RD'(p)_i}$$

and

$$(5) \quad \frac{p - \hat{C}'_i(S_i^*(p))}{p} = \frac{1}{\eta_{RD}(p)}$$

From (5) we notice that an estimate of the Lerner Index can be obtained from the elasticity of the residual demand facing bidder  $i$  in the equilibrium. Profit maximizing firms offering in a non perfectly competitive market, we expect  $1 \leq \hat{\eta}_{RD}(p) < \infty$ . If on the contrary at the equilibrium price  $p$  we have  $\hat{\eta}_{RD}(p) < 1$ , then the firm does not maximize profits. This means that, for some reasons, the firm is offering a quantity in excess with respect to the optimal one at a price level lower than the optimal one.

The computation of  $RD_i$  and  $RD'_i$  (which are ex-post step functions with either zero or infinite derivatives) needed for the evaluation of (4) was carried out by using the actual market demand and the quantity supplied by all  $j \neq i$  bidders. Smoothness was obtained by kernel fitting of residual demand data under standard normal distribution assumptions. In Figure 4 we plot the aggregate supply curve, the supply curve of the dominant firm (Enel), the supply curve excluding Enel and the residual demand for Enel together with

their kernel-smoothed versions. The graphs refer to the auction of the 20th May 2008 at 10 o'clock.

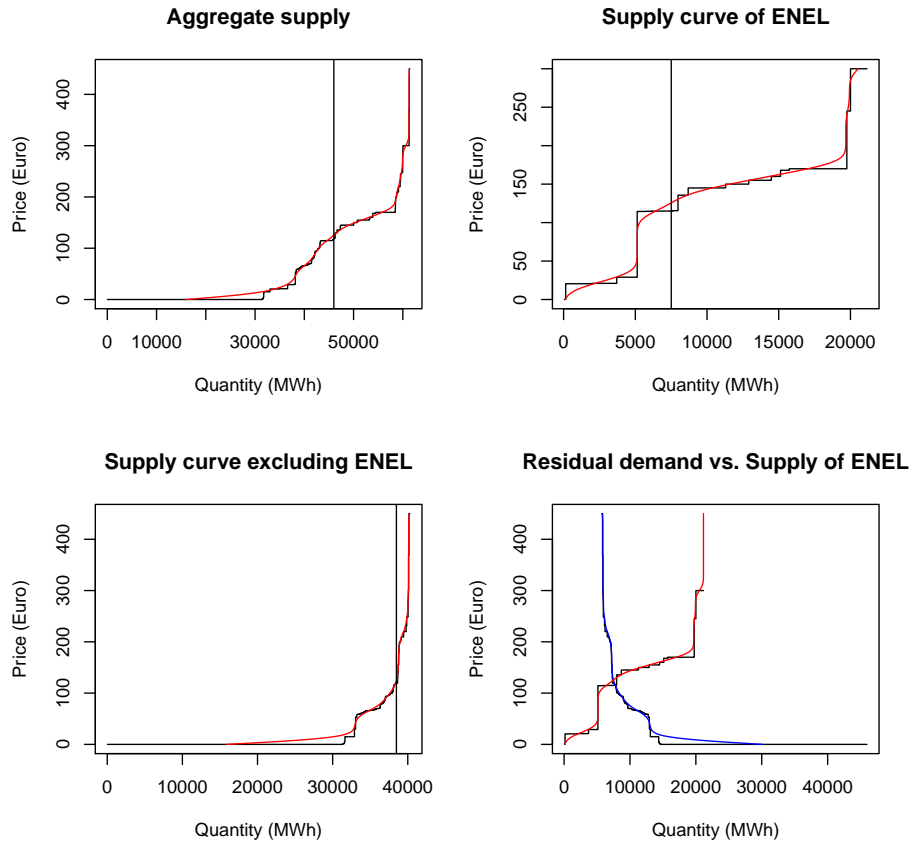


FIGURE 4. Supply functions for ENEL and kernel smoothing on 20th May 2008 at 10.

