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EMERGING ISSUES IN THE EUROPEAN ELECTRICITY MARKET

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Milan, June 2010 Daniela Floro

Contents

List of Tables

List of Figures

Chapter 1

Introduction

Prior to be reformed the electricity market was organized as a vertical integrated industry. Security of supply and commodity complexity can be considered the main determinants of its prior monopolistic organization. However, during the 1990s several features posed under question its monopolistic structure. Firstly, the development of more efficient technologies such as the combined cycle gas turbine (CCGT), which highlighted the possibility to reduce entry barriers for new generators. Indeed, CCGT plants involve a series of advantages with respect other plants, like higher efficiency rates, lower marginal cost and, short construction times. Moreover, CCGT plants are base-load plants, and then they can compete for a higher portion of supply.

Secondly, both international experiences of electricity market restructuring (like in Chile and UK) and the awareness that national electricity monopolies were the main obstacle to EU market integration have led to a general consensus towards EU electricity liberalization.

The EU reform of the electricity market has been established through the enforcement of several Directives and Regulations. Specifically, EU market restructuring started with the Directive 96/92/EC, which aimed to establish a competitive, secure and transparent EU internal electricity market. The Directive identified three economic conditions to achieve a competitive market: unbundling of the industry to separate the potential competitive activities generation and supply from the natural monopoly activities (transmission and distribution), gradual market opening and, third-party access. At the same time, the First Directive based on the harmonization principle allowed Member States to establish their own implementation strategies. As a result, several electricity markets emerged instead than a single market.

To strengthen the EU restructuring process the Directive 2003/54/EC came into force replacing the First Directive, introducing stronger regulation for TPA and defining a minimum standard timetable for the full market opening. In addition, Regulation 1228/2003 explicitly regulated the cross-border issues.

Two years later, in 2005, the Fourth Benchmarking Report pointed out that despite initial market opening was largely successful, involving a reduction in real terms of electricity prices compared to 1997, the most persistent shortcoming to the single market was the lack of integration among national markets. Thus, electricity markets in the EU, a part for few exceptions, remained national in their economic scope.

In 2007, the sector inquiry for the establishment of the Third Energy Package pointed out once again that the lack of electricity market integration was mainly due to insufficient interconnecting capacity among Member States, insufficient incentives to improve cross-border infrastructure and incompatible market design between Transmission System Operators and/or spot market operators. For these reasons, the Third Energy market package, introduced with the Directive 2009/72/EC and Regulation 714/2009, established more restrictive conditions for unbundling of the industry. Since some countries have been reluctant to adopt full unbundling, a compromise has been reached leaving to Member States the possibility to establish an independent transmission operator. As a consequence, supply companies can own transmission systems under the conditions that these systems are managed by an independent transmission operator. As regards to market regulation, the Third Package obliged all the countries to establish an independent regulator for the electricity and the gas markets. Moreover, it established the institution of a new European "Agency for the cooperation of Energy Regulation", with the task to oversee many parts of legislation. The package also ruled out support for low-carbon technologies, establishing European network of transmission system operator, transparent tariffs for use of networks, quality standards and others.

Focusing on the effects of the First and Second Directives, the contribution of the thesis is threefold. Firstly, it considers the European wholesale electricity market illuminating the progress made towards a single market for electricity. Secondly, it examines the retail market to assess the impact of the EU reform on consumer welfare. The two analyses are developed at cross-country level. The former using high frequency electricity prices and time series models, whereas the latter using yearly-data and panel data models. Third, it focuses on the Italian wholesale market, specifically the Italian day-ahead market, to establish the progress towards competition. The analysis is applied to hourly firm-data level applying both econometric and optimization techniques.

The thesis is organized as follows. In chapter 2, we assess the progress towards a single integrated EU market examining wholesale electricity price convergence in the main EU power exchanges (EXAA, Austria, Powernext, France, APX, the Netherlands, EEX Germany, Nord Pool, Scandinavia, OMEL, Spain and, IPEX, Italy), for a sample period ranging from 1 April 2004 to mid June 2006. The key idea is if the underlying national markets are integrated, then there is evidence of a real integrated market. Thus, over the long run wholesale electricity prices should follow the same pattern. According to Johansen (1988), market cointegration requires the fulfillment of two conditions. First, the series must show unit root, hence the process should be integrated of order (1). Given the non-stationarity feature, there may exist a linear combination of them, which lead to a stationary error term. The series are therefore defined cointegrated.

However, empirical literature on electricity prices shows that it is very difficult to state clearly whether electricity prices are unit root processes using high frequency prices. If the data generating processes do not show unit root, in general, it is not possible to apply cointegration models according to Johansen (1988). To overcome this problem, two different approaches are applied. The first suggests that despite of the empirical evidence of unit root, if the parameter is close to one, it is possible to apply cointegration models (Hendry and Juselius, 2000). The second requires the satisfaction of milder conditions to test the presence of unit root and apply cointegration analysis (Chigira, 2006). Following Haldrup and Nielsen (2006), our approach is placed in the middle. In particular, we assume that electricity prices are neither stationary nor unit root processes, but are fractional integrated processes. We therefore apply a two-step procedure, as defined by Breitung and Hassler (2002), to determine the fractional order of integration. Specifically, the first step tests the hypothesis of unit integration (unit root) against the fractional alternative (fractional root). The second step requires that the joint fractional root is the same in the cointegrated series. Knowing, the fractional order of integration, then we test for cointegration according to Granger (1981, 1983). Thus, we check whether two series are integrated of the same fractional order. Results show that only the German and the Austrian wholesale markets are perfectly convergent.

In chapter 3, we assess how the EU reform in the electricity market affects industrial-consumer welfare. Specifically, we study the price-cost margins in the EU15 countries over the period 1980-2006. Our analysis examines the long-run equilibrium of achieving a single internal electricity market allowing Member States to converge freely to the steady state as established by the harmonization principle of the EU reform. Differently from previous studies, we apply a novel econometric approach developed by Pesaran et al. (1999), which constraints the long run parameters to be same, representing therefore the EU mandated goal of market integration, and allows different rates of adjustment to the equilibrium, hence representing harmonization.

Empirical evidence shows that wholesale market opening, privatization and regulation result in an increase of industrial consumer welfare. However, as the degree of vertical integration decreases, price-cost margins increase shrinking industrial-consumer welfare. This result is due to a loss of efficiency in the economies of scale. In addition, the analysis of national rates of adjustment to long-run equilibrium shows that Italy and Germany are the countries with the highest and lowest profit persistence respectively.

In chapter 4, we study the Italian day-ahead market linking theoretical predictions and empirical findings to identify its underlying oligopolistic structure and to examine potential improvements in consumer welfare after market liberalization. Accounting for the zone organization of the Italian wholesale market, we study the two main macrozones North and South in the summer and winter months of 2005 and 2006. In each market, we define the set of the strategic players and price-taker firms, as in Puller (2007), according to both generation capacity and production. We then define two oligopolistic models to describe the underlying oligopolistic structure. In particular, in the North market, we compare the Stackelberg and the Cournot model, whereas, in the South, the Stackelberg and the Dominant firm model. Following Kim and Knittel (2006), Puller (2007), Bushnell et al. (2008), in all the models we first estimate the competitive fringe supply. Applying a variation of the traditional coefficient of determination as in Bushnell et al. (2008), we find that the northern market has recorded a change in the oligopolistic structure from the Stackelberg model (2005) to the Cournot model (2006). However, as stated by microeconomic theory this change implies a loss of efficiency.

Results on the southern market show that during weekdays, in both years, the market follows a Stackelberg model. Instead, during weekends the market has recorded a change from the Dominant firm model to the Stackelberg model. Hence, results show an improvement in consumer welfare.

Chapter 2

Are European wholesale electricity prices convergent?

2.1 Introduction

Wholesale electricity markets, also called power exchanges, can be considered the direct result of the liberalization process, which requires the establishment of organized markets where generators, industrial consumers and retailers can interact with each other.

Electricity restructuring has highlighted two main issues. On the one hand, prices have become very volatile, because the reorganization has introduced new elements of uncertainty typically of financial markets like financial risk management, derivative and hedging. Indeed, before electricity restructuring prices were determined by regulators as function of generation, transmission and distribution costs, hence uncertainty was minimal. On the other hand, a real integrated market should provide evidence of price cointegration in the individual underlying markets, thus price differences should only reflect physical congestion between markets. As regards to the EU reform, this implies that national wholesale electricity prices should be convergent to achieve the single internal market for electricity. Thus, European consumers should pay the *same* price at the *same* time in different locations. Consequently, arbitrage opportunities are not allowed.

Moreover, electricity industry is characterized by specific features, like no-economic storability of electricity, seasonality of demand, generation constraints and transmission congestions, whose combination make this sector unique.

Empirical literature studies the progress made towards a single EU market according to time series modelling, applying models of cointegration. Generally, these studies apply a two-step procedure. The first step analyses the main characteristics of the dynamics of wholesale electricity prices investigating whether they are stationary. Several tests are applied such as Dickey Fuller (DF)[1], Augmented Dickey Fuller (ADF)[2] and, Phillips-Perron (1988). The second step examines whether prices follow the same long-run pattern. Traditionally, econometric analysis applies Johansen (1988) cointegration technique.

However, the establishment of unit root as well as price convergence is an open issue in the electricity literature. As regards to stationarity, on the one hand, some authors (Escribano et al. 2002) threat electricity prices as stationary. On the other hand, other authors (Stevenson 2002) are more parsimonious and threat electricity prices as non-stationary. In addition, Haldrup and Nielsen (2006) argues that electricity prices are neither stationary or integrated of order one process I(1), but that they are fractionally integrated. As regards to price convergence different techniques are applied, for example Zachmann (2005) studies a time-varying coefficient model, whereas Bosco et al. (2006) applies Chigira (2006) cointegration method, which requires weaker assumptions than Johansen's technique.

Following Haldrup and Nielsen (2006) we apply a model of fractional cointegration to examine price convergence in seven power exchanges namely:

[1]See Dickey and Fuller 1979.

[2]See Dickey et al. 1984 and 1986.

EXAA (Austria), Powernext (France), APX (the Netherlands), EEX (Germany), Nord Pool (Scandinavia), OMEL (Spain) and IPEX (Italy), for a sample period ranging from 1 April 2004 to mid June 2006. The period has been chosen accounting for the establishment of the Italian power exchange, whose trading activity started from 1 April 2004.

We perform DF and ADF tests to examine whether hourly and daily electricity prices are random walks. In the latter case, we account for daily mean, peak and off-peak. Results show that unit root is partially rejected. As regards to hourly series, the lack of unit root can be due to mainly the short-run nature of the data. Instead, concerning daily series the rejection of unit root can be partly explained by the non-storability feature of electricity.

In order to evaluate possible price convergence in the wholesale markets analyzed, we apply Breitung and Hassler (2002) two-step procedure to establish whether daily (mean, peak and off-peak) electricity prices are fractional integrated processes and to select a common fractional order of integration. In particular, the latter is applied to pair of series. Knowing the fractional order of integration, we apply Granger's method (1981, 1983) to determine convergence among the wholesale markets, which satisfied the two-test procedure.

To anticipate we find evidence of perfect integration between the German and Austrian wholesale markets. In addition, the German market results well integrated with the other neighbouring markets.

The chapter is organized as follows. In the next section, we present the main characteristics of the wholesale markets analyzed. In section 3, we propose a preliminary analysis of both hourly and daily wholesale prices. In section 4, we apply Breitung and Hessler two-test procedure to determine the fractional order of integration, then we perform Granger cointegration analysis. Section 5 concludes.

2.2 Wholesale markets

In this section, we examine the main characteristics of the wholesale markets analyzed. We choose to study price convergence of the emerging power exchanges in Austria, France, Germany, Italy, Netherlands and Spain. In addition, we include Nord Pool, which is a more experienced market, as benchmark.

All the markets analyzed are non-mandatory. Indeed, participation can be either mandatory or voluntary, in the latter bilateral contracts are admitted.

Wholesale markets work as auctions, in which sale bids specify the quantity and the minimum price at which generators are willing to supply electricity. Conversely, buy bids specify the quantity and the maximum price at which retailers and consumers, mainly industrial consumers, are willing to buy electricity.[3] An independent system operator determines the market clearing price and quantity.[4] Two main types of auction are applied: the pay as bid and the system marginal price. The principal difference between these two auctions is the price that generators receive if their bids are accepted. In the former, generators are paid at the offered price, whereas in the latter all generators receive the market clearing price.[5]

Furthermore, wholesale markets operate on hourly base the day before the delivery, because the system operator must verify that transmission constraints are not violated and that demand and supply are in balance. In all the markets analyzed, electricity is traded in 24 contemporaneous hourly auctions. However, trade activity can be closer to the delivery as in the case of UK, where trading activity is on half-hour base.

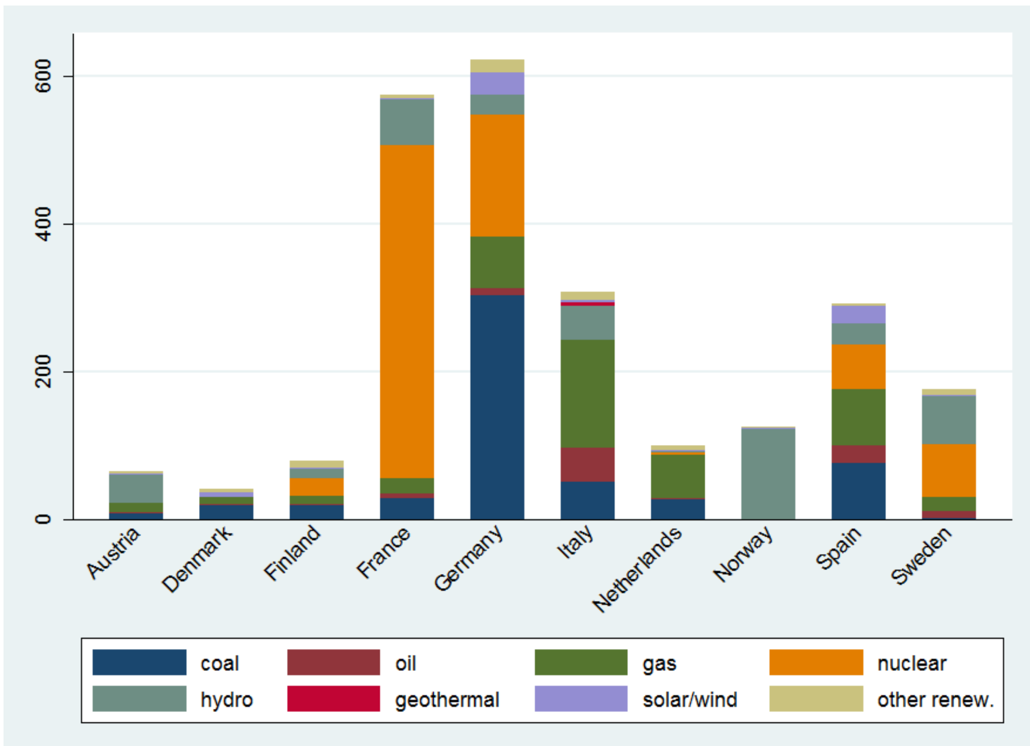
[3] Wholesale market opening has occurred gradually on the demand side. To represent the consumer sector, the Single Buyer has been established with the task to purchase electricity for the not eligible consumers.

[4] In the case of non-mandatory pool, bilateral contract quantities are also accounted to determine the equilibrium.

[5] For this reason the system marginal price auction is also called uniform price.

The wholesale markets analyzed differ mainly as regards to production structure. Figure 2.1 shows the generation mix of the countries analyzed over the sample span. Nordic countries use mainly hydro and nuclear plants, whereas thermal plants play a very marginal role.

Figure 2.1: Average generation mix (GWh) 2004-2006



Germany relies mostly on coal plants, also nuclear generation constitutes an important source. France uses principally nuclear plants. Spain shows a well-balanced generation mix. Finally, Netherlands and Italy uses mainly gas-power plants. Generation costs can be considered as the main driver of electricity prices. As a consequence different production structures determines price differences. However, price differences may be due to different concentration level as well. In general, the highest is market concentration; the highest is the possibility that generators exercise market power raising prices. A common measure used to analyze concentration is the concentration rate of the first three generators (CR3). As shown in table 2.1, all markets shows high concentration levels in generation, except Nord Pool.

Table 2.1: Market concentration in 2005

Country	Wholesale market	CR3 on production
Austria	EXAA (2002)	75
France	Powernext (2001)	95
Germany	EEX (2002)	70
Italy	IPEX (2004)	75
Netherlands	APX (1999)	65
Spain	OMEL (1998)	80
Scandinavia	Nord Pool (1993)	40

Source: European Commission 2005

Finally, the last feature we should consider is the level of integration of local wholesale markets. European market integration requires well-interconnected local markets, because when congestions take place local markets are split, consequently prices can not converge. Among the markets analyzed congestions are rarely observed between Germany to France, Germany to Austria and Austria to Germany. Positive levels of congestions are observed in the other markets.

2.3 Literature review

In this section, we summarize the main findings on the progress made towards a single EU wholesale electricity market.

The pioneer study of Bower (2002) examines the performance of 15 EU wholesale markets using daily data in 2001. The wholesale markets analyzed are located in: Norway, Sweden, Denmark, Finland, England & Wales, Spain, Netherlands, and Germany. Following Engle and Granger (1987), results show that mean daily electricity prices were well integrated among all locations, except Spain. In particular, locational wholesale market prices, throughout Nord Pool, are strongly integrated; German energy markets – EEX and LPX – and Sweden show a fair degree of integration. Instead, both Finland and Denmark appear less cointegrated with Norway, which may be due to insufficient transmission capacity. Despite the lack of a physical connection capacity to mainland Europe, prices in England and Wales, show a high degree of convergence with prices in Nord Pool, Netherlands, and Germany. Finally, the Spanish market shows a less degree of integration with any other EU locations due to its peripheral location and limited interconnection capacity. Bower argues that the different degree of convergence may be due to trading arbitrage between locations. Furthermore, he proposes an evaluation of the Lerner index assuming the marginal cost equal to the coal fired thermal plants. He finds that generating firms in some locations exercise market power yielding to an overall inefficiency.

By contrast, Boisseleau (2004), analyzing the same period as Bower, but accounting only for the Dutch and the two German wholesale markets, finds a very low degree of convergence in the weighted daily electricity price. Despite of the high degree of interconnection capacity, correlation analysis shows that the series follow the same pattern but weakly.[6] Boisseleau criticizes Bower's findings on two fronts. On the one hand, he argues that Bower's analysis is biased, because in the original time series there is no evidence of unit root. On the other hand, the different degree of convergence may be due to the use of arithmetic averages in Bower and weighted averages in Boisseleau.

Amstrong and Galli (2005) apply an exploratory approach and focus on the differences between the hourly day-ahead prices of four main EU power exchanges – France, Germany, the Netherlands and Spain – from 2002 to the 2004. Analyzing weekdays and the whole week, they show that prices are in a process of converging. Specifically, comparing the mean difference

[6]The correlation level between the Dutch wholesale price and each of the Germany series is roughly 33%. Moreover, the analysis of two-week ahead prices confirms the low correlation level, only 36%.

between two power exchanges in 2002, 2003 and 2004, they find that in the last year the differences are closer to zero in almost all the cases. In addition, they show that volatility decreases in peak hours, whereas in off-peak hours is stable or slightly decreasing.

According to Zachmann (2005), Amstrong and Galli's approach has several flaws. On the one hand, he points out that no statistical tests are performed to provide evidence of the dissimilarity of the yearly average price differentials. On the other hand, he argues that the study does not account for the cross-border capacity auctions between Netherlands and Germany. Zachmann starting from the idea that increasing cross-border trade should deliver price convergence in the national markets involved, studies price convergence between the Dutch and the German and, the Danish and the German markets. Accounting for cross-border capacity auction results and internal spot prices for the period 2002 to 2004, he estimates a time-varying coefficient model of the difference between domestic and import prices to derive an index indicating the deviation between the observed prices and the common price. The analysis of the index over time shows that the rate of convergence of national markets towards an integrated market follows the law of one price. Thus, results indicate a decrease of arbitrage opportunities due to improvements in the management of cross-border capacity.

Bosco et al. (2006) study the degree of convergence of four exchanges in Germany, France, Austria and the Netherlands using weekly median data for the period March 2002 to June 2006. By contrast with previous studies, they find strong, but not perfect, integration among the markets. This different result may be due to the estimation technique applied. Specifically, they argue that previous findings of no integration are based on the application of ADF test and Johansen's technique, which impose restrictive conditions that do not account for electricity price features. Hence, integration is not found. Therefore, they apply milder tests to detect integration. In particular, unit root is studied according to Phillips and Perron (1988) and Breitung

(2002) tests, whereas cointegration applying Chigira (2006) technique. The application of milder techniques can therefore explain the different empirical findings.

2.4 Data preliminary analysis

In this section, we apply a range of statistical and econometric techniques to hourly and daily wholesale electricity prices quoted from 1 April 2004 to mid June 2006. In particular, we perform two pretests to examine the quality of the data set. On the one hand, a principal component analysis (PCA) is proposed to analyze the interaction among the price series.[7] After evaluating the first and second principal components (PC), we analyse the correlation between each component and the original time series and present the results in a scatter plot.

On the other hand, we perform Dickey Fuller (DF) and Augmented Dickey Fuller (ADF) tests to check whether wholesale electricity prices are unit root processes.

2.4.1 Examining hourly wholesale electricity prices

Figure 2.2 shows a qualitative analysis of hourly wholesale spot prices during the period analyzed.[8] A first inspection confirms that wholesale electricity spot prices vary among locations and present regular spikes. The figure confirms some peculiar characteristics of electricity prices. Firstly, electricity prices are characterized by strong seasonality. In January 2006, for example, the electricity price quoted on the German market at 11th hour (10 am - 11 am) was twice higher than the price quoted at the same hour the year

[7] The principal component analysis calculates linear combinations of the original data matrix explaining most of the variance. In particular, the first component is evaluated accounting for as much of the variability in the data as possible, and each succeeding component accounting for as much of the remaining variability as possible.

[8] All prices are expressed in €/MWh.

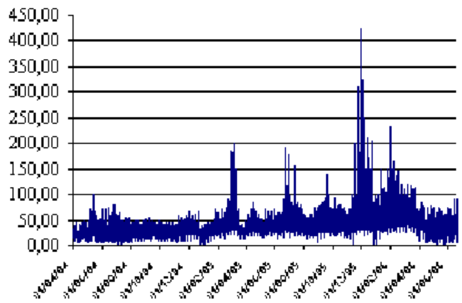
before. High seasonality can be explained by three factors: the necessary real time-balancing due to non storability of electricity, the strong dependence of electricity demand on weather conditions, and the effects of social and economic activities that lead to different holiday and seasonal patterns. Moreover, seasonality effects, which are classified in daily, weekly and yearly, change over time and over space.

Secondly, electricity prices are characterized by jumps and spikes due to sudden and strong increases in demand when supply is at the limit of its generation capacity. As shown in the figure, prices do not stay in the new level, but return to the previous one rapidly.

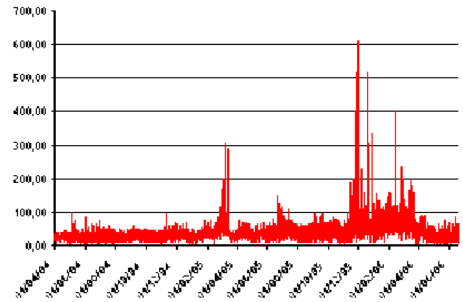
Finally, electricity prices are mean-reverting. Thus, prices remain close or tend to return over time to the long-run average value. This pattern can be due to both weather dependence of electricity demand and the exercise of market power by generators, which constraint generation capacity in the peak hours to raise electricity prices.

Figure 2.2: Hourly day-ahead wholesale electricity prices of emerging power exchanges (€/MWh)

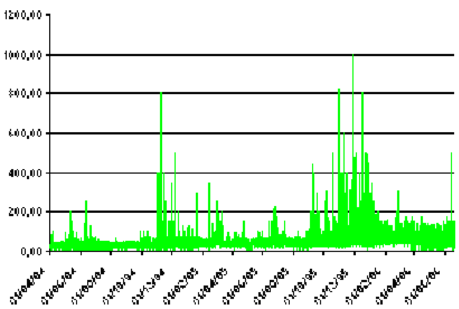
(a) EXAA



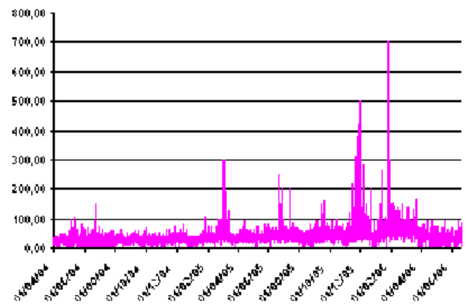
(b) Powernext



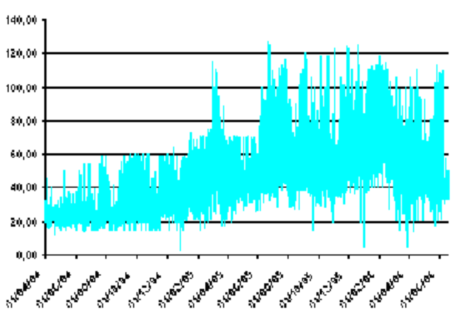
(c) APX



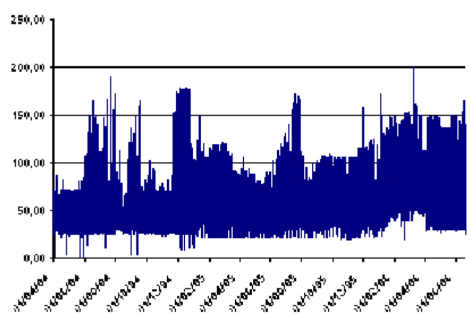
(d) EEX



(e) OMEL



(f) IPEX



The descriptive analysis of hourly wholesale electricity prices shows interesting features.

Table 2.2: Descriptive statistics hourly wholesale electricity prices (€/MWh)

Series	Obs	Mean	Std dev.	Minimum	Maximum
EXAA	19440	41.758	24.002	0.010	425.00
APX	19440	47.969	39.643	0.010	1000.12
EEX	19440	41.416	25.233	0.040	699.89
Powernext	19440	41.992	26.441	0.038	609.03
OMEL	19440	46.012	21.347	3.370	127.04
Nord Pool	15336	33.424	8.776	4.500	107.88
IPEX	19440	59.173	29.277	1.098	199.27

On average, the Italian market records the highest wholesale price (59 €/MWh), which is mainly due to the generation mix. Austria, France and Germany have the same average value (41 €/MWh). The Netherlands and Spain have similar average wholesale prices, but the former shows higher level of standard deviation indicating that the spikes in this market are higher, as shown by figure 2.2. Not surprisingly, the average hourly price of Nord Pool is the lowest as well as its standard deviation equal to 33 €/MWh and 8.776 respectively.

