Essays on European Electricity Market Integration

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Abstract

This thesis examines three aspects relating to the construction of the single European electricity market. The research begins with a welfare analysis of market integration by estimating the impact of introducing an efficient congestion management method (i.e. market coupling) to reduce barriers to cross-border trade of electricity. The Italian electricity market, Europe's highest-priced area, is used as a case-study. Deterministic simulations of the Italian electricity market with and without market coupling show the benefit that a high-priced country could reap from stronger market integration with its neighbours. The thesis then investigates the degree of integration of European wholesale electricity markets, by analysing the behaviour of electricity spot prices of Austria, Belgium, Czech Republic, France, Germany, Greece, Ireland, Italy, Poland, Portugal, Scandinavia, Spain, Switzerland, the Netherlands and the UK up to January 2012. Market integration is evaluated via three alternative econometric approaches, including fractional cointegration analysis, time-varying regressions and multivariate GARCH models. The results indicate that, as of January 2012, perfect EU-wide market integration is still a way off, though positive signs of convergence have emerged between many electricity markets. The final part of the thesis deals with the estimation of the determinants of residential electricity demand for nine major countries (Austria, Belgium, France, Germany, Italy, Spain, Switzerland, the Netherlands and the UK) using annual aggregate data for 1978-2009, with the aim of understanding how to incentivise electricity conservation and hence CO_2 emissions reduction. A general unrestricted error correction mechanism saturated with impulse, step and step-trend dummies is used to get consistent estimates of the impact of all the variables that may influence residential electricity demand. The results, revealing important similarities in the consumption behaviour of European households, can usefully inform policy makers as to how achieving households' electricity saving and hence CO_2 emissions reduction.

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1 Introduction

1.1 Preamble

The European energy policy of the past two decades has aimed to build a secure, competitive and sustainable energy system for the benefit of all European households and businesses. Since 2007, this has translated into three strategic targets for 2020: to reduce greenhouse gas emissions by at least 20% compared to the level of 1990; to achieve a 20% share of renewable energy in overall EU energy consumption; to see the annual primary energy consumption 20% below the forecasts for 2020 (EC, 2007a). Moreover, by 2050, the European Union is committed to reduce greenhouse gas emissions to 80-95% below 1990 levels (EC, 2011a).

Creating a single EU-wide electricity market is essential to ensure affordable and secure energy supplies and to tackle the climate challenge (EC, 2010 and EC, 2012a). An efficient and flexible internal market is expected to provide electricity companies with the right incentives to invest in new infrastructure, so as to reduce the chances of interruption to supplies. Moreover, it is likely to increase competition between producers and between suppliers and to allow a larger use of renewable sources of production. The full integration of Europe’s electricity markets is also expected to contribute to Europe's economic growth by stimulating investment in energy efficient technologies and in low-carbon infrastructure.

In order to build an internal market for electricity the European Commission has adopted a series of measures to radically reform the electricity supply industry of its Member States. Between 1996 and 2009, two major directives (Directive 96/92/EC and Directive 2003/54/EC) and a comprehensive “Third Legislative Package” (Directive 2009/72/EC, Regulation 713/2009/EC and Regulation 714/2009/EC) were enacted to dismantle vertically integrated monopolies, liberalise the production and supply of electricity, grant non-discriminatory third party access to networks and stimulate cross-border trade.

Building a single European electricity market first requires the presence of efficient network infrastructure that allows generators and suppliers from different countries to trade across the wholesale markets profitably. The Electricity Sector Inquiry of 2007 (EC, 2007b) highlights that the liberalisation of the electricity industry has meant that the demand for interconnection has often exceeded the available transmission capacity at many borders. Such capacity constraints have been responsible for causing congestion on the networks and hence for separating the wholesale markets of Europe from each other. Congestion, however, has not been determined only by the physical shortage of the interconnection facilities, but also by the way in which transmission capacity was calculated and allocated to market participants. Before the enactment of Regulation 1228/2003/EC, the most common allocation mechanisms were the "first-come-first-served" method, according to which capacity was granted on the basis of the order of the request, and the "pro-rata rationing" method, which foresaw the division of the capacity in equal shares and the subsequent allocation to those who requested it. As both mechanisms are non-market based, discriminatory and non-transparent, an inefficient use of interconnector capacity meant that transmission rights were not necessarily allocated to participants that valued them the most. Replacing inefficient congestion management methods is of key importance for generating the correct signal regarding the value of the existing interconnection capacity and therefore for evaluating the real need for the construction of new production and interconnection facilities.

In February 2011, at an EU summit on energy, the European Council declared that the single electricity market needs to become a reality by 2014[1]. However, in November 2012, the European Commission suggested that the EU is not likely to meet this deadline, unless

[1] The conclusions of the EU Summit of the 4th February 2011 can be found at the following web page http://ec.europa.eu/energy/council/2011_en.htm

Member States are able to address definitively the issues relating to the transposition of the legislation that guarantees a level playing field for all producers and retailers and that gives consumers the possibility of switching to the cheapest electricity supplier. The enforcement of competition and State aid rules, the development of well-functioning cross-border wholesale markets and modernisation of the transmission grid are also vital to obtain the result (EC, 2012a).

The empirical investigation carried out in this thesis assesses whether the EU reforms to date have been effective in delivering a single electricity market. The welfare implications of market coupling are assessed for a typically high priced European market, the extent of wholesale market integration is estimated and some demand side management policy guidance is possible given the correctly specified estimation of residential electricity demand. On the back of this assessment some policy guidance is offered as to how best to promote electricity savings that could contribute to the attainment of the 2020 and 2050 de-carbonisation targets. In particular, Chapter 2 reviews the development of the legislative framework regulating the electricity industry, highlighting similarities and differences in the structure and the dynamics of the electricity markets of Europe. Some disparities persist across Europe in wholesale and retail electricity prices, due to the different production mix and taxation regimes. In Chapter 3, the benefit that consumers located in high-priced areas could reach thanks to the introduction of an efficient congestion management method is quantified. The Italian electricity market is used as a case-study to conduct this welfare analysis, as it is Europe's highest-priced area. Market integration is found to be welfare enhancing for market participants, and the importance of understanding the extent to which a single electricity market has been attained is evident. The purpose of Chapter 4, therefore, is to identify the level of integration of the broadest set of European wholesale electricity markets for which data are available (Austria, Belgium, Czech Republic, France, Germany, Greece, Ireland, Italy, Poland, Portugal, Scandinavia, Spain, Switzerland, the Netherlands and the UK), by analysing the dynamics of the respective spot prices. Conclusions are drawn as to the effectiveness of the reforms and the need to speed up the process of removing barriers to the free flow of electricity across Europe. In Chapter 5, market integration is examined by estimating and comparing the impact of the determinants of residential electricity demand for nine major European countries, with the aim of verifying common consumption behaviour across European households. A novel econometric approach is used to ensure consistent estimates of all relevant variables that influence residential electricity demand of Austria, Belgium, France, Germany, Italy, Spain, Switzerland, the Netherlands and the UK. The empirical results of this chapter highlight similarities between countries and therefore inform policy makers as to which tools are best employed to induce electricity conservation and carbon emissions reduction.

1.2 Research questions

This thesis examines whether the reforms to date have successfully delivered an integrated European electricity market. In particular, the study addresses the following research questions:

- What are the welfare gains of having an integrated electricity market for a high-priced area such as Italy? How do these gains distribute across market participants? How can these gains be estimated? These questions are addressed in Chapter 3.
- What level of integration have the wholesale markets of Europe reached? What are the most important drivers of integration? These questions are addressed in Chapter 4.
- What are the determinants of electricity demand across European households? What is the role of price and income variables? What is the impact of technical progress and other exogenous factors, such as consumers' preferences, in determining electricity consumption? How similar is the impact of these determinants between countries? How can the determinants be consistently estimated? What policy tools are best employed to discourage electricity consumption? These questions are addressed in Chapter 5.

1.3 Outline and contribution of the study

This thesis contributes to the literature on European electricity markets in the following ways.

The economic literature on electricity market integration stresses that countries with high-variable cost generation capacity are expected to obtain a positive welfare gain from integration, Chapter 3 conducts a detailed empirical evaluation to test this hypothesis, using the Italian market, Europe's highest-priced area, as a case-study. This is the first study undertaking such evaluation for this market area. The structural market simulation model ELFO++™ is used to quantify the effect of introducing an efficient method, called market coupling, to manage interconnections between Italy and her neighbours. Optimising the use of the cross-border interconnection capacity, market coupling allows consumers located in high-cost generation countries to enjoy cheaper electricity produced abroad. A set of deterministic simulations of the Italian electricity market with and without market coupling demonstrate that a high-priced area such as Italy could benefit from the introduction of this mechanism.

Given that electricity market integration is found to be welfare enhancing and that the EU wants it completed by 2014, Chapter 4 presents an empirical assessment of the level of integration of European electricity markets by analysing the behaviour of the broadest set of wholesale electricity spot prices possible up to January 2012. This is the first study analysing the wholesale electricity markets of 15 countries (Austria, Belgium, Czech Republic, France, Germany, Greece, Ireland, Italy, Poland, Portugal, Scandinavia, Spain, Switzerland, the Netherlands and the UK). Moreover, this chapter assesses market integration in a more comprehensive way than previously undertaken, employing three alternative econometric approaches. The general framework of fractional integration and fractional cointegration is used to test for perfect market integration (i.e. achieved convergence), while time-varying pairwise relations are estimated to evaluate whether market integration is an ongoing process (i.e. ongoing convergence). Finally, multivariate GARCH models provide an indication of the returns volatility transmission between markets. Fractional cointegration analysis reveals that only a limited number of markets were perfectly integration by the end of January 2012 and consequently full Europe wide market integration is still a way off. However, evidence of convergence was found in 39% of market pairs tested, almost all belonging to countries at the geographical core of continental Europe. The remaining 61% of market pairs showed no sign of market convergence. In particular, the peripheral electricity markets of Greece, Ireland, Italy and Scandinavia showed little evidence of convergence to other markets. The results of this analysis highlight that the reforms have only been partially successful in delivering the internal electricity market and there is still a way to go to meet the 2014 electricity market integration target.

Market integration necessitates the implementation of common policies and electricity market rules. In order for central policy makers to make well informed decisions it is important that residential level information is available to them. In Chapter 5 market integration is finally assessed by examining the determinants of residential electricity demand for nine major European countries, with the aim of identifying the factors that impact households' electricity consumption across Europe. A novel econometric approach is proposed to model the determinants of residential electricity demand for Austria, Belgium, France, Germany, Italy, Spain, Switzerland, the Netherlands and the UK, using annual data for 1978-2009. Residential electricity demand is explained by income, electricity price and other exogenous factors (e.g. technical progress and consumers' preferences), which are not observable and must therefore be proxied. The methodological novelty in this chapter is the use of a general unrestricted error correction mechanism saturated with impulse, step and step-trend dummies to model electricity demand. Consistent estimates of the impact of the income and price variables are obtained and the importance of all the remaining explanatory factors not directly measured is quantified. The estimation of the residential demand models is carried out with the search algorithm *Autometrics*™ of OxMetrics™, which is able to identify a final model starting from the specification of an initial general unrestricted model that can contain a number of regressors higher than the number of observations. This is not possible with other estimation approaches commonly cited in the energy demand literature. The estimation results reveal important similarities in the electricity consumption behaviour of European households and therefore inform policy makers as to which tools are most appropriate to incentivise households to curb their electricity consumption and hence CO_2 emissions.

Finally Chapter 6 summarises the main findings of the thesis and provides suggestions for future research.

To set the scene Chapter 2 provides an overview of the key stages in the creation of the internal European electricity market, of the current market structure and most recent dynamics of the sector.

2 Development of the internal European electricity market

2.1 Introduction

The common European market based on the free movement of goods, persons, services and capital has been one of the core objectives of the European Union since the creation of the European Economic Community in 1957. However, it is only since the mid 1980's that Member States have recognized the need to create a single market for electricity.

