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MIncreasing Market Interconnection: an analysis of the Italian Electricity Spot Market

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Abstract

We estimate the benefits resulting from completely interconnecting the Italian electricity spot market. The market is currently divided into two geographic zones - North and South - with limited interzonal transmission capacity that often induces congestion, and hence potential inefficiency. By simulating a fully interconnected market for May 2004, we predict that the total spot market expenditure reduces substantially by almost four percent. Our analysis finds evidence that the (partly State owned) major firm in the market does not currently maximize its short-term profit, and would benefit as well from improved interconnection.

JEL classification: H44, L21, L22, L38.
Keywords: Transmission constraints, zonal pricing, congestion, self-regulated monopoly. .

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1 Introduction

In the Lisbon agenda, in March 2002, the European Union recognized market integration - both within and across its member countries - as a prerequisite for sustained economic growth. In this paper, we quantify the expenditure reduction that results from one such interconnection: the case of the Italian electricity spot market. Specifically, our paper has two aims. First, we characterize the objective function of a pivotal electricity generator in a *semi-regulated* environment with mixed ownership structure: the Italian treasury and private investors. And second, we estimate the expenditure reduction in the spot market – in the form of lower electricity prices primarily due to more efficient utilization of existing generation capacity.

€The Italian electricity market is a good example to consider benefit due to improved market interconnection. At present, there is a hot debate in Italy regarding infrastructural enhancements, primary among which is the discussion on the electricity transmission network. While the proponents of such venture argue that an improved network would reduce prices substantially, its opponents claim that it would lead to environmental damages without bringing about any significant benefits for the end-users[1]. To our knowledge, there is no scientific attempt on either side to quantify either costs or benefits. Our study estimates the benefits of complete interconnection.

Moreover, the structure of the Italian electricity spot market is particularly suitable for the analysis. Currently, the market is divided into several zones, with the amount of electricity that can flow across zones being limited due to insufficient transmission capacity. Generators, with varying degrees of efficiency and capacity, are located in each zone. While a no arbitrage condition ensures that the market clearing price is the same across all zones when the transmission capacity is not fully saturated, zonal prices differ when it is. One way to eliminate this price difference is to invest in inter-zonal transmission capacity. Therefore the question addressed in our paper can be restated as the following: what is the change in the expenditure of the Italian economy on the spot market electricity, after sufficient inter-zonal transmission capacity is installed such that the price difference between zones is completely eliminated?

We consider lower electricity prices as an indication of more efficient market, in spite of the short-run demand being inelastic (and hence overall welfare

[1]See, among others, Il Sole 24 Ore, October 7th, 2007 at www.ilsole24ore.it.

is invariant to price changes). Elasticity is larger in the medium and long-run than in the short-run. Furthermore, according to the conventional wisdom, higher prices have a negative impact on economic growth (see, for example, OECD 2006).

Expenditure reductions from interconnection are computed based on a behavioral assumption on the dominant player in the market, Enel. A natural assumption of market leader being a short-run profit maximizer need not be an appropriate one in the Italian case for a variety of reasons. First, Enel is partly State-owned. Second, electricity is a necessary good, and hence the fear of regulatory interventions is strong if there is an evidence of exploitation of market power. Finally, there is a potential chance of entry if short-run profits were too high. Therefore we assume that Enel's objective function has two portions. The first one is the short-run profit maximization and the second one is the minimization of consumers' expenditure. While the former represents the short-run interest of Enel's private investors, the latter is a proxy both for Enel's long run profit considerations (prevention of regulatory retaliation and entry), as well as the public ownership incentives (end-users' welfare).

We identify the relative weights of these two contrasting objectives empirically. We find that Enel places a weight of 0.64 on its profits and 0.36 on consumers' expenditure. Under the assumption that the weights in the objective function of Enel do not change due to interconnection, we find that easing bottlenecks would result in a saving of just over six million euros to the end-users of electricity in the month of May 2004, the sample period considered here. Maintaining that May is a representative month, this amounts to about seventy million euros. These savings account for almost four percent of overall spot market expenditures in the corresponding time period. Because we do not have complete data on the cost of providing additional transmission capacity, we characterize the gains alone. Therefore, the policy recommendation of our paper is to invest in inter-zonal transmission capacity if the annualized cost is less than seventy million euros.

Our model further suggests that improved interconnection benefits Enel. Enel's cost of generating electricity reduces by about five million Euros in May 2004, possibly due to the observed substantial reallocation among various Enel's generating units[2]. Moreover, this reallocation, which results in

[2]As discussed in the subsequent section, Enel's generating plants in the North are substantially more efficient than those in the South; thus, improved interconnection results

productive efficiency, increases Enel's profit by around one million euros. Since Enel's market share remains constant, this observation suggests that a large portion of the cost reductions is passed on to the end-users, in the form of price reductions. This may be due to the particular nature of Enel's objective function.

One issue we ignore is the question of optimal price differential. It is possible that the total welfare gain (net of costs of increasing transfer capacity) might be maximized at a point where prices are not always uniform across zones. Due to the fixed costs involved in increasing transmission capacity, a policy maker is likely to install *sufficient* transmission capacity so that the problem of inadequate interconnection does not recur in the near future. Moreover, since the overall net benefit would only increase barring such an assumption, any cost – benefit analysis based on the gains predicted here is in this respect conservative. We also do not consider the ownership of the transmission network and assume that the entire transmission network is under the control of a public authority.[3]

The industrial organization literature is rich in studies that investigate various nuances of (de)regulation in electricity markets. In a theoretical study, Borenstein, Bushnell and Stoft (2000) (BBS) show that a small investment in transmission capacity can substantially improve welfare. In their analysis of Norwegian electricity markets, Johnsen, Verma and Wolfram (2004) find that when the transmission capacity across zones binds, generators can more readily exercise market power. The main objective of our paper is to estimate the loss associated with this congestion.

Market imperfections - in the sense of market price distortion (away from the first best) - are well studied in the literature. The empirical literature suggests that there is little correlation between market concentration and the degree of market power exercised by electricity generators. For example, Wolfram (1999) shows that the mark ups in England and Wales electricity spot market in the early 1990s were lower than those resulting from a Cournot duopoly model. Sweeting (2006) shows that, in the second half of 1990s, firms in the English electricity market exercised significant market power *"in spite of decreasing market concentration"*. Borenstein, Bushnell and Wolak

in increased participation of Enel's Northern plants, thereby reducing overall costs for Enel.

[3] In 2004, private investment in transmission network was banned in Italy. See Joskow and Tirole (2005a) for arguments against and Harvey, Hogan and Pope (1997) for arguments in favor of merchant transmission.

(2002) find that, in 2002, the presence of market power doubled the wholesale electricity price. Hortacsu and Puller (2004) show that large generators' bids in the Texas market support the assumption of profit maximization. In this paper, we show that Enel does not exercise the fullest extent of its market power.

The organization of the rest of the paper is as follows. Section two describes the Italian electricity spot market. In the third section we present our theoretical model. Section four discusses our dataset and presents some summary statistics. In section five we present our results along with counterfactual simulations. Section six concludes.

2 The Italian Electricity Spot Market

2.1 Market Organization[4]

In 2004, Italian national electricity consumption was around 322 terawatt Hours (TWh), an increase of about 0.4% from the previous year. Hydrocarbons (coal, oil and natural gas) accounted for around seventy five percent of overall installed generation capacity. Hydroelectric power plants accounted for around twenty five percent and other bio-friendly generation plants (wind, photovoltaic, etc) accounted for less than 0.5% of the total production. Electricity prices are high in Italy relative to the rest of the European Union. In the summer of 2005, prices in Italy were close to 14 eurocents per KWh whereas the corresponding figures in the other European Union nations were between 8 and 12 eurocents per KWh. Nuclear energy has been banned in Italy since 1988[5]. This ban, combined with a lack of any substantial competition, is often blamed for Italy's high electricity prices.