## 5. MARGINAL COSTS AND LERNER INDEX

Equation (4) has been used to compute marginal costs (Euros per MWh) and Lerner Index for non-dominant firms active in the Italian market from 2005 to 2007. In Figures 5 and 6 we plot as an example marginal costs – June of the years 2005-2007 – against quantity supplied with fitted lines for two non-dominant firms; the first one, AEM, is mainly located in the North of Italy, whereas the second one, Edison, has plants more evenly spread over the entire country. For the latter we also show the scatter plot of data recorded in a regional market (Sicily) using observations recorded when that market was isolated from the MGP market.

Marginal costs curves have positive slopes and fitted values appear realistic. Differences in slopes and positions among the kernel fitted curves reflect differences in fuel expenditure from one year to the next as well as

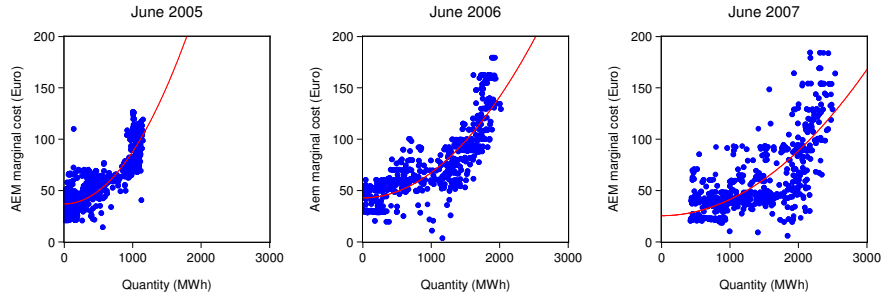


FIGURE 5. Estimated average marginal cost function for AEM

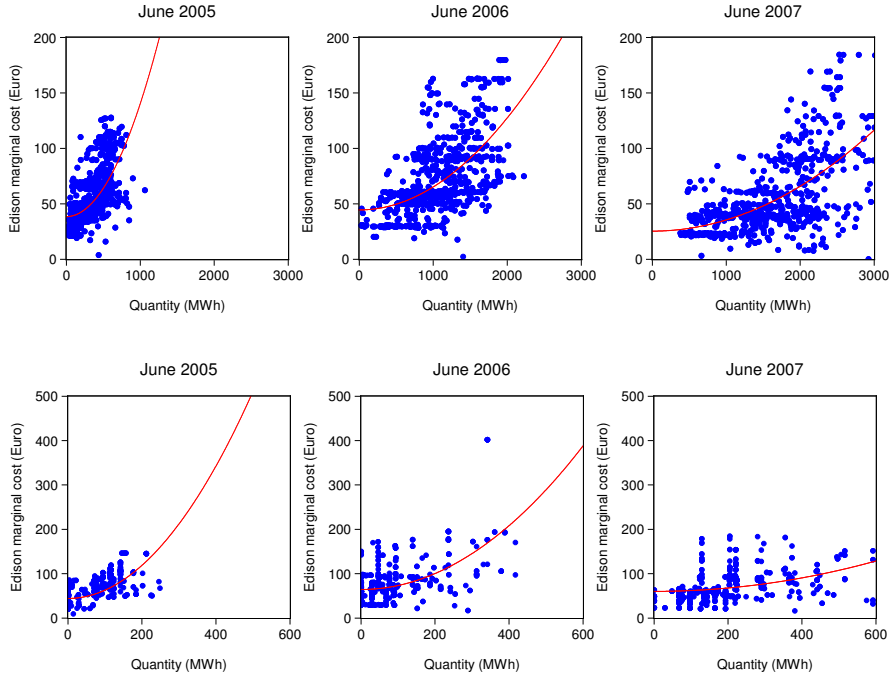


FIGURE 6. Estimated average marginal cost function for Edison for Italy (top) and Sicily (bottom) when it forms a separated market