Different price levels are mainly due to the generation mix. The countries, which produce electricity by nuclear and hydro plants have lower electricity price due to less costs of "fuel". By contrast, in the case electricity production is based mainly on thermoelectric generation, the price is higher. This is especially the case of Italy.

Table 2.3 reports the correlation matrix of hourly wholesale electricity prices among the different countries analyzed. If the correlation coefficient is close to one, prices in the two markets tend to move up and down by the same amount on any given hour. Instead, if the correlation coefficient is close to zero, prices in the two markets move in different direction.

Table 2.3: Correlation matrix of hourly spot prices

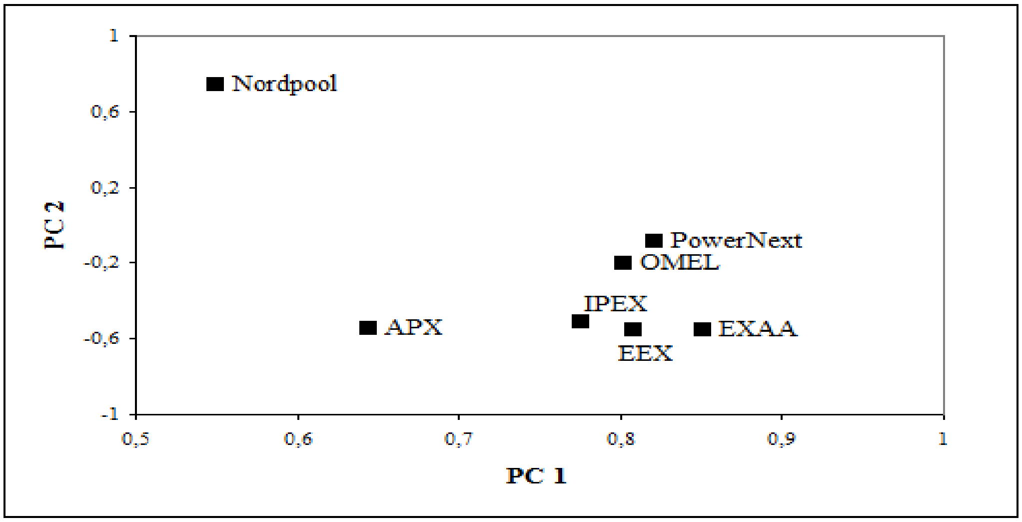
	EXAA	APX	EEX	Powernext	OMEL	Nord Pool	IPEX
EXAA	1						
APX	0.679	1					
EEX	*0.907*	0.650	1				
Powernext	*0.895*	0.645	*0.868*	1			
OMEL	0.678	0.490	0.641	0.682	1		
Nord Pool	0.429	0.307	0.404	0.406	0.345	1	
IPEX	0.645	0.498	0.612	0.609	0.564	0.384	1

High levels of correlation are indicated in italic.

As shown in table 2.3 wholesale prices, quoted on EXAA, EEX and Powernext show a high degree of correlation, which is above than 0.85. Italian, Dutch and, Spanish markets show a significant degree of correlation with these markets, with correlation coefficients higher than 0.60. Instead, Nord Pool prices show a less degree of correlation with the other markets.

Figure 2.3 shows the results of the principal component analysis. Emerging wholesale markets, apart APX, are characterized by the same regional price developments. The Netherlands show some affinity with the others emerging markets. Moreover, the analysis confirms that Nord Pool constitutes a different regional market.

Figure 2.3: Principal components analysis hourly wholesale electricity prices



As shown in table 2.4, DF and ADF tests reject the null hypothesis of non-stationarity, a part for Nord Pool. In particular, we find evidence of unit root at 48 lag length, hence two days before. However, the unit root rejection contrasts with figure 2.2, which shows a non-stationary pattern of the hourly series. The lack of unit root may be due to the short run nature of the data. Indeed, few hours are not sufficient to detect any deterministic or stochastic trend. Even if there is a trend – and it is likely that there is, since inflation is generally positive – the effect would be too small to distinguish from the statistical noise.

Table 2.4: Unit root test of hourly wholesale prices

Market	DF	ADF (24)	ADF (48)
EXAA	-34.610***	-8.616***	-9.157***
APX	-46.960***	-10.010***	-7.618***
EEX	-34.440***	-7.728***	-8.889***
Powernext	-31.740***	-6.887***	-7.778***
OMEL	-30.070***	-7.261***	-6.418***
Nord Pool	-12.000***	-2.965**	-2.6
IPEX	-48.620***	-11.910***	13.030***

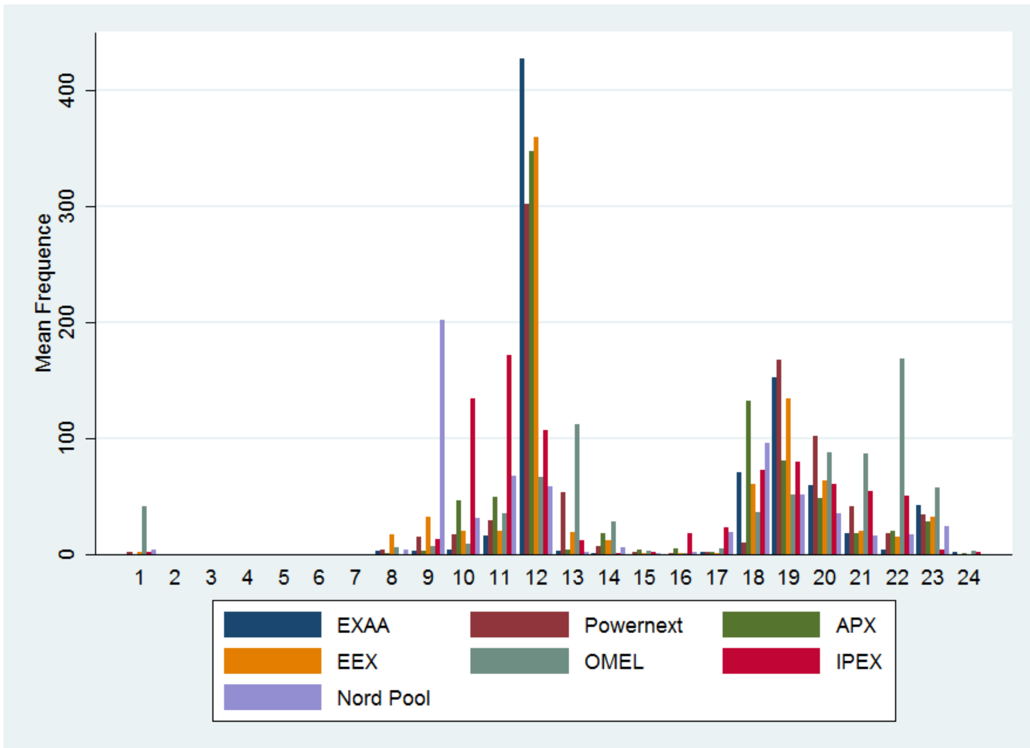
Critical values - 2.86 and -3.43 at 5% and at 1% significance level respectively

2.4.2 Examining daily mean, peak and off-peak wholesale electricity prices

In this section we propose the same analysis for the daily electricity prices. Starting from the hourly electricity price series we evaluate the daily mean, peak and off-peak. Figure 2.4 shows peak frequencies, we do not report off-peak frequencies, because in all the markets the off-peak is at midnight.

In the Austrian, German, French and Dutch wholesale markets the highest frequency of peak level is recorded at noon. Indeed, in Italy is recorded at 11, and in the Nordic countries the peak hour is mainly recorded in the early morning. The Spanish market shows a very different value, the peak hour is recorded principally at hour 22. This difference may be explained by the fact that in Spain all the activities are paused in the early hours of the afternoon (14-16). In addition another significant peak is shown at hour 13.

Figure 2.4: Peak hours frequencies



By way of example, we report in figure 2.5 the series for the Austrian market.[9] As in the case of hourly series, daily mean, peak and off-peak series are characterized by several spikes and jumps. Not surprisingly, they are higher in peak hours.

[9]Since the other markets show similar patterns, they are not shown.

Figure 2.5: Daily mean, peak and off-peak of EXAA series (€/MWh)

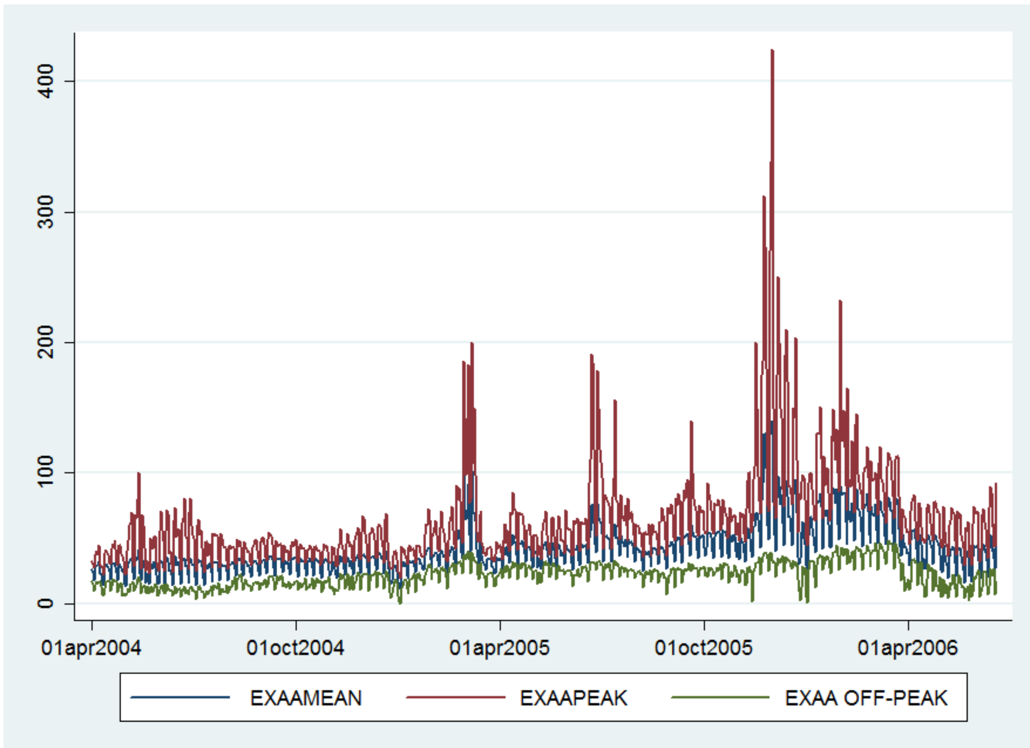


Table 2.5 reports the descriptive statistics for the daily wholesale electricity series. Austria, Germany and France show very close values in all the series. As in the case of hourly price, IPEX has the highest average and peak values. In addition, APX has the highest value of standard deviation in both the mean and peak series. Hence, the spread of the data around the mean has greater intensity than in other wholesale markets.

Table 2.5: Descriptive analysis of daily wholesale electricity prices

Series		Obs	Mean	Std Error	Min	Max
EXAA						
	Mean	810	41.7583	18.2991	11.4983	140.0025
	Peak	810	64.8825	40.4452	19.6300	425.0000
	Off-peak	810	21.6554	9.2952	0.0100	47.9300
APX						
	Mean	810	47.9690	23.4065	13.0000	250.6883
	Peak	810	107.7169	100.7686	22.5900	1000.1200
	Off-peak	810	21.5168	9.6720	0.0100	47.6500
EEX						
	Mean	810	41.4159	18.5281	12.0592	145.9654
	Peak	810	66.1798	51.7639	19.6500	699.8900
	Off-peak	810	21.5168	9.6720	0.0100	47.6500
Powernext						
	Mean	810	41.9918	20.4097	7.7599	154.7635
	Peak	810	66.3071	53.6209	8.2560	609.0350
	Off-peak	810	18.9854	10.8240	0.0380	67.9970
OMEL						
	Mean	810	46.0122	16.1754	17.2929	91.6554
	Peak	810	67.2527	23.7949	21.4700	127.0400
	Off-peak	810	29.4567	10.2389	3.3700	60.7500
Nord Pool						
	Mean	639	26.3681	13.5195	0.0000	58.6321
	Peak	639	37.1053	11.2924	22.4400	107.8800
	Off-peak	639	29.9403	8.7913	4.5000	54.7700
IPEX						
	Mean	810	59.1739	14.6847	1.2108	96.9726
	Peak	810	98.2147	33.8344	2.2577	199.2685
	Off-peak	810	28.8330	7.2481	1.0977	52.7097

In figure 2.6 we show the principal component analysis of daily peak electricity prices, which highlights interesting features. The figure identifies two main regional groups. The first involves Austria, France and Germany, whereas the second Nordic countries and Italy. Moreover, Spain is placed between these two regional groups. Instead, the Netherlands show some affinity with the first group.

Figure 2.6: Principal component analysis of daily peak electricity prices

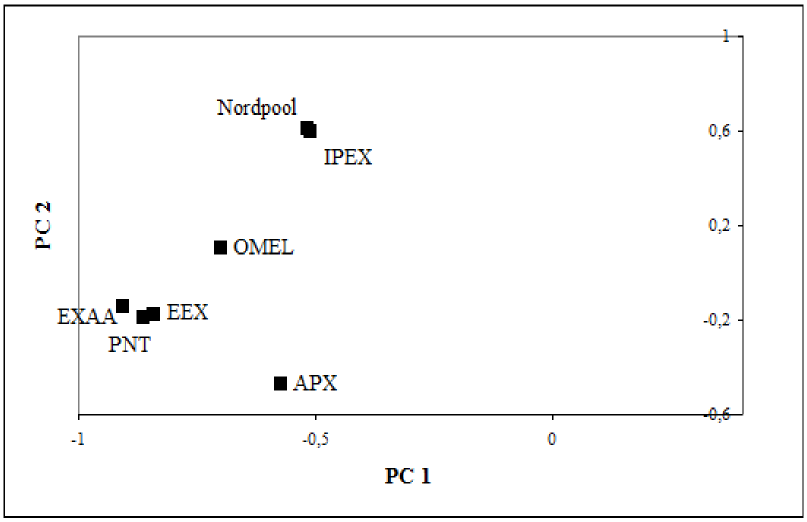


Table 2.6 reports the results of DF and ADF tests. According to the former all the series, apart Nord Pool, reject the null hypothesis of unit root. By contrast, the ADF test at 7 lag length, thus one week before, supports the non stationary nature of the data in the mean (OMEL and Nord Pool), peak (OMEL and Nord Pool) and off-peak (OMEL, Nord Pool and IPEX) series at 5% of significance level.

Increasing the lag length to 14, thus two week before, we find empirical support of unit root in the mean and off-peak series of all wholesale markets, except for Powernext. In addition, the analysis of the peak series shows that Netherlands, OMEL and Nord Pool prices are unit root processes.

Table 2.6: Unit root tests of mean, peak and off-peak

Series	EXAA	APX	EEX	Powernext	OMEL	Nord pool	IPEX
Mean							
DF	-8.998***	-8.272***	-9.462***	-8.035***	-5.983***	-2.675	-13.94***
ADF (7)	-3.091**	-2.940**	-3.058**	-2.935**	-2.641	-1.545	-2.711
ADF(14)	-2.779	-2.394	-2.854	-2.973**	-2.418	-1.894	-2.833
Peak							
DF	-10.76***	-11.22***	-12.39***	-10.73***	-5.759***	-2.503	-15.29***
ADF (7)	-3.430**	-4.620***	-4.353***	-3.881***	-2.649	-1.618	-3.440**
ADF(14)	-3.457***	-3.045	-3.829***	-3.652***	-2.433	-2.328	-3.560***
Off-peak							
DF	-7.886***	-8.432***	-9.167***	-8.08***	-5.623***	-2.866**	-8.693***
ADF (7)	-3.228**	-3.115**	-3.447**	-3.492**	-2.375	-1.697	-2.597
ADF(14)	-2.541	-2.603	-2.781	-2.931**	-2.248	-1.929	-2.619

Critical values - 2.86 and -3.43 at 5% and at 1% significance level respectively

The analysis of DF and ADF tests show the difficulties in detecting the presence of unit root in both hourly and daily series. For this reason, in the next section we study whether the daily mean, peak and off-peak electricity prices can be considered fractional integrated processes.

2.5 Model and results

European electricity restructuring aims to create a single market for electricity. Thus, over the long run, wholesale electricity prices quoted on different European power exchanges should converge.

A cointegration model is applied to analyze the relationship between wholesale prices quoted on different locations. The underlying idea of cointegration analysis is that if two markets are cointegrated, there will be a long-run equilibrium relationship between their price time series. According to the Johansen methodology, if two series show unit root (thus are integrated of order 1, denoted by I(1)), there may exist one or more linear combinations that are stationary (hence, integrated of order 0, denoted by I(0)). Following the Johansen methodology, if the series do not show unit root, they can not be tested for cointegration.

However, Granger (1981, 1983) proposes a broader notion of cointegration requiring that cointegrating linear combinations have lower orders of integration than their parent series. The term "fractional cointegration" defines the case where there exists an $I(d–b)$ linear combination of two or more $I(d)$ series, with $b \geq 0$. As discussed in the previous section daily electricity time series are characterized by the lack of unit root, but the series show a non-stationary pattern, thus they may be integrated of order d (with $d \neq 1$). To apply Granger technique, we first check for the order of fractional integration of the series. In particular, we apply Breitung and Hassler (2002) two-step procedure, which evaluates in the first step the fractional root of each series, then in the second-step constraints the fractional differencing parameter to be equal between pair of series. The analysis is applied to daily mean, peak and off-peak.

2.5.1 Model specification

According to Baillie (1996), fractional integrated processes are associated with hyperbolically decaying autocorrelations and impulse response weight. Hence fractionally integrated processes are long memory process. The presence of long memory is related to the persistence of observed autocorrelations that take far longer to decay than the exponential rate associated with the Autoregressive Moving Average (ARMA) class.

Following McLeod and Hiped (1978), given a discrete time-series process y_t with autocorrelation function: $\rho_j = \frac{\sum_{t=j+1}^{T}(y_t - \overline{y})(y_{t-j} - \overline{y})}{\sum_{t=1}^{T}(y_t - \overline{y})^2}$ at lag j, the process has long memory if the quantity:

$$\lim_{n \to \infty} \sum_{j=-n}^{n} |\rho_j| \tag{2.1}$$

is non-finite. Given the definition in (2.1), fractionally integrated processes are long memory processes and can be described by ARFIMA(p,d,q) model:[10]

$$\phi(L)(1-L)^d(y_t-\mu)=\theta(L)\varepsilon_t \tag{2.2}$$

where d denotes the fractional differencing parameter. All the root of $\phi(L)$ and $\theta(L)$ lie outside the unit circle, $(1-L)^d$ is the fractional differencing operator, μ is the mean and $\varepsilon_t \sim iid(0,\sigma^2)$ is a stationary process. [11]

The process y_t defined in (2.2), with $d \neq 0$, is considered integrated of order d (signified as $I(d)$). The autocorrelation function will decay according to hyperbolic law and for $-0.5 < d < 0.5$ the process is covariance stationary. In particular:

- for $-0.5 < d < 0$ the sum of the absolute values of the autocorrelations tends to a constant, hence it has short memory according to (2.1);
- for $0 < d < 0.5$ the autocorrelations are all positive and decay at a hyperbolic rate, hence the process has long memory as states in (2.1);

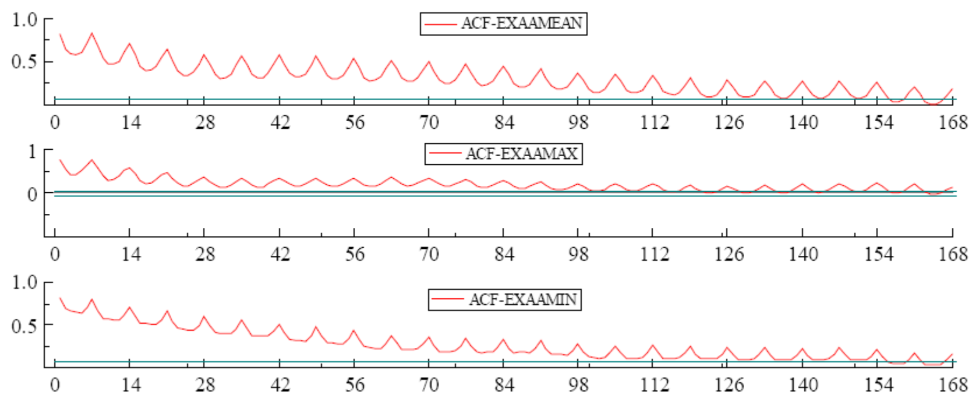
Equation (2.2) encompasses a special case for $d = 1$, in this case two time series are not cointegrated. Moreover, in the case $d < 1$ the process is mean-reverting, hence the effects of a shock on the wholesale electricity price slightly die out. Consequently, in the case $0.5 < d < 1$ the process is not covariance stationary and will remain mean-reverting.

Figure 2.7 shows, by way of example, the autocorrelation function at 168 lags of daily mean, peak and off-peak of EXAA. As shown in figure 2.7 the autocorrelation function decays according to a hyperbolic law, hence the series may have long memory.

[10] ARFIMA states for Autoregressive Fractionally Integrated Moving Average.

[11] Note that L is the lag operator and $(1-L)^d$ is given by the binomial expansion. Given an Autoregressive Moving Average process, ARMA (p,q): $y_t = \alpha_1 y_{t-1} + ...\alpha_p y_{t-p} + \varepsilon_t + \beta_1\varepsilon_{t-1} + ... + \beta_q\varepsilon_{t-q}$ can be rewritten as polynomials in the lag operator: $(1-a_1L-...-a_pL^p)y_t = (1+b_1L+...+b_qL^q)\varepsilon_t = \phi(L)y_t = \theta(L)$.

Figure 2.7: Autocorrelations of EXAA series



The autocorrelation functions show a weekly seasonal pattern and tend to decay at a hyperbolic rate. During a week it decreases from Wednesday to Sunday, on Monday it starts to increase slightly and achieves another spike on Wednesday.[12] In all the exchanges the weekly seasonal pattern in the daily mean, peak series is stronger than in off-peak. The spike difference is due to a less impact of the seasonal effect during off-peak hours. Indeed, at midnight the demand for electricity is lower than in other hours, nevertheless it is a Sunday or a Monday.

Since all the markets analyzed show the same weekly seasonal pattern, the latter will not be taken into account in the cointegration analysis without loss of significance.

2.5.2 A two-step procedure

In order to estimate the presence of fractional cointegration in the European electricity market, two necessary conditions must be satisfied. The first requires that $d > 0.50$ and the second that the cointegrated series have the same fractional order. A two-step testing procedure is therefore applied. The

[12]The first observation is on 1st April 2004 that was a Wednesday.

first step tests the hypothesis of integration against the fractional alternative. Only the series which satisfies the first test will be taken into account in the further analysis. The second step requires that the joint fractional root is the same in the cointegrated series. The fractional cointegration model is therefore applied to the daily series that satisfy the two-step testing procedure.

2.5.2.1 *Testing against fractional alternatives*

To test the presence of fractional root, we apply the test proposed by Breitung and Hassler (2002). Under the null hypothesis the test assumes that a univariate time series is an $I(d)$ process:

$$(1-L)^d y_t = \varepsilon_t \qquad t = 1, 2, 3, ..., T \tag{2.3}$$

where ε_t is a white noise process, against the alternative that y_t is $I(d+\theta)$. Alternately, the test can be defined assuming under the null hypothesis that:

$$x_t \equiv (1-L)^d y_t \qquad t = 1, 2, 3, ..., T \tag{2.4}$$

is a white noise process against the alternative that x_t is $I(\theta)$ with $\theta \neq 0$

.

Following the model proposed by Robinson (1991, 1994) and by Tanaka (1999) of fractionally integrated noise:

$$(1-L)^{d+\theta} y_t = \varepsilon_t \qquad t = 1, 2, 3, ..., T \tag{2.5}$$

where $\varepsilon_t \sim i.i.d.(0, \sigma^2)$ and $y_t = 0$ for $t \leq 0$, the test is defined as follows:

$$H_0 : \theta = 0 \qquad H_1 : \theta > 0 \tag{2.6}$$

The log-likelihood function is given by:

$$L(\theta,\sigma) = -\frac{T}{2}log(2\pi\sigma^2) - \frac{1}{2\sigma^2}\sum_{t=1}^{T}[(1-L)^{d+\theta}y_t]^2 \tag{2.7}$$

Table 2.7 reports the the test results. The test suggests that all the series exhibit fractional root except for Nord Pool series.[13]

Since a necessary condition of fractional cointegration is that the variables are integrated of order $d > 0.50$, then all the Italian series will not take into account in the following analysis. Both EXAA and OMEL show fractional root in all the series, whereas EEX and Powernext have fractional root only in the mean series. Moreover, the series, which show a d value very close to 0.50, (as in the case of off-peak series of APX and Powernext) will be taken into account.

[13] This is due to the fact that Nord Pool series are I(1) processes.

Table 2.7: Fractional root test results

Series		d	θ
Average	EXAA	*0.56631*	0.43369
	APX	0.4089	0.59109
	EEX	*0.55236*	0.44764
	Powernext	*0.57819*	0.42181
	OMEL	*0.58384*	0.41615
	Nord Pool	*0.85708*	0.14292
	IPEX	0.42379	0.5762
Peak	EXAA	*0.59318*	0.40681
	APX	0.30235	0.69765
	EEX	0.44882	0.55117
	Powernext	0.43774	0.56226
	OMEL	*0.53693*	0.46307
	Nord Pool	*0.9195*	0.0805
	IPEX	0.42609	0.57391
Off-peak	EXAA	*0.5269*	0.47309
	APX	0.48918	0.51082
	EEX	0.43558	0.56442
	Powernext	0.49805	0.50194
	OMEL	*0.54253*	0.45746
	Nord Pool	*0.91677*	0.08323
	IPEX	0.43018	0.56981

Note: All the results are statistically significant at 5%, apart for Nord Pool series. The value of d>0.50 are in italics.