The spot market is designed to cater to the needs of the residential sector and all the industrial customers that do not sign individual contracts. It also acts as a buffer for any unanticipated short-term shocks to the demand. This spot market operates on an hourly basis. There are two types of consumers: the residential sector and the industrial sector.

The residential sector is supplied through an intermediary (single buyer),

[4] The market structure described here is relevant for the sample period (May 2004). In some cases market rules have changed since then.

[5] Roughly 60% and 15% of electricity consumption in France and Germany, respectively, is produced by nuclear power plants. *(Source:* Brookings Institution: http://www.brook.edu/fp/cuse/analysis/nuclear.htm).

Table 2.1:?

	Gross			Net			available
	Producers	Autoproducers	Total	Producers	Autoproducers	Total	peak capacity
MW							**2004**
hydroelectric	20.862.1	210.5	21,072.6	20,538.6	205.6	20,744.1	13,550[1]
thermal	57,352.5	4,859.9	62,212.5	54,981.3	4,651.1	59,632.4	38,950[2]
conventional	*56,671.5*	*4,859.9*	*61,531.5*	*54,339.3*	*4,651.1*	*58,990.4*	*38,400*
geothermal	*681.0*	*0.0*	*681.0*	*642.0*	*0.0*	*642.0*	*550*
wind & photovoltaic	1,137.1	1.5	1,138.6	1,133.5	1.5	1,135.0	250[3]
total	**79,351.7**	**5,072.0**	**84,423.7**	**76,653.3**	**4,858.2**	**81,511.5**	**52,750**

1 The unavailability from hydro power plants is to be chiefly ascribed to hydrological causes (systematically occurring in the Winter period), as well as to faults and external causes. The net maximum capacity is the maximum value that is reached under conditions of maximum water flows. Since water supply is scarce in Winter with respect to other periods of the year, in-service hydro plants deliver a net capacity that is much lower than the maximum capacity.

2 The unavailability from thermal power plants is to be mainly attributed to:
- unplanned average unavailability of plants used for electricity production only;
- long outages, repowering projects, lack of authorisations for plants used for electricity generation only and for co-generation plants (the latter value also includes seasonal co-generation plants, such as sugar factories that typically operate in late Spring).

3 The production of these plants depends on a primary source whose availability is highly discontinuous. Consequently, available peak-load capacity is usually taken to be equal to 25% of installed capacity.

Source: "Power Plants" (a part of Statistical Data – 2004 published by the Italian electricity market operator)

who operates via the spot market. It accounted for more than 95% of overall spot market quantity. Residential consumers pay a tariff set by the Italian electricity regulator (AEEG), fixed throughout Italy irrespective of zone, and subject to a quarterly review[6]. Industrial spot market customers pay a weighted average of previous month's spot market clearing prices, where weights are given by overall spot market quantity consumed. Therefore the spot market demand can be safely regarded as independent of that day's spot market clearing prices. Hence, it is fixed for spot market considerations.

For generators, nodal pricing is in place. That is, generators participating in the spot market receive the market clearing price of the zone in which they are located. The market operator (MO) solicits bids from all generators each hour every day. A typical bid submitted by a generator consists of at most fourteen price-quantity combinations. A price-quantity combination is a commitment from the generator of the amount of electricity he is willing to supply at that price. The Transmission System Operator (TSO) announces the maximum amount of electricity that can be transferred across zones, which depends on several engineering criteria. The transmission lines need

[6]The Electricity price paid by the residential sector is a politically sensitive issue. Therefore, though in principle it is supposed to be set as a weighted average of all the spot market clearing prices (with weights being quantities consumed), several considerations play a role during the review.

to undergo regular maintenance operations, thereby frequently cramp the maximum amount of electricity that can flow across zones. As a result, transmission capacity is subject to wide fluctuations across various hours, even within a single day.

Given the location of the bidding generators, their supply curves, the transmission constraint set by the TSO and the forecast demand in each zone, the MO solves the *problem of optimal dispatch*, whose objective is to minimize total expenditure on electricity in the spot market for a given electricity usage. The MO then determines the market clearing price and quantities in each zone. All generators whose submitted bids are below the market clearing price are invited to generate the quantities they committed to in their bids.

The organization of bilateral contracts is straightforward. Contracting parties negotiate a mutually agreeable price-quantity schedule. These contracts are private information (to the generator). For the reasons explained in the subsequent sections (section 4), we concentrate only on the spot market. Therefore in the rest of the analysis, the word market refers to the spot market alone.

2.2 Zonal Structure

Geographically, the Italian electricity market is divided into several zones. Each zone identifies a geographical area within which the grid is *almost perfect* in the sense that congestion is rarely observed. The regulator defines these zones and makes frequent changes to the geographical boundaries of a zone either by joining two zones or by separating an existing zone depending on the amount of observed congestion. In 2004, there were seven large zones, [7] five of which are in Continental Italy (North, Center-North, Center-South, South and Calabria) and the remaining two zones are the islands of Sardinia and Sicily.

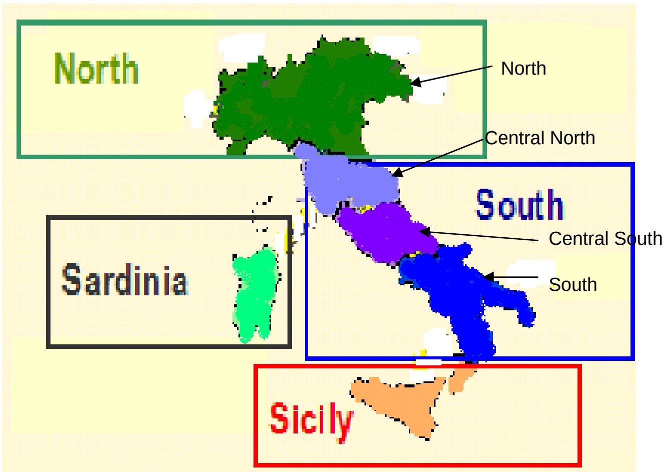
In 2004, the most critical bottleneck occurred between North and Center-North (separated 48% of all hours) [8]. There was another bottleneck between the zones of South and Calabria with the markets being separated for more

[7] Other small zones existed in 2004. Given their limited size, they are not relevant for our analysis.

[8] This 48% is for the entire year of 2004 and also includes weekends where the markets were seldom separated.

than 25% of the times, but for the reasons described in the data section, we ignore this bottleneck. Center-North and Center-South were seldom separated (around 4% of the hours). Center-South and South were never separated in 2004. Figure 2.1 better illustrates the zonal structure of the market:

Figure 2.1: Zonal Structure in the Italian Electricity Spot Market



Source: (edited from) www.mercatoelettrico.org

3 The Model

3.1 Model Description

We represent the two zones in the market, North and South, by letters n and s respectively. A *Market Operator (MO)* coordinates the actions of the two zones, and demand and supply conditions in the overall market. A monopsonist acts as an intermediary between generators and end-users. He buys electricity in the spot market and sells it at a predetermined and exogenous price. At that exogenously determined price, the *monopsonist* is obliged to supply whatever quantity is demanded by end-users in both the zones. The monopsonist's demand for electricity in the spot market is equal to the total fixed demand by the end-users.

On the supply side, the structure is similar in both zones. In each zone, there is a dominant firm, Enel, characterized by a substantial market power.

Besides, there exists a competitive fringe in each zone, comprising several small firms that supply their entire capacity whenever the market clearing price is above their marginal cost of production. The assumption on the timing of the game is as follows: every hour, the *Market Operator* predicts the quantity demanded in the retail market and announces the same in the spot market. There is an exogenously set transmission constraint, known to all suppliers. This constraint defines the maximum amount of electricity that can be transferred across zones in the market [9]. The firms then place their bids consisting of price – quantity combinations. Based on the location of demand, the location of generators, along with the transfer constraint, the regulator computes the most efficient electricity network that minimizes society's total cost, according to the *optimal dispatch* algorithm explained in the previous section.