some technical/organizational/learning progress. Only in one case (Edison in Sicily), fitted values show a tendency towards marginal cost constancy. In general non concavity is the most evident characteristic of the marginal cost behavior we recovered from the Italian market data. A possible explanation for this result when it is referred to non-dominant firms is that these bidders might be including in their figurative costs an opportunity-cost component motivated by the possibility of not being dispatched (e.g. when the dominant does not leave sufficient market shares to them) especially during no peak periods. In other words, bidders apply an high opportunity cost to each produced quantity, particularly to the quantities near the maximum

capacity of their plants. This means that when they bid for those quantities they inflate the pure operational marginal cost (basically the cost of their fuel) of that quantity by this “insurance” component. As a result, even when their plants are not entirely dispatched (i.e. when they do not sell at full capacity) their bids on the dispatched part of their supply already cover the opportunity cost associated to the capacity that remains idle. A similar interpretation is postulated by Wolak (2003, 167) for the Australian case when he interprets the behavior of marginal costs recovered using bid data generated in that market. However, he relates the opportunity costs to hedging activity motivated by the risk of “unit outages” when they have sold a significant amount of forward contracts.

From Figure 6 it is also evident that Edison has rapidly expanded its productive capacity through time.

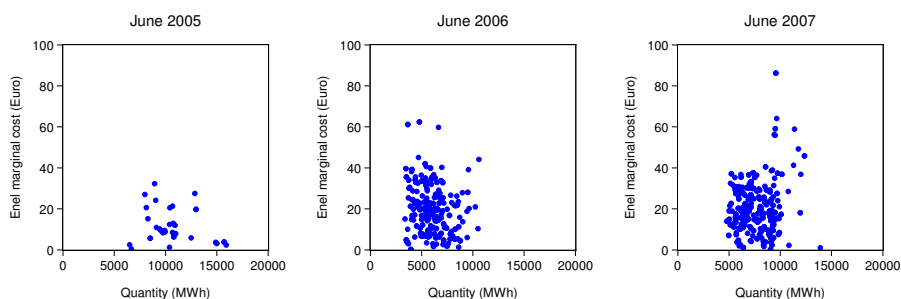


FIGURE 7. Scatter of supplied quantity vs. estimated marginal cost

As for the dominant firm (Enel, Figure 7), the interpretation of results of equation (4) appears more difficult. The use of ex-post actual equilibrium price in (4) implied, given the extremely high value of the numerator of the second term on the right hand side (generally corresponding to a value between a third and half of the entire quantity supplied), that calculated marginal costs result to be negative particularly when the dominant firm was the price setter. In turn this implies that the dominant is somehow restraining its potential market power by bidding below the optimal possible level. When for some reasons the dominant was not the price setter, results are more in line with those reported for non dominants. Calculated marginal costs are positive but scatter plots do not show any reasonable quantity-cost kernel fitting.

In Table 2 we report summary statistics for the estimated Lerner Indexes. For 2008 we report only statistics for Enel and Edison, since in that year AEM merged with ASM forming the new company A2A, while Endesa sold its Italian plants to E.ON.

One can appreciate the enormous differences of mean and median values of the Lerner index between of the dominant (when it was not price setter, see the differences in the number of observations) and the non dominant firms. However, Lerner index of Enel strongly decreases over time whereas non dominants’ indexes modestly increase. Given the above mentioned limited