2.5.2.2 ***Testing for a specific fractional root***

Fractional cointegration requires a second condition, the series must be integrated of the same order. Hence, the second-step procedure takes into account the uncertainty regarding d in its inference. A test to determine the joint fractional root is therefore performed. Given a series y_t, suppose that the fractional root is d_y and suppose that we would like to test whether d_y is equal to a specific fractional root d^*. Thus:

$$d_y + \theta = d^* \rightarrow d_y = d^* - \theta \tag{2.8}$$

then the fractional roots are equal if and only if $\theta = 0$. To establish the value of the joint fractional root the following test is defined:

$$H_0 : \theta = 0 \qquad H_1 : \theta \neq 0 \tag{2.9}$$

Thus, the test assumes under the null hypothesis that the fractional roots are equal ($d = d^*$), against their difference ($d \neq d^*$). As shown in table 2.8, in all the cases, the null hypothesis is not rejected. In particular, the fractional roots are equal to:

- $d^* = 0.55$ in the case of mean series;
- $d^* = 0.53$ in peak series;
- $d^* = 0.50$ in off-peak.

Table 2.8: Results of specific fractional root test

Series		θ	fractional root
Average	d= 0.55		
EXAA		0.000	0.5500
		(0.0163)	
EEX		0.000	0.5500
		(0.0164)	
Powernext		0.000	0.5500
		(0.0170)	
OMEL		0.000	0.5500
		(0.0054)	
Peak	d=0.53		
EXAA		0.000	0.5300
		(0.0097)	
OMEL		0.000	0.5300
		(0.0233)	
Off-peak	d= 0.50		
EXAA		0.000	0.5000
		(0.0237)	
APX		0.0020	0.4892
		(0.0209)	
Powernext		0.0019	0.4981
		(0.0209)	
OMEL		0.0000	0.5000
		(0.0000)	

Standard Error in brackets

2.5.3 Fractional cointegration analysis

According to Granger (1981, 1983), two time series $y_t \backsim I(d)$ and $x_t \backsim I(d)$ are defined fractionally cointegrated of order (d, b) if:

$$z_t = (y_t - \beta x_t) \sim I(d-b) \tag{2.10}$$

where $d > 0.50$ and $d \geq b > 0$. [14]

Thus, the two cointegrating series tend to move in closer to each other over the long run. This, implies that for two cointegrating series, the equilibrium error z_t is mean-reverting in spite of the wandering behaviour of y_t and x_t.

The presence of fractional cointegration has been estimated by the maximum likelihood function:

$$L(\theta, \Sigma) = -\frac{T}{2} log(2\pi|\Sigma|) - \frac{1}{2}\sum_{t=1}^{T}[(1-L)^{d+\theta}y_t^{'}\Sigma^{-1}(1-L)^{d+\theta}y_t]^2 \qquad (2.11)$$

Table 2.9 shows results of the fractional cointegration analysis. The analysis is applied only to the series that have satisfied the two-step procedure. In addition, we report only the results, which highlight a reasonable degree of convergence.

The overall results show a fair degree of convergence in the following cases: EEX (Germany) and EXAA (Austria); EEX (Germany) and Powernext (France); APX (the Netherlands) and EXAA (Austria) and APX (the Netherlands) and Powernext (France) .

We find evidence of perfect cointegration in the mean series of the Austrian and German wholesale markets. In fact, the residual memory is equal to zero. Moreover, we find a fair degree of convergence between the Austrian and Dutch off-peak series. Although these two countries are not neighbouring, the moderate degree of convergence may be due to the efficient interconnection capacity between Germany and Austria and between Netherlands and Germany. As regards to the French market, we find a discrete degree of convergence with the German wholesale market in the mean series.

[14] Granger has also provided an error correction formulation for fractionally cointegrated processes. If $y_t \backsim I(d)$ is a k-dimensional vector and z_t, is a set of cointegrating vectors such that $z_t = \alpha^{'} y_t \sim I(d-b)$, then Granger has shown the appropriate error correction representation is: $H(L)(1-L)^d y_t = -\gamma[1-(1-L)^b](1-L)^{d-b}z_t + C(L)\varepsilon_t$ where $H(0) = I$ and $C(1) < \infty$.

Finally, we do not find empirical evidence of convergence in the peak series. As shown in table 2.8, only OMEL and EXAA passed the two-step procedure. This result is due to two main features. On the one hand, these two countries are not neighbouring. On the other hand, congestions with their neighbouring countries, justify the lack of convergence between these markets.

Table 2.9: Fractional cointegration results

Series	y_t	x_t	θ	t-statistic	Residual Memory
Average d= 0.55					
	EEX	EXAA	0.5500	3.0603	0.0000
	EEX	Powernext	0.3106	2.6978	0.2394
Off-peak d= 0.50					
	APX	EXAA	0.3831	1.8694	0.1169
	APX	Powernext	0.2341	1.2285	0.2659

2.6 Conclusions

The analysis carried out in this chapter applies a fractional cointegration model in order to study the behaviour of European electricity prices over the long run. As pointed out, the lack of unit root in hourly and, partly in daily prices, does not allow the application of cointegration models according to Johansen's methodology (1988). However, the analysis of the autocorrelation function of daily series (mean, peak and off-peak) shows that it decays according to a hyperbolic law highlighting the presence of long memory.

Following Haldrup and Nielsen (2006), which argues that electricity prices are fractionally integrated processes, we apply Granger (1981, 1987) techniques of fractional cointegration to determine convergence in the wholesale markets analyses. Differently from Haldrup and Nielsen (2006), we apply Breitung and Hessler (2002) two-step procedure to identify the fractional order of integration of the series. Then, we apply Granger's technique.

Results show that only the German and Austrian wholesale markets are perfectly convergent. In particular, the German market shows a fair degree of convergence with French markets. The high degree of convergence is due to an efficient interconnection capacity characterizing this market, which is never congested. In addition, the German efficient transmission capacity may explain the fair degree of convergence between the Netherlands and Austria in the off-peak series.

As regards to the Italian and the Spanish markets, we do not find evidence of price convergence with any of the other electricity wholesale markets. In particular, the analysis shows that all the Italian series do not satisfy the necessary conditions to apply the cointegration analysis. This result is due to its insufficient interconnection capacity, which leads most of the time to a separation of the Italian market with respect the other European markets. On this point, the Fourth Benchmarking of the European Commission (2006) pointed out that Italy did not satisfied the EU requirements.

We can therefore conclude, as in previous studies, that insufficient interconnection capacity constitutes one of the most important barrier to develop a real efficient internal market for electricity in Europe.

Chapter 3

The impact of European electricity restructuring: evidence from generation price-cost margin

3.1 Introduction

The European restructuring process in the electricity market aims for the creation of a single integrated market in which competition and secure energy supply can be fostered. Traditionally, national electricity markets were characterized by vertical integrated firms, often publicly owned.

According to Jamasb (2002), Joskow (1998) and Newbery (2002), international experience from electricity liberalization has produced a measure of consensus on a series of steps necessary to achieve a well-functioning market oriented industry. Electricity restructuring requires a combination of the following features: vertical unbundling of generation, transmission, distribution and supply activities, third-party access and incentive regulation of transmission and distribution activities, establishing wholesale and retail markets, privatizing existing publicly owned firms and allowing entrance of new private players, and establishing an independent regulator.

The EU restructuring process established with the Directive 96/92/EC, also called the First Directive, defined common rules for the reorganization of national markets requiring a minimum harmonization level, hence leaving to Member States some choices for its implementation. As a result, 15 separate and divergent liberalized electricity markets have gradually emerged.

To reduce differences across national markets and to accelerate the liberalization process a Second Directive, 2003/54/EC, came into force imposing more restricting rules on: unbundling of production stages, compulsory institution of a national energy regulator and immediate market opening to all customers. Furthermore, a system of incentives has been introduced to improve the interfaces between national markets by strengthening cross border transmission links.

As regards to the evaluation of the effects of electricity market restructuring, in the literature there is a wide debate, both at European and International level, because these reforms appear to be costly but their benefits are difficult to evaluate.

This chapter aims to measure the impact of EU electricity reorganization on consumer welfare. In contrast to previous studies, we estimate the long-run effects of the EU policy allowing Member States to converge differently to long-run equilibrium as established by the harmonization principle characterizing the EU reform. We assembled a panel of data for the EU15 countries over the period 1980-2006. During this period, the EU reform has been established according to consumption thresholds, involving mainly industrial consumers, so we study its effects on this group of consumers. In particular, we examine the impact of the EU reform on profitability on industrial consumers, which is defined as the ratio of the difference between electricity pre-tax price paid by industrial consumers and generation marginal cost, to the price. Our data come mainly from two sources: the International Energy Agency and the OECD International Regulation Database. We use the former to characterize national electricity markets, whereas the latter defines the regulatory indicators such as degree of vertical separation, ownership structure, establishment of wholesale market and regulatory authority.

To anticipate, we find that privatization, wholesale market opening and regulatory authority reduces profitability on industrial consumers, hence increasing their welfare. By contrast, vertical separation increases industrial price-cost margin, hence shrinking industrial consumer welfare. Moreover, the analysis of national speeds of adjustment to long-run equilibrium shows that Italy and Germany have the highest and the lowest profit persistence respectively.

The organization of the chapter is as follows. The next section discusses the main features of the EU reform model and previous empirical findings. In section 3, we revise the principal developments of the Industrial Organization literature on industry-firm profitability and present the theoretical framework, which constitutes the base for our empirical specification. In section 4, we present the data and discuss the evaluation of the generation price-cost margin. In section 5, we outline our empirical model. In section 6, we present the empirical results, section 7 concludes.

3.2 The EU reform: main features and previous findings

In this section, we revise the key steps of the EU reform in the electricity sector and summarize its principal empirical findings.

3.2.1 The EU reform

Electricity markets can be classified into five activities: generation, retail, system operators, transmission and distribution. While the first two are potential competitive activities, the last two are natural monopolies. Moreover, an independent system operator is required to keep in balance demand and supply and to ensure the reliability of the industry.

A necessary condition to change a vertical integrated industry into a competitive market is the requirement that competitors (in generation and supply) have non-discriminatory access to the natural monopoly segments (transmission and distribution).

To develop a European single market for electricity two different policies have been introduced: a system of Directives that require in each Member States the adoption of at least a minimum set of steps by certain key dates, and a system of incentives to improve cross-border transmission links.[1]

The key principles to achieve the EU mandated goal of electricity restructuring can be summarized in wholesale and retail market opening, third-party access (TPA), unbundling and establishing a sector authority.

Market opening gives the possibility for both producers and consumers to negotiate freely the purchase and sale of electricity. On the demand side, the First Directive did not require full market opening, but specified the percentage share of the market to open gradually to competition.[2] In 2003, France and Greece opened only 34% of their markets, whereas UK, Germany, Austria and Spain opened the full market. To accelerate the process, the Second Directive introduced full market opening in all Member States requiring that all non-household consumers became eligible from 1 July 2004, and all consumers, thus including households, from 1 July 2007. Although the EU legislation allowed for different rates of market opening until 1 July 2007, after this date there has been one level playing field in the entire EU.[3] On the supply side, the Directives removed any obstacles which the incumbent

[1] First directive on price transparency (90/377/EG) of 29.6.1990 (for electricity and gas), then the one on electricity transit (90/547/EG) of 20.10.1990, finally directive 96/92/EC represents the last step to the liberalization of the electricity sector in the European Union.

[2] The threshold values were: 40 GWh by 1999, 20 GWh by 2000 and 9 GWh by 2003.

[3] Moreover, both directives established a reciprocity clause to avoid imbalance in the market opening. Supply contracts with customers in other member states could not be prohibited if the customer was eligible in both systems.

monopoly could impose on the construction of new power plants.

After allowing free negotiations, a further step to reform the market requires producers, suppliers and eligible consumers to have access to the transmission and distribution grids. For this purpose, the First Directive introduced either negotiated or regulated TPA according to transparent and non-discriminatory principles. In the former, consumers and producers must be able to negotiate access to the grid with the system operator, whereas in the latter prices are regulated, hence not subject to negotiations, and should be publicly available. Different access schemes, consequently several tariff regimes, remained as one of the main obstacles to the realization of the internal electricity market. To reduce such differences the Second Directive recognized the regulated TPA as the unique regime.

Given the separation of network and supply activities, the Directives required unbundling of accounts to avoid any cross-subsidization between different types of activities. As before the regulation introduced by the First Directive was weaker than the Second. The former required only separate balance sheet for each activity, whereas the latter required vertical separation between transmission and the rest of the industry from the 1 July 2004, and between distribution and the rest of the industry from the 1 July 2007. According to the European Commission benchmark (2005), four levels of separation have been adopted: ownership separation, legal separation, management separation and accounting separation. Among the four, accounting separation is the weakest: the company keeps accounts for its network and competitive activities, and must charge to the competitive businesses the same fees for using the network as it charges third parties. Indeed, ownership separation is the strongest: the institution of an independent organization allows to remove the incentives to favour one market player over the others. Management and legal separation can be placed in the middle.[4]

[4] In the case of management separation different people are responsible for the network and the competitive activities, whereas in the case of legal separation a separate legal entity is responsible for the management of the network. Differently from ownership separation,

Furthermore, electricity restructuring needs all the players to have non-discriminatory access to the grid. To avoid any abuse in the negotiations the First Directive required Member States to designate a competent and independent authority to settle disputes on contracts and negotiations. Most Member States appointed the antitrust authority, while others established an appropriate regulator, especially in the case of regulated TPA applies. The co-existence of a regulator and dispute settlement authority led to discussions about the division of the authorizations. To overcome these problems and to improve efficiency of the reform, the Second Directive required to Member States to set up an independent regulatory agency.

Effective competition also needs a well functioning wholesale market. Only, the Second Directive contained a reference to the role of power exchanges in electricity trading. Moreover, restrictions on access to cross-border networks and reciprocity are applied indirectly.

3.2.2 Previous findings on the EU reform

The empirical literature studies the impact of electricity restructuring according to the structure-conduct-performance model and evaluates its effects on either consumer welfare or firm profitability. In the former the analysis is based on cross-country data, whereas in the latter on cross-country firm-level data.

In this section, we summarize the main results of four studies, three on consumer welfare and one on firm profitability. The first two use OECD data (and therefore EU data), while the others focus explicitly on the EU countries.

Among the several works, which study the effects of electricity restructuring on consumer welfare, Steiner's study (2001) constitutes the baseline model. She analyses the reform impact in the generation segment assessing

the staff working for the network business will be aware of the financial interests of their parent organization and its competitive activities, and may take decisions in their favour.

potential competitive and cost efficiency effects resulting from the deregulation process. The former is based on the analysis of the industrial price and the ratio of industrial to residential price to evaluate whether the reform reduces price or increases efficiency of the relative prices. The latter is based on the generation capacity utilization ratio and generation reserve margin to determine whether the reform increases efficiency in the use of capital. The study is applied to a panel data of 19 OECD countries, mostly European, over the period 1986-1996.[5] Results show that unbundling of generation and transmission, which is statistically insignificant, reduces industrial prices and leads to a lower price ratio. It also increases capacity utilization rates and decreases reserve margins statistically significantly. Moreover, the introduction of either negotiated or regulated TPA lowers prices, but statistically insignificantly. The establishment of a wholesale market reduces statistically significantly both the industrial price and the price ratio. Finally, the study shows that privatization leads to a statistically significant increase in both the industrial price and the price ratio, but does not have a significant effect in terms of cost efficiency.[6]

Following Steiner (2001), Hattori and Tsutsui (2004) re-examine the impact of regulation on prices using a similar panel data for OECD countries, but over a longer period 1987-1999.[7] As in Steiner (2001) they define several indicators to measure the reform impact.[8] Differently from Steiner the analysis of the industrial price shows a statistically significant reduction due to

[5] The analysis therefore constitutes a preliminary test to evaluate the reform effects given that the first EU directive was enforced only by 1996.

[6] According to Steiner this result might be due to government's attitude to raise electricity prices to sell assets and generate revenue.

[7] The reform impact is evaluated on either industrial prices and the ratio of industrial to households prices.

[8] The set of indicators is quite similar to Steiner's model. The main differences concern the definition of unbundling and TPA. In the former, they consider only legal separation between generation and transmission, whereas in the latter they account for the institution of a retail market. In particular, they distinguish between partial and total retail market opening.

TPA and privatization, but an increase due to the establishment of a wholesale market. They argue that such differences might be attributed to an increase in the transaction costs resulting from unbundling of generation and transmission. Moreover, the unexpected reduction of the industrial price due to the institution of wholesale market may be due to the exercise of market power by generators.

The comparison of these two works shows the difficulties in evaluating clearly the effects of the reform in its early stages. As argued by Pollitt (2009) it is not clear whether the different results in Hattori and Tsutsui (2004) should be attributed to the composition of the sample, because a significant number of countries reformed quite late in the sample period.

An explicit analysis of the EU reform impact is defined in the work of Fiorio et al. (2008), in which they use a panel of data for the EU15 countries over the period 1978-2005 to study the effects on domestic electricity prices. The EU reform effects are measured using weighted indicators to account for public ownership, vertical integration and entry regulation. These indicators take a value in a range from 0 to 6, where the lowest values indicates a more competitive structure (0 = no public ownership, 0 = no entry regulation and 0 = no vertical integration). They find that none of the reform variables is individually statistically significant. Moreover, the estimated coefficients of vertical integration and entry regulation have the expected signs. As their indexes decrease, the price decreases as well. However, concerning the ownership structure as the index decreases, indicating a more privatized structure, the price increases.

As regards firm profitability, Zarnic (2009) examines the effect of EU restructuring on a full sample of 676 firms over the period 1995-2007. Moreover, he divides the sample into two subsamples according to the enforcement of the Second Directive. The analysis shows that reforms have gradually decreased the markups. However, actual markup premiums of incumbent firms are on average larger than theoretical models would predict under effective economic integration. This result is in line with previous findings (c.p. Wolfram, 1999) which argued that imperfectly competitive outcomes are largely due to insufficient unbundling, rigid financial contracts and limited cross-border arbitrage of electricity constrained by poor investments into the interconnection grid.

3.3 Modelling profitability

We begin this section by discussing the structure-conduct-performance literature, which highlights useful insights for the further definition of the theoretical framework. We do not attempt to survey the results of this literature, but instead analyze its main developments to justify our empirical strategy.

3.3.1 Firm profitability, market structure and market share

The relationship between firm profitability and market structure has always been a core topic of Industrial Organization (IO) literature. The pioneer study of Bain (1956) on firm profitability identified its main causes in barriers to entry, such as economies of scale and scope, and market concentration. Starting from this study the structure-conduct-performance (SCP) paradigm dominated the IO literature until the 1980s. The paradigm assumes that market structure, the number and size distribution of firms, determines market conduct, the way in which firms interact in an industry, which in turn determines firm performance, hence profitability. Typically, these studies used cross-country regression analysis based on Standard Industrial Classification (SICs) and regressing average profit rates on a number of market-wide variables, such as horizontal concentration, measures of economies of scale and scope and other indicators to assess entry barriers. According to these studies, high firm profitability was the result of the exercise of market power.

Moreover, the relationship between market structure and firm profitability was generally found positive, but not necessarily significant.

During the 1970s, these studies were subject to more and more criticism under both theoretical and empirical fronts. On the one hand, theorists claimed that the SCP paradigm was not based on a rigorous theoretical framework. The revolution introduced with the establishment of game theory posed under question the notion that market structure could be considered exogenous. Indeed, game theory models assume that market conduct is exogenous, presuming for example a Cournot or a Bertrand framework, in an attempt to endogenize entry and firm performance. On the other hand, empiricists criticized that many indicators used to control for entry barriers, such as advertising and R&D, were potentially endogenous leading therefore to biased results. Moreover, they pointed out that SICs, which contains broad information, could not be used to represent markets.

The above critiques produced two main results: the definition of theoretical models yielding the SCP predictions, for example Stigler (1964), and the application of SCP to heavily concentrated sectors, such as banking and agriculture, in place of SICs, as well as to economies in transition.

Furthermore, the main critique to the SCP model came in the early 1970s by the "Chicago-school", which claimed that high firm profitability is not due to the exercise of market power, rather is the result of competition and market efficiency. According to Chicago economists markets are workably competitive, but firms are characterized by different efficiency levels. Only efficient firms grow, increasing their market share, while less efficient firms shrink, losing market shares and eventually exit from the markets. As a result, asymmetric markets and high concentration level are due to efficiency. Thus, the positive relationship between market structure and firm profitability is a consequence of efficiency and not of market power.

The above discussion points out two extreme predictions according to market power and market share models. While the former, conditional on market structure, predicts that horizontal concentration alone determines firm profitability, hence market share should not matter; the latter, conditional on firm's market share, predicts that horizontal concentration should not determine firms profitability. In addition, as regards to small firms, Bain (1951) argued that these firms are less profitable because they can not take full advantage of economies of scale.

Although market power and market share models identify different causes to explain firm profitability, empirical analysis supports both theories. For example, Cowling and Waterson (1976), assuming a Cournot framework with homogeneous product, showed that firm price-cost margin is directly proportional to its market share, and that an index of industry price-cost margin is directly proportional to the Herfindahl-Hirshman index. Dickson (1998), starting from Cowling-Waterson's result, showed that in a dominant model with competitive fringe, an index of industry price-cost margin is directly proportional to a k-firm concentration ratio.

In the second half of the 1970s, the increase of international trade questioned the role of foreign trade on profitability and concentration. The increase of international trade led to recognize that domestic markets are imperfectly competitive rather than perfectly competitive as defined by traditional trade theorists. Foreign trade has been therefore considered as a way of expanding national markets and of making room for more efficient-size sellers in the domestic market. Consequently, import penetration can lead to lower domestic price-cost margin by preventing both implicit collusion among domestic firms and domestic firms to control imports.[9] The increase of foreign trade has therefore pointed out that market concentration can be used as a proxy of domestic market competition, but it does not account for the actual competition that is affected by international trade. Thus, the inclusion of foreign trade variables into the structure-performance model allows to account for a reduction of market distortions due to imperfect competition.

[9]It is also necessary to prevent collusion between domestic and foreign firms.

Another criticism to SCP model, at least regarding its empirical application, concerned the issue of dynamic adjustment. Firstly, Brozen (1971) and Demsetz (1973) argued that a static analysis neglects important information about the causes of firm profitability, then a wide literature on profit persistence has been developed assuming that competition is a dynamic process. According to Goddard and Wilson (1999) future market outcomes are the results of the forces of competition on the present state of the world, which in turn depend on past market outcomes. Firm conduct is therefore affected by exogenous shocks, for instance cost or demand shocks, which move them away from their long-run equilibrium, with the intensity of competition determining how fast they return to the equilibrium.

To complete our analysis we should also consider the most recent developments of the theory, which introduced the relationship between market structure and consumer welfare. Specifically, in the 1980s and the 1990s the so-called post-Chicago school studied the behaviour of incumbent monopolist facing a single potential entrant to illuminate the effects on consumer welfare. According to these theorists incumbent plays aggressive strategies (namely aggressive pricing, exclusive dealing, bundling) to avoid entrance, engaging therefore in anti-competitive conducts. As a consequence, consumer welfare shrinks.

However, in the 2000s the post-Chicago school approach has been criticized by the market leader theorists. This novel approach claims that leading market position associated with aggressive strategic investments can be the consequence of competitive market environment and not the results of market power. The main difference with the post-Chicago school framework regards the assumptions on entry. While the post-Chicago assumes that entry is exogenous, modelling an incumbent facing a single potential entrant, market leader theorists assume that entry is endogenous. Moreover, Etro (2007) shows, assuming competition in quantity, high fixed and constant marginal costs, that when entry is endogenous the leader has incentive to produce aggressively to deter entry and, at the same time, exploits scale economies. In this framework, consumer welfare is higher welfare than the free entry equilibrium without a leadership.

3.3.2 The Theoretical framework

The prior analysis points out that firm-industry profitability is the result of the combination of concentration, market structure, firm-industry efficiency and international trade. Jacquemin (1982) defined a theoretical model which accounts for such features and which provides the theoretical framework for our empirical specification.

Assume a Cournot model with n-domestic firms producing a homogeneous product and facing an inverse demand function defined as:

$$p_d = f(q_d + q_m) \tag{3.1}$$

where p_d is the domestic price, q_d is the domestic output and q_m is an exogenous level of imports in this industry. [10]

The profit equation of a domestic firm i is given by:

$$\Pi_i = f(q_d + q_m)q_{d_i} - c_i(q_{d_i}) - F_i \tag{3.2}$$

where $c_i(q_{d_i})$ is its variable cost and F_i is the fixed cost. Maximizing (3.2) with respect to q_{d_i} gives the equilibrium condition for any domestic firm i and rearranging we get:

$$L_{d_i} = \frac{p_d - c_i'}{p_d} = \frac{1}{\varepsilon_d}\frac{q_{d_i}}{q_d}\frac{q_d}{q_d + q_m} \tag{3.3}$$

where L_{d_i} is the domestic Lerner index for firm i and ε_d is the price elasticity of domestic demand.

[10] Import supply is assumed perfectly inelastic, hence import supply does not respond to domestic prices.

Aggregating over the n firms in the industry we get:

$$L_d = \frac{p_d q_d - \sum_{i=1}^{n} q_{d_i} c_i'(q_{d_i})}{p_d q_d} = \frac{H_d}{\varepsilon_d}(1 - t_m) \tag{3.4}$$

where H_d is Herfindahl term measuring the domestic producer concentration and $t_m = \frac{q_m}{q_d + q_m}$ is the rate of imports.

Assuming marginal costs equal to average variable costs, $c_i'(q_{d_i})$, the Lerner index in the left hand-side of equation (3.4) becomes the industry rate of gross return on domestic sales. Thus, equation (3.4) shows a negative relationship among price-cost margin and domestic price elasticity of demand, a measure of potential competition, and import penetration rate, a measure of actual competition. Moreover, it shows a positive relationship between the price-cost margin and the Herfindahl term, a measure of concentration in the domestic market. Hence, the domestic price-cost margin will be higher, the higher the "domestic product concentration"; it will be lower, the more elastic the domestic demand and the higher the rate of imports. These results hold in the case domestic firms are unable to control imports.

Although Jacquimin (1982) assumes a Cournot framework, Urata (1984) has shown that the above predictions hold in a conjectural variation oligopoly model.

3.4 Data and preliminary data analysis

To assess the impact of the EU reform model on profitability on industrial consumers, we define a data sample of the EU15 countries over the period 1980-2006. This interval was chosen according to both data availability and the definition of benchmark levels. Although the restructuring process took place in the last third of the sample, except for UK, the earlier period allows to establish benchmark levels of the dependent variable, and to reduce potential biases, which may arise in the use of short panel. Because of missing observations, our panel is unbalanced and the total number of observations is 367.[11]

The data have been collected from several sources. Data on electricity sector (industrial electricity prices, generation production and capacity, factor prices for thermal electric generation, input factors and real growth rate of GDP) have been retrieved from the International Energy Agency. Data on nuclear generation such as uranium prices and uranium requirements have been retrieved from the International Atomic Energy Agency (IAEA), Nuclear Energy Agency (NEA) and Euratom.