In the second half of the 1990's, European countries took the first step towards the construction of an internal electricity market starting with a wide process of liberalization of their electricity industries, which had been organised for decades as vertically integrated undertakings with a national or regional scope. Major reforms were implemented with the enactment of several directives and regulations. The "First Electricity Directive" (Directive 96/92/EC) opened to competition the production and the supply segments of the electricity industry and established the principle of non-discriminatory third party access to networks for new entrants. The "Second Electricity Directive" (Directive 2003/54/EC) strengthened the provisions in the previous directive and set 2007 as a deadline for full market opening. Regulation 1228/2003/EC aimed at regulating cross-border trade of electricity between Member States, so as to improve the degree of integration between national markets. The "Third Legislative Package" improved competition and consumers protection (Directive 2009/72/EC), set up the Agency for the Cooperation of the Energy Regulators (Regulation 713/2009/EC) and the European Network for Transmission System Operators (Regulation 714/2009/EC). To reinforce the effectiveness of the reforms, since 2006, a bottom-up approach named Electricity Regional Initiatives project has been introduced as an interim step to achieve full market integration.

In this chapter the key stages of the creation of the internal European electricity market are presented as is the current structure of the national markets and the most recent dynamics of the sector. Section 2.2 analyses the changes in the legal framework governing the electricity supply industry that have occurred in the past 20 years. Section 2.3 illustrates the Electricity Regional Initiatives project. Section 2.4 presents an overview of the main features of the electricity markets across Europe. Section 2.5 concludes.

2.2 Legal framework

With the European Economic Community (EEC) Treaty signed in Rome in 1957, the then members of the future European Union[2] laid the foundations for the creation of the internal market based on the free movement of goods, services, capital and persons. The key provisions that allowed free circulation of goods included the abolition of quotas and custom tariffs among Member States, the prohibition of agreements between undertakings with the effect of restricting or distorting competition in the common market, the prohibition of abuse of dominant position and the limitation of state aid to national industries only to the cases where the social character of the aid was prevalent.

Energy has been a key element of the European Union since its creation, given that the EEC was founded on the European Coal and Steal Community (established by the Treaty of Paris in 1951) and together with European Atomic Energy Community (Euratom Treaty, signed in Rome in 1957). However, none of the three Treaties included specific measures referring to the creation of a common market for electricity. Therefore, despite the existence of an explicit provision in the EEC Treaty requiring Member States:

> "*to adjust any State monopolies of a commercial character so as to ensure that […] no discrimination regarding the conditions under*

[2] In 1957 Member States were: Italy, France, West Germany, Belgium, Luxemburg and the Netherlands.

which goods are procured and marketed exists between nationals of Member States" (Article 37(1), EEC Treaty)

national governments, in the aftermath of the Second World War, felt free to organize their electricity industries as vertically integrated monopolies, which were either state-owned or regulated. At that time, the electricity sector was of strategic importance for the development of the economy and for military purposes so the industry was organised as a monopoly (Cameron, 2007). The question of whether electricity should be included in the provisions of the Treaty remained open for several years even though on some occasions the jurisprudence of the European Court of Justice interpreted the Article 37(1) such that electricity could fall within its scope of application[3].

The model of vertically integrated utility either state-owned or regulated prevailed for three main reasons (Chao et al., 2008). The first reason was technical and resulted from the introduction of the alternating current model in multi-region networks. A system of alternating current generators connected to a complex network has to be operated centrally to remain stable, thus the simplest way to manage the system was to have a single company in charge of the whole supply chain. The second reason was economic, transmission and distribution of electricity have natural monopoly features, and duplication of facilities when different companies enter the market is wasteful. In addition, economies of scale also featured large base-load power plants and hydroelectric dams. The third reason was financial, because governments were the sole institution able to provide a large amount of capital at a low cost.

National monopolies remained unchallenged for nearly 30 years since the creation of the EEC and it was only in 1986 that the European Council inaugurated a new common energy

[3] In 1964 the European Court of Justice, ruling on the Costa vs Enel case, indirectly suggested that electricity could fall within the scope of Article 37 of the EEC Treaty, but it did not determine any change for the national electricity monopolies (De Sépibus, 2008).

policy, which outlined three goals to be reached by 1995[4]. These goals, still valid today, were to build a competitive, sustainable and secure energy system for the benefit of all European households and businesses. The strategy to succeed in these goals was spelled out in a working document of 1988 (EC, 1988), where the European Commission explicitly extended to the energy market the provisions of the Single European Act of 1986[5] relating to the free movements of goods and services, the state monopolies of commercial character, the rules of competition and the state aid.

The first step towards a new legal framework for electricity was taken in 1992 with a Directive proposal concerning common rules for the internal electricity market (EC, 1991). The principles of the proposal were adopted four years later with the enactment of Directive 96/92/EC. The "First Electricity Directive" started the process of dismantling the national monopolies, including provisions for: 1) separating the activities of production and supply from those of transmission and distribution, the so-called unbundling; 2) introducing competition in generation and retail segments; and 3) ensuring non-discriminatory access to both the transmission and the distribution networks.

Among the different types of unbundling, the first choice of the European Commission was the accounting version. This type of unbundling required that an integrated electricity company kept separated accounts of its generation, transmission, distribution and supply activities, to avoid the risk that it would use its ownership of the network to favour and cross-subsidize its generation and retail units. Member States were required to appoint transmission and distribution system operators (TSO and DSO), which could remain under the ownership of the integrated company, but had to dispatch the network power plants on the basis of objective and non-discriminatory procedures.

[4] Council Resolution of 16 September 1986 concerning new Community energy policy objectives for 1995 and convergence of the policies of the Member States. (O.J. C 241, 25/09/1986).
[5] The Single European Act, or single market act, was the first major revision of the 1957 Treaty of Rome.

Competition in generation was introduced by allowing the construction of new production capacity under two procedures: authorization and tendering. Under authorisation, anyone could build a power plant provided that it complied with some criteria regarding safety of the installation, protection of the environment, use of public ground, plants' efficiency and fuel, and commercial credentials of the undertaking. Under tendering, Member States could keep a centralised planning of the power system and could tender out the construction of new capacity.

To enable new generators and retail companies to enter the market, Directive 96/92/EC established the principle of non-discriminatory access to the network. In particular, Member States were required to adopt either a Third Party Access system (TPA), with conditions of use either negotiated or regulated, or a Single Buyer system. Under a negotiated TPA, the network operator was free to negotiate a tariff of access; while under a regulated TPA, third parties had to pay a regulated tariff of access. In both cases, the TSO or the DSO could refuse access, if there was insufficient transmission or distribution capacity. The Single Buyer system required Member States to appoint a legal person as a unique wholesale buyer for the market. In accordance with the principle of subsidiarity, the decision about the type of regulation to fix access tariffs was left to the discretion of Member States. Also the issue about market concentration was devolved to national governments, which in many cases forced the incumbent to divest its generation capacity.

Directive 96/92/EC opened the demand side of the market to competition gradually, with only a fraction of the customers, the largest one, being able to choose a preferred supplier. However, the Directive also established a timetable to enlarge the fraction of eligible customers in the subsequent years.

The first electricity directive featured several shortcomings. The possibility to opt for a negotiated TPA and to refuse access on the basis of generic security issues could be easily used by integrated companies to preclude network access to independent undertakings. A weak form of unbundling and the absence of an obligation to create a national regulatory body were also an obstacle to create a fully competitive environment. The absence of precise rules on cross-border trade of electricity between countries slowed down the process of integration. Finally, the first directive left some important issues to the discretion of Member States (e.g. the type of wholesale market organization, the role of the state ownership in different segments and the measure against market concentration), with the result of generating the development of different market designs across Europe.

Directive 2003/54/EC, which replaced Directive 96/92/EC, together with the Regulation 1228/2003/EC on cross-border trade, enabled the European Union to take a step further to the single electricity market, correcting and enlarging the instruments and the scope of the previous reform. In particular, in order to strengthen the separation of the TSOs and DSOs from the rest of the integrated companies, Member States were required to implement the legal and functional unbundling of the activities. This meant that the transmission and distribution activities had to be carried out by legally separated companies, although a vertically integrated undertaking could still own a TSO or DSO. Moreover, the Second Electricity Directive eliminated the possibility to opt for a negotiated TPA to networks and obliged network operators to submit their tariffs to regulators for approval. Furthermore, it required the set-up of an independent regulatory authority to ensure non-discrimination and competition in the market.

To spur investment in new generation capacity, the second electricity Directive gave priority to the authorisation procedure, limiting the use of tenders only when the first procedure did not ensure security of supply. Member States could also use tendering in the interests of environmental protection and the promotion of infant technologies.

Retail markets were opened up by, Directive 2003/54/EC which gave all non-residential electricity consumers the faculty to choose their retail suppliers from 1st July 2004, while it allowed residential consumers to access the free market from 1st July 2007.

The 2003 legislative package also included a specific provision for regulating cross-border trade of electricity (Regulation 1228/2003/EC). This provision was the result of the meetings of the Electricity Regulatory Forum (also known as Florence Forum), which was set up in 1998 by the European Commission to discuss the tarification of cross-border electricity exchanges and the management of scarce interconnection capacity[6]. In particular, Regulation 1228/2003/EC established a compensation mechanism between TSOs of neighbouring countries for the cost related to cross-border flows of electricity. It introduced harmonised principles on cross-border transmission charges, including that tariffs should be cost-reflective and not be distance-related, ensuring that cross-border flows were not discriminated against when compared with national flows. Most importantly, it established the use of non-discriminatory market-based solutions to manage congestions occurring on the networks. The *Guidelines on the management and allocation of available transfer capacity of interconnections between national systems* (Annex to 1228/2003/EC) indicates explicit auctions as the preferred option to allocate interconnection capacities between countries.

In 2005, the European Commission launched a Sector Inquiry to monitor the state of competition in the energy sector. The results of the inquiry, published in the 2007 final document (EC, 2007b), shed lights on several problems affecting the electricity industry: 1) high concentration in wholesale markets and exercise of market power; 2) vertical foreclosure due to ineffective unbundling of networks and suppliers; 3) low level of integration because of lack of cross-border capacity, inefficient congestion management

[6] The Florence Forum meets once or twice a year. Participants include energy regulators, Member State governments, the European Commission, TSOs, electricity traders, consumers, network users, and power exchanges.

methods and differences in market designs; 4) limited competition at the retail level due to the presence of long-term contracts and with tacit renewal clauses with old suppliers; 5) high concentration in balancing markets because of the limited size of balancing zones; and 6) lack of transparency on market information, especially about data of network availability, and on end-users price formation.

In 2007, the European Commission established three strategic objectives to be reached by 2020: to reduce greenhouse gas emissions by at least 20% compared to the level of 1990; to achieve a 20% share of renewable energy in the EU overall energy consumption; to save 20% of annual consumption of primary energy compared to the energy consumption forecasts for 2020 (EC, 2007a). Moreover, the Commission referred to the internal energy market as the essential tool to meet all three challenges. However, the evidence of the Sector Inquiry suggested, that existing legislation had partially failed to deliver the completion of the internal market.

In the light of this conclusion, a third legislative package was introduced, including Directive 2009/72/EC, Regulation 713/2009/EC and Regulation 714/2009/EC. This package, currently in force, repealed Directive 2003/54/EC and Regulation 1228/2003/EC in March 2011.

Directive 2009/72/EC grants Member States a choice between three alternative models of unbundling. The first and most radical model is the ownership unbundling, according to which supply and production companies are not allowed to hold a majority share in a TSO, nor to exercise voting rights or to appoint board members. However, supply and production companies can choose to whom and at what price they sell their networks. The second model is that of the independent system operator, according to which supply and production companies can own the physical network, but have to delegate any operation, maintenance and investment decision to an independent company. The third model is that of the independent transmission system operator, where supply and production companies can own the network and can operate it via a subsidiary of the parent company, which can take all decisions independently of the parent company.