3.2 Behavior of Firms

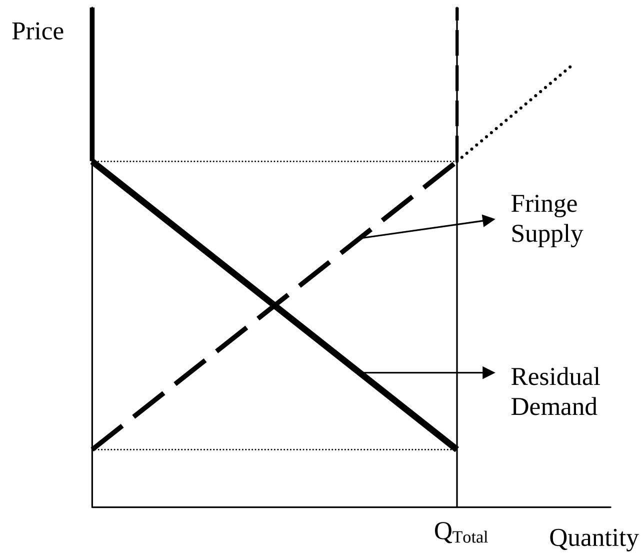
The competitive fringe consists of several firms, each of which in turn comprises several plants with varying efficiency levels. We assume that these plants produce their entire capacity whenever the price is above marginal cost. The dominant firm, Enel, is assumed to act based on the residual demand. We assume that Enel estimates its own demand function in the following way: it estimates the supply curve of the fringe and subtracts it from the fixed demand in each zone, thereby calculating its downward sloping demand. This idea is illustrated in Figure 3.1.

As the spot market price increases, more fringe generators find it profitable to employ (weakly) more plants for electricity generation because the price exceeds their marginal cost. Hence the supply curve of the fringe is upward sloping, as represented by the thick dotted line in Figure 3.1. The thin vertical line at Q_{Total} represents the total electricity demanded by the monopsonist (equal to the total demand by end-users in the spot market). The residual demand curve, obtained by subtracting the dotted line from the fixed demand, is represented by the thick downward sloping line in the picture.

For every hour every plant submits a menu of price-quantity combinations (a supply curve). In order to characterize the supply function of the fringe,

[9] We assume that the transfer is from North to South only. In the data, electricity never flowed to the North.

Figure 3.1: Derivation of a Hypothetical Demand Curve for Enel



we estimate the following equation for every hour for every zone. Quantity supplied in bid b at price p on day d for a given zone at a given hour is given by:

$$q_{bd} = \gamma + \beta p_{bd} + \theta_d + \varepsilon_{bd} \tag{1}$$

θ_d indicates day fixed effects. The parameter we are interested in is beta. The additive inverse of parameter beta is the slope of the residual demand function faced by Enel. We estimate Equation (1) using ordinary least squares, and day fixed effects. As there are several factors that could influence the fringe firms' bids on a given day, it is likely that the bidding pattern of the fringe firms is different across days. Any supply function estimation that does not take into account such differences – as in the case of OLS estimation - is likely to create a bias in the estimates of the slope parameters. Therefore, these differences necessitate us to use day fixed effects that implicitly take into account these daily changes.

The functional form chosen for the supply curve is linear. Though it simplifies computations, and guarantees the existence of a unique equilibrium, the assumption of linearity is restrictive. Not withstanding its limitations, it is common in the electricity literature[10]. It is also well known that the

[10]See, for example, Green and Newbery (1992), Bolle (1992) and Hogan and Baldick (2003)

linearity assumption is susceptible to bias from extreme observations, the treatment of which is presented in the subsequent analysis.

After estimating $\beta_h$each hour, we can characterize the supply function of the fringe for every hour in every zone. The supply function of the total fringe for hour $h$and zone z for day $d$is of the following form:

$$Q^f_{h,z,d} = \zeta_{h,z,d} + \beta_{h,z} p_{h,z,d} \tag{2}$$

Here $\zeta$is the sum of the constant term, the day fixed effect and the idiosyncratic error. While the slope of the realized fringe's supply curve (β) is point identified, the intercept (ζ) is identified only up to an error term.

3.3 Behavior of Enel

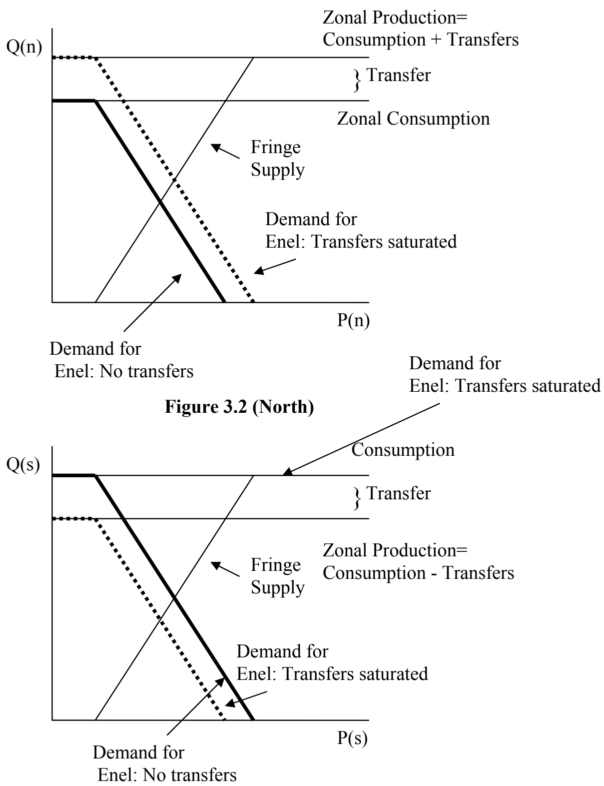
We assume that Enel is aware of the supply of the fringe up to an error term. After having previously observed the fringe's behavior over several periods, it is not unreasonable to assume that Enel could estimate (1). Moreover, by assumption, the cost structure of various firms that comprise the fringe is known to Enel. The presence of uncertainty occurs for a couple of reasons. First, the presence of the bilateral contracts market coupled with increasing marginal costs. A firm's commitment in the bilateral contract market is private information. As marginal costs are assumed to be weakly increasing (step functions), it is not necessarily clear to Enel as to what the market clearing price ought to be to induce market participation by a given firm. In a typical bilateral contract, the variables that are contracted upon are price(s), and a range of quantities. Second, every firm in the fringe is composed of several small generating plants with varying degrees of efficiency. These plants need to be shut-down occasionally for maintenance reasons. Enel's guess of these shut-downs might not be accurate.

As previously mentioned, we assume that the electricity only flows from North to South[11].

We now characterize the demand faced by Enel when there is limited interconnection between the markets. We call this regime **(C)**. Say the maximum transfer capacity for hour$h$ and day d is given by $T_{d,h}$. This demand function can be seen clearly in Figures 3.2 and 3.3.

[11] The rationale behind such assumption is two-fold. First, electricity flowing from South to North is never recorded and second, North has more efficient generators than that of South.

Figure 3.2: Demand Function for Enel (North and South)



As we know the slope of the demand curve (from estimating Equation 1) and the realized price and quantity for every hour (a point on the demand curve), we can identify the realized demand for the hour.

In the case where market is unified, denoted by the regime **(UC)**, we assume that Enel is still the residual demand monopolist, albeit now for the combined demand. Also, we have separate fringes participating in the market. Total fringe supply is the summation (across quantities) of both the fringes. Figure 3.3 depicts the summation of the two fringe supplies.

As already mentioned, due to a host of reasons, Enel does not behave like a profit-maximizing monopolist. Therefore the next task is to characterize the objective function of Enel.