Data on EU reform have been retrieved from the OECD International Regulation Database, which contains information about the degree of vertical integration and ownership structure of incumbent firms. Instead, key dates on the establishment of wholesale markets and national electricity authority have been collected from their websites.

In the following sections, we discuss the evaluation of the price-cost margins, which entails the evaluation of the marginal cost. Then we present the variables defined to control for industrial profitability on the basis of the Jacquemin model (1982).

3.4.1 Price-cost margin definition and evaluation of industry marginal cost

We assume that marginal cost is equal to average variable cost, which comprises fuel cost and operation and maintenance (O&M) expenses. Due to data unavailability of O&M costs at country level, our measure of marginal cost accounts only for fuel costs.

Generation plants are classified in fossil fuel, nuclear and hydroelectric plants. For each category, the evaluation of fuel cost is characterized by specific features, which we discuss in the following. However, it is important to bear in mind that due to data unavailability at country level on plants

[11] Missing observations are 38 and are related to Luxembourg (the series ends in 1989), Belgium (2003-2006), Netherlands (2002-2006), Sweden (1998-2006) and Greece (2006).

efficiency rates and fuel costs per electricity generation, our evaluation is a proxy of fuel costs.

As regards to fossil fuel production, fuel costs represent the main determinant of marginal cost accounting for roughly 80% for coal and oil, and for more than 90% for natural gas generation. In general, the evaluation of fossil fuel costs is a function of fossil fuel price, plant efficiency and fuel heat rate. As a proxy of fossil fuel price for electricity generation, we use a EU15 average price for each fossil fuel.[12] Moreover, to account for plant efficiency we define the ratio of country electricity production to fuel input as proxy of country efficiency in production. As regards to nuclear production, the evaluation of marginal cost is more complex, because it is necessary to consider the different phases of fuel cycle and the specific requirement of uranium to produce a KWh. Moreover, differently from fossil fuel production, uranium price constitutes only 26% of nuclear marginal cost, while O&M accounts for 74%. According to IAEA, uranium cycle comprises the following phases: uranium cost (35%), enrichment phase (35%), waste fund (17%), fabrication (9%) and conversion (4%). Given data unavailability on the cost of each phase, but knowing the uranium price, we evaluate nuclear fuel cost applying a percentage on the base of uranium cycle and determining the uranium price \$/KgU.[13] The evaluation of the specific requirement of uranium to produce a KWh is defined as the ratio of uranium requirement of nuclear power station to nuclear station power generation. As reported in the Red Book of NEA (2005), the former was equal to 67,320 tU and the latter to 2,638TWh, their ratio yields on average to 0.0255gU per KWh.[14]

[12] Data have been collected from the IEA database. Due to missing observations in the EU15 series, we fill missing values imputing the EU15 generation cost for each type of fuel on country generation cost where available.

[13] As uranium price we use a weighted average of uranium price per multi-annual contracts and spot contracts, assigning a higher weight to the former because the majority of contracts are multi-annual (roughly 87%).

[14] We use the world average requirement of 2004 for all the sample, for two main reasons. First, during the period 1980-2006 the nuclear production has been quite constant. Second, the majority of world nuclear plants are in France.

Finally, the evaluation of hydroelectric marginal cost is based on the assumption that they are zero marginal cost plants due to their negligible amount.[15]

Table 3.1 shows the following average values: industrial electricity price, production per plant category, weighted average fuel costs and the industrial price-cost margin. Moreover in table 3.2 we report the main statistics per country.

Table 3.1: Industrial electricity prices, average variable costs and price-cost margin

Variable	Units	Obs	Mean	Std. Dev.	Min	Max
ind_price	$/KWh	367	0.061	0.020	0.022	0.163
hydro_prod	GWh	405	19116	21968	0	78835
nuclear_prod	GWh	405	47231	88838	0	451529
coal_prod	GWh	405	48897	80687	0	328728
oil_prod	GWh	405	12785	23485	0	120800
gas_prod	GWh	405	18497	30562	0	158079
mc_nuclear	$/KWh	405	0.002	0.002	0	0.007
mc_coal	$/KWh	405	0.025	0.012	0	0.116
mc_oil	$/KWh	405	0.046	0.027	0	0.213
mc_gas	$/KWh	405	0.037	0.022	0	0.190
AVC	$/KWh	405	0.019	0.009	0.002	0.042
pcm	unit	367	0.676	0.145	0.226	0.927

As shown in table 3.2, among the countries which have no missing observations, France is the country with the highest price-cost margin (0.845) followed by Austria (0.816). The country with the lowest price-cost margin is Ireland (0.556), followed by UK (0.605).

[15] Alternatively, the literature assumes a strategic use of hydro production. The hydro cost is defined as the opportunity cost of thermal electric plants, it replaces marginally in each period. For simplicity, we assume that hydroelectric production has a zero marginal cost.

Table 3.2: Statistics by country

Country	Industrial Price Obs.	($/KWh)	Production (TWh) hydro	nuclear	coal	oil	gas	TAVC ($/KWh)	pcm
AT	27	0.061	33.79	0	5.81	2.30	7.45	0.011	0.816
BE	23	0.058	1.29	39.37	15.85	3.44	10.08	0.015	0.74
DK	27	0.059	0.03	0	24.27	2.60	3.99	0.027	0.515
FI	27	0.051	12.84	19.72	15.98	1.33	6.21	0.014	0.729
FR	*27*	*0.046*	*63.71*	*320.84*	*37.08*	*11.21*	*7.89*	*0.007*	*0.845*
DE	27	0.068	21.28	141.92	308.63	10.69	46.91	0.021	0.68
GR	25	0.054	3.57	0	25.96	7.96	2.29	0.026	0.534
IE	27	0.068	1.09	0	6.75	3.24	6.40	0.029	0.556
IT	27	0.081	39.82	1.49	31.37	91.89	58.78	0.025	0.67
LU	10	0.05	0.72	0	0.24	0.03	0.62	0.015	0.678
NL	22	0.054	0.06	3.79	22.84	5.48	44.32	0.029	0.467
PT	26	0.086	9.69	0	9.10	8.41	2.92	0.02	0.762
ES	27	0.064	29.04	46.84	61.51	18.00	16.23	0.015	0.732
SE	18	0.034	63.97	63.40	2.31	3.11	0.38	0.005	0.822
UK	27	0.063	5.85	71.10	165.77	22.09	62.98	0.025	0.605

3.4.2 Modelling industry profitability in the EU reform model

The previous discussion on firm or industry profitability suggests that industry profitability can be defined as follows:

$$pcm = f(C, E, X, B) \tag{3.5}$$

where the price-cost margin is a function of variables reflecting the competitiveness of the market (C), market elasticity of demand (E), market efficiency (X) and entry barriers (B). We therefore define the following variables and report in table 3.3 their descriptive statistics and average values per country.

Competitiveness

We measure market competitiveness distinguishing between domestic and actual competition. The former is defined accounting for domestic market concentration, whereas the latter for import penetration. Given data unavailability on firm market shares over the entire sample span, we control domestic concentration accounting for the presence/absence of a dominant player in the generation activity. We therefore define a dummy variable (CR1), which takes value 1 if the incumbent in the generation activity has a market share less than 33% and, 0 otherwise. This threshold value has been chosen according to IO theory, which presumes the presence of a dominant firm if its market share is higher than 33%.[16] In the sample analyzed only Austria, Denmark, Finland, Germany, Spain and UK do not have a dominant player.[17]

As a proxy of import penetration, we define the variable (TRADE) according to the ratio of imports minus exports to domestic consumption. This variable allows us accounting for net importer and exporter countries. As shown in table 3.3 France is the most important EU net exporter, followed marginally by Austria, Sweden and Denmark. Indeed, Luxembourg is the most important net importer, followed by Italy and Netherlands.

Market Demand Elasticity

Electricity sector is characterized by inelastic market demand. The inclusion of a constant variable over time does not allow to capture changes in the price-cost margin due to business cycles and macro effects. As a proxy for price elasticity of demand, we therefore use the real GDP growth rate (RGDP). The countries with the highest and lowest real GDP growth rate are Ireland and Italy respectively.

[16] The market share of the largest operator is defined as the ratio of total net electricity generation to total national net generation.

[17] In particular, they do not have a dominant player in the following years: Austria (1999-2000), Denmark (2002, 2005), Finland (1999-2006), Germany (2000-2006), Spain (2006) and UK (1996-2006).

Market efficiency

Market efficiency is defined to reflect differences among countries related to input availability and capital utilization. The former is defined according to oil import price $/bbl (OIL) per country, which has always been the main driver of electricity price.[18] We deflate the oil import price using the OECD consumer price index (OECD 2000) and is thus in constant dollars. As shown in table 3.3, the average oil import cost is 39 $/bbl. Moreover, the country with the highest oil import cost is Greece almost 90 $/bbl, followed by Portugal with 61 $/bbl.

As a proxy of capital utilization, we use the capacity utilization rate (CAP_UTI), which is defined as the ratio of the difference between potential output and actual output (net production) to potential output. Potential output is evaluated considering the yearly net-electrical capacity per country and multiplying it by 8760 hours (or by 8784 hours in the case of leap year), which yields the potential output assuming no interruptions due to maintenance. Since we do not account for maintenance, our measure over evaluates country capacity utilization. Among the others, Germany has the lowest differential between potential and actual output, followed by Austria, Finland and UK. Not surprisingly, Luxembourg has the highest differential between potential and actual output.

[18] In the case of Luxembourg due to missing data on oil import price, we use the average EU15 oil import price.

Table 3.3: Descriptive statistics explanatory variables

Variable	Obs	Mean	Std. Dev.	Min	Max
rgdp	405	2.635	2.184	-6.200	11.700
oil	405	38.931	42.536	12.344	438.759
trade	405	0.084	0.233	-0.476	1.022
cap_uti	405	0.517	0.127	0.213	0.917

Statistics by country

	Mean			
	rgdp	oil	trade	cap_uti
Austria	2.252	32.043	-0.025	0.601
Belgium	2.074	29.908	0.024	0.409
Denmark	2.100	33.117	-0.002	0.617
Finland	2.715	32.827	0.097	0.424
France	2.148	33.626	-0.122	0.460
Germany	1.941	30.355	0.004	0.328
Greece	2.130	89.959	0.038	0.495
Ireland	5.296	34.197	0.011	0.522
Italy	1.807	38.773	0.137	0.530
Luxembourg	4.522	30.491	0.879	0.850
Netherlands	2.381	29.046	0.111	0.459
Portugal	2.641	61.006	0.073	0.556
Spain	2.959	38.658	0.001	0.563
Sweden	2.204	34.558	-0.005	0.498
UK	2.359	35.398	0.031	0.438

Entry Barriers

We define four variables to account for entry barriers according to the EU restructuring process.

- Wholesale spot market: The institution of a wholesale spot market is due to the possibility to facilitate competition in the generation segment and to encourage new firms to enter in the market. Thus, we define a dummy variable (WHOLE) which takes value one if there is a wholesale market and, zero otherwise.

Figure 3.1: Establishment of wholesale markets

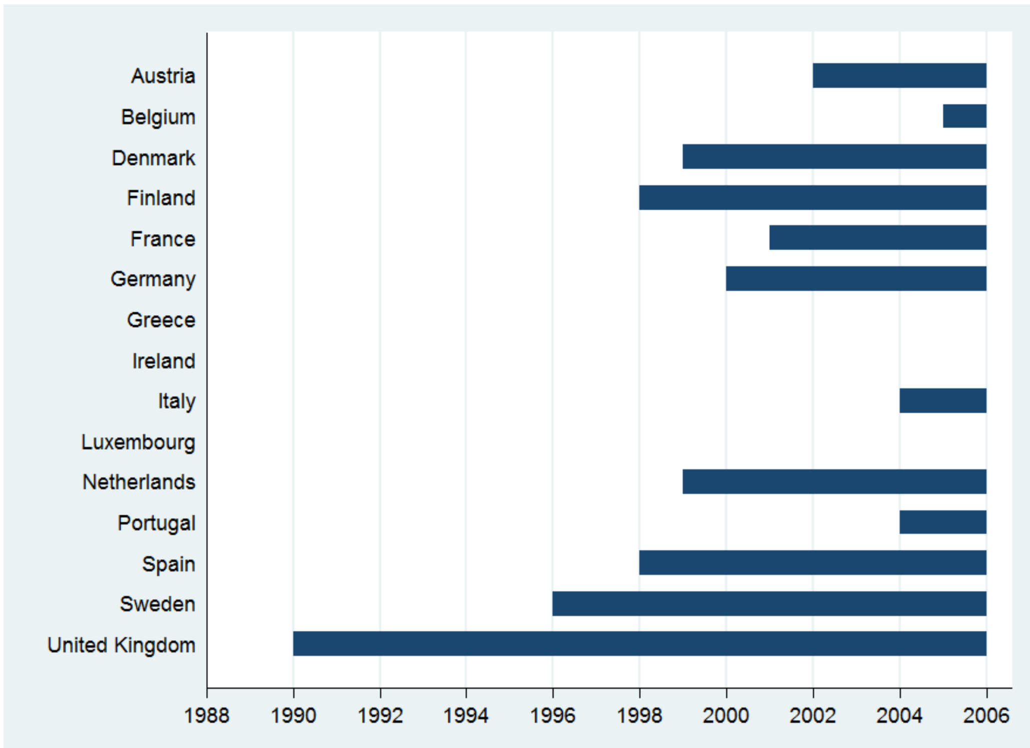


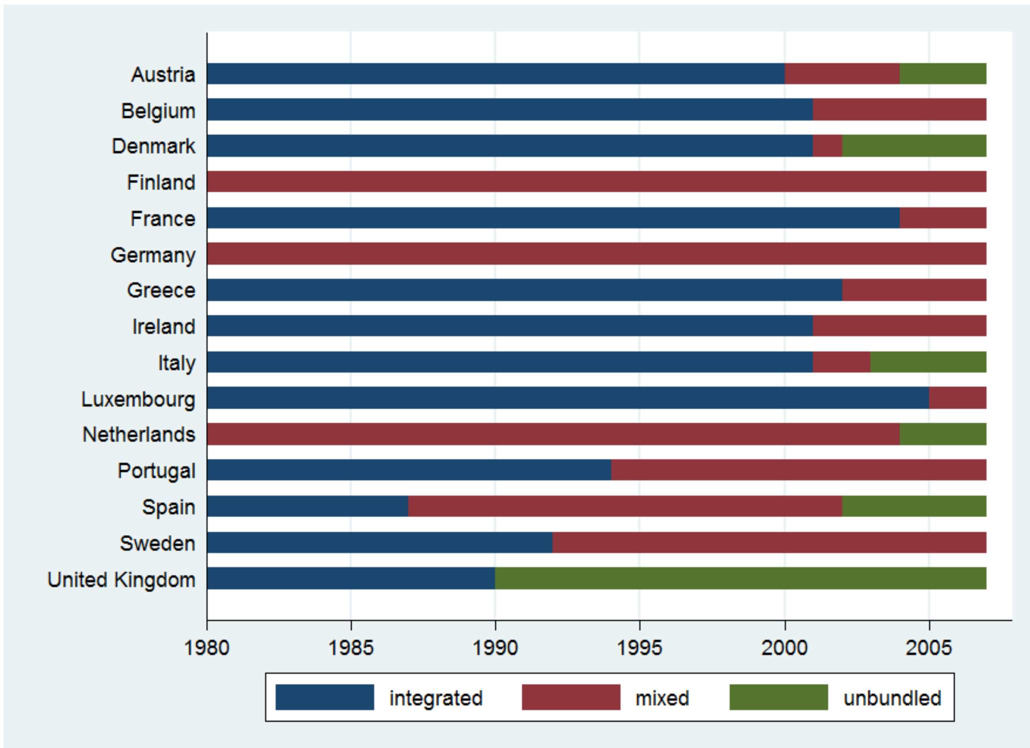
Figure 3.1 shows the establishment year of wholesale markets in the sample analyzed. The first country, who established a wholesale market, was the UK in 1990. As regards to the Nordic countries, Sweden joined Nord Pool in 1996, followed by Finland in 1998, by Western Denmark in 1999 and by Eastern Denmark in 2000.[19] Spain established OMEL in 1998, then together with Portugal, institutes the integrated market MIBEL in 2004. Netherlands established APX in 1999, France Powernext in 2001 and Italy IPEX in 2004. As regards to Germany, the actual wholesale market EEX is the result of a merger between two power exchanges, Leipzig and Frankfurt, both established in 2000,

[19] In the case of Denmark, we consider that the establishment of the wholesale market was in 1999, because it constitutes the year of a first market opening.

which took place in 2002. We therefore consider 2000 as the year of wholesale market opening in Germany. Finally, the trading activity in Greece, Ireland and Luxembourg started in 2007.

- Vertical separation: The EU reform model identifies in vertical separation, of generation, transmission, distribution and supply activities, a prerequisite to create a single EU electricity market. Effective unbundling of generation from transmission activity is conditional to the institution of an independent Transmission System Operator (TSO). Only, ownership separation can remove the incentives to favour one market player over the others. The OECD Regulation database contains information about the overall degree of vertical integration of national markets distinguishing: integrated (if electricity activities are integrated), mixed (if electricity activities show a medium degree of separation) and unbundled (if electricity activities are not integrated). On the base of this classification, we define three dummy variables: INTEGRATED, MIXED and UNBUNDLED to account for vertical disintegration. We use INTEGRATED as the default case.

Figure 3.2: Degree of vertical integration



According to figure 3.2, national markets show different degrees of vertical integration. The change from a vertical integrated industry to an unbundled one has been gradually realized. Only the UK moved directly to an unbundled industry. Moreover, most of the national markets (Austria, Belgium, France, Greece, Ireland, Italy and Luxembourg) have been characterized by vertical integration for most of the sample period.

- Privatization: In the literature, there is a wide debate on which model of ownership structure is preferable. As argued by Vickers and Yarrow (1988) privatization can lead to efficiency improvements and cost savings due to incentive arguments. A diversify ownership allows to facilitate direct competition in the generation and supply activities and introducing comparative performance in the networks. Privatization is not a prerequisite to foster competition in the electricity market. Competition and incentive regulation can be applied to publicly owned firms. However, as argued by Newbery (1999 and 2002a) privatization delivers several benefits especially when combined with restructuring, competition and regulation. For these reasons, many reforming countries have sold off publicly owned firms allowing new private firm to enter in the market. The OECD Regulation database provides information about the ownership structure of the largest company in the national electricity industry. Five different ownership structures are defined: public, mostly public, mixed, mostly private and private. To account for the effect of different degrees of privatization, we define a dummy variables per each category (public_own, mpub_own, mixed_own, mpriv_own, priv_own) and set "public_own" as the default case.

Figure 3.3: Ownership structure

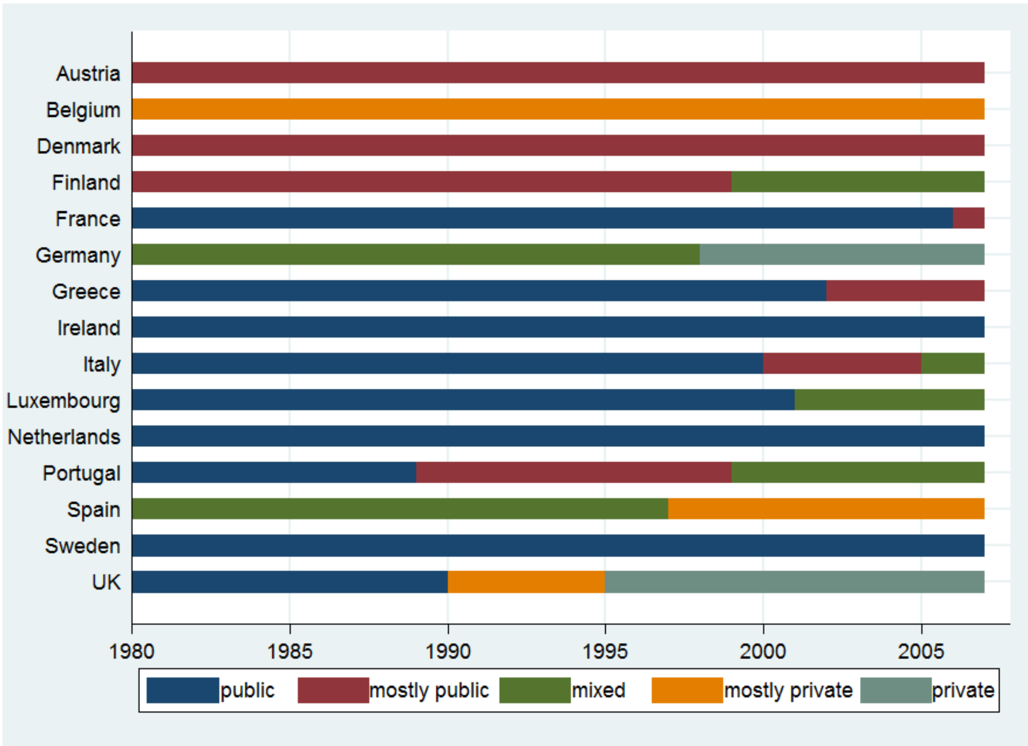


Figure 3.3 shows the ownership structure in the sample analyzed. Two main features emerge. Privatization is established gradually and the incumbent has been publicly owned for most of the sample period. The countries which have fully privatized the incumbent firm are Germany and UK. In contrast, Ireland, Netherlands and Sweden have preferred to maintain a public ownership.

- *National Energy Authority*: The independent regulator carries out several tasks such as: defining clear rules for the wholesale market, minimizing regulatory uncertainty, ensuring real and non discriminatory access to transmission and distribution networks, in the case competitive and monopoly stages remain integrated. We account for it setting a dummy variable (AUT), which takes value 1 if there is sector authority and, zero otherwise.

Figure 3.4: Establishment of Energy Authority

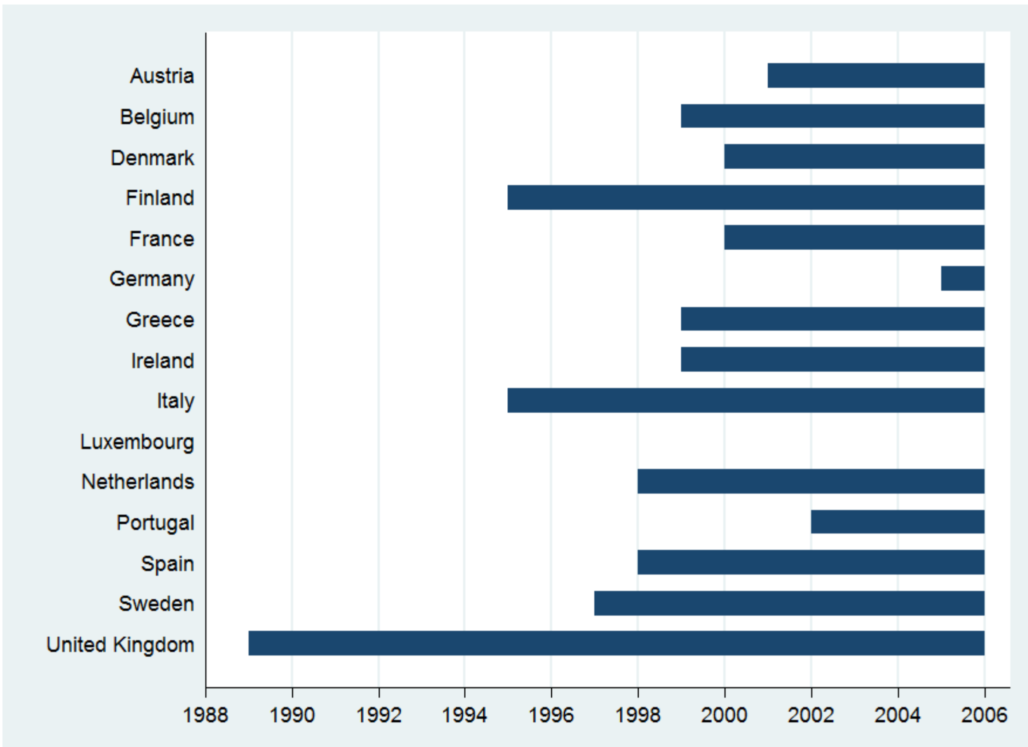


Figure 3.4 shows the year of establishment of the national energy authority. The UK was the first country to set up an energy authority. By contrast, most of the others introduced the authority in the last third of the sample period. Luxembourg established the authority only in 2007.

The comparison of national reform timings shows that the sector authority has been established before the other elements of the reform in most of the countries (Finland, France, Greece, Ireland, Italy, Netherlands and

UK). Instead, Belgium, Germany and Luxembourg opted first for the vertical disintegration of the industry. Austria, Portugal, Spain and Sweden first privatized the incumbent. Finally, only Denmark established firstly the wholesale market.

3.5 The Empirical Model

In this section we present the empirical specification of the model justifying our preference for a dynamic specification. Then, we examine the main econometrics issues which can arise in the model estimation.

3.5.1 Specification

On the base of equation 3.5, our model can be written as:

$$pcm_{it} = \alpha_i + \beta' Z_{it} + \gamma_t + e_{it} \qquad i = 1, ..., 15 \quad t = 1, ...27 \tag{3.6}$$

where i is a country, t is a year, pcm_{it} is the price-cost margin evaluated on industrial pre-tax price, Z_{it} is a vector of variables accounting for competitiveness, demand, industry efficiency and entry barriers; γ_t is a deterministic trend (1980=0) and e_{it} is a zero-mean random variable.

The above specification assumes that price-cost margins adjust instantaneously to exogenous shocks. However, as argued by the literature on profit persistence, competition is a dynamic process, thus we should allow for a dynamic specification of the model. In particular, the process of creating a well-functioning European electricity market is dynamic, because market opening requires time to succeed.[20]

[20] As discussed in the IEA Report ,"Lessons from Liberalized Electricity Markets": "Electricity market liberalization is not an event. It is a long process that requires strong and sustained political commitment, extensive and detailed preparation, and continuous development to allow for necessary improvements while sustaining on-going investment".