2005				
	ENEL	EDISON	ENDESA	AEM
Mean	0.786	0.014	0.035	0.011
Median	0.809	0.003	0.011	0.003
Maximum	0.999	0.948	0.996	0.869
Minimum	0.412	0.000	0.000	0.000
Std. Dev.	0.141	0.053	0.082	0.047
Skewness	-0.449	9.876	5.898	9.806
Kurtosis	2.302	124.281	45.585	121.819
2006				
	ENEL	EDISON	ENDESA	AEM
Mean	0.627	0.017	0.027	0.015
Median	0.635	0.003	0.006	0.003
Maximum	0.999	0.986	0.976	0.990
Minimum	0.102	0.000	0.000	0.000
Std. Dev.	0.213	0.066	0.083	0.057
Skewness	-0.133	7.417	5.948	8.079
Kurtosis	2.080	71.011	45.293	89.030
2007				
	ENEL	EDISON	ENDESA	AEM
Mean	0.632	0.060	0.038	0.048
Median	0.632	0.007	0.004	0.004
Maximum	1.000	0.999	0.982	0.987
Minimum	0.141	0.000	0.000	0.000
Std. Dev.	0.212	0.145	0.093	0.116
Skewness	-0.095	3.483	4.282	3.737
Kurtosis	2.015	16.027	26.547	19.674
2008				
	ENEL	EDISON	ENDESA	AEM
Mean	0.564	0.150	.	.
Median	0.544	0.049	.	.
Maximum	1.000	1.000	.	.
Minimum	0.117	0.000	.	.
Std. Dev.	0.213	0.211	.	.
Skewness	0.216	1.978	.	.
Kurtosis	2.044	6.341	.	.

TABLE 2. Descriptive statistics for the Lerner indexes estimated in each auction

number of observations recorded for Enel, however, one cannot interpret these results as a reliable clue of increased competition in the Italian market.

## 6. REGRESSING COST AND EQUILIBRIUM PRICES AGAINST FUEL PRICE

Short run generation marginal costs basically depend on fuel prices, according to the technology of each plant. In this section we test the hypothesis

that producers' costs react to fuel changes less intensively than equilibrium wholesale market prices against the alternative hypothesis that electricity market prices hamper the impact of fuel changes on consumers. Thus, the alternative hypothesis corresponds to the idea that the actual design of electricity auctions guarantees a "smoothed" cost increase pass-through on consumers than any cost-plus form of regulation.

In order to test the above hypotheses we regress cost observations of three non dominant firms – retrieved from previous calculations – against a measure of production activity of each firm (i.e. its residual demand), a 6-month moving average of Brent prices and a time trend. At the same time we use the same independent variables (with total quantity sold that replaces residual demand) against the SMP dependent variable. All the variables are in logarithms. Results are reported in Table 3.

	AEM	EDISON	ENDESA	SMP
log(Quantity)	0.24**	0.24**	0.16**	1.33**
log(Brent 6m-MA)	0.49**	1.63**	0.69**	1.26**
Linear Trend ( $\times 365 \times 24$ )	-0.15**	-0.31**	0.02	-0.13**
...				
R-squared	0.62	0.53	0.63	0.84
S.E. of regression	0.23	0.28	0.23	0.14
Durbin-Watson stat	2.02	2.09	2.06	1.92

\*\* denotes significance at 1% level.

TABLE 3. Regression coefficients for the logarithm of the marginal costs of AEM, Edison and Endesa and for the System Marginal Prices (SMP).

As one can see, in each regression the time trend is negative, probably indicating some improvements in the efficiency and the variable incorporating quantity is always positive and significant. Costs elasticity to residual demand is in range between 16% and 24% whereas the elasticity of SMP to total quantity is almost triple in value. Far higher than the elasticity of the firms' costs to the Brent price is also the elasticity of SMP to Brent price, with an estimated coefficient of 1.26. There is one important exception, however, for a firm has the Brent estimated coefficient equal to 1.63 which is higher than the value estimated in SMP equation. In all, equilibrium prices seem to react to fuel price increase more strongly than (average) generation costs leading one into thinking that the market amplifies rather than hamper any increase of fuel price. This would make consumers less protected with respect to other non-market regulation mechanisms, such as price-cap or pure cost-plus. This evidence can also be explained by observing that the dominant firm (Enel) is the one that fixes the SMP in the majority of the auctions, and, as noted above, this firm does not follow a competitive behaviour in forming its supply function.

Notice, however, that this conclusions are very preliminary and drawn on the basis of results obtained for non-dominant and non price setter firms.