Figure 3.3: Summation of Fringe Supply Functions in the Unified Market

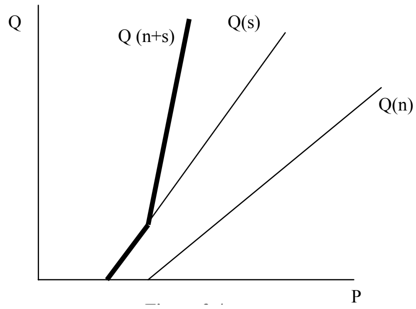
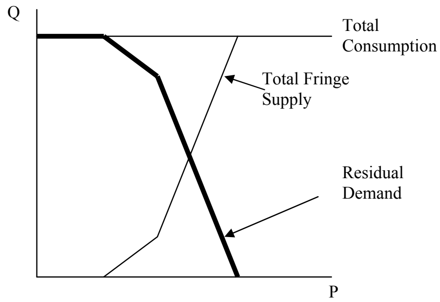


Figure 3.4: Deriving the Demand for Enel in the Unified Market



3.4 Objective Function of Enel

As Enel's stock is held jointly by the Italian Treasury (around 40%) as well as private investors (the remainder), we assume that the objective function of Enel is a convex combination of public incentive and profits. As the demand is inelastic, the consumer surplus theoretically is infinite. Therefore we measure the change in consumer surplus by the change in the total expenditure on electricity. Let α be the weight given to the profits. Then, the objective function of Enel for a given hour$h$can be written as:

$$\max_{P_{n,h},P_{s,h}} \sum_{z=n,s} \left[\alpha_{z,h}\left(P_{z,h}Q_{z,h} - C\left(Q_{z,h}\right)\right) + \left(1-\alpha_{z,h}\right)\left(-P_{z,h}Q_{z,h}^{spot}\right)\right] \ (*)$$

Q_z^{spot}represents the overall quantity consumed in the spot market in zone z and Q_z is the overall spot market production in zone z. The first part of the objective function, whose weight is α, is a standard profit function, while the second part, whose weight is $1-\alpha$, is the *optimal-dispatch* algorithm (the goal of the market operator).

The weight on profit, α, can be computed by equating the predicted prices from (*) with the observed prices in the market. More precisely,

$$z \in \{N, S\}\, \alpha_z = \frac{Q_z^{spot}}{Q_z^{spot} + p_z \frac{\partial Q_z}{\partial p_z} + Q_z - C'(Q_z)\frac{\partial Q_z}{\partial p_z}}$$

We assume α to be different for different periods and different zones. We advance two arguments to justify the assumption onα. The first justification relates to dynamic considerations. In a dynamic setup, Enel could potentially considerα to be a variable, instead of a parameter. That is, by varying α strategically, one could construct a situation where a better result for the end-users can be achieved, while Enel's profits over the time horizon considered are the same (as in uniform α). The second relates to regulatory retaliation. Huge fluctuations across zones and across hours can be perceived as an undue exploitation of market power that could lead to the market regulator imposing a stricter regulatory regime in the market, a scenario not in the best interests of Enel in the long run.

The results presented in Section 5 show that the computed α does not vary much across hours since the standard deviation is only 0.04. They also show that the correlation between α and the elasticity of demand faced by Enel is -0.21. That is, as the demand faced by Enel becomes more inelastic, the weight placed by Enel on profits (α) decreases. We provide further details on α in section 5.

3.5 Evaluating Counterfactual

To estimate the gains from interconnection, we need to estimate the prices in the integrated market. For evaluating the counterfactual, we make the following assumptions. As a result of improving the transmission network: a) the behavior of the fringe does not change, and b) the objective function of Enel does not change. We compute α in the integrated market as the weighted average of α_n and α_s.

$$\alpha = \frac{\alpha_n \overline{Q}_n + \alpha_s \overline{Q}_s}{\overline{Q}_n + \overline{Q}_s}$$

Therefore the objective function in the integrated market is given by:

$$\max_P \alpha \left[P\left(Q_n(P) + Q_s(P)\right) - C\left(Q_n + Q_s\right)\right] - (1-\alpha)\, P\left(Q_n^{spot} + Q_s^{spot}\right) \text{ (**)}$$

We provide a step by step analysis of the empirical methodology in the appendix.

4 Data

4.1 Data Sources

The Italian electricity market data are collected from two sources. The primary one is the Italian Electricity Market Website[12]. The market operator releases information on all bids submitted on this website one year from the time of market participation for all parties concerned. The information for each bid, plant and hour consists mainly of the price-quantity pair, whether or not the bid has been accepted, and whether or not it has been cancelled. The Website also reports the hourly zonal equilibrium price and quantity combinations. From these, we compute hourly price differences in the market, and identify the congested hours as those where prices differ across zones.

After the bids are submitted, some of them can be cancelled by either the firms or the Market Operator on the grounds of technical incompatibility. These bids are removed from the dataset. From the information on bids, it is straightforward to build the actual bid supply function for the entire fringe for every hour and day by aggregating the total quantity bid by every firm at a given price. This enables us to estimate the supply function of the fringe firms for every hour separately.

The data on estimated marginal costs of all thermo-electric (coal, oil or natural gas based) generating plants is provided by *Researches for Economics and Finance* (REF).

4.2 Aggregation of Zones

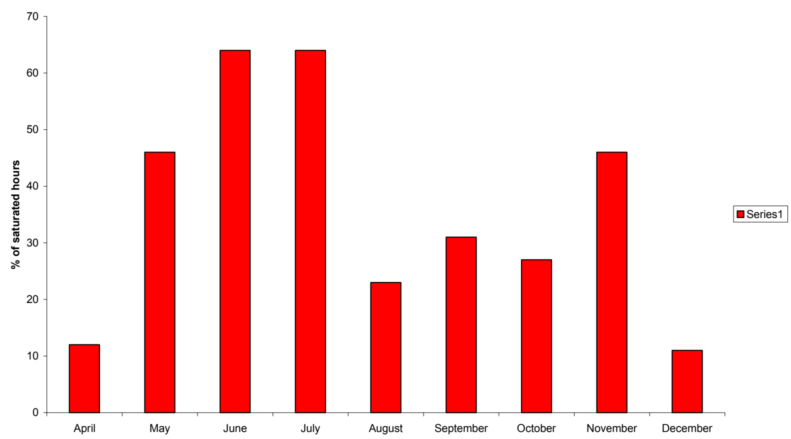
As previously mentioned, the Italian electricity market is divided into seven large zones: North, Center-North, Center-South, South, Calabria, Sicily and Sardinia. We ignore the islands of Sicily and Sardinia for the analysis because they could be regarded as almost separate markets at the time of the analysis. For computational convenience, we further combine the remaining four zones into two zones, *North* and *South*, based on geographical proximity and frequency of bottleneck occurrences. The North zone consists of just the North, while the South zone consists of Center-North, Center-South and South.

[12]http://www.mercatoelettrico.org/GmeWebInglese/Default.aspx

4.3 Choice of Time Period

Our analysis focuses on the month of May 2004. The choice of the month is due to the fact that saturation in transmission capacity occurs in May for 46% of the hours, a figure very close to the average value for the year 2004, that is 48%. Therefore, May could be regarded as a representative month in terms of transmission line saturation. Graph 4.1 shows the frequency of saturation of the North-South transmission line across months in 2004.

Graph 4.1: Frequency of Saturation of the Transmission Line Across Months in 2004



Source: Calculated from the data in the Italian Electricity Market website (http://mercatoelettrico.org)

Out of the thirty one days in May 2004, weekends account for ten days. We ignore weekends for the purposes of this paper because the demand is generally low, and hence the supply pattern of the fringe could be different. Moreover, the transmission constraint does not bind and hence prices are the same across zones. This information is summarized in Table 4.1:

On average the highest price difference occurred in hour 22 (9 P.M. to 10 P.M.) while the least amount of price disparity occurred in hour 5 (4 A.M. to 5 A.M.). Sample characteristics are summarized in graphs 4.1 and 4.2 for each zone separately.

Table 4.1: Sample Characteristics

Total Days	31	Weekend Days	10	Weekdays*	21
Total Hours Considered	504	Hours where Prices are the same	195	Hours where Prices differ	309

* No other holidays in this month

Source: Calculated from the data in the Italian Electricity Market website (http://mercatoelettrico.org)

4.4 Analysis of Bids

To estimate the supply curve of the fringe, we consider all the bids presented by generators other than Enel, assuming that Enel acts as a residual demand monopolist. The reason for this assumption is clear by looking at Table 4.2 and Graphs 4.4-4.6, which show that Enel had significant market power in May 2004. In all of Italy, Enel had close to 60% of the capacity. Ignoring the zones of Sicily and Sardinia, the share is much higher.?