We therefore assume that generation price-cost margins do not adjust instantaneously to exogenous shocks, but they take more than one period to adjust to the new equilibrium. Allowing for a dynamic specification, our model can be written as a partial adjustment model:

$$pcm_{it} - pcm_{it-1} = (1 - \lambda_i)(pcm^*_{it} - pcm_{it-1}) + e_{it} \tag{3.7}$$

where $(pcm_{it} - pcm_{it-1})$ measures the actual change; $(pcm^*_{it} - pcm_{it-1})$ measures the desired change and λ_i is an unknown parameter that measures the rate of adjustment of pcm_{it} to pcm^*_{it}, the long run steady-state. The long run industrial profitability is defined as:

$$pcm^*_{it} = \theta_{1i} + \theta'_{2i} Z_{it} + \theta_{3t} \tag{3.8}$$

where θ_{1i} ,θ_{2i} and θ_{3t} are long run coefficients and indicate that the relationship among industrial profitability and the explanatory variables, which account for competitiveness of the industry, demand, firm-industry efficiency and entry barriers, is complete.

Since pcm^*_{it} is not observable, we cannot estimate equation 3.8. However, substituting 3.8 into 3.7 we get:

$$pcm_{it} - pcm_{it-1} = (1 - \lambda_i)(\theta_{1i} + \theta'_2 Z_{it} + \theta_{3t} - pcm_{it-1}) + e_{it} \tag{3.9}$$

Setting $\varphi_i = -(1 - \lambda_i)$[21] we can rewrite equation 3.9 as:

$$\triangle pcm_{it} = \varphi_i(pcm_{it-1} - \theta_{1i} - \theta'_2 Z_{it} - \theta_{3t}) + e_{it} \tag{3.10}$$

Table 3.4 shows the yearly change of the industrial price-cost margin in

[21] The process is stable if the root z of the characteristic equation $1 - \lambda_i z = 0$ lies outside the unit circle, that is greater than one in absolute value. This assumption ensures that $\varphi_i < 0$, then there exists a long-relationship between the dependent and the explanatory variables.

the full sample and by country according to the EU reform timing. On average, the yearly change of the price-cost margin on industrial consumers is positive. However, its analysis according to the Directives timing and wholesale market opening. Before the EU reform, when EU national markets were vertically intergrated, the yearly change was on average positive. Hence, indicating a average increase in industrial profitability. As the First Directive came into force, it shrank due to a positive reaction to market restructuring. In particular, in this period there was an increase of the number of players in the dispatching activity. Only, Greece, Ireland and Italy recorded an increase. After the Second Directive, the yearly change of the price-cost margin shows an upward trend due to a growing concentration trend. Finally, in Denmark and Ireland it always grows.

In addition, considering the establishment of a wholesale market, the yearly change of industrial profitability decreases on average except in Denmark, Germany and UK.

Table 3.4: Mean values of pcm yearly change

Country	Full sample	Before 96/92/EC 1980-1995	After 96/92/EC 1996-2002	After 2003/54/EC (2003-2006)	After wholesale opening
EU15	0.0079	0.0123	-0.0003	0.0041	-0.0027
Austria	-0.0010	0.0005	-0.0016	-0.0054	-0.0012
Belgium	0.0128	0.0190	-0.0003		
Denmark	0.0073	0.0010	0.0158	0.0163	0.0119
Finland	-0.0004	0.0041	-0.0116	0.0020	-0.0035
France	0.0062	0.0173	-0.0062	-0.0138	-0.0097
Germany	0.0089	0.0144	-0.0083	0.0183	0.0018
Greece	0.0015	0.0024	0.0041	-0.0085	
Ireland	0.0153	0.0149	0.0230	0.0034	
Italy	0.0071	0.0065	0.0150	-0.0044	-0.0191
Luxembourg	0.0448	0.0448			
Netherlands	0.0045	0.0094	-0.0079		-0.0121
Portugal	0.0073	0.0168	-0.0079	0.0034	-0.0213
Spain	0.0105	0.0229	-0.0102	-0.0003	-0.0106
Sweden	0.0121	0.0144	-0.0047		-0.0047
UK	0.0071	0.0080	-0.0081	0.0305	0.0033

3.5.2 Econometric issues

Before to present the empirical results, there are at least four econometric issues that we need to examine: the possibility that some variables are non-stationary, the presence of high correlation among the explanatory variables, the selection of the estimation technique and possible endogeneity of some explanatory variables.

First, consider the non-stationarity issue. To test the presence of unit root in both the dependent and explanatory variables, we apply the panel unit-root Fisher test, which assumes under the null hypothesis that all panels contains unit-root against the alternative that at least a panel is stationary. This test has the advantage to be applied to long unbalanced panel (fixed N, large T). Specifically, the Fisher type test performs a unit-root test on each panel's series separately, then combines the p-values to obtain an overall test of whether the panel series contains unit root. Table 3.5 shows the results of the test. The industrial price-cost margin is stationary in both levels and first difference. Among the explanatory variables, only the capacity utilization rate is a random walk. However, we can reject the null hypothesis of unit root if we control for cross-sectional means, which allows to mitigate the impact of cross-sectional dependence.

Table 3.5: Results of Fisher unit root test

variables	without demeaning		demeaning	
	Z	p-value	Z	p-value
pcmi	-4.986	0.000	-3.821	0.000
$\triangle$pcmi	-8.633	0.000	-10.600	0.000
rgdp	-6.983	0.000	-5.568	0.000
oil	-7.486	0.000	-21.892	0.000
trade	-2.581	0.005	-2.830	0.002
cap_uti	*-0.038*	*0.485*	*-2.189*	*0.014*

Second, consider the multicollinearity issue. High correlation in the explanatory variables can lead to multicollinearity problems. High collinearity can arise especially in the definition of the EU reform indicators. For this reason, we select carefully the indicators to control for institutional entry barriers. Moreover, it should be noticed that panel data analysis has the advantage to mitigate collinearity issues among the explanatory variables. In table 3.6, we report the correlation matrix among the explanatory variables of our model, which shows a modest level of correlation between the variables indicating the establishment of a wholesale market and of a sector authority. However, this level is lower than the commonly used threshold value (0.80) signalling absence of multicollinearity problems.

Third, one of the main issues related to pooling panel data is the restriction of homogeneity of slope parameters. In dynamic panel data models, where the number of time series observations is large and the number of groups (N) can be either fixed or large, the parameters of interest are the long run coefficients and the speed of adjustment to the long run equilibrium. In econometric applications, two procedures are commonly adopted. At the one extreme, it is possible to estimate separate equations for each group and examine the distribution of the estimated coefficients across groups. Pesaran and Smith (1995) propose a mean group (MG) estimator, which after estimating the coefficients for each country, evaluates the average of the parameters. This estimator allows all parameters, intercepts, short-run coefficients, long-run coefficients and error variances to differ across groups. At the other extreme, it is possible to apply the traditional pooled estimators, such as the fixed and the random effects, which allow the intercepts to differ across groups, but restrict all the other coefficients and error variances to be equal across groups.

Pesaran et al. (1999) propose an intermediate estimator, pooled mean group (PMG), which allows for pooling and averaging. This estimator allows intercepts, short run coefficients, and error variances to differ freely across groups, but constraints the long-run coefficients to be equal across groups.

In our case, it is reasonable to apply the PMG estimator for two main reasons. On the one hand, requiring homogeneity in the long-run coefficients allows to account for the EU goal of creating a single market for electricity. On the other hand, allowing different speeds of adjustment we can account for the arbitrariness left to member States in implementing the EU Directives.

Furthermore, Pesaran et al. (1999) suggest implementing the Hausman test to choose between the two estimators. Thus, in analyzing the empirical results, we will discuss the results of the Hausman test.

In addition, the PMG estimator has the advantage that can be applied to both stationary I(0) and integrated of order one I(1) processes as long as $\phi_i <$

Table 3.6: Correlation matrix explanatory variables

							ownership structure				vertical separation	
	cr1	trade	rgdp	oil	cap_uti	whole	mpub	mixed	mpriv	priv	mixed	unbundled
cr1	1											
trade	-0.054	1										
rgdp	0.003	0.142	1									
oil	-0.022	0.057	-0.213	1								
cap_uti	-0.220	0.524	0.046	0.191	1							
whole	0.563	-0.083	-0.051	-0.046	-0.155	1						
mpub_own	-0.091	-0.063	-0.055	-0.085	0.275	-0.041	1					
mixed_own	0.099	-0.058	-0.057	0.013	-0.207	0.050	-0.243	1				
mpriv_own	-0.075	-0.059	-0.035	-0.105	-0.181	0.147	-0.202	-0.142	1			
priv_own	0.683	-0.043	-0.038	-0.050	-0.256	0.437	-0.149	-0.104	-0.087	1		
mixed	0.095	0.000	-0.016	-0.184	-0.372	0.109	0.025	0.406	-0.128	0.031	1	
unbundled	0.373	-0.038	-0.051	-0.008	-0.035	0.621	0.028	-0.081	0.201	0.405	-0.251	1
aut	0.331	-0.030	0.076	-0.111	-0.200	0.685	0.011	0.002	0.148	0.209	0.149	0.512

0 ensuring a long-run relationship between the dependent and explanatory variables and a stationary error term.

Finally, regulatory indicators are influenced by past electricity prices, which may pose an endogeneity problem.[22] However, the use of the PMG estimator should mitigate this problem.

3.6 Empirical Results

In this section, we present the empirical results. In the appendix we provide the estimation results of alternative model specifications. Applying Akaike Information criteria (AIC) and Bayesian Information criteria (BIC) to choose among competing models, we select the following model. Having said this, we first analyze the long-run equilibrium highlighting the effects of the EU reform on industrial profitability. Then, we discuss the national speeds of adjustment to the long-run equilibrium.

3.6.1 Long-run analysis

Prior to analyze the results, let us consider the preference for the PMG vs. the MG estimator. The choice between the two techniques concerns the assumption of homogeneous or heterogeneous long-run slope of parameters. If the true model is heterogeneous, the PMG estimates are inconsistent, whereas the MG estimates are consistent in either cases. To choose between the two techniques, as suggested by Pesaran et. al. (1999), we apply the Hausman test. Hausman test failed to reject the PMG restriction that long-run coefficients were similar across countries. In particular, Hausman test statistic was negative, which Hausman and McFadden (1984) attribute to a lack of positive semi-definiteness in finite sample. Moreover, they argue that

[22]The EU reform has been promoted to eliminate market inefficiencies due to the presence of national vertical-integrated industries.

negative test scores can be interpreted as strong evidence of failure to reject the null hypothesis that the PMG is consistent and efficient.

Table 3.7 reports the result of PMG estimation on the yearly change of the price-cost margin evaluated accounting for the electricity price paid by industrial consumers.

National and international competition leads to lower price-cost margin. The former is measured controlling for the presence/absence of a dominant firm in the generation activity, whereas the latter by trade activity. As expected, the absence of a dominant firm reduces the yearly growth of the industrial price-cost margin. Thus, the increase of domestic competition leads to a reduction of the price-cost margin.

As international competition increases the price-cost margin decreases lowering the differential between two years. Moreover, international competition leads to the highest reduction pointing out the crucial role of economic integration. A point percentage (p.p.) increase in the trade activity reduces by 0.41 p.p. the yearly growth of the price-cost margin.

Not surprisingly, an increase in demand, which is represented by the real growth rate of GDP, leads to a reduction of the yearly growth of industry profitability. The low coefficient can be explained by the inelastic demand characterizing electricity markets. According to electricity literature, the demand for electricity is inelastic, but not perfectly as often assumed for simplicity.[23]

An increase in input cost, which is measured by the national import cost of oil, lowers the price-cost margin. Among the other long-run coefficients, oil import cost constitutes the most statistically significant. This result is due to the fact that before electricity restructuring consumer prices were defined partly accounting for oil-price fluctuations.

[23] See Taylor (1975) for a survey.

Table 3.7: Empirical results

Average Adjustment coefficient (φ)		-0.3890***
		(6.21)
Long run coefficients (θ)	cr1	-0.0503**
		(2.73)
	trade	-0.4081***
		(6.76)
	rgdp	-0.0042**
		(2.58)
	oil	-0.0030***
		(14.32)
	cap_uti	0.2789**
		(2.59)
	whole	-0.0092
		(0.94)
	mpub_own	0.0201
		(1.63)
	mixed_own	0.0131
		(0.57)
	mpriv_own	-0.0910*
		(2.28)
	priv_own	-0.0218
		(0.45)
	mixed	0.0261**
		(2.91)
	unbundled	0.0812***
		(5.38)
	aut	-0.0239*
		(2.52)
	t	0.0035***
		(3.47)
Observations		350
Maximum Log-Likelihood		709.7308

Notes: The dependent variable is the yearly growth in the industrial price-cost margin. Z-statistics in absolute values are in parentheses.
*,**, *** denote statistically significance at 5%, 1%, 0.1% respectively.

As regards our measure of capacity utilization, we should bear in mind that this is defined as the ratio of the difference between potential and actual output to potential output. A higher value of (CAP_UTI) implies a higher difference between potential and actual production, hence lower capacity utilization. As (CAP_UTI) increases, there is a lower use of national capacity, consequently the price cost margin raises. In particular, the yearly growth of profitability increases by almost 0.28 p.p. as (CAP_UTI) increases by one p.p..

Concerning national institutions we should first notice that the establishment of organized wholesale market, although reduces the yearly differential by almost 0.01 p.p., it is not statistically significant. This statistically insignificant result might be explained by the fact that most of the countries established the wholesale market in the last third of the sample span. Thus, it might be too early to evaluate significant effects from its institution.

Privatization of the main firm in the electricity industry indicates that only mostly private ownership leads to a statistically significant decrease in the price-cost margin. Applying the F joint test, which account for the four types of ownership structure, we do reject the null hypothesis of dropping the ownership variables. In addition, we should notice that only Germany and UK have fully privatized the ex-incumbent, hence it might be too early to find empirical evidence on full privatization. Results are consistent with the prediction of Vickers and Yarrow (1988) according which privatization increases efficiency due to incentive arguments. Moreover, in the electricity literature, Newbery argues that privatization is not a prerequisite to foster competition in the electricity industry, because electricity restructuring can be applied to publicly owned firms. However, he also pointed out that privatization can deliver several benefits when combined with restructuring, competition and regulation.

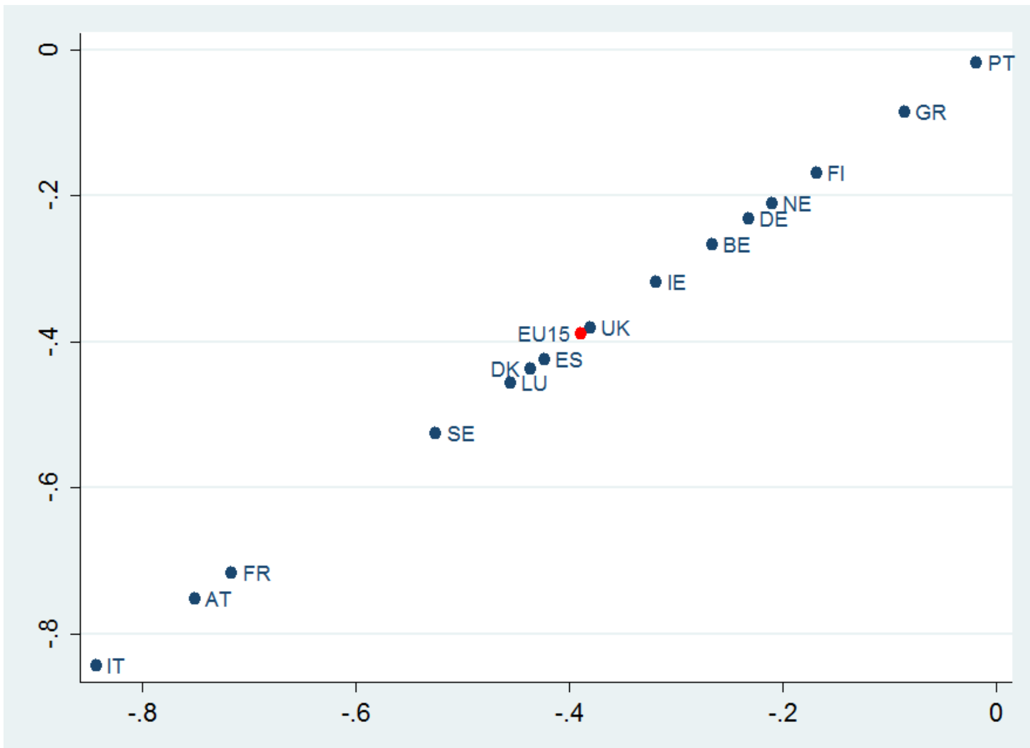
Vertical separation leads to an increase of the yearly change of profitability on industrial consumers. Results show that the higher is the degree of overall industry separation, the higher is the increase in profitability. Hence, this prediction denies the argument that vertical separation can lower industrial price-cost margin. This result can be explained according to two features. On the one hand, vertical separation implies a loss of efficiency in terms of economies of scale, hence raising the price-cost margin and reducing consumer welfare. On the other hand, few countries experienced full unbundling in the sample analyzed, hence it may be too early to evaluate a negative effect. Furthermore, empirical literature shows conflicting results in evaluating the effects of unbundling. For instance, Steiner (2000) finds a negative effect of unbundling on the industrial electricity price over the period 1986-1996, but the period analyzed is too short to assess the impact in the European market. Hattori and Tsutsui (2004), which re-examine Steiner's work for a longer period, find that unbundling leads in some cases to a statistically significant increase in the electricity price. Fiorio et al. (2009), analyzing the impact of the EU reform on the households electricity price, find the same result but not statistically significant. Finally, Zarnic (2009), studying profitability of European firm over the period 1995-2007, find empirical support that vertical integration leads to higher markups. However, the period analyzed does not account for benchmark level before the reform.

Finally, the institution of a national sector authority reduces the yearly change in the price-cost margin illuminating a more efficient functioning of the market.

3.6.2 Comparison of national speeds of adjustment to long run equilibrium

The average speed of adjustment to long run equilibrium is equal to -0.39, which is highly statistically significant indicating therefore the existence of long-run equilibrium in the full sample. In this section, we analyze the national specific rates of adjustment. Although we find the existence of long-run equilibrium in the full sample, the analysis of country speeds of adjustment shows that some countries do not converge to the long run equilibrium. These countries are Finland, Greece, Portugal and Netherlands. Their rates of adjustment, though negative, are not statistically significant. [24]

Figure 3.5: National speeds of adjustment to long-run equilibrium



The speeds of adjustment can be interpreted as a measure of profitability persistence. A low rate of adjustment implies high profit persistence. According to figure 3.5 Italy is the country with the highest profitability persistence. As shown in table 3.2 on average the Italian market has the second highest industrial price. However, the price-cost margin is close to average value of the entire sample, implying a high average variable cost. In the sample analyzed, Italian generation costs are characterized by a wide dependence of generation

[24] The Z coefficients are: Finland (-1.72), Greece (-1.26), Netherlands (-1.93) and Portugal (-0.13).

from oil, which account for 50% of thermoelectric production. Only, in the last years of the sample, Italy has reduced the use of oil investing in new generation plants, such as CCGT, which use mainly natural gas. Moreover, the Italian profit persistence may be explained by several causes such as: the presence of a dominant firm in the generation activity, the establishment of a wholesale market only in 2004 and a delay in privatizing the incumbent, in the last year of the sample the national incumbent is still characterized by a mixed ownership.

The other two countries with high level of profit persistence are Austria and France. Differently from Italy, their price-cost margins are on average very high, equal to 0.81 and to 0.845 respectively. The high price-cost margin is not due to high industrial prices, which are close to the average value in the case of Austria, and lower than the average in the case of France, but to low average variable costs, which are due to an extensive production from hydro and nuclear respectively. As in the case of Italy, both markets are characterized by: a dominant firm in the generation activity, a low level of privatization and the institution of a wholesale market in the last years of the sample (2002 Austria and 2001 France). In addition, both countries are net exporters; consequently, the effect of international competition is vanished.

Among the countries, which converge to the equilibrium statistically significantly, Germany has the highest rate of adjustment, hence the lowest profit persistence. The combination of several features justifies this result. On the one hand, accounting for the EU reform aspects, Germany has opened to competition the wholesale segment in 1999, quite early comparing with the others apart from the UK. Moreover, from 2000 the generation activity does not have a dominant player. The incumbent has always had a good balance between public and private ownership. In addition, from 1998 it has been fully privatized. On the other hand, the German market has the highest capacity utilization rate, implying a higher rate of capital utilization.

Finally, it is interesting to notice that UK and EU15 rates of adjustment are very close. To explain this result we should consider that UK was the first country to restructure the electricity market in Europe. Moreover, the EU reform model has been inspired on the UK experience. The closeness of the two rates of adjustment is therefore reasonable.

In general, we can conclude that the countries which record less persistence are characterized by: modest impact of international competition, high capacity utilization rate, prevalence of private to public ownership and mixed degree of vertical separation of the full sector.

3.7 Conclusion

This chapter has studied the impact of the EU reform model on industrial price-cost margin. Our results are partly in line with previous findings. The EU reform model which aims for the creation of a single market for electricity, requires effective competition in the generation activity and unbundling of the competitive and monopolistic segments. Our results show that wholesale market opening, establishment of a sector authority and international trade lead to a reduction of industrial price-cost margin. In addition, the change from a publicly owned firm to either a mostly-private or private ownership leads to a further decrease of profitability. Thus, these elements of the EU reform imply a positive impact on consumer welfare.

Differently from other studies, we assess the effect of vertical separation accounting for the overall degree of the electricity industry. We find that in the long run, the higher is the degree of vertical separation, the higher is the price-cost margin. This result points out a loss of efficiency due to a reduction of economies of scale, confirming Etro's (2007) prediction. However, we agree with the main electricity literature on market restructuring, which suggests that only the combination of effective competition and vertical unbundling can lead to a contraction of the industrial price-cost margin and a consequent welfare improvement. In the sample analyzed, most of the countries, although they have established a wholesale market, are still characterized by a dominant player in the generation activity. In addition, only Austria, Denmark, Italy, Netherlands, Spain and UK have a fully unbundled electricity industry. Thus, the resulting increase of industrial profitability can be due to an insufficient level of both competition and vertical separation.

Moreover, the analysis of national rates of adjustment to long-run equilibrium has shown that Italy and Germany have the lowest and the highest rates respectively. Since the rate of adjustment is inversely related to profit persistence, we can conclude that the Italian and German market have the highest and lowest persistence respectively. Thus, German consumers have became better off faster than Italian consumers are. Among the several causes that determine this result, high capacity utilization and privatization seem to be the main determinants. On the one hand, as argued by Wolak and Patrick (1997) constraining plant availability involves a higher price-cost margin. Thus, the German market, which has the lowest differential between potential and actual output, achieves a significant reduction of the price-cost margin. On the other hand, as discussed by Vickers and Yarrow (1988), privatization leads to efficiency improvements. Moreover, as argued by Newbery (1999 and 2002a), although privatization is not a prerequisite to restructure electricity market, when combined with competition and regulation it can lead to efficiency improvements. Our results support these theories.

Chapter 4

Selecting static oligopolistic models in the Italian wholesale electricity market

4.1 Introduction

Having analyzed the EU reform impact at cross-country level, in this chapter we focus on the restructuring effects on the Italian wholesale electricity market. As discussed in the previous chapters, the establishment of the spot market for the purchase and sale of electricity aims to increase competition in the generation activity.

Following the EU reform, the Italian wholesale electricity market has been liberalized. Specifically, given limited transmission capacity across the country, the market has been organized according to a zone structure. Whenever electricity flows exceed the maximum inter-zone capacity, the national market is split into several zones until the exhaustion of the transmission limits. As a result, different market clearing prices are defined.

To assess potential improvements of competition in the Italian wholesale market after the liberalization, this chapter proposes a study based on the comparison of two competing models and the selection of the one, which fits the market better. The analysis takes into account the zone market structure studying the main macro-zones: North and South, which together count for around 90% of total electricity consumption and 75% of total production.

In each market, we choose two competing models according to firm production and generation capacity. In the North market, we study the Stackelberg and the Cournot model. In the South, we analyze the Stackelberg and the Dominant model. The comparison of two oligopolistic models is due to the behaviour of the incumbent . Although the former monopolist holds a significant proportion of the generation capacity, 50% in the North and 63% in the South, its supply is not as high as expected. In the sample analyzed, the former monopolist supplies in the northern day-ahead market on average more than 50% (2005) and 30%(2006). Instead, in the southern market, her supply is on average higher than 66% (2005) and 63% (2006). The less production between the two years is partially due to the reduction of the demand of the captive market and the increase of the other firms supply. Furthermore, in each local market another three firms supply more than 30% of zone spot market demand in both years.

For each model, we first define the strategic player set and estimate the competitive fringe supply via the general method of moments. Assuming a perfectly inelastic spot market demand and subtracting the estimated fringe supply, we determine the residual demand of the strategic players. Then, we evaluate the equilibrium output of the above models using optimization procedures.

The selection of the model which fits the zone market better is based on a variation of the traditional R^2, which is defined as the difference between the actual and the simulated values in the two models. The study is applied to hourly firm level-data collected in the winter and summer months of 2005 and 2006, taking into account two seasonal patterns according to weekday (peak) and weekends (off-peak).

Results show that the North market records a change in the oligopolistic structure during the period analyzed. In 2005, the model, which fits the market better, is the Stackelberg model, whereas in 2006 the Cournot model is preferred to the former. Results therefore highlight a loss of consumer welfare in the period analyzed. According to microeconomic theory, consumers are better off under the Stackelberg model because quantity and price are higher and lower than the Cournot model respectively. As regards to the South market, results show a clear preference for the Stackelberg model in both years, during weekdays. Instead, during weekends we find that the Dominant firm model is preferred to the Stackelberg model in 2005. Conversely, in 2006 results show that the latter is slightly preferred to the former.

The chapter is organized as follows. Section II describes the main features of the Italian wholesale electricity market. Section III proposes a literature overview of both the International and the Italian studies of the sector. Section IV discusses the set of assumptions, the definition of the models, the methodology applied to determine the equilibrium outcome and, the model selection test. Section V presents the data set motivating our study. Section VI summarizes the main results of: competitive fringe supply estimations, model simulations and model selection in the two markets. Section VII concludes.

4.2 The Italian electricity market: rules and data

The European liberalization process in the electricity market aims for the creation of an internal electricity market, within which effective competition can be fostered. Before deregulation, national markets were characterized by a vertically integrated industry, in which regulators fixed prices as a function of generation, transmission and distribution costs. However, one of the condition *sine qua non* to achieve the single electricity market is the reduction of the national incumbent dominance. Consequently, the re-structuring process has opened to competition the generation and supply activities, whereas transmission and distribution activities, which are instead characterized by natural monopoly elements, have been regulated using models of competition "for" the market.