For the authorization of new generating capacity, the Directive foresees that Member States shall define their criteria also taking into account the contribution of new capacity towards the Commission's "20-20-20" objectives.

To improve consumers protection, Directive 2009/72/EC includes provisions enabling customers to switch suppliers within three weeks and to receive all the relevant consumption data. Moreover, it foresees efficient complaint handling procedures and specific protection of vulnerable customers (in particular those living in remote areas). Finally, it imposes stronger requirements of independence from any public and private interests on energy regulators.

Regulation 713/2009/EC establishes an Agency for the Cooperation of Energy Regulators (ACER) to regulate cross-border infrastructure. ACER participates in the creation of network codes, drafts the framework guidelines for the operation of cross-border electricity networks and makes decisions regarding cross-border infrastructure, if national regulators cannot agree or ask it to intervene. It also monitors the status of the internal market (including retail prices, network access for electricity produced from renewables and consumer rights) and facilitates the cooperation between national regulatory authorities.

Regulation 714/2009/EC introduces the European Network of Transmission System Operators (ENTSO), which is responsible for managing the electricity transmission system and for allowing the trading of electricity across borders in the European Union. The main tasks of ENTSO are the development of network codes and of non-binding Community-wide network plans.

2.3 The Electricity Regional Initiatives project

In 2004, the European Commission published a strategy paper which recognised that the scarce level of interconnection between several Member States required the introduction of regional electricity markets as an interim stage towards the single integrated market (EC, 2004). In 2006, the European Regulators' Group for Electricity and Gas (ERGEG), at the request of the European Commission, launched the Electricity Regional Initiatives (ERI) project, identifying and dividing Europe into seven electricity regions.

The ERI project is based on the voluntary cooperation of several stakeholders, namely regulators, TSOs, power exchanges, generation companies, consumers, Member States, and the European Commission. The seven ERI regions are presented in Table 2.1. A given country may be involved in several ERI regions, according to the number of neighbours it has. Each region has a lead National Regulatory Authority (NRA) responsible for to chairing and coordinating work within the region.

	Baltic States (BS)	Central East Europe(CEE)	Central South Europe (CSE)	Central West Europe (CWE)	Northern (NE)	South-West Europe (SWE)	France, UK, Ireland (FUI)
NRA	*Latvia*	*Austria*	*Italy*	*Belgium*	*Denmark*	*Spain*	*UK*
Austria		X	X				
Belgium				X			
Czech Republic		X					
Denmark					X		
Estonia	X						
Finland					X		
France			X	X		X	X
Germany		X	X	X	X		
Greece			X				
Hungary		X					
Ireland							X
Italy			X				
Latvia	X						
Lithuania	X						
Luxembourg				X			
Netherlands				X			
Norway					X		
Poland		X			X		
Portugal						X	
Slovakia		X					
Slovenia		X	X				
Spain						X	
Sweden					X		
United Kingdom							X

Table 2.1: Seven Electricity Regional Initiatives. Data source: ACER.

The objectives of the ERI are to identify and implement practical solutions to remove barriers to electricity trade within each region and facilitate regional market integration. Across the regions, common priorities associated with the development of cross-border trade and with the enhancement of competition include: adoption of efficient congestion management methods to maximise the use of interconnection capacity; increase of transparency in market information and introduction of cross-border balancing markets.

Cross-border congestion management methods are a set of rules used to organize cross-border network access, including methods for the calculation of the available transmission capacity, mechanisms for the allocation of available transmission capacity to market participants and procedures to relieve potential congestion (Frontier Economics and Consentec, 2004 pp. 4-6). Efficient methods to manage interconnectors are fundamental to achieve a well-integrated electricity market. Explicit congestion management guidelines were first introduced as Annex to Regulation 1228/2003/EC and then substituted by Annex I to Regulation 714/2009/EC. The most important points of these guidelines are:

- *"when congestion occurs the TSO has to alleviate it using redispatching or countertrading"* (Paragraph 1.3);
- *"congestion management methods shall be market-based in order to facilitate efficient cross-border trade"* (Paragraph 2.1). This provision means that interconnector capacity shall be allocated by means of auctions rather than on a discretionary basis, such as that of the first-come-first-served principle;
- *"the congestion-management mechanisms may need to allow for both long and short-term transmission capacity allocation"* (Paragraph 2.2). This provision means that there can be different auctions of capacity for different time-frames (i.e. day, month, year);
- *"each capacity-allocation procedure shall allocate a prescribed fraction of the available interconnection capacity plus any remaining capacity not previously allocated and any capacity released by capacity holders from previous allocations"* (Paragraph 2.3). This provision implies that the total capacity of an interconnector can be split up in fractions,

each of which has to be auctioned off for a given time-frame (i.e. day, month, year). If, during a long-term capacity allocation auction (i.e. month, year), some capacity is not sold, this has to be added to the auction relating to the subsequent time-frame;

- *"the access rights for long and medium-term allocations shall be firm transmission capacity rights. They shall be subject to the use-it-or-lose-it or use-it-or-sell-it principles at the time of nomination"* (Paragraph 2.5);
- *"capacity shall be freely tradable on a secondary basis, provided that the TSO is informed sufficiently in advance"* (Paragraph 2.12).

The common coordinated congestion management methods do not apply only to the Member States, but are extended to the whole Energy Community, which is an organisation established in 2005 including the European Union, Romania, Bulgaria, Albania, Bosnia and Herzegovina, Croatia, FYR of Macedonia, Moldova, Montenegro, Serbia, the Territories within the United Nations Interim Administration Mission in Kosovo and Ukraine. The Energy Community aims to create a stable regulatory and market framework to attract new investment and to extend the EU internal energy market to the countries above.

To avoid diverging development in congestion management methods, ERGEG and then ACER worked to prepare the *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity* between 2008 and 2011 (ACER, 2011a). This complements the congestion management guidelines reported in Annex I of Regulation 714/2009/EC, establishing pan-European target models of capacity calculation and allocation rules.

The target models, to be implemented by 2014, are:

- for capacity calculation, TSOs need to apply an available transfer capacity[7] or a flow-based method;

[7] With the available transfer capacity method, the TSO establishes ex-ante a fixed limit of exchange between each market and its neighbours, on the basis of assumptions about the distribution of generation and consumption on a territory. The flow-based method allows the limit to depend on the actual flows between all markets.

- for the forward interconnection capacity market: capacity is allocated by means of explicit auctions[8] of long-term transmission rights either financial (FTR) or physical (PTR) with "use-it-or-sell-it" clauses, with the objective of giving participants an instrument to hedge against day-ahead congestion pricing. In FTR auctions, the TSO sells financial contracts that entitle the holder to receive, over a given period of time, the price difference between two interconnected countries, generated by the congestion. The holder does not have any right to physically use the interconnector. In contrast, in PTR auctions, the TSO sells to market participants the right to inject power in a country and to (simultaneously) withdraw power in another country over a given period of time. Moreover, under the "use-it-or-sell-it" clause, capacity holders must either use or sell the capacity in the day-ahead market;
- for the day-ahead interconnection capacity market: capacity is allocated with implicit auctions[9] via price coupling (European Price Coupling). According to this procedure, market participants of different areas only have to bid for electricity on their power exchange. The power exchanges share the bids and calculate the allocation of the cross-border transmission capacity that minimize the price difference between the areas, using a common allocation algorithm;
- for the intra-day interconnection capacity market: capacity is allocated simultaneously with energy, under continuous trading.

Figure 2.1 shows the long-term capacity allocation rules in operation in Europe, as of the end of 2012.

[8] Explicit auction refers to the situation where transmission rights are sold separately from the market place where electricity is auctioned off.
[9] Implicit auction means that the auctioning of transmission capacity is included in the auction of electricity.

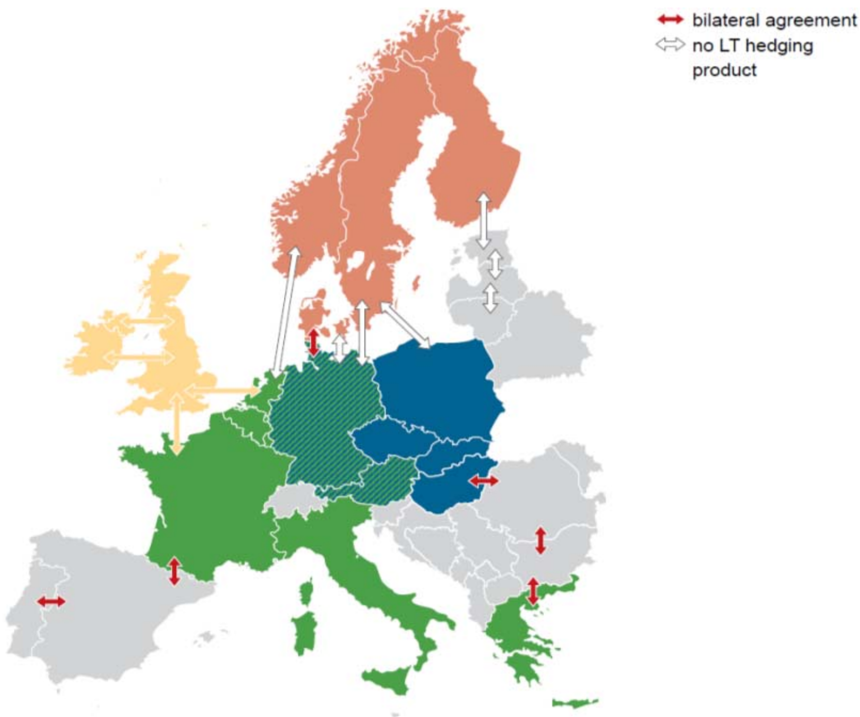

Figure 2.1: Long-term capacity allocation methods in Europe in 2012. Source: ACER (2013a, p. 37).

Within the CWE and CEE regions long-term transmission rights allocation is carried out with PTRs, while FTRs are used across the entire Nordic area and within the Italian market zones. In the FUI region, the direct current cables connecting Great Britain with Ireland, France and the Netherlands are allocated via a common coordinated approach. Bilateral agreement or no long-term hedging product feature the remaining European borders.

The day-ahead price coupling projects in operations in Europe, as of the end of 2012, are summarised in Figure 2.2.

Figure 2.2: Day-ahead price coupling projects in Europe in 2012. Source: ACER (2013a, p. 27).

Price coupling is in operation between Spain and Portugal; within the whole CWE region; between CWE and Great Britain through the BritNed cable (green arrow); within the whole Nordic region; between the Nordic region and Estonia through the Estlink cable (blue arrow); between the Nordic region and Poland through the SwePol Link (blue arrow); between the Nordic area and the CWE region (grey arrow); between Czech Republic, Slovakia and Hungary; between Italy and Slovenia. Explicit auctions or no congestion exist on the remaining borders.

The intraday capacity allocation rules in operations in Europe are summarised in Figure 2.3.

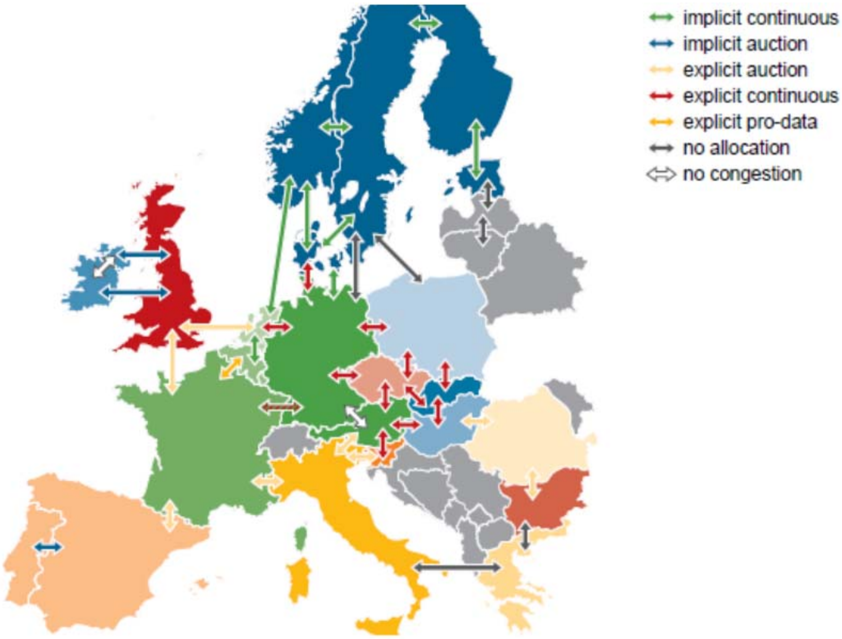

Figure 2.3: Intraday capacity allocation methods in Europe in 2012. Source: ACER, (2013a, p. 33).