Table 4.2: Fringe's Share of Production

Max	0.58	**Min**	0.05
Median	0.31	**First Quartile**	0.22
Third Quartile	0.39		
# of firms in fringe	13		

Source: Calculated from the data in the Italian Electricity Market website (http://mercatoelettrico.org)

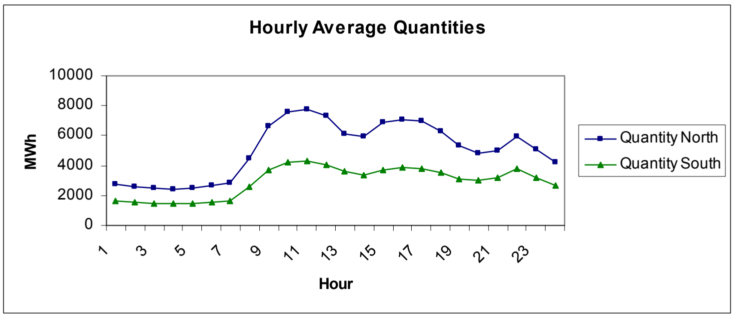
The admissible price set ranges from zero (negative bids are not allowed) to 500 euros per megawatt hour (price cap). During certain hours, generators may have an incentive to bid a price of zero for strictly positive quantities. This zero price bid ensures that the generator would be asked to produce in equilibrium. At the same time, the generator receives the market clearing price. By assumption, a fringe generator is not powerful enough to unilaterally influence market clearing prices. Therefore when a generator bids a zero price for a strictly positive quantity, he merely ensures spot market participation and actually obtains a strictly positive price. If a generator has substantial commitments in the contract markets for the next hour with none at a given hour, he might find it optimal to ensure spot market participation

Graph 4.2: Average Hourly Price Difference
(Price in the South - Price in the North)

Source: Calculated from the data in the Italian Electricity Market website
(http://mercatoelettrico.org)

Note: Calculated for 21 days in May 2004

Graph 4.3: Zonal Average Hourly Quantities



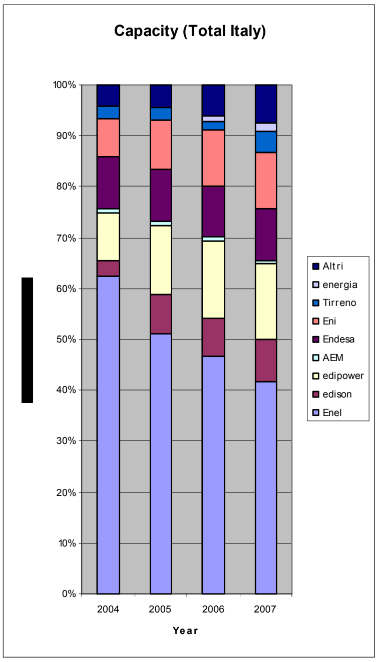
Source: Calculated from the data in the Italian Electricity Market website
(http://mercatoelettrico.org)

Note: Calculated for 21 days in May 2004

in that hour. Significant startup costs suggest that switching the plant is not an economically viable option in such circumstances. From some informal discussions with a few fringe generators, it was evident that they have a fairly good idea of the interval in which market clearing price will be realized.

According to the model we proposed, this estimated supply function of the fringe reflects Enel's belief about the fringe firms' behavior. Considering such extreme bids would bias the estimate ofβ.Therefore, to avoid such situation, we took the maximum and minimum market clearing price for every hour and constructed a "*reasonable price*" interval for every hour separately. The lower bound of the interval was 25% below the minimum ever realized during

Graph 4.4: Generation Capacity for the Entire Italy



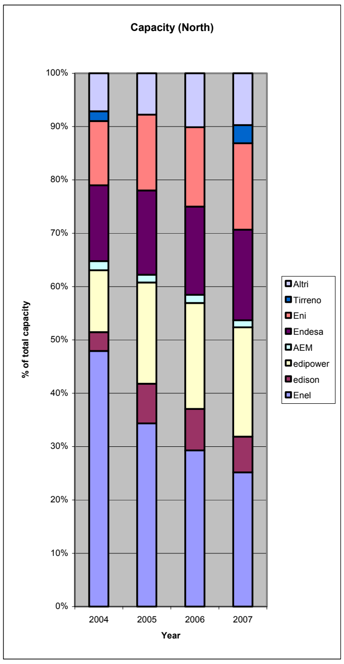
Source: www.mercatoelettrico.it

that hour, while the upper bound was 25% more than the maximum price ever realized (for that hour). If the lower bound is below zero, we set it equal to zero[13]. The maximum and the minimum prices realized every hour (for both the zones) are given below in the Graph 4.7.

Out of the remaining bids, we ignore the bids where the bid price was zero. This was done for the following reason: the supply function of the fringe firms is supposed to represent the belief Enel has about the fringe firms' behavior. As discussed previously, the lowest possible price that one can bid is zero and if the minimum were not zero, it would perhaps have been possible to observe negative price bids as well. Therefore zero is only a lower threshold and any price-quantity combination involving zero-price does not reflect Enel's true belief about the fringe firms' supply at a price of zero. Including these bids overestimates the trueβ.

[13]This 25% is fixed arbitrarily. Ideally we should consider a weighting scheme such that the farther the bid is from equilibrium, the lesser weight the bid gets. The present approach gives uniform weight to all the observations within the interval and zero weight to all the bids outside the interval.

Graph 4.5: Generation Capacity in the North



Source: www.mercatoelettrico.it

4.5 The Cost Function of Enel

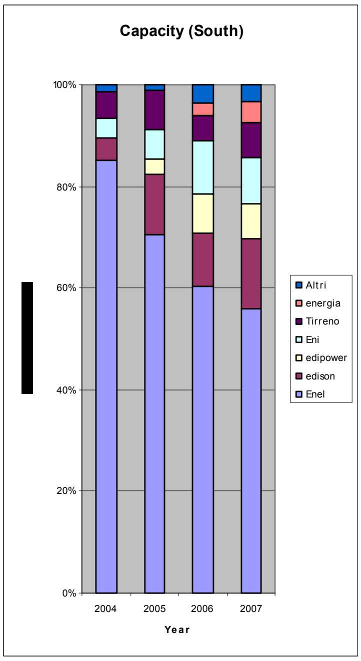
Most generators are multi-plant firms. Based on the location of the plant, its production process and the inputs required for electricity generation, marginal cost for each plant may be accurately computed using engineering data. In such computations, it is assumed that the marginal cost of any given plant is constant. Since each plant has a specific efficiency level, the marginal cost of a generator is a weakly increasing function, i.e., a step function. REF provides us with engineering estimates of the marginal costs of every thermo-electric plant of Enel.

Graph 4.8. shows the marginal cost of various thermoelectric plants.

4.6 Bilateral Contracts versus the Spot Market

In this paper we only consider the spot market and not the contracts market. The data on the contracts market are proprietary and unavailable to us. Bilateral contracts form a significant portion of electricity consumption in Italy. The details of the amount of electricity transacted in the spot market

Graph 4.4: Generation Capacity in the South



Source: www.mercatoelettrico.it

as a fraction of overall consumption, termed as liquidity, are presented in Table 4.3 and Graph 4.9.