## 7. CONCLUSIONS

In this paper we estimate price-cost margins and Lerner Indexes for big Italian generators competing in the Italian electricity auction during four years (2005-2006-2007-2008) in order to evaluate the existence and the degree of market power in that period. Results indicate that there is an enormous differences of mean and median values of the Lerner index between of the dominant firm and the non dominant competitors. However, Lerner index of dominant decreases over time possibly as a result of tighter regulation and monitoring activity on the part of Italian authorities. We have also evaluated the way in which the dynamics of costs' components (fuel price above all) affect generation costs and final electricity prices. By testing for a possible differential impact of Brent price increase on costs and prices, we tested for the hypothesis that electricity auctions smooth costs increase (i.e. limit the extent to which cost increases are transferred to prices) and then somehow protect consumers from avoidable price increases through the simple force of competition among generators and without direct state intervention. In order to do so we recovered hourly generation cost from supply bids and residual demand and estimate their log-elasticity to Brent price. Results are mixed but on average they indicate that contrary to expectations equilibrium prices over-react to Brent prices and therefore the "smoothing costs attitude" of electricity auctions should be seen with caution.

## REFERENCES

- Athey S., P. A. Haile (2006), Empirical models of auctions, NBER Working Paper Series, 12126
- Ausubel L., P. Cramton (2002), Demand reduction and inefficiency in multi-unit auctions, mimeo, University of Maryland.
- Bosco B. L. Parisio, M. Pelagatti, F. Baldi, (2010), "Long Run Relations in European Electricity Prices", *Journal of Applied Econometrics*, forthcoming.
- Crawford G. S., J. Crespo and H. Tauchen, (2007), Bidding Asymmetries in Multi-unit Auctions: Implications of Bid Function Equilibria in the British Spot Market for Electricity, *International Journal of Industrial Organization*, 25, 1233-1268.
- Garcia-Diaz A, P. L. Marin, (2003) Strategic bidding in electricity pools with short-lived bids: an application to the Spanish market, *International Journal of Industrial Organisation*, 21, 201-222.
- Guerre E., I. Perrigne, Q. Vuong (2000), Optimal non-parametric estimation of first price auctions, *Econometrica*, 68, 3, p. 525-574
- Hortaçsu A. and S. L. Puller (2008), Understanding strategic bidding in multi-unit auctions: a case of the Texas electricity market, *Rand Journal of Economics*, 39, 1, 86-114.
- Kühn K. and M. Machado (2004), Bilateral market power and vertical integration in the Spanish electricity spot market, CEPR Discussion paper 4590, [www.cepr.org/pubs/DP4590.asp](http://www.cepr.org/pubs/DP4590.asp).
- Fabra N., von der Fehr N.-H., Harbord D. (2006), Designing electricity auctions. *Rand Journal of Economics*, 37, 23-46
- Fehr N.-H. von der, D. Harbor, (1993), Spot market competition in the UK electricity industry, *The Economic Journal*, 103, 531-546.
- Parisio L. and B. Bosco (2003), Market Power and the Power Market: Multi-Unit Bidding and (In)Efficiency in Electricity Auctions, *International Tax and Public Finance*, 10, 377- 401.



- Parisio L. and B. Bosco (2008), Electricity prices and cross-border trade: Volume and strategy effects, *Energy Economics*, 30, 1760–1775.
- Wolak F. A. (2003), Identification and estimation of cost functions using observed bid data: an application to electricity markets, in M. Dewatripont, L. P. Hansen, and S. J. Turnovsky, eds., *Advances in economics and econometrics: theory and applications*, Eighth World Congress, Volume II, New York: Cambridge University Press, 133-169.
- Wilson R.B. (1979), Auctions of shares, *Quarterly Journal of Economics*, 93, 675-689.
- Wolfram C. D., (1999), Measuring Duopoly Power in the British Electricity Spot Market, *The American Economic Review*, 89(4), 805-826.