Implicit continuous trading is in operation within the Nordic market, between the Nordic market and Estonia, between the Netherlands and Belgium, between the Netherlands and Norway and between Germany and Denmark. A combination of implicit continuous trading and explicit continuous allocation of capacity exists between France and Germany. Implicit auctions are used between Spain and Portugal and within the Italian market zones. Between France and England, between France and Spain, between Romania and Hungary, between Romania and Bulgaria and on the Northern Italian borders intraday capacity allocation is made via explicit auctions. Explicit continuous allocation of capacity is used within the borders of the CEE region, between Germany and the Netherlands and between Germany and Denmark. Between France and Belgium intraday capacity is allocated on a pro-rata basis, while no allocation or no congestion occur on the remaining borders.

2.4 Structure of the European electricity industry

The electricity industry includes four main activities: 1) production (or generation) of electricity; 2) transmission of electricity on high-voltage grids from generating stations to electrical substations close to demand points; 3) distribution on low-voltage grids from substations to final consumers; 4) supply of electricity to final consumers including wholesale and retail marketing activities. This section presents the current structure of electricity supply industry and highlights the most important dynamics in place over the last 20 years. The data used in this section is the latest available and comes from Eurostat, the European Commission, ACER and national power exchanges.

2.4.1 Electricity generation and consumption

Between 1991 and 2011, gross electricity generation[10] in the EU-27 area[11] increased from 2631 TWh to 3280 TWh (25% increase), showing a steady growth pattern with the only exception of 2009[12] (Figure 2.4). Over this period, the electricity production mix of many EU countries changed considerably due to the electricity and gas sectors reforms. In particular, Directive 96/92/EC (and following legislation) on the liberalisation of the electricity sector, Directive 98/30/EC (and following legislation) on the liberalisation of the gas sector, Directive 2001/77/EC (and following legislation) on the promotion of electricity generated from renewable sources and Directive 2003/87/EC (and following legislation) establishing a scheme for greenhouse gas emission allowance trading, reshaped the national electricity industries across Europe.

Renewable generation increased by 18 times between 1991 (20 TWh) and 2011 (364 TWh), and natural gas grew by 3.7 times, going from 188 TWh in 1991 to 693 TWh in 2011. Production of electricity from hydro power plants remained essentially constant over the whole period, increasing only by 6% between 1991 (316 TWh) and 2011 (335 TWh). Generation from nuclear plants increased by 11% (from 820 TWh in 1991 to 907 TWh 2011), leading nuclear to become the first source of electricity production from 2008

[10] Gross electricity generation is defined as: "the electricity measured at the outlet of the main transformers, i.e. including the amount of electricity used in the plant auxiliaries and in the transformers". Source: Eurostat glossary (http://epp.eurostat.ec.europa.eu/statistics_explained/index.php/Glossary:Gross_electricity_generation).
[11] The EU-27 area includes: Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden and the United Kingdom.
[12] In 2009, the recession hitting European economies brought back electricity generation to the level of 2003.

onwards. The use of solid fuels in power generation decreased by 16% between 1991 (1052 TWh) and 2011 (882 TWh), though remaining the second source of electricity generation. The use of petroleum products diminished by 68%, with the result that petroleum derivatives have become a residual source of generation in the last years.

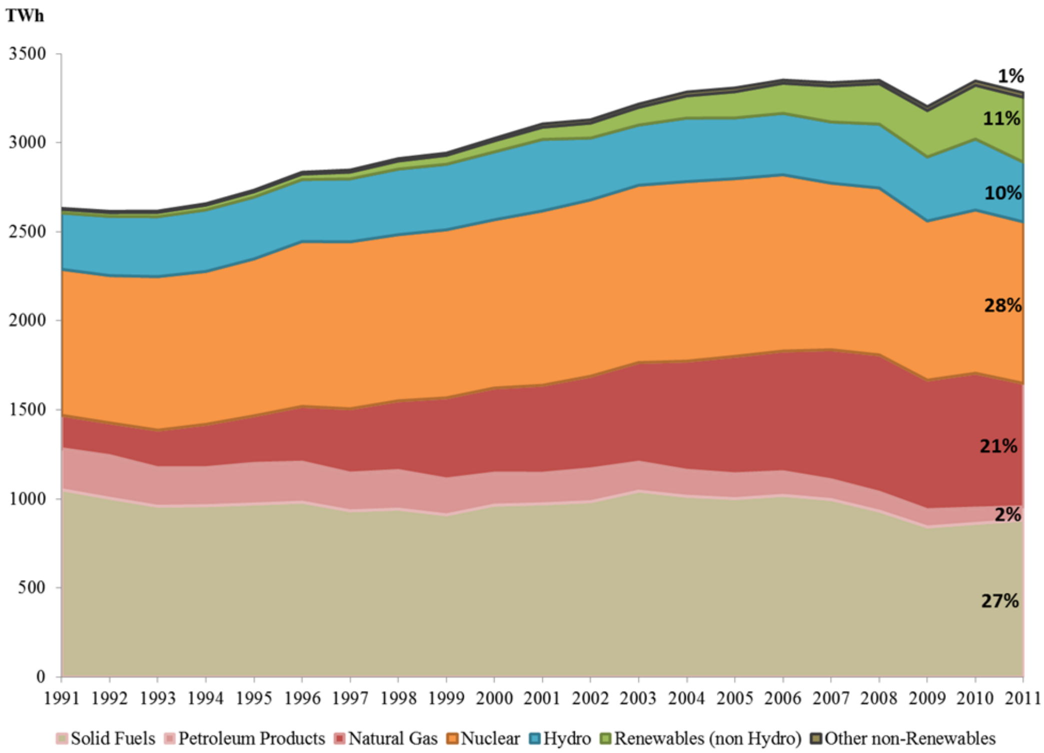

Figure 2.4: Gross electricity generation in EU-27, between 1991 and 2011. Data source: Eurostat.

Renewable sources other than hydro started to play an ever more important role on electricity generation from the beginning of the 2000's (Figure 2.5), thanks to ad-hoc legislation enacted to promote the use of green electricity (i.e. Directive 2001/77/EC). Wind production reached 179 TWh in 2011, showing a growth of nearly 7 times with respect to 2001 (27 TWh). Wind is also the first source of renewable electricity (excluding hydro), accounting in 2011 for nearly 50% of green generation (excluding hydro). The increase in the production of electricity from biomass (i.e. wood), biogas and biofuels was fourfold (from 28 TWh in 2001 to 114 TWh in 2011). Solar power grew rapidly since 2008, reaching 46 TWh of production in 2011. Tidal power and geothermal (category "Other") have the smallest share of production, accounting in 2011 for only 6.6 TWh or 2% of the total renewable production.

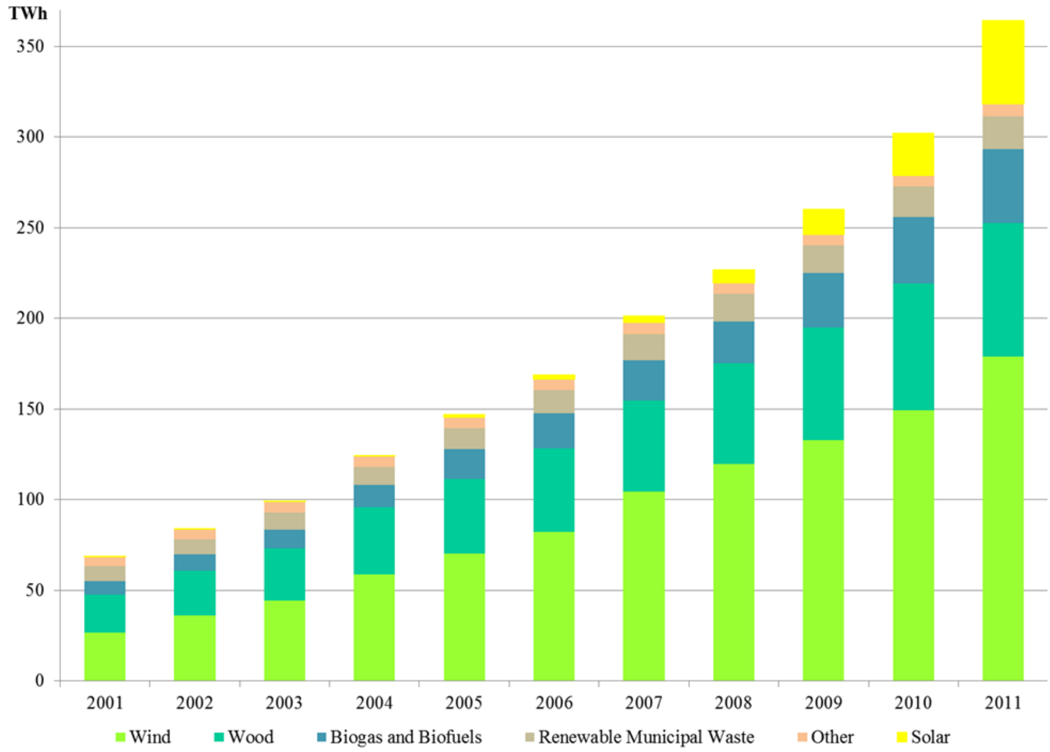

Figure 2.5: Gross electricity generation from renewables in EU-27 between 2001 and 2011. Data source: Eurostat.

In 2011, the first seven EU countries made up 75% of the gross electricity generation, which corresponds to 2447 TWh out of 3280 TWh (Figure 2.6). Germany was the largest producer in the EU-27 area, with 609 TWh of electricity generated, France accounted for 562 TWh, UK for 368 TWh, Italy for 303 TWh, Spain for 291 TWh, Poland for 164 TWh and Sweden for 150 TWh. These figures reflect the dimension of the countries, both in terms of population and in terms of economy.

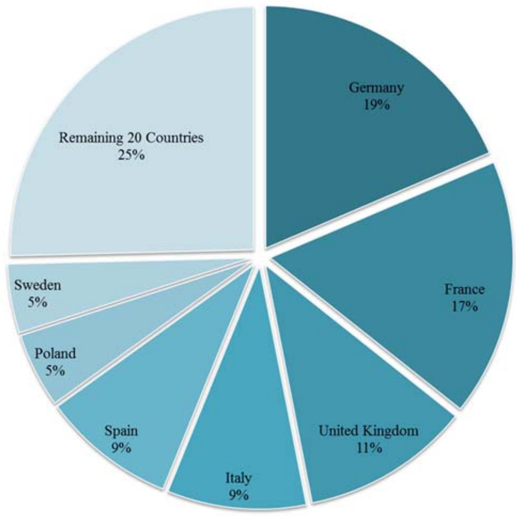

Figure 2.6: Breakdown of total gross generation by major country in 2011. Data source: Eurostat.

Breaking down gross generation by Member State and fuel (Figure 2.7), it emerges that in 2011 thermal generation (i.e. natural gas, coal and oil products) was predominant in all countries but Belgium, France, Austria, Slovenia, Slovakia and Sweden. Moreover, in Estonia, Ireland, Greece, Cyprus, Malta, the Netherlands, Poland and the UK thermal generation accounted for more than 80% of the production mix. Nuclear was the first production source in France (79% corresponding to 442 TWh), Belgium (53% corresponding to 48 TWh) and Slovakia (54% corresponding to 15 TWh). The share of hydro power and other renewables was particularly large for Austria (68% of gross generation corresponding to 44 TWh), Sweden (56% of gross generation corresponding to 84 TWh), Latvia (54% of gross generation corresponding to 3 TWh), Portugal (47% of gross generation corresponding to 25 TWh) and Denmark (40% of gross generation corresponding to 14 TWh).