Table 4.3: Liquidity

Maximum	40.01	Minimum	9.89
Average	0.3	SD	7.05

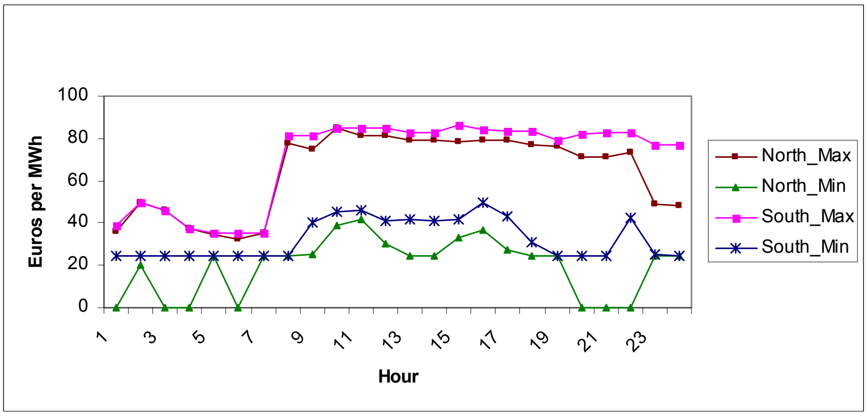
Source: www.mercatoelettrico.it

On average, liquidity is around 30%.

The Italian contracts are mostly bilateral physical contracts and not just the financial instruments (hedge contracts) previously addressed in the literature (see Wolak (2000)). A retailer/generator who signs the contract is expected to physically deliver electricity to the consumer involved in the contract at a pre-determined and mutually agreed price[14]. From the few contracts we have obtained, the price agreed upon is often a weighted average of

[14]The Italian law forbids generators from signing bilateral contracts directly. These generators operate in long–term contracts market via the retailers (middlemen)

Graph 4.7: Maximum and Minimum Realized Prices



Source: www.mercatoelettrico.it

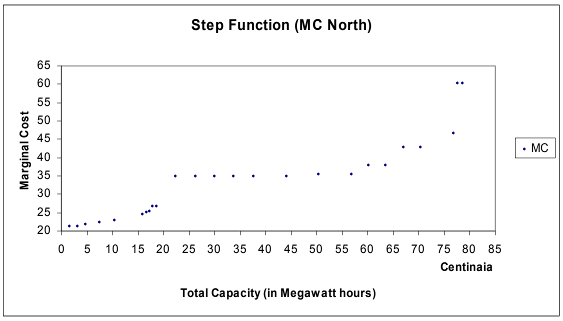
the previous month's spot market clearing price. But this is, by no means, a general rule. Our guess, however, is that there is a positive high correlation between the contracted price and the spot market prices. Therefore, if this were the case, our estimate of expenditure reduction is conservative.

The contracts market plays a role in determining the '*marginal plant*' Enel uses for production in the spot market. As honoring bilateral contracts is mandatory, while participation in the spot market is not, it is clear that a given generator uses his most efficient plants to supply the contract market. Therefore it becomes crucial to determine the *marginal plant*, i.e., the most efficient plant employed in the spot market[15]. The method with which we identify the marginal plant in the unintegrated regime is as follows. We manually identify, using data on bids and marginal cost, the most efficient of Enel's plants that participated in the spot market for every hour and every zone, and we labeled it the marginal plant for that hour for that zone. We also assume that all plants whose marginal cost is below the marginal plant participate exclusively in the contracts markets. Further, the marginal plant and all those with higher marginal cost bid exclusively in the spot market.

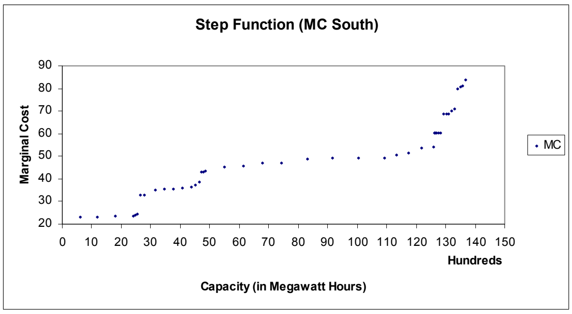
In order to determine the marginal plant in the unified market (i.e., the counterfactual), we assume that the market share of Enel in the contracts market is equal to its share in the spot market. This assumption allows us to roughly predict the amount of electricity that needs to be generated by

[15] Clearly, plants that are more efficient than the marginal plant produce for the contract market.

Graphs 4.8 (a & b): Marginal Cost Functions for North and South Respectively



(a): Marginal Cost for the North



(b): Marginal Cost for the South

Source: Proprietary dataset from REF

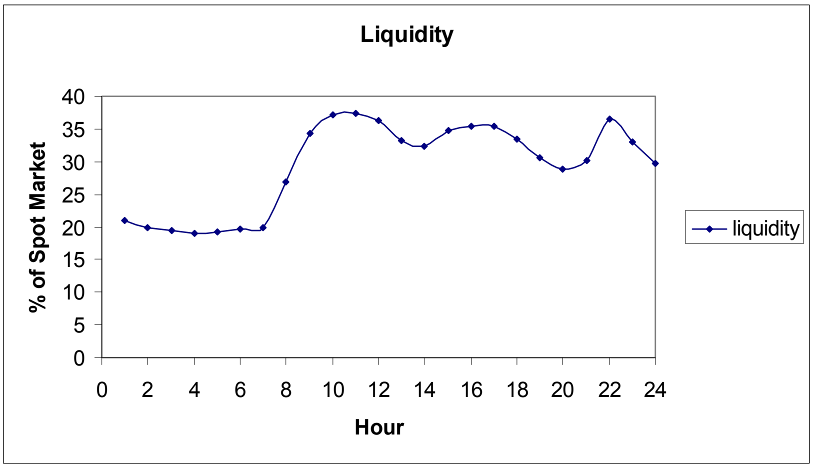
Enel for the contract market. By arranging Enel's plants in decreasing order of efficiency (increasing order of marginal cost), it is now straightforward to identify the marginal plant under the assumption that the most efficient plant(s) participate(s) in the contract market. The identification of marginal plants comes at a cost. The method described above implicitly assumes there are no plant shut-downs and start up costs. It also fails to take into account any network imperfections within a zone. Therefore, our predicted expenditure savings could be overstated.

5 Results

5.1 Fringe Regression

We estimate Equation (1) by both OLS and day fixed effects. The results of various estimation methods are presented in Tables 5.1 and 5.2. For the rest of the analysis and simulations, we use the slope estimates obtained from the fixed effects regression.

Graph 4.9: Hourly Average Liquidity



Source: www.mercatoelettrico.it

The OLS regression results indicate that for the south zone, the slope of the supply curve of the fringe for hour 16 is negative and insignificant. But on any given day, generators bid such that the quantity bid is strictly increasing in price. This highlights the need for day fixed effects. Though, on a given day, correlation between price and quantity is positive, it is not so when all the days are considered. Considering day fixed effects also accounts for any idiosyncratic shocks to the overall consumption (for example, previous hour's fringe production). Discussion in the data section indicates that fringe has a larger presence in the North than in the South. Therefore one should find Enel to be more responsive to the price in the North than in the South. The regression results indicate that, as expected, the slopes of the supply of the fringe in the North are higher than that of the South for all hours.

To see if slopes, in fact, statistically differ across all hours, we have tested the null-hypothesis of the slope being equal across all the hours. For the North, we are able to reject the null hypothesis at 99% significance. At the same time, we are unable to reject the hypothesis that the slopes are the same for any two successive hours. But the difference between the slopes of hours one (1 AM to 2 AM) and twenty-four (11 PM to 12 AM) is statistically different. For the South, we are unable to reject the null-hypothesis that the slopes of various hours are equal. The average value of the slope in the South is 5.95, significantly different from zero.