In this framework the Italian electricity market has been liberalized by the legislative decree 79 in 1999, also called Bersani Decree. In order to achieve the liberalization process, the decree has established three different institutions: national Grid Operator, which is responsible for the security and physical stability of the system; the Single Buyer, which guarantees the security, continuity and efficiency of supply and defines a unique tariff to the captive consumers; and the electricity Market Operator, which ensures the short-run and long-run efficiency through price signals.[1]

Moreover, free access to the national grid for the new generators has been guaranteed trough the establishment of a state-owned company (Terna S.p.A.).[2] Finally, the supervision of the market has been assigned to the Italian energy authority.

The Italian wholesale electricity market has been organized according to a zone structure due to transmission congestion problems across the country. In particular, a zone constitutes a portion of the power grid in which congestions are rarely observed. In 2005 and 2006, the Italian market is composed of seven national physical zones: five are located in mainland Italy (North, Centre North, Centre South, South, Calabria), whereas the other two are the two main islands, Sicily and Sardinia. The Italian energy authority defines the aggregation of the zones into macro zones taking into account the realized congestions, as follows: North, South (refers to Centre North, Centre South,

[1] In the original version of the Bersani decree the national grid operator (GRTN) was responsible for both the management of the grid and the promotion and development of renewable sources in Italy. From 1 November 2005, the GRTN has transferred to Terna the management of the national grid and has changed its denomination in GSE (Gestore Servizi Energetici).

[2] Terna S.p.A. is also responsible for the dispatching activities.

South, Calabria), Sicily and Sardinia. Moreover the market is made up of foreign virtual zones, which are not zones *per se*, but injections of electricity into the belonging national zone.[3]

The liberalization process has introduced several changes on both the demand and the supply side. On the demand side, the decree classifies the consumers in either "eligible clients" or "small consumers", as established by the EU directives. The former includes large consumers to who the State has recognized the legal capacity to purchase or sell electricity.[4] The latter includes household consumers which have to remain the captive market of local distributors until the 1st July 2007. Nowadays, all the consumers are eligible clients.

On the supply side, the former monopolist has to disinvest part of its total capacity. As main consequence, her contribution to national electricity consumption has fallen from 77.4% in 2000 to 34.8% in 2006.

Moreover, the decree has established two alternative systems for electricity purchase and sale: the bilateral physical trading system and the power exchange. The former is characterized by "private" contract agreements between a wholesaler and an eligible customer, in which the parties define both hourly price and quantity. These contracts constitute private information because the parties are not obliged by law to divulge any information about them.

With regard to the power exchange, demand and supply are centrally selected at a minimum cost under procedures specified and managed by the electricity market operator (GME). In practice, GME runs three different

[3] The foreign virtual zones are: Foreign North-East, Foreign North-West, Foreign South, France, Switzerland, Austria, Slovenia, Corsica, Corsica AC and Foreign Corsica. Indeed, the constrained zones, or limited production zones, are: Turbigo -Roncovaldaliga, Monfalcone, Foggia, Brindisi, Rossano, Priolo Gargallo. In 2006, Foggia has replaced Piombino in 2006.

[4] The eligibility has been granted to those consumers who consumed in 1999 no less than 20 GWh and more than 9 GWh per year today. Associations of buyers were also included under the condition that each member had a minimum consumption level of 1 GWh.

markets: the day-ahead market, where the participants submit demand and offer bids for each hour of the next day; the adjustment market, where participants may revise both demand and offer schedules submitted in the day-ahead market; and, the ancillary services market, where the Transmission System Operator is responsible for ensuring a secure power system and dispatch service, by procuring the resources required for managing, operating and controlling the system.

In day-ahead market, the GME derives the aggregate supply and demand curve according to the merit order principle and taking into account the transmission limits notified by Terna S.p.A. If the resulting flows on the grid do not violate any transmission constraints, there is a single market clearing price (P*) and all the accepted offers/bids are paid at P*. Hence, the value of transmission right is zero, because it is not a scarce commodity. The transmission rights are assigned first to the bilateral contracts, without the payment of any fees, and then to the most competitive bids submitted in the spot market.

However, if at least one transmission limit is violated, the market is split into different market zones until the exhaustion of the inter-zone capacity. Thus, the presence of scarce transmission capacity determines different market clearing prices across the country. In particular, the value of the transmission right between zones x and y is equal to the zone price difference. As before, transmission rights are assigned first to bilateral contracts, then to the spot market. In both cases, there is the payment of the transmission right. On the one hand, bilateral contracts pay to the Grid Operator a fee equal to the zone price difference, $(p_y - p_x)$, on the electricity quantity indicated in the contract. On the other hand, in the spot market generators receive the price of the belonging zone (p_x), while consumers pay the national average price. Moreover, given the insufficient transmission capacity across the country, local price differences highlight disparities in both plant technology and generators market behaviour.

4.2.1 The Italian electricity market: data

This section examines the main data of the Italian wholesale electricity market in the years 2005 and 2006. The data analysis points out the different macro zone structure characterizing both demand and supply side. Local prices diverge quite often across Italy. In 2006, the national average wholesale electricity price was 74.75 €/MWh, increasing by 27% with respect the previous year. The comparison between the national and the macro zone average price shows that: the lowest price was in the North (73,63 €/MWh), in the South the price was slightly higher (75.15 €/MWh), in Sicily was (78.96 €/MWh), and Sardinia recorded the highest average price (80.55 €/MWh).

On the demand side, in 2006, the national electricity consumption was around 329 TWh, 2% higher than the previous year. Electricity consumptions were not equally distributed across the country: more than 54% of national consumptions were concentrated in the North, only 35% in the South and finally 10% in the two Islands (Sardinia and Sicily).

On the supply side, there are significant differences in terms of both contributions to national production and supply structure. In 2006, the highest contribution to national production is given by the North (45%), while only 30% by the South. In addition, the two islands count for roughly 10% of national production.

As regards to market concentration, the annual report of the Italian energy authority points out that the contribution to national production of the former monopolist decreased from 38% (2005) to 34% (2006). The Herfindahl-Hirschman index (HHI) on the production confirms the different macro-zones structure. Although, in the North the HHI is close to the competitive level (1345), in the South the HHI is equal to 2781 highlighting a more concentrated market structure. In the two islands, the HHI is equal to 4267 and 3241 in Sicily and Sardinia respectively.

The disparities in firm contribution to national or zones production can be attributed to firm capacity. As shown in table 4.1, the former monopolist holds the majority of power plants in both zones. However, the other more important firms own more than 36% and 24% of zone generation capacity, in the North and South respectively. As regards to the composition of the fringe the firm, which has the highest percentage of generation capacity, holds 4.00% (North) and 4.47% (South) of total zone capacity.

As shown in table 4.1, new firms usual invest in combined cycle gas turbine plants, which are characterized by high efficiency rate and short construction times.

Table 4.1: Firm capacity per market zone in 2006 (%)

	hydro	CCGT	coal	oil	other gas	total capacity
North						
firm N1	72.61	23.51	78.67	100.0	15.91	49.55
firm N2	5.04	20.08			27.29	12.13
firm N3		14.76	7.34		41.17	9.82
firm N4	8.78	9.73				7.28
firm N5		16.26				7.01
fringe	13.57	15.67	13.99		15.63	14.19
South						
firm S1	67.50	16.14	100.0		89.59	63.08
firm S2		24.49			7.70	10.75
firm S3	0.88	24.29			0.81	7.68
firm S4	25.74					6.00
fringe	6.48	35.08			1.89	12.05

Source: CESI Research Institute

4.3 Literature overview

In order to analyze the potential of market power and market structure the electricity literature studies oligopolistic models according to either optimization or econometric techniques. Market power and market structure can be estimated according two different approaches: at firm level and at market level. The first approach takes into account the ability of a firm to affect the price studying the bidding and output supply decisions of each firm to detect deviation from marginal cost. The second approach considers if the market as a whole is deviating from the competitive outcome. However, this method captures all the inefficiencies of the market that maybe are not due to market power and, for example, can be due to faults in the dispatch algorithm. According to Borenstein, Bushnell and Wolak (2002), if low-cost generators were systematically held out of production simply due to a faults in the dispatch algorithm, this would impact the estimate of market power. Particularly, they explain that from June 1998 to October 2000, the Californian market had a number of flaws that may contribute to inefficient dispatch and market pricing.

The oligopolistic models analyzed are based on either supply function equilibrium or Cournot models. The former theoretical framework has been developed by Klemperer and Meyer (1989) showing that the equilibrium is bounded between the Bertrand (below) and Cournot (above) outcomes. Green and Newbery (1992) apply the supply function equilibrium to the UK Pool. They assume that the bidding function can be represented by a "smooth" cost function, hence continuous and differentiable.

By contrast, Boreistein and Bushnell (1999) apply a Cournot model with competitive fringe to study the Californian electricity market. The study simulates the market using a repeated grid-search method to determine the profit-maximizing output for each strategic player under the assumption that the production of the other suppliers is fixed. Unlike the supply function equilibrium, the cost function is a step function and can be derived sorting the plants from the cheapest to the most expensive according to firm available capacity for each generating source. They find that before the regulation of the generation ownership, there is evidence of potential market power in high demand periods due to both the (un)availability of hydroelectric production and the elasticity of the demand.

Borestein, Bushnell and Wolak (2002) analyze the potential of market power in the Californian market according to a market level approach. In analyzing the price-cost margin, they estimate the system marginal cost of serving a given level of demand through Monte Carlo simulations. Particularly, they explain how the timing of outages constitutes a strategic decision in evaluating the marginal cost. In high demand period, scheduled maintenance allows increasing the potential of market power, because it reduces the available capacity. Using data from June 1998 to October 2000, they find significant departures from the competitive outcome during the peak-demand summer months and near the competitive outcome during the off-peak demand months.

All the studies analyzed so far are based on direct measures of production cost data allowing the detection of departures from competitive outcome. As pointed out by the "new empirical industrial organization" (NEIO), when marginal cost can not be observed directly it is possible to make inference on the market conduct considering the responsiveness of price to changes in demand elasticity and cost components. The conduct parameter can assume different values according to the model analyzed: unity in the case of perfect collusion or monopoly; zero under perfect competition and equal to the inverse of the number of the firms in the market in the symmetric Cournot case. Wolfram (1999) studies the exercise of market power in the British market estimating the price-cost margin using both direct measures of marginal cost and several approaches that do not rely on cost data. She finds that prices are higher than marginal cost, but not as much as Cournot and supply function equilibrium theories predict.

Puller (2007) analyses how supply and demand contribute to the variation in price-cost margin over time. The analysis is applied to the California market taking into account the period from April 1998 to the end of 2000. In particular, he applies static and dynamic analyses using hourly firm-level data on output and marginal cost. The electricity generators are split in strategic and non strategic players. The analysis shows how strategic players withhold output when price is higher than marginal cost, indicating a positive degree of market power. Furthermore, he finds no significant differences in the estimation of the conduct parameter comparing the static and the dynamic analysis.

As regards to the Italian electricity market, we summarize the results of three main papers. Bosco and Parisio (2001) propose a model based on auction theory to study the competition in a multi-unit wholesale electricity market. Following Brunekreft (2001) and von der Fehr and Harbord (1993) they analyze the bidding strategies in two basic contests: firstly assuming a dominant firm vs. a competitive fringe and secondly using an oligopolistic setting. In both models, they assume that demand can be either fixed or variable but always price-insensitive as in von der Fehr and Harbord (1993). The first model takes into account the market conditions prevailing in the forthcoming Italian wholesale electricity market. The second model allows forecasting the future market characterization at the end of the privatization process. The analysis shows that under reasonable assumptions about the technology the system marginal price can lead to supply restriction in both the base and peak load. Thus, the overall inefficiency is ambiguous.

By contrast, Bollino and Polinori (2007) study the degree of competition in the Italian wholesale market analyzing the residual demand of each Italian generation firms. This approach, introduced by Wolak (2003) allows to determine the unilateral degree of market power without taking into account firm cost function. Results show that in 2004, the former monopolist set the price in 69.88% of hourly zones, followed by Endesa 21.23% and Edison 24.00% but in specific regions, in Sardinia and Sicily respectively. Furthermore the cluster hour analysis shows that the incumbent set the price in both the very high peak hours (79.2%) and in the peak hours (68%). The Lerner index results confirm her dominant position with respect all other competitors.

Boffa and Pingali (2006) study the Italian wholesale market in order to identify the possible gains deriving from market integration. The study is based on hourly weekday data of May 2004 and proposes a comparison between two different scenarios according to the presence or not of transmission constraints. They find that easing transmission bottlenecks would result in substantial cost savings. In addition, they argue that the former monopolist does not exercise her full market power.

4.4 Model and assumptions

The aim of this chapter is the identification of the oligopolistic model, which fits the Italian wholesale electricity market better. The presence of transmission constraints across the country and the resulting split of the national market into several zone markets justifies a zone market analysis.

As discussed in the previous section, the market data highlights a deep difference among the several zones. In general, the North and the South are characterized by the same features, whereas the two islands show noticeable differences with respect the above zones. For example, the disparities between the zone price and the national price are less marked in continental Italy than in the two islands.

Moreover, the consumption pattern is the same in the North and in the South reaching the peak at 6pm and at noon, in the winter and in the summer months respectively. In the two islands it reaches the peak at 7 pm in the winter months, whereas in the summer months at 10pm, in Sardinia, and 11 pm in Sicily.

Given the disparities between mainland Italy and the two islands, the following analysis is applied to the two main macrozones: North and South.

4.4.1 Assumptions

The main assumption is related to the definition of the strategic player set accounting for both zone generation capacity and contribution to zone production per firm. As shown in table 4.1, the former monopolist owns around

50% (North) and 63% (South) of zone generation capacity. In addition, another four and three firms, in the North and in the South respectively, own more than 34% of zone generation capacity.[5]

As regards to firm generation, shown in table 4.2, the incumbent contribution to zone production has decreased significantly. This reduction is due to on the one hand to the increase of the other firms market shares, and on the other hand to a decrease of trade activity in the spot market in the period analyzed.

Table 4.2: Firm market shares in the data sample (%)

Market	Firm	2005	2006
North			
	firm N1	53.14	29.61
	firm N3	13.40	13.48
	firm N4	5.63	9.64
	firm N5	8.61	11.83
	fringe	13.86	35.44
South			
	firm S1	66.64	63.41
	firm S2	19.66	15.19
	firm S3	7.53	8.20
	firm S4	0.09	4.03
	fringe	6.17	13.2

Source: Own evaluation on GME data

The comparison between incumbent contribution to zone production and her generation capacity justifies the analysis of different oligopolistic models. Specifically, the oligopolistic models analyzed are: in the North, the Cournot and the Stackelberg model; whereas in the South, the Dominant firm and the Stackelberg model. In these models, the above firms constitute the set of the strategic players, whereas all the other firms form the competitive fringe.

[5] Firm N2 is not taken into account in the following analysis because, she does not offer on the spot market in the sample analyzed.

Thus, the former set of players is able to affect the market clearing price through its bids. Indeed, the other firms act as price takers, they offers their entire capacity whenever the market clearing price is above their marginal cost.

The other assumptions are related to both demand and supply side. On the demand side, we assume that the zone market demand is perfectly inelastic. Specifically, in the day-ahead market the Market Operator links the retail and the supply market. On the demand side, the Market Operator buys electricity on the spot market and sells it to the retail market at a predetermined and exogenous price. Thus, the total electricity output is equal to the demand of the retail market at a fixed price. Consequently, the demand for electricity, at least in the short run, can be considered independent of the wholesale electricity price.

Moreover, we account only for the electricity consumption that is traded on the spot market. In general, the total consumption includes the consumption of both residential and industrial consumers. In the Italian spot market, the former are represented by the Single Buyer and account on average 70% of overall spot market demand. The latter can satisfy their needs through either bilateral contracts or spot market. As said above, bilateral contracts are private agreements in which price and quantity are determined by the parties independently from the spot market results. Thus, we subtract from total electricity consumption the bilateral contract level. In the sample analyzed, the electricity traded in the spot market counts for 62.8% and 59.6% of overall electricity consumption, in 2005 and in 2006 respectively. The decrease of wholesale liquidity is due to the drop of CIP6 production, which may only be purchased on the exchange, and the gradual shrinking of the captive market demand (-6.9%).

On the supply side, the assumptions are related to: renewable production, electricity flows between the two zones and imports. The total production of renewable plants is composed by hydroelectric, geothermal, other renewable and assimilated sources. In Italy, renewable plants are subject to a special regime established with the resolution n. 6 in 1992 by the Interministerial Committee on Price (CIP6) according to necessary qualifications. Firms owning CIP6 plants have to sign a contract for difference with the Electric Grid Operator (GSE). The GSE purchases the electricity generated by these plants and sells it on the Power Exchange. Furthermore, CIP6 plants have dispatching priority, thus are inframarginal plants. As a consequence, they do not determine the market clearing price. Given the particular regime characterizing CIP6 plants, we subtract their production and capacity.

The analysis of the market according to the zone structure should take into account the electricity flows between the two zones. In the period analyzed, the direction of the electricity flows is only from the North to the South. This accounts for 20% of total South electricity consumption. The electricity flow data refer to the total amount of electricity that is exchanged between the two macro zones including both bilateral contracts and spot market flows. Thus, it is not possible to determine the value of flows traded on the spot market. As discussed in the market regulation analysis, when transmission constraints are violated, transmission rights are assigned first to bilateral contracts, then to the most efficient offer/bid in the spot market. However, generators always receive the zone clearing price of its belonging area. In the spot market, the transmission cost affects only the consumers.

Since the southern spot demand, obtained by subtracting the value of bilateral contracts and CIP6 production, can be satisfied by its capacity, we can expect low flows traded on the spot market. Hence, we do not account for electricity flows in the following analysis. We therefore assume that a firm maximizes her profit separately in the macro zones.

As regards to imports, in the North market, electricity is imported from France at a pre-determined price through bilateral contracts. Since we subtract bilateral contracts from both demand and supply, we do not model explicitly imports.

4.4.2 Model simulation and selection

In each model, we define the residual demand faced by the strategic players as the difference between the total spot market demand, ($Q^D_{z,tot}$), and the competitive fringe supply, ($Q^S_{z,fringe}(p)$), as:

$$Q^D_{z,strat}(p) = Q^D_{z,tot} - Q^S_{z,fringe}(p) \tag{4.1}$$

In the next section we explain our empirical specification.

Knowing the residual demand of the strategic players, the next step is the evaluation of the market equilibrium outcome according to the oligopolistic model chosen.

In analyzing the Cournot outcome, we apply a repeated grid-search approach as in Borestein and Bushnell (1999). The equilibrium quantity is determined iteratively under the assumption that the production of the other players is fixed. Thus, the first generator maximizes its profit assuming that the other players are not producing; the second generator chooses its optimal output considering that the first one does not change its output and the others are not producing; and so on. Repeating this process for all the generators and returning to each maximizing decision, taking into account the most recent output decision of the others, the Cournot equilibrium is determined when no firms have incentive to change its output given the output of all the other players.

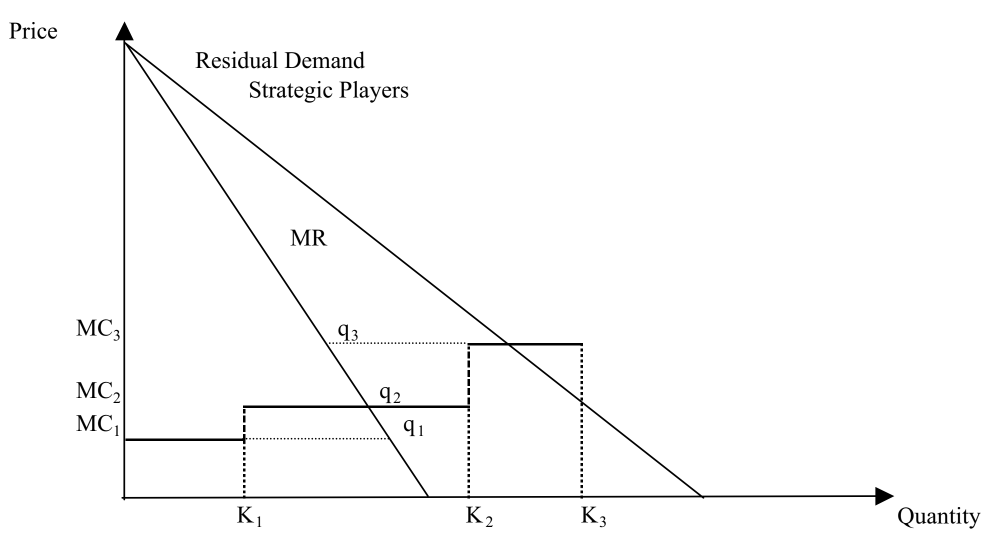
In the Stackelberg model, the equilibrium output is determined solving the game by backward induction and considering for which marginal power plant a firm does not have incentive to deviate from the equilibrium. We first derive the best reply functions of the followers and the leader according to standard theory. Then, we determine leader and followers output according to a grid-search approach.

In the Dominant firm model with competitive fringe the equilibrium output is defined maximizing the incumbent profit function according to its residual demand.

In each model the optimal output is evaluated according to both firm first order condition and firm capacity for each generating source. For example, in the dominant firm model with competitive fringe, assuming that the firm has three different plants K_i for $(i = 1, 2, 3)$ with marginal cost MC_i (for $i = 1, 2, 3$), by ordering the plants according to the merit order principle and cumulating firm capacity, the equilibrium output is determined solving profit first order condition accounting for the capacity constraint for each type of plant.

As shown in figure 4.1, q_1 is not feasible, because the optimizing output is higher than firm capacity. Also q_3 is not feasible, because does not belong to the interval $[K_2, K_3]$. Finally, the optimal output is q_2, which belongs to the interval $[K_1, K_2]$.

Figure 4.1: Strategic players residual demand and generation capacity



The oligopolistic model simulations allow the determination of the equilibrium price, the strategic player total output and each firm output in every model. Following Bushnell et al. (2008), in order to identify the model which fits the Italian electricity market better we compute a variation of the traditional R^2 to measure each model fit. The R^2 is defined as the difference between the actual and the simulated values in the two models. Thus, the R^2 is evaluated as one minus the ratio of the sum of squared errors over the sum of the squared actual values according to the both weekdays and weekends, for each zone market. The test is defined as follows:

$$R^2 = 1 - \frac{\sum_{t=1}^{T}(q_{z,j,y,t}^{actual} - q_{z,j,y,t}^{sim})^2}{\sum_{t=1}^{T}(q_{z,j,y,t}^{actual})^2} \tag{4.2}$$

where $q_{z,j,t}^{sim}$ equals, in the North, either the simulated quantity in the Cournot model or in the Stackelberg model, whereas in the South, $q_{z,j,t}^{sim}$ equals the simulated quantity in the Stackelberg and in the Dominant firm model according to the seasonal pattern analyzed ($j = weekdays, weekends$) and the two years analyzed ($y = 2005, 2006$). The model selection is based on the model which has the highest R^2. In both markets, the selection of the model, which fits the market better, is based on the evaluation of the R^2 on either the quantity produced by the strategic players and the former monopolist.

4.4.3 Competitive fringe supply

In each zone market, the competitive fringe is composed of several firms, which behave as price takers. These firms are not able to affect the market equilibrium price, but they find profitable to offer a positive quantity whenever the market equilibrium price is above their marginal costs. Thus, the competitive fringe supply curve is upward sloping. As defined in equation 4.1, subtracting the competitive fringe supply from the spot zone market demand, it is possible to define the residual demand of the strategic players, which is downward sloping.

According to electricity literature the analysis of the competitive fringe supply can be based on either evaluation, adding together the quantity that each price-taking firms would produce, as in Borestein and Bushnell (1999), or econometric estimation as in Kim and Knittel (2006), Puller (2007) and Bushnell et al. (2008). For simplicity, we follow the latter method.

In each market, the competitive fringe supply is estimated according to:

$$Q^S_{z,fringe} = f(P, X, \beta, \varepsilon_{z,fringe}) \tag{4.3}$$

where P is the hour wholesale price, X represents the cost variable, β is a vector of unknown parameters and $\varepsilon_{z,fringe}$ is an error term that captures unobserved components of competitive fringe supply.

The fringe supply is a function of the wholesale electricity price. Since electricity demand is not constant over time but subject to seasonal patterns, we allow the wholesale price to affect the competitive fringe supply according weekdays and weekends. The interaction between the seasonal pattern and the wholesale price allows to define two coefficients associated with the wholesale price in each market.[6]

The vector X indicates variables affecting the marginal cost of the competitive fringe. In both markets, we consider the natural gas price because the majority of fringe plants are gas-power plants. In order to control for the availability of hydroelectric resources we use year/month indicator variables.

To account for temporal changes in the fringe supply, we define the variable $weekday_t$, which takes value 1 during weekdays and 0 during weekends and public holidays.[7]

Thus, the competitive fringe supply function is estimated as:

[6] We also estimate a seasonal pattern accounting for the difference between summer and winter months. However, results show no structural break. We therefore estimate seasonality effects according to weekdays and weekends. Other studies on the Italian market confirm the absence of structural break between winter and summer months. See Petrella and Sapio (2009).

[7] In the sample analyzed, the public holidays are: 2nd June, 1st November, and 8th, 25th and 26th December.

$$Q^S_{z,fringe} = \alpha_0 + \alpha_1 weekday_t + \sum_{i=2}^{8} \alpha_i month_{i,t} + \\ \alpha_9 natgas_t + \beta_1 p_{z,t} + \beta_2 (weekday_t) p_{z,t} + \varepsilon_{z,t} \quad (4.4)$$

where $z = north, south$ and $i = June05$, $July05$, $Nov05$, $Dec05$, $June06$, $July06$, $Nov06$.

We estimate the fringe supply according to both linear and constant elasticity models. In order to select the functional form which fits the market better, we apply the J-test proposed by Davidson and MacKinnon (1981). In discussing the results, we present the result of the linear model, which is the one that fits better the two markets.

Having defined the fringe supply, we can evaluate the coefficients of the strategic player residual demand ($Q_{z,t}$), which is assumed downward sloping. The slope of the residual demand is equal to the additive inverse of the parameter β according to weekdays and weekends.[8] Moreover, the vertical intercept $\alpha_{z,t}$ is defined as:

$$\alpha_{z,t} = \sum_{i=1}^{N} q^{actual}_{i,z,t} + \beta_1 p^{actual}_{z,t} + \beta_2 (weekday_t) p^{actual}_{z,t} \quad (4.5)$$

where $\sum_{i=1}^{N} q^{actual}_{i,z,t}$ is the sum of the actual zone output produced by the strategic players and $p^{actual}_{z,t}$ is the actual zone price. Thus, the inverse residual demand is defined as:

$$p_{z,t} = \frac{\alpha_{z,t} - \sum_{i=1}^{N} q_{i,z,t}}{\beta_1 + \beta_2 (weekday_t)} \quad (4.6)$$

[8]In estimating the competitive fringe supply, we define weekends as default case.