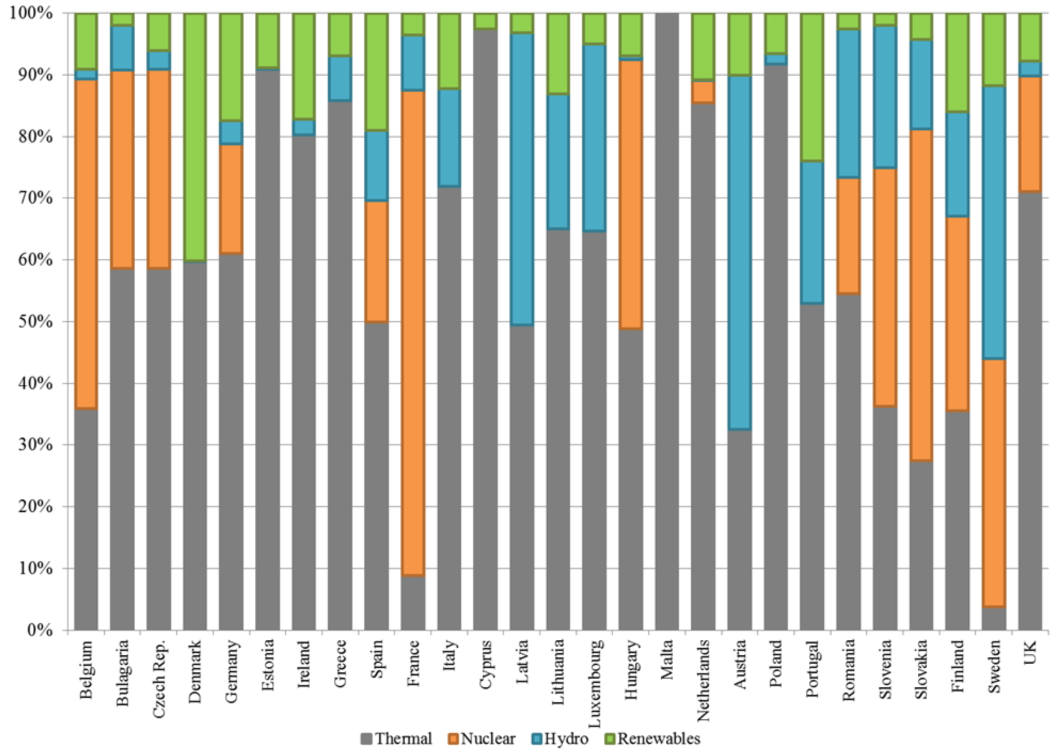

Figure 2.7: Breakdown of gross electricity generation by fuel and by country in 2011. Data source: Eurostat.

In 2011, the EU-27 area turned out to be a net importer of electricity for about 139 GWh. At Member State level, 15 out of 27 countries were net importers, 10 were net exporters, while Cyprus and Malta were completely self-sufficient (Figure 2.8). Italy ranked first among the net importers of electricity with 45,732 GWh of net import (47,519 GWh import and 1,787 GWh export), which covered 15% of its total final consumption. The second largest importer was Finland with net imports accounting for 13,852 GWh (17% of total final consumption), coming from 17,656 GWh of import and 3,804 GWh of export. The Netherlands, third largest importer of electricity, accounted for 9,089 GWh of net import (20,620 GWh import and 11,531 GWh export), which was used to cover 8% of its total final consumption. The largest proportion of electricity imported by Italy originated from Switzerland, while Russia and Germany were the first sources of import from Finland and the Netherlands, respectively. France was the main net exporting Member State with 56,413 GWh (9,501 GWh of import and 65,914 GWh of export), Czech Republic and Bulgaria ranked second and third with 17,044 GWh and 10,661 GWh, respectively. Germany was the first destination of France's electricity, France exported 20,176 GWh out of 56,413 GWh to Germany. Czech Republic mainly exported to Austria (9,968 GWh of net exports), while Bulgaria mainly exported to Turkey (net exports 3,022 GWh).

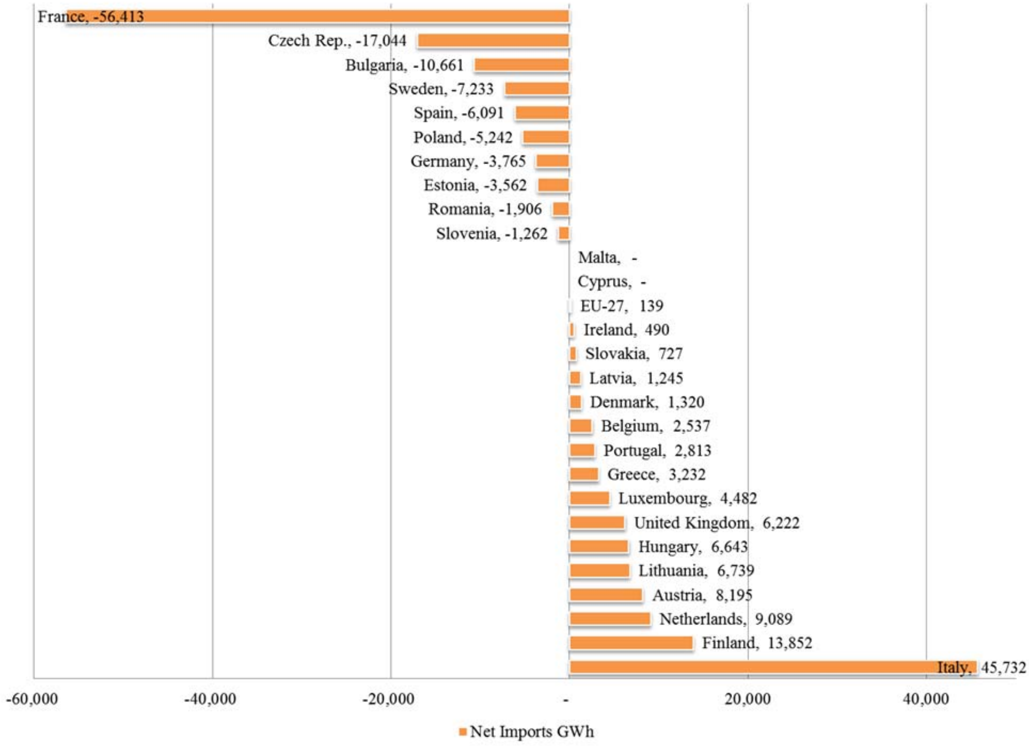

Figure 2.8: Net Import of electricity in European countries in 2011. Data source: Eurostat.

Final electricity consumption broken down by sector (Figure 2.9) reveals that, over the period 1991-2011, the industry sector remained the largest consumer of electricity, though its share over total final consumption decreased from 44% in 1991 (corresponding to about 957 TWh out of 2168 TWh), to 37% in 2011 (corresponding to about 1032 TWh out of 2768 TWh). The weight of the services sector grew from 21% in 1991 to 29 % in 2011, while the share of electricity consumed by households remained stable around 29% over the period considered. The change in the relative weight of industry and services reflects the structural change and deindustrialisation of many EU economies over the past twenty years.

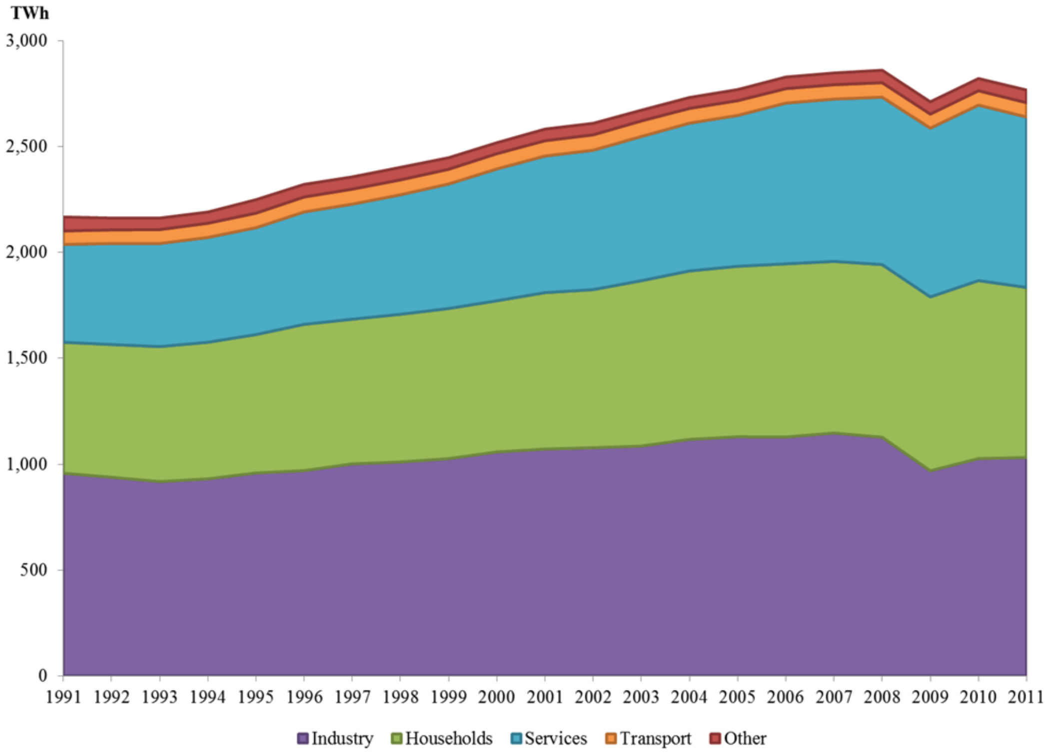

Figure 2.9: Final electricity consumption in EU-27, between 1991 and 2011. Data source: Eurostat.

Directive 2009/28/EC on the promotion of the use of energy from renewable sources set out individual targets of renewable electricity consumption for all Member States, with the goal of reaching an overall EU target of a 20% share of total energy consumption from renewables by 2020. Each European Member State is responsible for building a National Renewable Energy Action Plan, detailing the technology mix and the trajectory for meeting its 2020 renewable energy target. The targets established for the electricity sector and the actual level of consumption from renewables in 2011 are reported in Figure 2.10. In 2011, the most virtuous countries were Estonia, which already hit the 2020 target of 5% of electricity consumption from renewables, Italy, which has a 2020 target of 26% of electricity consumption from renewables and reached 24% in 2011, Czech Republic and Sweden, which are very close to their objectives and only need to increase their share of renewables by 4 percentage points. The Netherlands, Greece, Ireland and the United Kingdom are lagging behind their respective targets.

Figure 2.10: Share of renewables in gross final electricity consumption and target for 2020 (%). Data source: Energy Research Centre of the Netherlands.

2.4.2 Transmission and distribution networks

Electricity networks, comprising transmission grids and distribution grids, are major infrastructures that present the feature of natural monopoly. As such, they are subject to regulation regarding tariffs and ownership. In 2010, all the Member States but Germany, Italy, the Netherlands, Austria, Portugal and the UK had only one TSO (Table 2.2). The model of ownership unbundling introduced by Directive 2009/72/EC was present in about half of the Member States. Unbundled TSOs of Czech Republic, Denmark, Estonia, Netherlands, Poland, Slovenia, Slovakia and Sweden were entirely (100%) state-owned, while unbundled TSOs of Germany and of the UK were 100% owned by private companies. TSOs of other the remaining countries featured a mixed ownership.