Table 5.1: Fringe Regression (OLS)

OLS Regression (Fringe's supply curve, equation (1))						
	North			South		
Hour	Slope ^	n	R Sq	Slope	n	R Sq
1	11.51	392	0.52	5.24**	103	0.20
2	14.63	486	0.56	6.06**	110	0.18
3	13.18	470	0.55	5.33**	113	0.14
4	12.80	416	0.58	4.06	94	0.14
5	11.78	348	0.68	4.99	45	0.20
6	7.22	323	0.55	3.32	50	0.21
7	13.99	358	0.59	5.46	94	0.1
8	16.36	676	0.80	5.03***	160	0.43
9	19.03	913	0.86	5.42***	160	0.50
10	22.51	922	0.86	4.08**	117	0.65
11	22.33	933	0.83	3.45**	113	0.63
12	24.59	957	0.87	5.68***	143	0.62
13	22.36	1022	0.88	4.64**	132	0.62
14	23.49	1050	0.89	5.08***	137	0.60
15	24.91	1003	0.86	5.76***	146	0.63
16	25.06	991	0.86	-1.23	78	0.75
17	25.81	970	0.90	5.69***	131	0.06
18	25.03	1012	0.86	5.87***	185	0.66
19	24.84	982	0.87	5.6***	185	0.69
20	23.57	980	0.90	5.4***	179	0.72
21	22.90	970	0.89	5.23***	182	0.75
22	27.76	1273	0.83	5.49***	180	0.07
23	28.92	896	0.63	3.71***	187	0.49
24	31.43	865	0.67	3.72	171	0.61
Dependent Variable				Quantity bid		
Slope is the coefficient of price						

^ All coefficients are significant at 99% for North
*** significant at 99%, **significant at 95%
*significant at 90%

$$q_{bd} = \gamma + \beta p_{bd} + \varepsilon_{bd} \quad (1)$$

5.2 Enel's Objective Function

Before we simulate the market under the alternative market regime of no transmission constraint we characterize the objective function of Enel as described in Section 3. Enel places a weight α on profit and $1-\alpha$ on consumer welfare. We compute α for every hour by equating observed prices in both zones with the prices predicted from the first order conditions of the objective function (*) characterized in Section 3.4. We compute the overall α in the integrated market as a weighted average of α_n and α_s, with the weights given by the total quantities consumed in the spot market in the respective zones. On average α takes the value 0.64 with a low standard deviation of 0.04. The median value of α is also 0.64 while the weighted average of α (where weights are given by corresponding quantities consumed that hour) is 0.59[16]. Characteristics of computed α are presented in Table 5.3 and Graph

[16] Around 60% of Enel is owned by private investors and around 40% by the Italian treasury.

Table 5.2: Fringe Regressions (Fixed Effects Regression)

FE Regression (Fringe's supply curve, Equation (1))

	North			South		
Hour	Slope	n	R Sq	Slope	n	R Sq
1	12.17	392	0.71	8.71	103	0.6
2	14.84	486	0.65	7.9	110	0.59
3	13.63	470	0.64	7.55	113	0.58
4	13.53	416	0.68	7.89	94	0.53
5	13.16	348	0.79	8.08	45	0.87
6	10.56	323	0.74	7.88	50	0.86
7	11.38	358	0.78	5.85	94	0.74
8	15.88	676	0.81	6.45	160	0.59
9	19.59	913	0.76	6.45	160	0.54
10	22.96	922	0.77	5.22	117	0.39
11	23.82	933	0.78	5.32	113	0.38
12	24.92	957	0.79	5.6	143	0.46
13	23.27	1022	0.82	5.48	132	0.43
14	23.59	1050	0.82	5.58	137	0.45
15	25.88	1003	0.81	5.53	146	0.45
16	25.76	991	0.80	4.24	78	0.32
17	25.58	970	0.80	5.09	131	0.4
18	25.78	1012	0.80	6.63	185	0.59
19	25.58	982	0.79	6.64	185	0.59
20	25.79	980	0.82	6.63	179	0.58
21	23.32	970	0.82	6.6	182	0.59
22	26.78	1273	0.83	5.66	180	0.5
23	27.57	896	0.85	3.9	187	0.51
24	31.03	865	0.85	3.58	171	0.5

Dependent Variable Quantity bid

Slope is the coefficient of price

All coefficients significant at 95%

$$q_{bd} = \gamma + \beta p_{bd} + \theta_d + \varepsilon_{bd} \quad (1)$$

5.2.

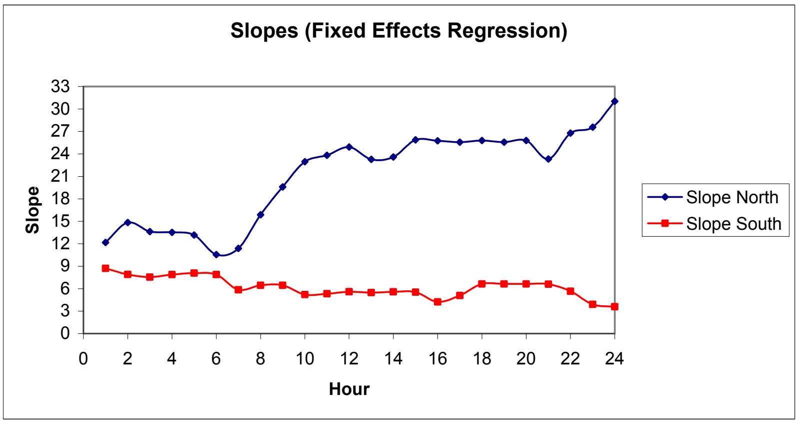
Casual observation suggests Enel may have, among its objectives, to reduce the price difference between the North and the South. This can result from the fear that a relevant price difference may be perceived as the result of market power exploitation, and thus may lead to regulatory retaliation. However, data seem to suggest that, when a homogenous behavior (in terms of markup) between the North and the South entails a large price difference, Enel tends to increase the North profit, in order to align the prices in the two zones.

5.3 Simulations in the Alternative Market

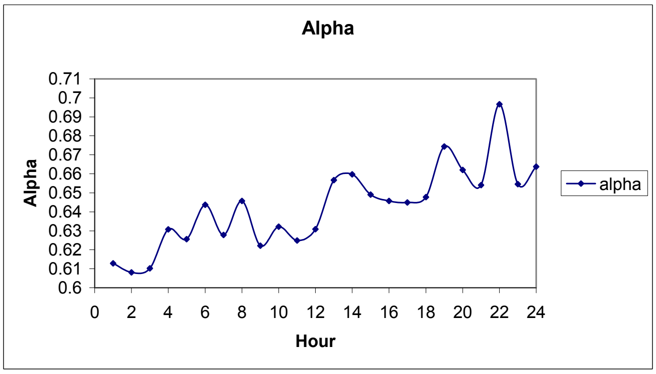
After characterizing the objective function of Enel, we simulate the market under the alternative market structure of no transmission congestion. The two assumptions we make are: objective function and fringe behavior do not change as a result of market integration.

We employ an iterative procedure to obtain equilibrium in the integrated market regime. First, we identify the marginal plant in the interconnected

Graph 5.1: Slopes of Fixed Effects Regression



Graph 5.2: Slopes of Fixed Effects Regression



Note: Calculated for all hours where price difference is non-zero

market using the method discussed in Section 4.6. Then, we order Enel's plants that participate in the spot market in a decreasing order of efficiency[17]. Later, we calculate the objective function–maximizing output for the most efficient plant ignoring the plant's generation capacity constraint. If that output is feasible (i.e. lower than the plant's generation capacity), it is the equilibrium quantity. Otherwise, we consider the two most efficient firms and reiterate the process.

We present simulated prices and quantities in Graphs 5.2 and 5.3 respectively.

[17] Observe that firms participating in the spot market may be different before and after interconnection. Interconnection could lead to reallocation of electricity generation for the contracts market.

Table 5.3: Characteristics of α

Characteristics of Alpha	
Maximum	0.756
Minimum	0.509
Mean	0.647
Median	0.646
Weighted Average^	0.589
Standard Deviation	0.04
First Quartile	0.615
Third Quartile	0.679

^ Weights given by spot market consumption for the hour

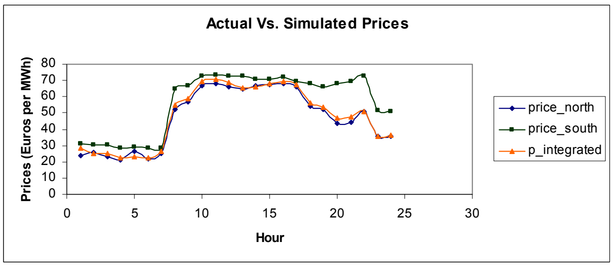
Note: Calculated for all hours where price difference is non-zero

Hourly average prices in the integrated market, as well as quantities, are between the average prices in the north and average prices in the south. The prices and quantities produced by Enel in the alternative market structure closely resemble that to the North, than those of the South. While the prices in the North only increase marginally, the prices in the South decrease substantially. Therefore one should expect cost reduction as a result of integration.