4.4.4 Evaluating marginal cost

The marginal cost function is assumed constant up to firm zone capacity for each power plant type. By ordering firm power plants according to the merit order principle, it is possible to define the marginal cost function as a step function. Given the discontinuous points of the marginal cost function, we assume that in such points the marginal cost is equal to the cost of producing one more unit of output. Therefore, the production cost of an extra unit is defined as the marginal cost of the most expensive operating unit with excess capacity.

As regards to the marginal cost of hydroelectric power plant there are two main approaches in the literature. The first one considers hydro plants as zero marginal cost facilities given their negligible amount. By contrast, the second defines the hydro marginal cost as the opportunity cost equal to the operating cost of the thermal power plant that it replaces marginally in each period. However, the marginal cost of run river plants is still assumed equal zero because the water will be flowing anyway. We opt for the latter. Specifically, to determine the opportunity cost of reservoir and pumped hydro plants, for each model, we first evaluate the equilibrium output assuming a zero marginal cost. Knowing the optimal output we then establish which is the thermal plant replaced by the hydro plants. Thus, we re-compute the equilibrium setting the marginal cost of reservoir and pumped plants equal to the marginal cost of the thermoelectric plant that they replace in each period.

The marginal cost of thermoelectric plants is evaluated taking into account fuel costs and the variable operation and maintenance cost (O&M). Fuel costs are defined according to: the fuel price, used by the generating plant; the heat rate, indicating the amount of heat that the fuel needs to produce a specific power output; and the efficiency rate, usually in percentage, indicating the efficiency of a particular power plant. Since firm generation costs and plant efficiency rates are confidential information, we evaluate the former according to 4.7:

$$Fuelcost_t(€/MWh) = Fuelprice_t * \frac{1}{Efficiency\_rate * heat\_rate} \quad (4.7)$$

As regards to plant efficiency rate we use average efficiency as reported in appendix B.

The variable operation and maintenance (O&M) costs are determined as the ratio between the total variable operation and maintenance costs and the total electricity production. The O&M data have been collected from the annual reports of the strategic firms in the year 2005 and 2006.

According to the electricity literature the net efficient available capacity should take into account the probability of forced outage of each unit.[9] The available capacity of a generating unit i is evaluated as $(1 - fof_i) * cap_i$, where cap_i is the total available capacity and fof_i is the forced outage factor indicating the probability of the unit being unavailable at any given time. Given unavailability of forced outage values of each power plant, we use the total forced outage factor reported in the firm annual report for hydro and thermoelectric power plants. On average the forced outage factor is around 2%.

Knowing the marginal cost for each plant type and the net available capacity per zone market, it is possible to construct a stepwise function by ordering the plant according to the merit order principle. Thus, a firm starts its production using the lowest generating source and when this source is used at its full capacity, the next less expensive source will start to produce. Repeating this process for all the generating sources, it is possible to determine the marginal cost function as a step function.

Appendix B contains a detailed explanation of the efficiency rate per power plants, the heat rate per fuel and the change of firm net efficient

[9] Net efficient capacity indicates the total capacity minus the capacity that the plant consumes in order to work.

available capacity per zone market between 2005 and 2006.

4.5 Data

The data sample is composed of hourly data collected in the summer and winter months of 2005 and 2006. The summer months are June and July, whereas the winter months are November and December. The choice of the time period is due to both data availability and the possibility to investigate a different firm behaviour during the two years and weekdays and weekends.

The analysis is applied to the hour 7 p.m. for two main reasons. On the one hand, 7 p.m. constitutes a peak hour, but not very high, thus firm capacity constraints is never bounded. The optimization calculations of the market outcomes are therefore simplified. On the other hand, at 7 p.m. the North market is split from the rest of mainland Italy most of the times justifying a zone market analysis.

The data have been collected from two main sources: the Italian Electricity Market Operator (GME) Website and Datastream. On the GME website it is possible to find all the main information regarding the day-ahead market such as prices, consumptions, demand forecasts, transmission flows and especially the generator bids.[10] Particularly, demand and supply bids are considered confidential information and are published with one year of delay.[11] For each hour of a day, the bid file indicates:

- the purpose: whether it is a demand bid or a supply offer;
- the market: day-ahead, adjustment market, or the ancillary service market;
- the status of the bid: if the offer/bid has been accepted, rejected, revoked, replaced or found incompatible;

[10] Italian Electricity Market Operator website: http://www.mercatoelettrico.org/en/
[11] Nowadays, demand and supply bids are published with one week of delay.

- offer/bid quantity and price and the respective awarded quantity and price;
- the unit reference, its grid supply point, the zone where the plant is located and the name of the generator.

In each market, the hourly firm supply curve is defined summing up firm awarded quantity. The competitive fringe supply is defined aggregating the supply curve of the firms which contribution to zone production can be considered marginal. The analysis of the fringe supply shows that often these firms offer at a zero price. In particular, in each bid the generator has to specify both quantity and price. According to the market regulation, the price can not exceed the price cap level of 500 €/MWh and must be positive. Offering a positive quantity at a zero price allows to a firm, which is not able to affect unilaterally the equilibrium price, to ensure her participation to the market supply. Under the system marginal price this strategy is consistent, because all the bids having a price equal or lower than the marginal price are accepted. Thus, the competitive fringe supply is defined summing up the awarded quantity of the "marginal" firm independently from the bid price. In the same way, we determined the quantity supplied by each strategic firm.

The fuel price data (coal, natural gas and oil) have been collected from Datastream. These data are used to evaluate firm marginal cost in the optimizations and to estimate the competitive fringe supply.

Appendix C reports the descriptive analysis of the full sample.

4.5.1 Zone structure analysis

As shown in figure 4.2 the national market is composed of 7 zones: North, Centre-North, Centre-South, South, Calabria, and the two main islands Sicily and Sardinia. As can be noticed the average price in the Centre-North, Centre-South, South and Calabria is almost the same.

Figure 4.2: Italian market: zone structure and average price €/MWh in 2006

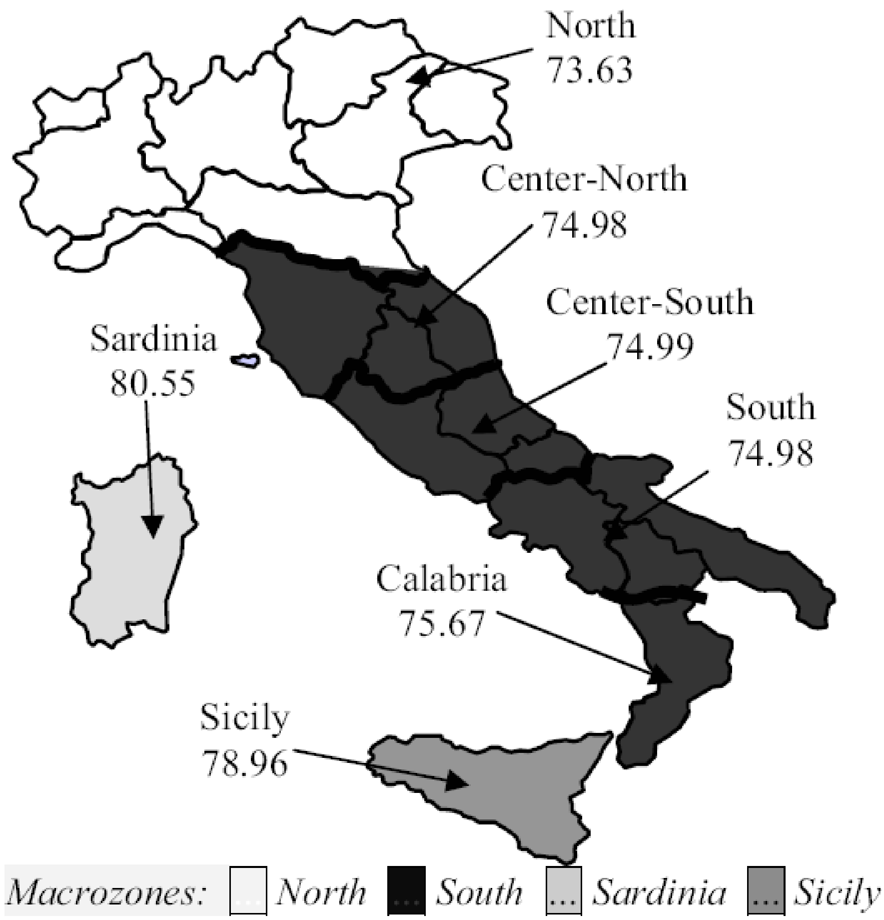


Table 4.3 shows the critical bottlenecks in the data sample. As can be noticed during off-peak hours, which is from 10 p.m. to 8 a.m., the market is rarely split into zones. However, as electricity demand increases during peak hours, the market is most of the time separated into several zones. In the data sample, the main bottleneck is the one between North and the rest of continental Italy. This bottleneck occurs mainly at 7 p.m. Moreover, Centre-North, Centre-South, South and Calabria constitute a unique market for 50%

of weekdays. Although the average electricity price of Calabria is slightly higher that the one of the rest of South Italy; in the data sample, this zone is rarely separated from the rest of the South Italy, just 9% at 7 p.m. during weekdays. The frequency of the bottlenecks justifies a zone market analysis according to two main macro zones: North and South (which includes Centre-North, Centre-South, South and Calabria), which is consistent with Italian energy authority aggregation.

Table 4.3: Main bottlenecks per hour

	Italy		North≠South		South: CN=CS=S=CAL	
hour	weekday	weekend	weekday	weekend	weekday	weekend
1	0.78	0.71	0.09	0.08	0.07	0.08
2	0.81	0.74	0.11	0.06	0.10	0.06
3	0.87	0.74	0.06	0.06	0.05	0.06
4	0.87	0.80	0.08	0.04	0.08	0.04
5	0.86	0.84	0.08	0.05	0.08	0.05
6	0.87	0.85	0.06	0.05	0.06	0.05
7	0.91	0.83	0.05	0.04	0.05	0.04
8	0.76	0.73	0.20	0.09	0.19	0.09
9	0.57	0.59	0.38	0.14	0.32	0.11
10	0.47	0.43	0.47	0.26	0.41	0.20
11	0.44	0.39	0.49	0.31	0.41	0.24
12	0.43	0.36	0.48	0.38	0.41	0.30
13	0.38	0.36	0.55	0.35	0.49	0.26
14	0.48	0.44	0.45	0.28	0.40	0.24
15	0.51	0.53	0.41	0.23	0.36	0.21
16	0.42	0.58	0.47	0.20	0.38	0.19
17	0.43	0.51	0.51	0.24	0.40	0.21
18	0.38	0.41	0.56	0.29	0.43	0.24
19	*0.32*	*0.33*	*0.62*	*0.33*	*0.50*	*0.25*
20	0.34	0.34	0.61	0.39	0.53	0.24
21	0.26	0.23	0.66	0.40	0.59	0.31
22	0.41	0.40	0.54	0.34	0.48	0.25
23	0.23	0.40	0.52	0.35	0.28	0.24
24	0.41	0.50	0.31	0.23	0.24	0.16

Source: GME and own calculations

4.6 Empirical results

In this section we present the empirical findings. Firstly, we examine the results of the competitive fringe supply, which allow the evaluation of parameters of the strategic players residual demand. Secondly, we present the oligopolistic model results. Finally, the section concludes discussing the result of model selection test.

4.6.1 Competitive fringe supply estimation

Three competitive fringe supplies have been estimated according to the two local markets. In the North, we estimate a unique competitive fringe supply[12] because in the following simulated models the fringe does not change, what changes is the interaction between the strategic players according to the model analyzed.

In the South, we estimate two different competitive fringe supplies according to the definition of the simulated models. In the first case, we consider a Stackelberg model where the former monopolist is the leader and there are three followers, whereas all the other firms have a marginal contribution to the zone production. In the second case, we consider a Dominant firm model with competitive fringe in which all the firms except the former monopolist are assumed price-takers.[13]

We first check whether prices are endogenous in the fringe supply. As expected, prices are exogenous in the Stackelberg model with competitive fringe, in this case the fringe supply is too small to affect the market price. Therefore, we estimate it using ordinary least squares (OLS) taking into account for serial correlation and heteroskedasticity. In the other models prices are endogenous, hence shocks to the competitive fringe supply affect the wholesale price. In this case, we estimate the fringe supply using the general method of moments (GMM) and instrumenting the wholesale price according to TERNA zone demand forecast and zone bilateral contracts. As well as the price, we define four instruments by interacting demand forecast

[12]The northern fringe supplies on average 32% during both weekdays and weekends.

[13]In the Stackelberg model, the non strategic players, which are in total 15 firms, supply just 5.9% and 7.8% in weekdays and weekends respectively. Adding the supply of the three followers, we obtain the fringe supply of the Dominant model, which supply roughly 36% and 29% in weekdays and weekends respectively.

and bilateral contracts with $weekday_t$. In order to check the validity of the instrument set we test overidentifying restrictions using the Hansen (1982) J test and their relevance using the Likelihood Redundant instrument test developed by Hall and Peixe (2000). In the North, the error term is heteroskedastic and serial correlated, we therefore report Newey-West robust standard errors. Indeed, in the Dominant firm model, the error term is homoskedastic and serial correlated. Therefore, we correct it only for serial correlation according to Newey West. Table 4.4 shows the results of the estimation for each zone market analyzed.

Table 4.4: Competitive fringe supply estimation results

$Q^S_{z,fringe}$	$North^1$	$South\_Dominant^2$	$South\_Stackelberg^1$
$p_{z,t}$	27.168***	10.763***	2.573**
	(4.711)	(3.359)	(0.913)
$(weekday_t)p_{z,t}$	-9.080	-7.514**	-1.362*
	(3.204)**	(2.408)	(0.603)
$natgas$	-2.870	-3.118	-0.702
	(1.956)	(2.577)	(0.459)

Weekday, month/year dummies included but not reported. [1] Robust standard error in brackets. [2] Standard error corrected for serial correlation.
** indicates significance at 5%, *** indicates significance at 1%

Results are consistent with economic intuition. As expected the fringe supply decreases as the natural gas price increases. However, in the Stackelberg model the decrease is lower than in the other models due to composition of fringe plant portfolio. Specifically, these firms have two main types of plants, CCGT and other gas plants, therefore even if the natural gas price increases their production decreases slightly because most of them do not have other production alternatives.

In all the estimated models, the competitive fringe supply is more responsive to price changes during weekends than weekdays. The comparison of the slope coefficients shows that these are higher in the northern than in the southern models. Specifically, the slope coefficients are higher in the Dominant firm model than in the Stackelberg one. As shown in table 4.2, the non strategic players have a higher influence in the North than in the South. Thus, the strategic players in the former are more responsive to price changes than in the latter.[14]

4.6.2 Oligopolistic model results

In this section we present the results of the simulated oligopolistic models. In both markets and in each model the marginal cost is assumed constant up to firm net available capacity for each power plant. In order to identify the opportunity cost of hydro generation, we first evaluate the equilibrium assuming hydro plants having a zero marginal cost. We then distinguish hydro sources according to run-river, reservoir and pumped storage. We assume the marginal cost of the latter two equal to the marginal cost of the thermoelectric plant they replace, while the marginal cost of the former is assumed equal to zero. Here we present the final results.

Northern market results

Figure 4.3 and 4.4 show the actual and the predicted output of the strategic players. To appreciate better the results, we show several graphs accounting for the two year and winter and summer months. As regards to 2005, the comparison of the three series shows that both models slightly underevaluate the actual output. However, the Stackelberg model appears to predict better

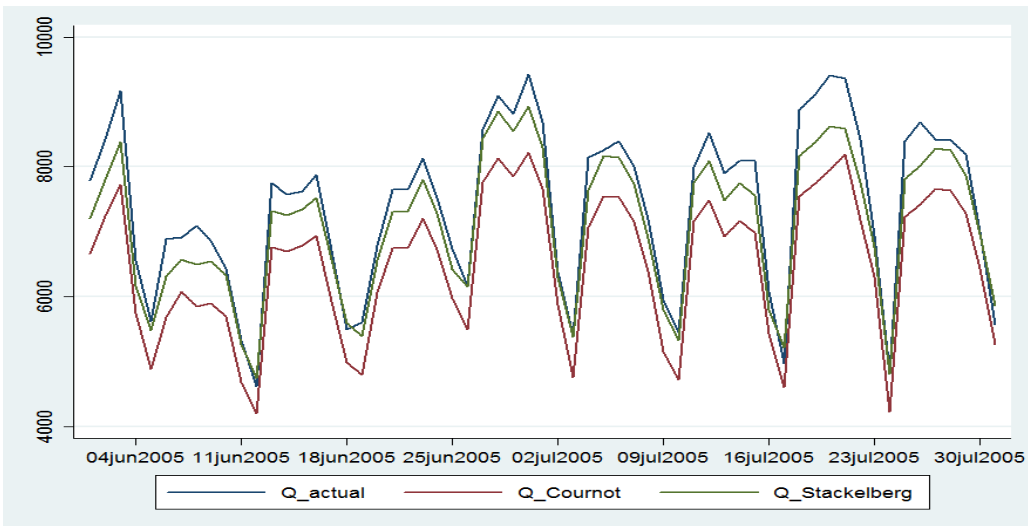
[14] The evaluated β coefficients are the following:

- North: 18.088 (weekdays) and 27.168 (weekends);
- South (Dominant): 3.249 (weekdays) and 10.763 (weekends);
- South (Stackelberg): 1.211 (weekdays) and 2.573 (weekends).

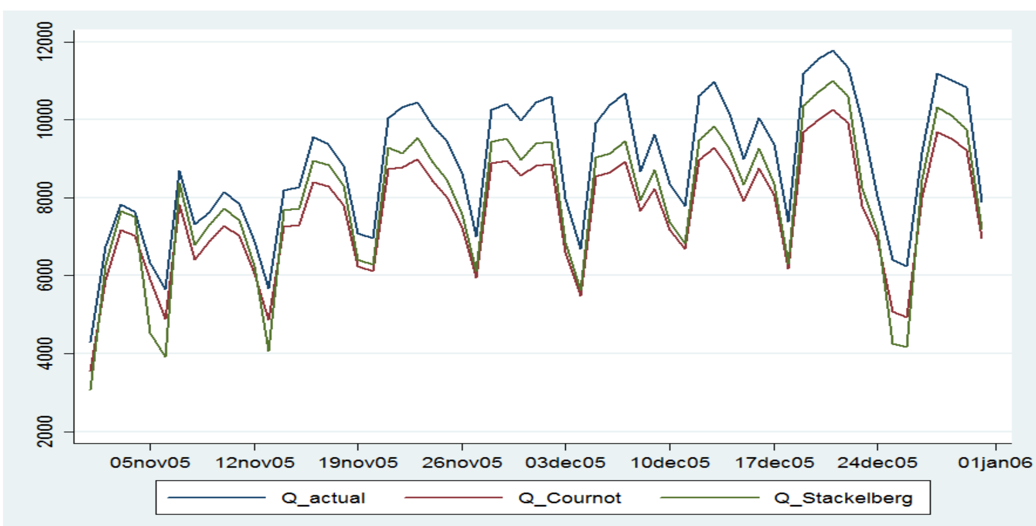
the actual output.

Figure 4.3: Results strategic player output in the North market 2005

(a) summer months 2005



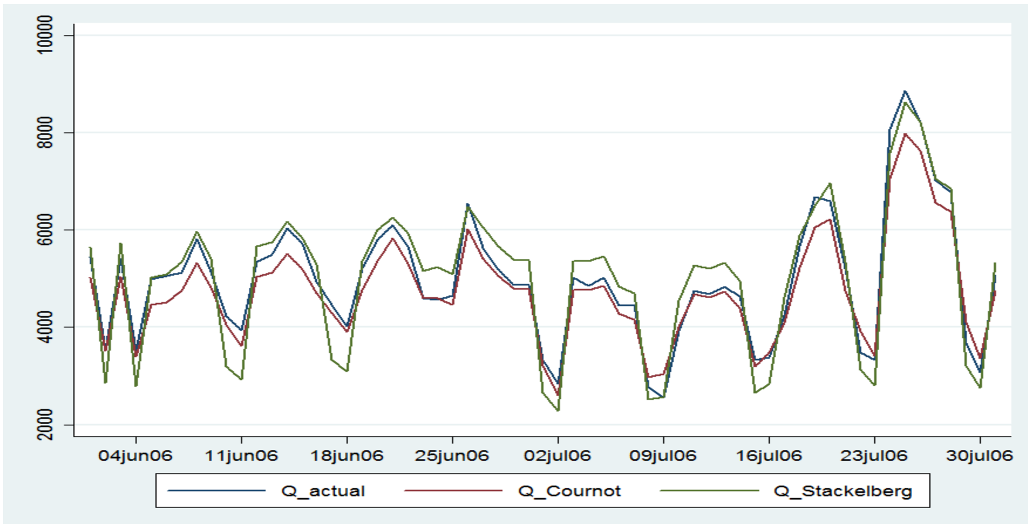
(b) winter months 2005



Concerning to 2006, the comparison between summer and winter months shows different patterns. In the summer months, the actual values are generally bounded between the Stackelberg model above and the Cournot model below. However, during weekends Stackelberg predictions are slightly lower than actual and Cournot output. Indeed, in the winter months both models overevaluate the actual series.

Figure 4.4: Results strategic player output in the North market 2006

(a) summer months 2006



(b) winter months 2006

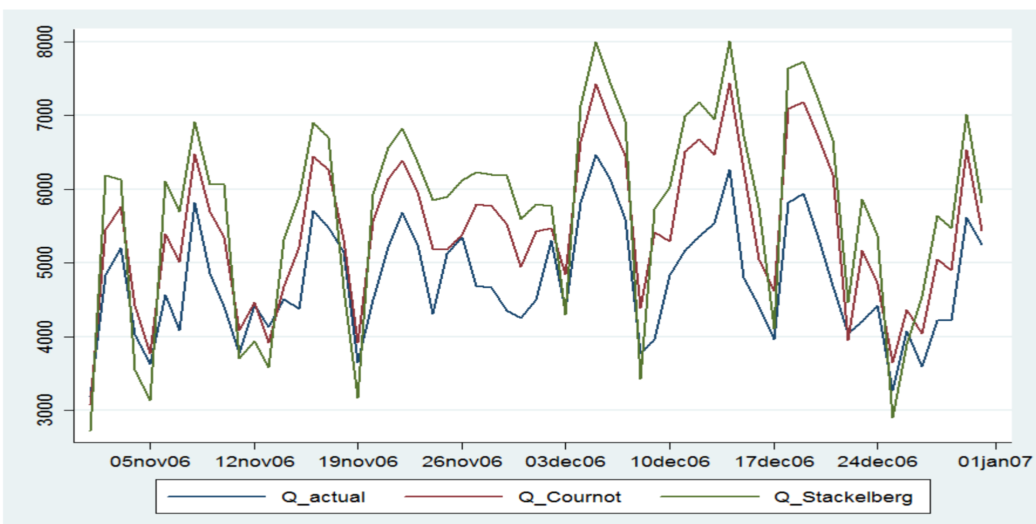
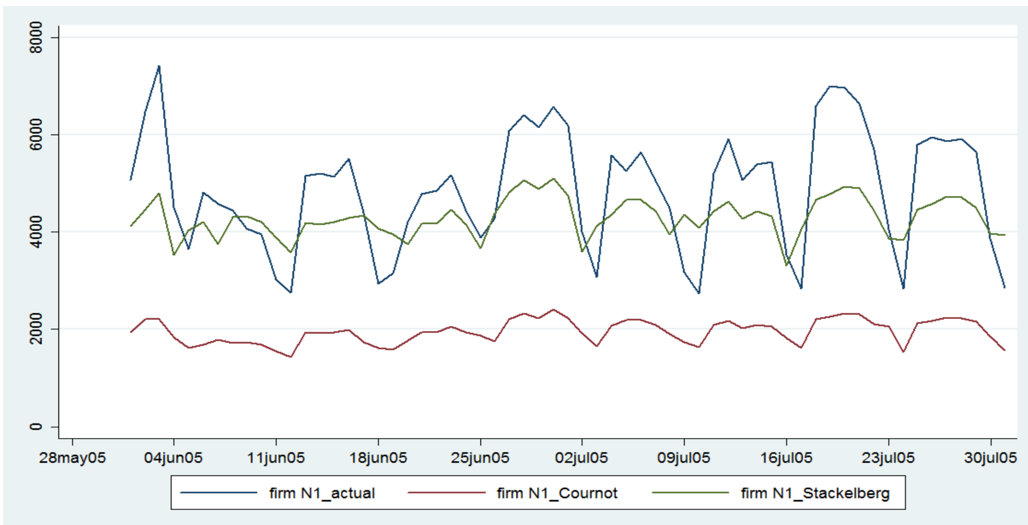


Figure 4.5 and 4.6 shows the actual and predicted outputs of the former monopolist. The comparison of the incumbent output and the predicted values in the two models confirm the above analysis. In particular, in 2005

the Cournot predictions are significantly lower than the incumbent production. Indeed, in 2006 the actual values are generally bounded between the Stackelberg (above) and the Cournot (below) models.