	No. of TSOs	*No. of TSOs that are ownership unbundled*	*Public ownership (%)*	*Private ownership (%)*
BELGIUM	1	1	47.9	52.1
BULGARIA	1	0	100	0
CZECH REPUBLIC	1	1	100	0
DENMARK	1	1	100	0
GERMANY	4	2	0	100
ESTONIA	1	1	100	0
IRELAND	N/A	N/A	N/A	N/A
GREECE	N/A	N/A	N/A	N/A
SPAIN	1	1	20	80
FRANCE	1	0	84.5	15.5
ITALY	11	1	30	70
CYPRUS	N/A	N/A	N/A	N/A
LATVIA	N/A	N/A	N/A	N/A
LITHUANIA	1	0	97.5	2.5
LUXEMBOURG	1	0	42.5	57.5
HUNGARY	1	0	0	100
MALTA	0	0	0	0
NETHERLANDS	2	2	100	0
AUSTRIA	3	0	75.6	24.4
POLAND	1	1	100	0
PORTUGAL	3	1	51	49
ROMANIA	1	1	73.7	26.3
SLOVENIA	1	1	100	0
SLOVAKIA	1	1	100	0
FINLAND	1	1	12	88
SWEDEN	1	1	100	0
UNITED KINGDOM	3	1	0	100

Table 2.2: TSOs in EU-27 in 2010. Source: European Commission (2012b, p.43, partially modified).

The number of DSOs recorded in 2010 in Europe was 2163, as distribution lines are local infrastructure and are typically operated by municipal utilities (Table 2.3). For this reason the number of DSOs in a country may depends on its geographical size. In 2010, the number of DSOs in Germany was the highest among the 27 Member States (869), followed by Spain (351), Sweden (173), France (148) an Italy (144). In most of the EU Member States, legal unbundling of DSOs turned out to be preferred to ownership unbundling. In Bulgaria, Italy, the Netherlands, Portugal, Romania and in the UK ownership unbundling was selected by all or nearly all the DSOs.

	No. of DSOs	No. of DSOs that are ownership unbundled	No. of DSOs that are legally unbundled
BELGIUM	27	11	27
BULGARIA	4	4	4
CZECH REPUBLIC	3	0	3
DENMARK	77	0	77
GERMANY	869	0	146
ESTONIA	37	N/A	1
IRELAND	N/A	N/A	N/A
GREECE	N/A	N/A	N/A
SPAIN	351	0	351
FRANCE	148	0	5
ITALY	144	119	10
CYPRUS	N/A	N/A	N/A
LATVIA	N/A	N/A	N/A
LITHUANIA	2	0	2
LUXEMBOURG	6	0	1
HUNGARY	6	0	6
MALTA	1	0	0
NETHERLANDS	7	5	7
AUSTRIA	128	0	11
POLAND	22	0	7
PORTUGAL	13	10	11
ROMANIA	37	5	8
SLOVENIA	1	0	1
SLOVAKIA	3	0	3
FINLAND	85	0	51
SWEDEN	173	0	173
UNITED KINGDOM	19	13	6

Table 2.3: DSOs in EU-27 in 2010. Source: European Commission (2012b, p.44, partially modified).

2.4.3 Wholesale markets

Wholesale markets are where generators sell their output and retailers buy the electricity they need to supply final customers and also where traders (market participants without physical positions) buy and sell electricity to exploit price differences both over different time horizons and between geographical locations.

Wholesale electricity trading includes bilateral (bespoke) trading, over-the-counter (OTC) transactions and power exchanges. Bilateral trading occurs between power producers and retailers that desire non-standard products and flexible arrangements. Given the private nature of such agreements, the prices of these transactions are not publicly available. OTC transactions refer to standard electricity contracts and are usually cleared by either brokers or power exchanges. The prices of such transactions are estimated by independent data provider companies (e.g. Platts, Argus). Power exchanges are organised marketplaces, where market participants transact anonymously using the exchange as the central counterparty. In this case, prices are made available by the power exchange.

Bulk electricity can be traded with delivery over long- and short-term horizons. Forward markets are used to trade power for delivery up to several months/years in the future. Spot markets typically include day-ahead, intraday and balancing markets and have the purpose of allowing market participants to manage the short-term changes in predicted generation or demand by adjusting their long-term positions in the market. In Europe, the term spot electricity market is often used to identify the day-ahead market (see Weron, 2006, pp.7-8). Both power exchanges and OTC markets allow electricity trading for spot and future delivery. Power exchanges clear the day-ahead markets by holding 24 separate auctions, one for each of the 24 hours of the day, the day before the physical delivery of the electricity. Market participants formulate bids and offers of electricity from which the power exchange derives the aggregate demand and supply curves and the corresponding equilibrium price and quantity. Prices and quantities for the individual hours are publicly available and are posted on the power exchange's web-site. On OTC markets, day-ahead transactions are carried out in continuous trading using brokers. Since prices and quantities are unknown to all market participants, it is only possible to have an assessment of market deals via specialized data providing companies. Standardised forward contracts traded OTC are sold under continuous trading in a way similar to that of short-term contracts, while forward contracts sold on exchanges are called futures.

Over the last ten years, an increasing number of European countries have opened power exchanges to trade long- and short-term standardised contracts of electricity. In 2011, among the 27 EU countries, only Cyprus, Latvia, Lithuania, Luxembourg and Malta had not yet opened a power exchange. Table 2.4 reports the evolution over the period 2005-2011 of annual average day-ahead (or spot) prices and a proxy indicator of market liquidity for the major European exchanges. Day-ahead prices of European exchanges ranged between 27.9 €/MWh (Nordic Countries, year 2007) and 87 €/MWh (Italy, year 2008). Over the period considered, day-ahead prices showed a very similar growth pattern: they increased on average by about 55% between 2005 and2008 and then, following the economic recession, they went back to the 2006 values. Nordic prices were the lowest in Europe, with the exception of 2006 and 2010 due to a lower than normal level of the reservoirs of the hydro-power plants. Italy and the UK, having a power mix dominated by gas-fired generation, recorded the highest prices in Europe (70.2 €/MWh and 54.8 €/MWh respectively, on average over 2005-2011), which plateaued in 2008 when oil and gas prices skyrocketed. In countries of central-western Europe, i.e. France, Germany, Austria, Belgium and the Netherlands, the prices were somewhere in between the Nordic and the Italian prices (49.4 €/MWh on average over 2005-2011), as the price-setting plants were not only gas-fired stations but also coal condensing units.

Over the period 2005-2011, the amount of electricity traded on power exchanges in day-ahead markets increased steadily for the majority of the countries (Table 2.4). This meant that the liquidity of day-ahead markets, as measured by dividing the amount of electricity traded on the day-ahead market by the total consumption of electricity of the relative area, grew as well. Market liquidity is essential to the function of wholesale markets, as it allows the formation of competitive prices that serve as signal for risk management and investments. The most liquid power exchanges were OMIE (Spain and Portugal) with an average of 74% traded electricity and the NORDPOOL (Scandinavian countries) with an average of 70%. Markets of Central Eastern Europe, such as the Polish POLPX, the Czech OTE and the Austrian EXAA, displayed an average liquidity of only 5%.

	Annual average day-ahead price (€/MWh)							*Annual average traded volumes as a percentage of consumption (%)*						
	2005	2006	2007	2008	2009	2010	2011	2005	2006	2007	2008	2009	2010	2011
Nordic Countries-NORDPOOL-	29.3	48.6	27.9	44.7	35.0	53.1	47.0	49	66	72	73	77	75	75
United Kingdom -APX-*	53.4	56.5	41.4	86.7	41.4	48.8	55.1	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*
Netherlands -APX-	52.4	58.2	42.0	69.9	39.1	45.1	51.9	14	17	18	21	25	29	32
Belgium -BELPEX-	*NA*	NA	41.8	70.6	39.4	46.3	49.4	*NA*	NA	8	NA	12	13	14
France -EPEXSPOT-	49.3	49.3	40.9	69.2	43.0	47.5	48.9	4	6	9	10	11	10	13
Germany -EPEXSPOT-	47.6	50.8	38.0	65.8	38.9	44.5	51.1	15	16	21	26	25	40	41
Austria -EXAA-	46.5	51.0	39.0	66.2	38.9	44.8	51.8	3	3	4	4	8	10	12
Italy -IPEX-	58.6	74.8	71.0	87.0	63.7	64.1	72.2	61	58	65	69	67	61	58
Spain -OMIE-	53.7	50.5	39.3	64.4	37.0	37.0	49.9	94	52	59	51	89	83	67
Portugal -OMIE-	*NA*	*NA*	52.2**	70.0	37.6	37.3	50.5	*NA*	*NA*	44 **	93	81	64	67
Czech Republic -OTE	30.0	38.8	36.4	64.4	37.8	43.7	50.6	1	1	1	2	4	8	14
Poland -POLPX-	28.6	30.4	31.1	55.9	39.7	49.0	49.6	1	1	2	1	2	5	13

**Data of the APX Power UK Spot market **Data is from July 2007.*

Table 2.4: Annual average day-ahead prices and traded volumes as a percentage of national consumption at European power exchanges. Data source: Power Exchanges and ACER.

One of the major issues in European wholesale markets between 2000-2010 has been the high concentration in electricity generation, as shown in Figure 2.11. A high degree of concentration in generation may prompt the exercise of market power by large producers. As highlighted by the Sector Inquiry (EC, 2007b), generators can influence prices in two main ways: either by withdrawing capacity (i.e. power plants) from the market, or by setting high prices when their production is required to meet demand.

In 2000, in Malta, Cyprus, Greece, Ireland, Latvia, Belgium, Estonia, France, Slovakia and Luxembourg the market share of the largest generator was above 81%. In the same year, in Denmark, Germany, Austria, Romania, Finland, the UK and Poland the market share of the largest generator was below 36%. For the remaining countries, the position of the largest producing company was between the 41% for Hungary and 73% for Lithuania. Ten years later, electricity generation in Malta and Cyprus was still a monopoly. Malta's monopolist is the company *Enemalta*, which supplies the entire island with electricity generated via mainly heavy fuel oil and gasoil. In Cyprus, *EAC* is the only generating and supply company.

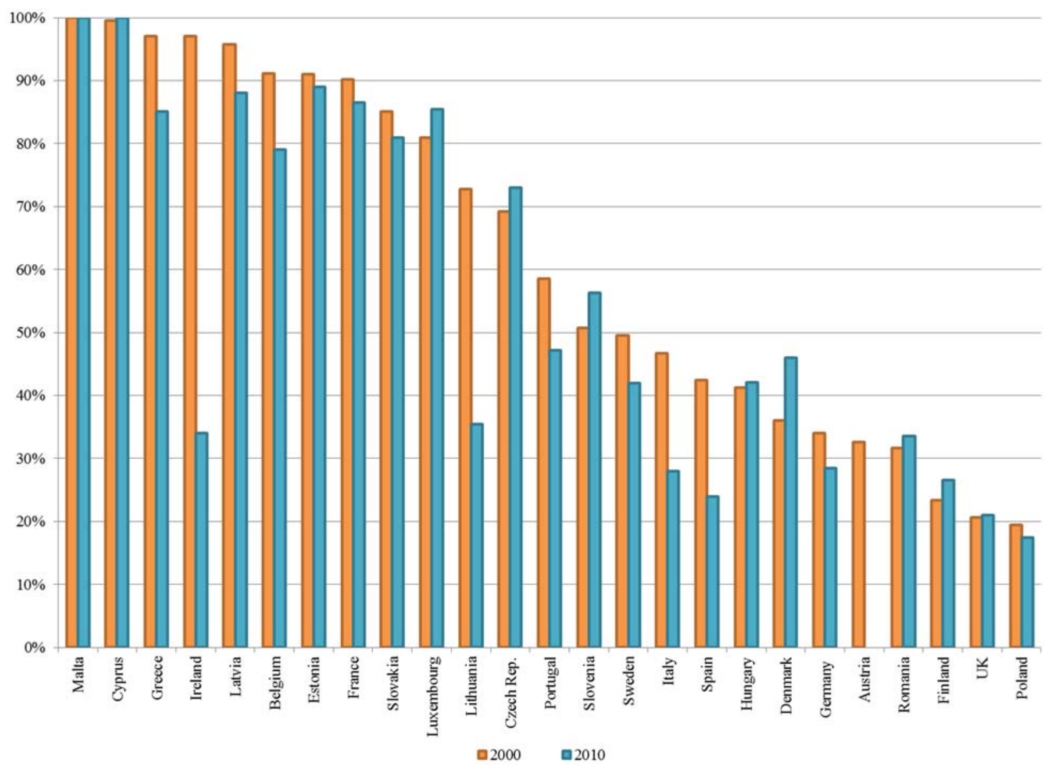

Figure 2.11: Market share of the largest electricity generator in 2000 and 2010. Data source: Eurostat.