The simulation results indicate that market integration significantly increases welfare. The overall gains due to interconnection are a little above six million one hundred euros for May 2004. The above illustrated statistics show that saturation in May occurred for 46% of the hours. This is very close to the yearly average percentage of hours with saturation: 48%. This suggests that there are reasons to believe that May is representative month. Under such assumption, the expenditure reductions can be estimated to be little over 70 Million Euros for 2004.

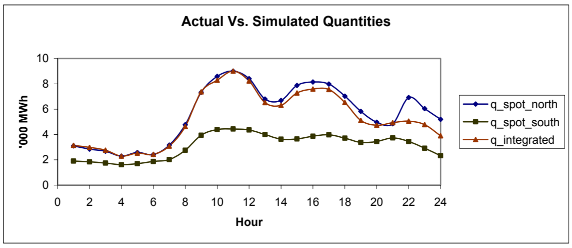
Some hours gain more than others. The maximum gain due to intercon-

Graph 5.3: Simulated Vs. Actual Prices



Note: Calculated for all hours where prices in the North and the South are different

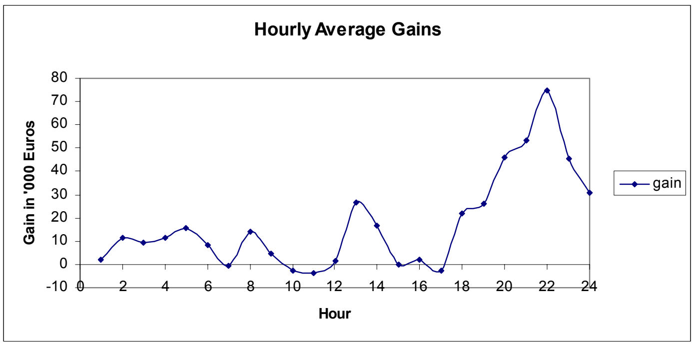
Graph 5.4: Simulated Vs. Actual Quantities



Note: Calculated for all hours where prices in the North and the South are different

nection is observed in hour 22 (9 PM to 10 PM) on 17^{th} May 2004. The gain recorded is around one hundred and sixty thousand euros. The maximum loss due to interconnection, little less than fifty thousand euros, is recorded for the hour 17 (4 PM to 5 PM) on 7^{th} May 2004. On average, twenty two hours per day recorded a gain due to interconnection. Average hourly gains are presented in Graph 5.5.

Graph 5.5: Hourly Average Gains



Note: Calculated for all hours where price difference between zones is not zero

We have also checked the gains from interconnection when α(the weight given to profit by Enel) is constant and equal to its median value, α= 0.64. In that case we find that the gains from interconnection are a little less than three and a quarter million euros for May 2004. These gains from interconnection did not differ substantially when we set the slope of the South as constant at 5.95. In such case, the gains were little under six million eighty seven thousand euros for the month of May 2004. Gains from interconnection are summarized in Table 5.4.

Table 5.4: Gains from Interconnection

	Hour	**Gain**
Maximum Gain	Hour 22: 17th May	€ 159,599
Maximum Loss	Hour 17: 7th May	€ 49,598
Overall Welfare Gain	Month of May 2004	€ 6,148,771
Welfare Gain (alpha = 0.64)	Month of May 2004	€ 3,219,849

Note: Calculated for all hours where price difference between zones is not zero

5.4 Effect of Integration on Enel

As discussed earlier, this price reduction in the South (and hence overall cost reduction) could be happening for two reasons. First, market integration results in South becoming more competitive. That is because though Enel owns more than 80% of the capacity in the South, it only owns around 60% when the overall Italian market is considered. Second, Enel has several more efficient firms in the North that remain idle. Data show that there were hours where firms in the North with marginal cost less than twenty seven dollars were idle, while in the South plants with marginal cost more than forty dollars were in operation. Therefore Enel has a chance of reorganization of its production plans. Our results indicate that by reallocating its production across zones, Enel's total cost in the spot market reduces by little over five million euros. Enel's profits also improve substantially by little over one million euros. Since the market share of Enel only registers marginal improvement (from 0.586 in the constrained regime to 0.589 in unconstrained regime), the role of reallocation becomes clearer. This result suggests that Enel also has an incentive to invest in the interzonal transmission. Another point to observe is that most of the cost savings by Enel are passed on to consumers in the form of lower spot market prices. This could partly be explained by the unconventional ownership structure of Enel.

6 Conclusion

In our paper, we analyze the benefits associated with eliminating transmission bottlenecks across zones in the Italian electricity spot market.

The simulation of such benefits requires knowledge of the objective function of Enel, the major generator in the market. There are many reasons to believe that mere short-run profit maximization does not apply to Enel. Our results confirm that the expenditure minimization is a significant component of Enel's objective function. In particular, we find that Enel associates a weight of 64% to short-run profits and the remaining 36% to expenditure minimization with a standard deviation of 4%. The incentives towards expenditure minimization may stem either from long-run profit considerations (related to the need to prevent regulatory retaliation and entry), or from State ownership and orientation to consumer surplus. While we can not disentangle the relative importance of each of these two sources, we observe a similarity between the share of expenditure minimization in the objective function, and the ownership share by the Italian Treasury in Enel, amounting at around 40% in May 2004. Under the assumption that these weights do not change after the elimination of the transfer constraints, we find that the total expenditure savings to the end-users would be approximately six million euros in the month of May 2004, our sample period. These gains are primarily driven by a major reallocation of production across plants by Enel. This reallocation also results in reducing Enel's costs in the spot market by around five million euros and improves Enel's profits by little over one million euros. This suggests that Enel also might have an incentive to invest in the transmission capacity[18]. Since May can be regarded as a representative Month in terms of the saturation occurrence rate, we may speculate that yearly expenditure saving to end-users in the spot market would amount to approximately 60 Million Euros. There are reasons to believe that a no-

[18]See, for example, Harvey, Hogan and Pope (1997) and Joskow and Tirole (2005a) for arguments for and against private ownership of transmission network respectively.

arbitrage condition would ensure that the contracts market would – at least partially - match the spot market in terms of price reduction. Hence, it is reasonable to claim that overall end-users savings in the electricity market our expenditure-saving estimates are in this respect conservative.

The decline in total expenditure triggered by interconnection leads to welfare improvement in medium and long runs, where demand elasticity is larger due to the emergence of potential substitution patterns (if not in the short-run, where demand is inelastic). Furthermore, at an aggregate level, it is well-known that high electricity prices in the medium and long - run reduce economic growth.

In 2004, the owner of the Italian infrastructure responsible for interconnection - Terna - estimated that it would cost around four hundred thousand euros of labor and material cost per kilometer of interconnection. Though the actual bottleneck occurs only for around one hundred kilometers, and hence the cost being forty million euros, an improved interzonal transmission network also requires a more efficient intra-zonal transmission mechanism, the cost of which we have no data on. Furthermore, a complete cost analysis should also involve quantifying several other factors. For example, it should include environmental costs and the opportunity cost incurred due to disturbances to the existing transmission network. Further studies are needed before more complete cost estimates can be obtained.

One caveat of the analysis is the assumption of linearity of fringe supply. Notwithstanding the restrictive nature of the assumption, it is popular among economists in electricity literature. By eliminating the extreme observations, we have taken into account some of the possible problems with the linearity assumptions. Further, we have not imposed any functional form restrictions on the overall cost function of Enel. A possible extension aimed at checking the robustness of the results is to consider the step function approach à la Hortacsu and Puller, in which the supply function of the fringe consists of a discrete set of points.

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