Figure 4.5: Firm N1 output in the North market (2005)

(a) summer months 2005



(b) winter months 2005

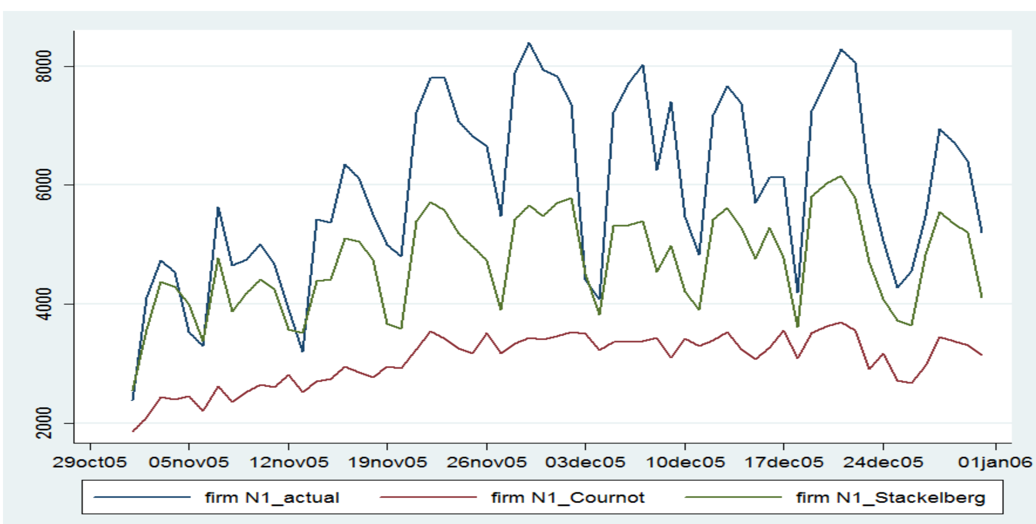
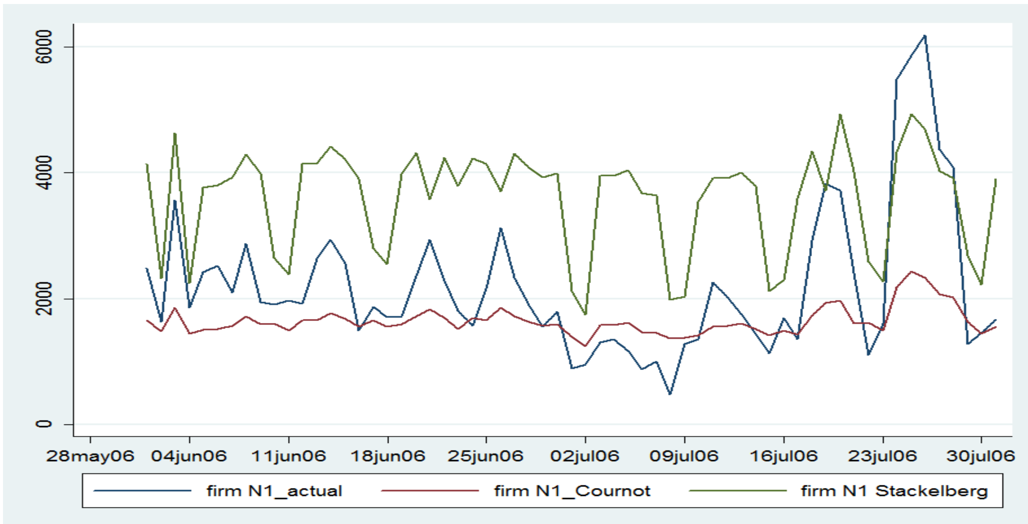
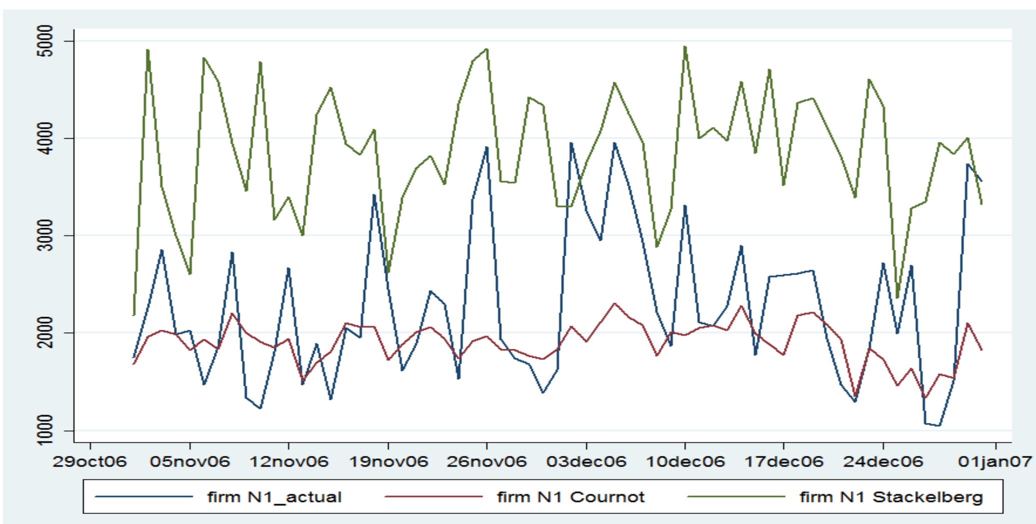


Figure 4.6: Firm N1 output in the North market (2006)

(a) summer months 2006



(b) winter months 2006



As regards to the results in the South market, we discuss the main results related to former monopolist output, because we are interested in establishing whether the incumbent behaves as either Dominant firm or a Stackelberg leader. On average, she supplies 3187 MWh (weekdays) and 2218 MWh (weekends). In the Stackelberg model, the incumbent output is on average equal to 2290 MWh and 1359 MWh, whereas in the Dominant firm model it is 1682 MWh and 1193 MWh during weekdays and weekends respectively. Thus, both the simulated models on average underestimate the former monopolist supply in both periods.

4.6.3 Model selection results

Having evaluated the outcomes of the two competing models in each market, we can now select the model, which fits each zone market better, according to R^2 defined in equation 4.2. In particular, the test is evaluated distinguishing between the two years studied and the weekly seasonal pattern. Model selection results are shown in table 4.5.

First, consider the North market. Results show that this market recorded a change in the underlying oligopolistic structure. In 2005, the Stackelberg prediction of total strategic players output ($Q_{strategic}$), incumbent output (Q_{firmN1}) and the other strategic players output ($Q_{-firmN1}$) are strictly preferred to the Cournot ones during weekdays. As regards to weekends, focusing on total strategic players output, the two predictions lead to very close values of the R^2 pointing out a slight preference for the Cournot model. However, accounting for incumbent and other strategic player predictions, the test confirms the preference for the Stackelberg model also during weekends.

Instead, in 2006 the test shows a clear preference for the Cournot model in both weekdays and weekends as confirmed by figure 4.4.

Table 4.5: Model selection results

			2005		2006	
North			Cournot	Stackelberg	Cournot	Stackelberg
	weekday					
		$Q_{strategic}$	0.982	*0.994*	*0.982*	0.963
		Q_{firmN1}	0.669	*0.958*	*0.841*	0.354
		$Q_{-firmN1}$	0.325	*0.672*	*0.879*	0.690
	weekends					
		$Q_{strategic}$	*0.981886*	0.981852	*0.989*	0.966
		Q_{firmN1}	0.804	*0.9469*	*0.865*	0.755
		$Q_{-firmN1}$	0.799	*0.848*	*0.682*	0.569
South			Dominant	Stackelberg	Dominant	Stackelberg
	weekday					
		Q_{firmS1}	0.782	*0.908*	0.815	*0.929*
	weekends					
		Q_{firmS1}	*0.864*	0.811	0.894	*0.905*

Note: higher values than competing model in italics

To select the model which fits better the South market, we report the R^2 evaluated on the predicted and actual values of the incumbent.

Results show that during weekdays the Stackelberg model is strictly preferred to the competing model in both years. However, during weekends the former monopolist behaves as a Dominant firm in 2005 and as a Stackelberg leader in 2006. Although the R^2 in the two models are very close, the change from a Dominant firm to a Stackelberg model highlights an improvement towards competition. The two models differ for the assumption regarding the composition of the fringe. In the former model, all the other firms are assumed price-takers, whereas in the latter some firms take industry output minus own output and others are price-takers. The two model predictions are equal if the fringe is composed by a large number of firms, but this is not our case. Indeed, the fringe is composed by 15 (Stackelberg) and 18 firms (Dominant) firms. In the former, they supply on average 7% of the southern spot market demand, whereas in the latter 32%. Thus, the analysis points out that the market recorded a slight improvement in competition during weekends.

4.7 Conclusions

This chapter has proposed a study of the Italian wholesale electricity market focusing on the underlying oligopolistic structure characterizing the market in the summer and winter periods of 2005 and 2006. Given the organization of the national market as a zone market, we study the two main macrozones (North and South) located in mainland Italy.

Differently from previous studies we propose the evaluation of two oligopolistic models for each local market, defined according to both firm generation capacity and production, and the selection of the model, which fits the market better. In the North market, we analyze the Stackelberg and the Cournot models, whereas in the South market we analyze the Dominant firm and the Stackelberg model. All the models are assumed with competitive fringe.

Results show that the North market records a change in the underlying competitive structure from the Stackelberg model (2005) to the Cournot model (2006). This result suggest two main remarks. On the one hand, the empirical findings may imply a progress towards a more competitive market due to the decrease of market concentration. On the other hand, the results suggest a loss of efficiency. Precisely, according to microeconomic theory the Stackelberg model predicts higher output and lower price than the Cournot model, hence is more efficient. Thus, results show that in spite of a reduction of market concentration, it is not possible to state that consumers are better off.

With regard to the South market, results show that the former monopolist behaves as a Stackelberg leader during weekdays in both years. However, during weekends we find a change in the underlying oligopolistic structure from the Dominant firm (2005) to the Stackelberg (2006), highlighting therefore an improvement towards competition.

Our analysis highlights two main remarks: one related to the organization of the Italian market and the other concerning the effects of generation restructuring on consumer welfare. As regards the former, the current zone structure is due to insufficient transmission capacity across the country. However, as argued by Borestein et al. (2000) when congestions occur two main implications arise. On the one hand, most efficient generators cannot serve the geographically distant consumers due to insufficient transmission capacity. On the other hand, congestions reduce the competitive pressure strengthening the position of the former monopolist. Thus, the enforcement of competition requires the total reduction of congestions. On this point, as reported in the annual report of the GME (2009), the role of congestions is currently reduced at least in mainland Italy. In particular, in 2008 the North and South markets were a unique market for more than 68% of the hours, while the national market was a single market only for 17% of the hours. Despite of the investments done so far to improve the national grid, these results point out that there is more to do.

As regards to the effects of restructuring on generation, we should notice that EU competition policy, consequently Italian policy, is still dominated by the pre-Chicago school theory, which associates market power and large market share to anticompetitive conducts. According to this theory, it is possible to foster competition by allowing entrance and reducing market concentration. However, more recent theories, like the market leader[15], argue that there is no relationship between market share and market power of the leader and may lead to misleading welfare comparisons.

Moreover, Motta (2004) argues that the reduction of market concentration does not constitute *per se* a measure to foster competition in a market and to enhance consumer welfare. Our results in the North market are therefore in line with the most recent theories.

[15] See Etro (2007) for an excellent discussion.

Chapter 5

Conclusions

The analysis developed in this thesis shows several critical points concerning the restructuring process of the EU electricity market.

First, consider the wholesale market integration issue. As shown in chapter 2, which examines wholesale electricity price convergence of the main EU Power exchanges over the period April 2004 to mid June 2006, we find evidence of perfect integration only in the case of the German and the Austrian markets. Moreover, a fair degree of integration is observed between the German and the French markets as well as the Austrian and the Dutch markets. Specifically, the latter may be explained by a good integration between the Dutch and the German markets. The high degree of convergence of Germany with its neighbouring can be explained by an efficient interconnection capacity, which is rarely congested. These results confirm the development of a regional market, which can be considered a first step towards EU market integration.

Moreover, as regards to the Spanish and Italian markets we do not find evidence of integration with none of their neighbours. In both cases, limited interconnection capacity is the main cause of these results. However, we should point out that the Italian case is worse than the Spanish. In fact, applying the two-step procedure, proposed by Breitung and Hassler (2002), we exclude the Italian prices after the first step. Thus, the overall analysis of wholesale price convergence highlights the lack of EU market integration, the development of regional markets and the need to improve the interconnecting capacity.

Second, consider the EU reform impact on industrial consumers. As explained in chapter 3, we assess the impact of EU restructuring focusing on industrial consumers, since market opening has been established gradually according consumption thresholds. Specifically, we examine a panel of data of EU15 countries over the period 1980-2006. The novelty of our approach compared to other studies is twofold. On the one hand, we study the EU reform impacts on the generation price-cost margins, which in turn implies how industrial consumer welfare change accounting for different features of the reform. On the other hand, the empirical technique, pooled mean group (PMG), applied, which have been developed by Pesaran et al. (1999), (at least to our knowledge), is for the first time implemented to assess the impact of the EU reform. This estimator has several advantages, in particular in our case, offers the best representation of long and short run relationship according to the EU restructuring. Specifically, it imposes homogeneity in the long run coefficients, coherently with the EU mandated goal of market integration, leaving short run parameters to differ freely, as established by the harmonization principle.

Results are partly in line with previous findings, that is wholesale market opening, establishment of a sector authority and international trade lead to a reduction of industrial price-cost margin, hence raise industrial consumer welfare. However, overall vertical separation leads to an increase in the price-cost margin. This result is on the one hand consistent with recent theoretical development of market leader theory, and on the other hand points out that only the combination of effective competition and vertical unbundling can lead to a contraction of the industrial price-cost margin. However, the structure of the national markets analyzed is far away from both effective competition and full vertical unbundling.

Moreover, as regards to the national rates of adjustment to long-run equilibrium, the analysis developed confirms the results of chapter 2. As pointed out in chapter 3, short-run parameters are indirectly proportional to profit persistence. Hence, a less adjustment rate implies higher profit persistence, shrinking industrial consumer welfare. On this point, results show that the German market can be considered the most efficient market in the sample analyzed, whereas the Italian market is the less efficient. The German success may be due to both high capacity utilization and privatization. As regards to the former, Wolak and Patrick (1997) argues that when plant availability is constrained, the price-cost margin raises. Concerning privatization, as discuss by Vickers and Yarrow (1998) and Newbery (1999 and 2002a), it leads to efficiency improvements. Instead, the Italian failure may be caused by the presence of a dominant firm in the generation activity, the establishment of a wholesale market only in 2004 and a delay in privatizing the incumbent.

After examining the impact of the EU reform at cross-country level, we have focused on the Italian wholesale electricity market to assess the potential improvements towards competition arising from generation liberalization. We therefore propose an exercise to link theoretical predictions and empirical findings. Accounting for the zone organization of the market, we study the two main macrozones in mainland Italy during the summer and winter months of 2005 and 2006. Specifically, we classify firms in strategic and price-takers players according to firm production and generation capacity. In the North market we examine the Stackelberg and the Cournot models, whereas in the South the Dominant firm and Stackelberg model. Estimating the competitive fringe supply, we derive the parameter of the strategic-player residual demand. Then, we compute the market equilibrium by optimization techniques. Knowing the market outcomes in all the models and for each market, we select the model, which fits the market better according to a variation of the traditional coefficient of determination.

Results show that the North market records a change in the underlying competitive structure from the Stackelberg (2005) to the Cournot (2006) model. As regards to the South, we find, in both years and during weekdays, that the former monopolist behaves as a Stackelberg leader, whereas during the weekends the incumbent conduct records a change from the Dominant firm to the Stackelberg leader. However, we should consider that the difference between the two R^2 is very low.

These results are partly due to the growth of both the other strategic player and the price-taker firms. Moreover, as discussed in the chapter, two main remarks emerge one related to the national transmission capacity and, the other, more general, regarding the implication of generation liberalization. Concerning the former, transmissions congestions characterize the Italian market not only at international level, but also at national level, determining a zone organization of the market. As pointed out by Borestein et al. (2000) market congestions imply a reduction of the overall efficiency of the market. As regards to generation liberalization, the reduction of market concentration does not necessarily imply enhancement of competition and consequently increase of consumer welfare.

Chapter 6

Appendix

Appendix A

In chapter 3, we study the effects of the EU reform on industrial profitability. The model, we present, is the result of a carefully selection of the parameters.

To select the best model we apply the Akaike Information criteria (AIC) and Bayesian Information criteria (BIC), which are used to compare maximum likelihood models.[1] Given two models fit on the same data, the model with the smaller value of the information criterion is considered to be better.

As discussed in chapter 3 the EU reform involves several features that can be summarized in: TPA, establishment of wholesale market, privatization, vertical separation and establishment of a sector authority. In our model, these features accounts for entry barriers, but no all these record a statically significant impact on industrial profitability. We therefore define a general model, in which we account for competitiveness, demand, market efficiency and entry barriers. In particular, the latter accounts for:

- legislation effects: we define two variables to check the effect of legisla-

[1] AIC and BIC are defined as:
$AIC = -2 * ln(likelihood) + 2 * k$
$BIC = -2 * ln(likelihood) + ln(N) * k$
where$N$ is the number of observations and k indicates the degrees of freedom.

tion on industrial profitability. The first is defined according to the establishment of the EU directives, whereas the second according to the enforcement of national electricity act. The variable (eudir) takes the following values: 0 before than the First Directive, 1 from 1996, year of came into force First Directive, to 2002, and 2 from 2003. Instead, the variable (elecact) takes value 1 if there is a national legislation that regulates the electricity market, and 0 otherwise.

• establishment of regulated TPA: we define a dummy variable TPA which takes value 1 in case of regulated TPA and 0 otherwise. The definition of this variable is based on the OECD Regulation Database.

• ownership structure: we define five dummy variables (public_own, mpub_own, mixed_own, mpriv_own, priv_own) accounting for the different types of ownership and set public ownership as the default case.

• wholesale market (whole): we define a dummy variable which takes value 1 if there is a wholesale market and 0 otherwise.

• vertical separation: we define the variables integrated, mixed and unbundled to control for different degrees of vertical separation.

• sector authority (aut): we define a dummy variable which takes value 1 if there is a sector authority and 0 otherwise.

In the following table, we report the results of the PMG estimation, which Hausman test prefers to the MG estimator.

Table 6.1: Model selection

Variables	MOD 1	MOD 2	MOD 3	MOD 4
cr1	-0.0565**	-0.0553*	-0.0552*	-0.0503**
	(2.60)	(2.55)	(2.56)	(2.73)
trade	-0.4113***	-0.4058***	-0.4064***	-0.4081***
	(6.76)	(6.71)	(6.74)	(6.76)
rgdp	-0.0045**	-0.0043**	-0.0042**	-0.0042**
	(2.82)	(2.64)	(2.63)	(2.58)
oil	-0.0032***	-0.0030***	-0.0030***	-0.0030***
	(13.23)	(14.26)	(14.35)	(14.32)
cap_uti	0.2572*	0.2667*	0.2701*	0.2789**
	(2.35)	(2.45)	(2.49)	(2.59)
ecdirec	0.0102			
	(1.36)			
electact		0.0040		
		(0.20)		
tpa	0.0075	0.0025	0.0059	
	(0.53)	(0.11)	(0.42)	
whole	-0.0132	-0.0108	-0.0108	-0.0092
	(1.29)	(1.04)	(1.05)	(0.94)
mpub_own	0.0206	0.0196	0.0195	0.0201
	(1.68)	(1.59)	(1.58)	(1.63)
mixed_own	0.0169	0.0143	0.0138	0.0131
	(0.72)	(0.62)	(0.60)	(0.57)
mpriv_own	-0.0872*	-0.0910*	-0.0910*	-0.0910*
	(2.17)	(2.26)	(2.26)	(2.28)
priv_own	-0.0139	-0.0192	-0.0179	-0.0218
	(0.27)	(0.37)	(0.35)	(0.45)
mixed	0.0257**	0.0261**	0.0259**	0.0261**
	(2.90)	(2.90)	(2.89)	(2.91)
unbundled	0.0785***	0.0812***	0.0808***	0.0812***
	(5.13)	(5.33)	(5.36)	(5.38)
aut	-0.0284*	-0.0278*	-0.0276*	-0.0239*
	(2.15)	(2.14)	(2.13)	(2.52)
t	0.0024	0.0034***	0.0034***	0.0035***
	(1.95)	(3.31)	(3.41)	(3.47)
φ	-0.3849***	-0.3881***	-0.3885***	-0.3890***
	(6.17)	(6.16)	(6.18)	(6.21)
MLL	710.7139	709.8253	709.808	709.7308
AIC	-1385.428	-1383.651	-1385.616	-1387.462
BIC	-1315.985	-1314.208	-1320.031	-1325.735

Notes: The dependent variable is the yearly change in the industrial price-cost margin. Z-statistics in absolute values are in parentheses.

*,**, *** denote statistically significance at 5%, 1%, 0.1% respectively.

First, let us consider model 1 and model 2, in which we check for a structural break due to the enforcement of the EU directives and national legislation respectively. In both models, we do not find empirical evidence for it. We therefore re-estimate the model (MOD3) eliminating the EU and national legislation variables. Moreover, we notice that regulated TPA is not statistically significant in all the three models. Hence, we re-estimate the model eliminating the effect of regulated TPA. As regards to ownership structure all the models show that only mostly private is individually statistically significant. Private ownership is not individually statistically significant, because in our sample only Germany and UK have fully privatized the ex-incumbent. Applying a joint test to ownership structure, we reject the null hypothesis at 5%. The comparison of the AIC and BIC criteria shows a preference for model 4 among the others. We therefore select model 4 as our final model.

Appendix B

Firm power capacity is composed by hydroelectric and thermoelectric power plants.

The hydroelectric power plants includes run of river, reservoir and pumped storage. In the period analyzed there has been no change in the hydroelectric national capacity.

Thermoelectric power plants can be classified in:

- Coal plants: uses coal and have an efficiency rate is equal to 36%. Coal plants are characterized by the lowest average marginal cost (22 €/MWh) and therefore constitute the Italian base load capacity.

- Combined cycle gas turbine (CCGT): burns natural gas and have a very high efficiency rate equal to 55%. The average marginal cost is 40 €/MWh. The majority of the Italian new plants are CCGT because they can be used to satisfy both the base and peak load demand.

- Other gas plants:
  - Repowering plants: are old gas plants that have been subject to repower. They use natural gas and have an efficiency rate of 40%. The average marginal cost is 52.63 €/MWh.
  - Turbo gas: uses natural gas and are characterized by a low efficiency rate of 28%. The average marginal cost is 75.18 €/MWh.
  - Steam plants: can work burning fuel oil or natural gas. The marginal cost is determined as the average cost of the fuel oil and natural gas. Finally, steam plants have an efficiency rate equal to 36% and the average marginal cost is 76 €/MWh.
- Oil plants: uses fuel oil, have an efficiency rate of 38% and the average marginal cost is of 87.9 €/MWh.

The change in the net efficient capacity from 2005 to 2006 is due to the introduction of the following plants:

- in the North:
  - Firm N2 introduced a new CCGT plant in Piacenza with a net efficient capacity of 800 MW;
  - Firm N1 introduced a new CCGT plant in Piacenza with a net efficient capacity of 375 MW;
  - in the fringe a firm introduced a new CCGT plant in Cassano with a net efficient capacity of 770 MW.
- in the South:
  - Due to a change in the structure of the zone market, Piombino limited pole of production has been assigned to the Centre-North. Therefore, Firm S1 and firm S3 capacities have been increased of 1207 MW and 60 MW respectively.

- Firm S1 introduced a CCGT and two steam plants of 375 and 238 MW;
- Firm S3 introduced a new CCGT plant of 766 MW;
- Firm S2 introduced two new CCGT plants with a total capacity of 1135 MW;
- in the fringe four new plants were introduced with a total net capacity of 1885 MW.

Appendix C

Table 6.2 shows the descriptive analysis according to the zone markets.

Table 6.2: Descriptive analysis

	Obs	Mean	Std. Dev.	Min	Max
$North$					
Q_n	244	8731.65	2221.15	4359.15	14749.61
$Q^S_{n,fringe}$	244	2233.81	749.30	545.45	4229.08
$firm\, N1$	244	3824.53	2022.20	477.00	8405.10
$firm\, N3$	244	1200.25	496.25	54.84	2302.48
$firm\, N4$	244	823.15	284.07	61.91	1673.82
$firm\, N5$	244	823.15	284.07	61.91	1673.82
p_n	244	92.00	38.09	34.00	198.39
$forecast_n$	244	22585.37	4168.88	13270.00	28690.00
bil_contr_n	244	7865.75	2020.58	3792.66	11586.82
$South$					
Q_s	244	4298.00	1390.42	829.17	7332.70
$Q^S_{s,Dominant}$	244	1428.32	548.58	161.53	2596.76
$Q^S_{s,Stackelberg}$	244	281.20	274.94	13.4	1002.32
$firm\, S1$	244	2869.67	1055.26	621.47	5746.83
$firm\ S2$	244	763.22	398.58	0.00	1323.81
$firm\, S3$	244	50.00	57.72	0.00	398.46
$firm\, S4$	244	333.90	113.07	20.50	624.63
p_s	244	96.71	39.69	35.73	199.27
$forecast_s$	244	15431.56	2158.34	9680.00	19130.00
bil_contr_s	244	1184.51	305.86	504.28	2269.23
$Fuelprices$					
$coal$	244	2.22	0.16	1.14	2.43
$natgas$	244	22.92	13.04	8.71	78.48
oil	244	32.93	3.43	16.54	40.73

- Q_z $(z = North, South)$ indicates the hourly consumption of electricity in MWh at 7 p.m. excluding bilateral contracts, renewable generation and imports. The average quantity demand in the two markets is highly different: the North demand is almost equal to the double of the South demand.

- $Q^S_{n,fringe}$,$Q^S_{s,Dominant}$,$Q^S_{s,Stackelberg}$: indicate the competitive fringe supply in the different models and market analyzed. Data are in MWh. In the North, we estimate a unique competitive fringe supply because in the simulated models the fringe does not change, what changes is the interaction between the strategic players according to the model analyzed. The northern fringe is composed by 31 firms. In the South, we estimate two different competitive fringe supplies according to the simulated models. In the first case, we consider a Dominant firm model with competitive fringe in which all the firms except the former monopolist are involved in the competitive fringe. In the second case, we consider a Stackelberg model where the former monopolist is the leader and there are three followers, while all the other firms have a marginal contribution to the zone production. In the first case the fringe is composed by 18 firms, while in the second by 15 firms.

- $p_z(z = North, South)$ is the zonal market clearing price. The maximum and the minimum price have been recorded in the winter and in the summer period respectively.

- $Firm\,N1$, $firm\,N3$, $firmN4$ and $firm\,N5$: are the strategic players in the North market.

- $Firm\,S1$, $firm\,S2$, $firm\,S3$ and $firm\,S4$: are the strategic players in the South market.

- $forecast_z(z = North, South)$: indicates the hour forecast of electricity demand. These forecasts are provided by Terna according to different parameters such as temperature and previous consumptions. As can be noticed there is a big difference between the quantity analyzed and the demand forecast, this is due to the inclusion of bilateral contract in the latter.

- $bil\_contr_z(z = North, South)$: indicate the bilateral contracts level in a particular zone market.

- *coal*, *natgas*, *oil*: indicate the fuel prices in €/MWh. Fuel prices are financial data, thus there is no value for weekends. We fill the Saturday and Sunday values according to the average value between Friday and Monday.

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