In 2010, in Greece, Latvia, Belgium, Estonia, France and Slovakia the share of the largest generator had reduced slightly, but had remained above 80% in all cases. In Greece, the state-owned company *PPC S.A.* saw its market share fall from 97% in 2000 to 85% in 2010. In Latvia, the dominant utility *Latvenergo* produced around 90% of all power in 2010. In Belgium, the market share of the incumbent Electrabel fell by 12 percentage points between 2000 and 2010, while in Estonia, France and Slovakia, the dominant players *Eesti Energia, EDF, Slovenske Elektrarne* saw only a small decline in their market share (around 3%). A different picture emerges when looking at Ireland's data. For Ireland, the market share of the largest generator, the state-owned *ESB*, went from 97% in 2000 to 34% in 2010. Lithuania also had a marked drop in generation concentration, with the market share of the largest producer going from 73% in 2000 to 35% in 2010. In Italy and Spain concentration decreased by about 19% between 2000 and 2010, with the market share of the largest generator passing from 47% to 28% and from 42% to 24%, respectively. In a few countries, namely Luxembourg, Czech Republic, Slovenia, Romania, Hungary and Denmark an increase occurred in the market share of the first generator between 2000 and 2010. In particular, Denmark had the largest rise in generation concentration of about 10%, while all other countries showed an increase on average of about 3%.

2.4.4 Retail markets

Competitive retail electricity markets are based on the premise that it is possible for many potential suppliers to enter the market and for consumers to select their preferred supplier. In Europe since 2007 all final consumers have been free to choose their preferred power supplier. However the presence of regulated prices for many countries has made it harder for new entrants to compete against incumbent suppliers, which is one reason for low switching rates between suppliers. Regulated prices can hinder competition in retail markets if they are set at a level which does not allow the new entrant to recover costs. Table 2.5 reports some indicators of competition in EU retail electricity markets, as of the end of 2010. As for the wholesale market, there are significant differences between Member States in terms of the structure of the retail market. The number of electricity retailers ranges between one in Cyprus and Malta to more than 1,000 in Germany. Countries of a similar size (in terms of population), such as France, Italy, Poland and Spain had a large number of supply companies (between 146 and 342), while the UK had only 22 retailers. However, in France only one company had a market share of more than 5% of total national consumption, while in the UK some 6 companies had more than this amount. In Estonia, Greece and Latvia only one utility had a market share of more than 5% of total national consumption, while 8 companies qualified as main retailers in Romania and 7 in Poland and Slovenia.

Regulated prices for households were present in 15 countries in 2010, while for non-household consumers regulated prices were present in 12 countries. Switching rates were very low for most of the countries. Where price regulation did not apply, switching rates were the highest. UK ranked first for households' switching rate (17.3%), Belgium came second with 8.8% of domestic customers opting for a new supplier. Non-household customers' switching rate in Portugal was the highest in Europe (27.4 %), followed by Spain, where the 17.3% of non-household customers chose a new supplier.

	No. of electricity retailers	No. of main electricity retailers*	Household regulated prices	Non-Household regulated prices	Household Switching rates (%)	Non-Household Switching rates (%)
BELGIUM	37	3	No	No	8.8	16
BULGARIA	36	5	Yes	Yes	NA	NA
CZECH REPUBLIC	324	3	No	No	3.2	7.9
DENMARK	33		Yes	Yes	4.2	11.4
GERMANY	>1000	3	No	No	6	7.5
ESTONIA	41	1	Yes	Yes	0	NA
IRELAND	8	5	Yes	Yes	NA	NA
GREECE	11	1	Yes	Yes	NA	NA
SPAIN	202	4	Yes	No	2.1	17.3
FRANCE	177	1	Yes	Yes	2.3	0.9
ITALY	342	3	No	No	4.1	12.4
CYPRUS	1	1	Yes	Yes	NA	NA
LATVIA	4	1	NA	NA	NA	NA
LITHUANIA	15	3	Yes	No	0	4.1
LUXEMBOURG	11	4	No	No	0.2	0.6
HUNGARY	38	5	Yes	Yes	NA	NA
MALTA	1	1	Yes	Yes	NA	NA
NETHERLANDS	36	3	No	No	NA	NA
AUSTRIA	129	6	No	No	1.7	2.1
POLAND	146	7	Yes	No	NA	NA
PORTUGAL	10	4	Yes	Yes	2.1	27.4
ROMANIA	56	8	Yes	Yes	0	1
SLOVENIA	16	7	No	No	1	9.6
SLOVAKIA	77	5	Yes	Yes	0.8	1.6
FINLAND	72	3	No	No	7.6	NA
SWEDEN	134	5	No	No	8.2	1.2
UNITED KINGDOM	22	6	No	No	17.3	NA

**Retailers are considered as 'main' if they sell at least 5% of the total national electricity consumption.*

Table 2.5: Structure of retail electricity market in 2010. Source: European Commission (2012b, p.45, partially modified).

Between 2005 and 2011, retail prices for households measured in constant 2005 EUR increased in the majority of European countries with the exception of the Netherlands (-17%), Romania (-12%), Italy (-11%), Bulgaria (-7%) and Luxembourg (-4%) (Figure 2.12). In Latvia, France, Estonia, Hungary, Slovakia, Poland, Denmark, Portugal and Slovenia households prices in constant 2005 EUR increased moderately (by less than 20%). In Bulgaria, Austria, Belgium, Germany, Lithuania, Ireland, Finland, Sweden, United Kingdom, Czech Republic and Greece prices grew between 24% and 48%, while in Spain, Cyprus and Malta prices rose by 59%, 69% and 93% respectively.

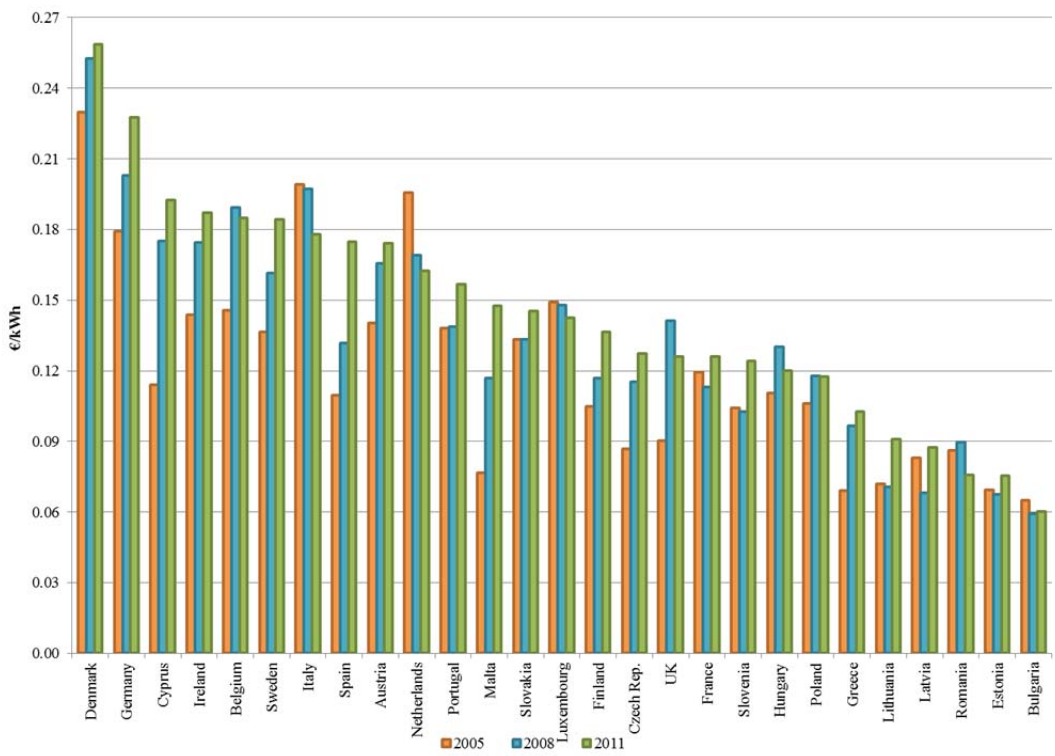

Figure 2.12: Retail electricity prices for households in 2005 EUR. Consumption band DC (in 2005 annual consumption 3500 kWh of which night 1300; from 2007 onwards, 2500 kWh < Consumption < 5000 kWh). Data source: Eurostat.

In 2011, the average price paid by households in the EU-27 area was 0.18 €/KWh for electricity. The price ranged between 0.085 €/kWh in Bulgaria to 0.29 €/kWh in Denmark. High prices (above 0.20 €/kWh) were recorded also in Germany, Cyprus, Belgium, Sweden, Spain and Italy. Low prices (below 0.14 €/kWh) were reported also Latvia, Greece, Lithuania, Romania and Estonia. After correcting the nominal prices for purchasing power standard (PPS)[13], price dispersion throughout the EU-27 appears lower, as prices ranged between 0.12 €/kWh (France) and 0.27 €/kWh (Hungary) (as in Figure 2.13). When using PPS, it emerges that electricity was much less affordable for consumers in Hungary, Romania, Bulgaria and Poland. Danish and Swedish households, which seemed to pay very high prices for electricity, spent relatively less than many other EU countries.

[13] The Purchasing Power Standard is a measure developed by Eurostat which allows for price comparisons of goods and services across the EU-27 area. It is defined as: "an artificial currency unit […] derived by dividing any economic aggregate of a country in national currency by its respective purchasing power parities". Source: Eurostat glossary (http://epp.eurostat.ec.europa.eu/statistics_explained/index.php/Glossary:Purchasing_power_standard_(PPS)).

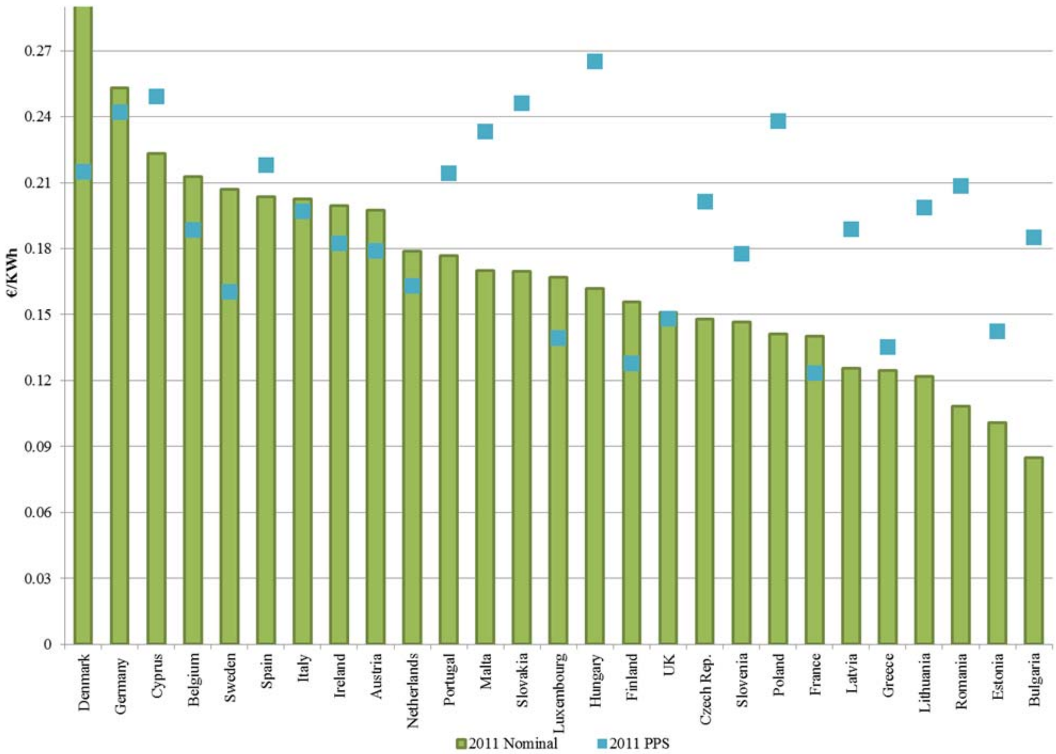

Figure 2.13: Nominal retail electricity price for households versus PPS in 2011. Consumption band DC: 2500 kWh < Consumption < 5000 kWh. Data source: Eurostat.

Breaking down 2011 electricity prices by energy and supply costs, network costs, and taxes and levies, it emerges that energy and supply costs had an average weight of 44% of the final electricity bill, while network costs and taxes and levies accounted on average for 33% and 24%, respectively (Figure 2.14). Across the EU-27 countries, there are some differences in the structure of the prices paid by households. Energy and supply costs had a very large impact on the electricity bill of households in Malta (82%), UK (74%), Cyprus (69%) and Greece (59%). Network costs were particularly high for Czech Republic (51%) and Romania (46%). Taxes and levies were the most important component of the final retail price in Denmark (56%), Germany (45%) and Portugal (43%). A high proportion of taxes and levies in these countries were determined by the national energy policies for promoting the use of renewables.

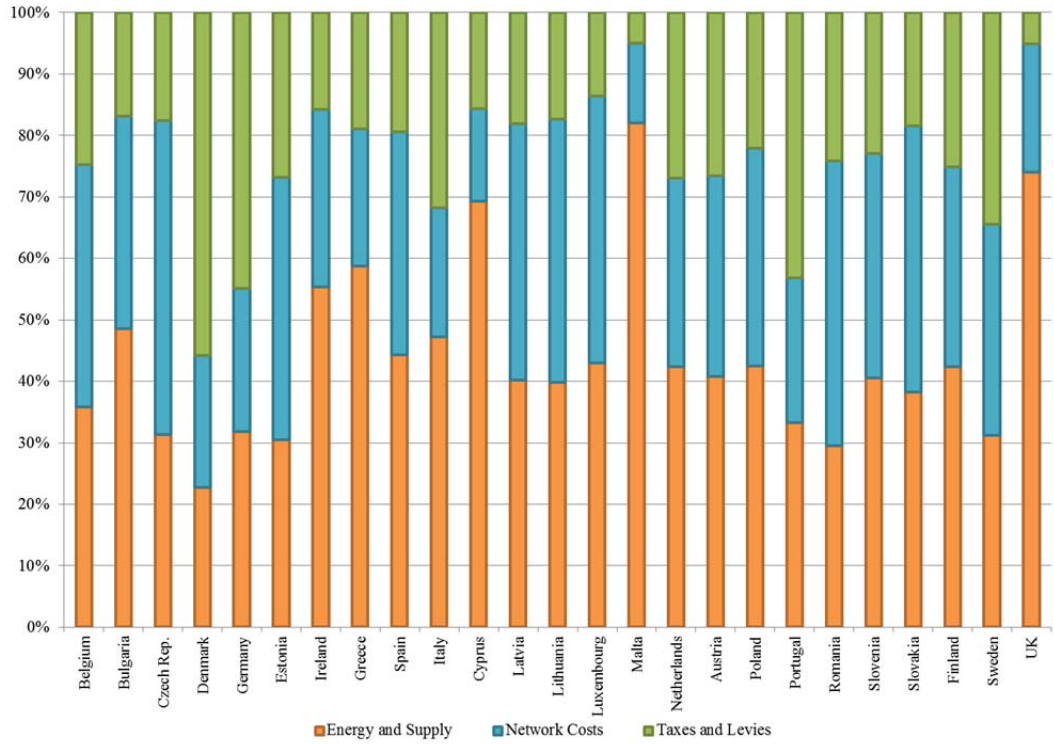

Figure 2.14: Breakdown of 2011 retail electricity prices for households by cost. Data source: Eurostat.

Over the period 2005-2011, retail prices for industry measured in 2005 constant EUR increased in all European countries but in Romania, the Netherlands and Hungary, with an average growth rate of 33% (Figure 2.15). Price increases were comparatively reduced (between 0% and 23%) for Luxembourg, Bulgaria, Ireland, Belgium, Estonia, Finland, Austria, Portugal and France. Prices grew between 29% and 51% in Italy, Slovenia, Germany, UK, Spain, Greece, Poland, Czech Republic and Slovakia. In Cyprus, Sweden, Latvia, Denmark and Malta prices went up by more than 70%.

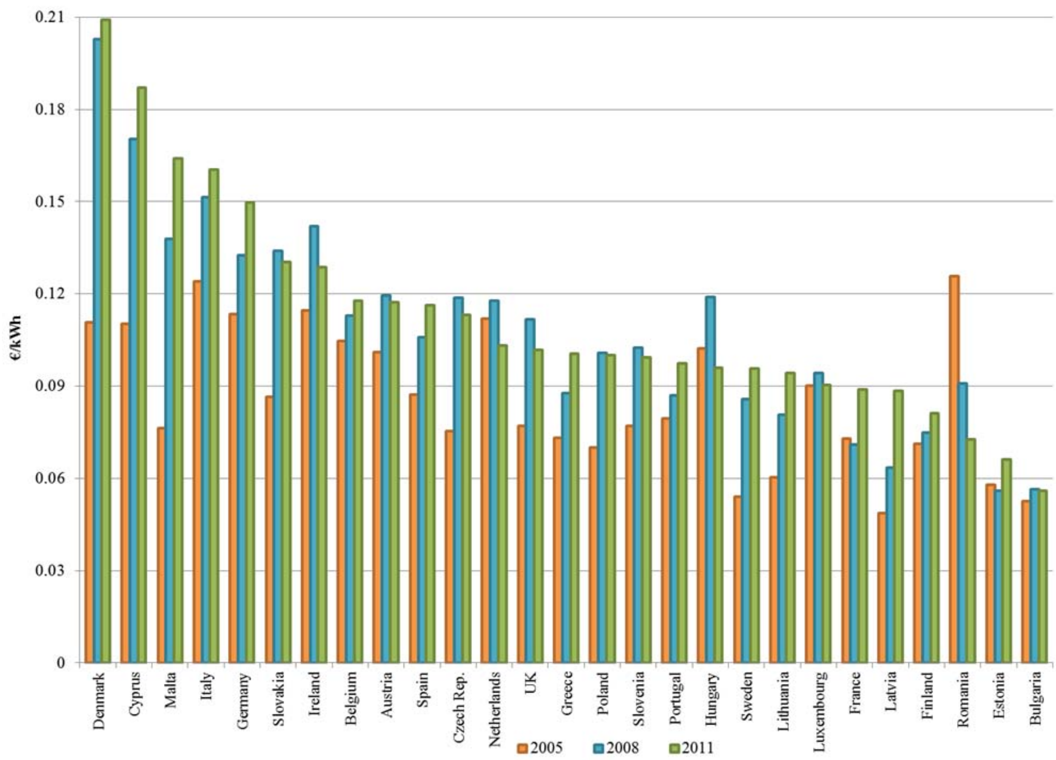

Figure 2.15: Retail electricity prices for industrial consumers in 2005 EUR. In 2005, consumption band IE (annual consumption 2000 MWh, maximum demand 500 kW, annual load 4000 hours); from 2007 onwards consumption band IC (500 MWh < Consumption < 2 000 MWh). Data source: Eurostat.

Industrial prices are generally lower than household prices. In 2011, the average nominal price paid by industrial customers for electricity in the EU-27 area was 0.14 €/KWh (Figure 2.16). Nominal prices ranged between 0.079 €/kWh in Bulgaria and 0.24 €/kWh in Denmark. Industrial customers in Denmark, Cyprus, Malta, Italy and Germany paid the highest nominal prices (above 0.16 €/kWh). In Bulgaria, Estonia, Finland and France, industrial customers enjoyed very low prices (less than 0.10 €/kWh). In all other countries prices were between 0.11 €/kWh and 0.14 €/kWh. When correcting nominal prices with PPS, it emerges that Malta, Cyprus and Slovakia paid the highest prices, while Finland, Sweden and France the lowest.

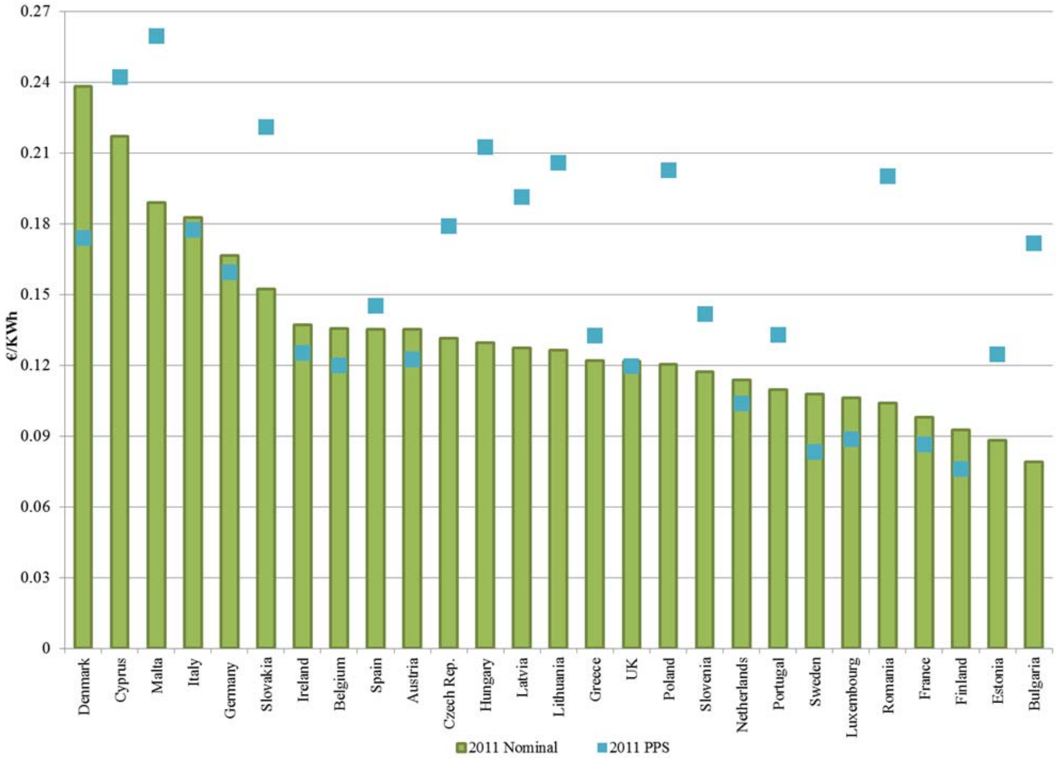

Figure 2.16: Nominal retail electricity price for industry versus PPS in 2011. Consumption band IC (500 MWh < Consumption < 2000 MWh). Data source: Eurostat.

Breaking down industrial electricity prices by energy and supply costs, network costs, and taxes and levies, it emerges that energy and supply costs accounted on average for 53% of the final electricity price paid by industrial customers in 2011 (Figure 2.17). Energy and supply costs were particularly large for industrial customers in Malta (84%), Cyprus (74%), Luxembourg (67%) and Greece (65%). Network costs and taxes and levies accounted on average for about 23% each of the final electricity price. Lithuania, Slovakia and Estonia recorded a very high level of network costs, corresponding to 43%, 41% and 37%, respectively. Taxes and levies represented the first source of costs for Denmark (65%) and Germany (46%).

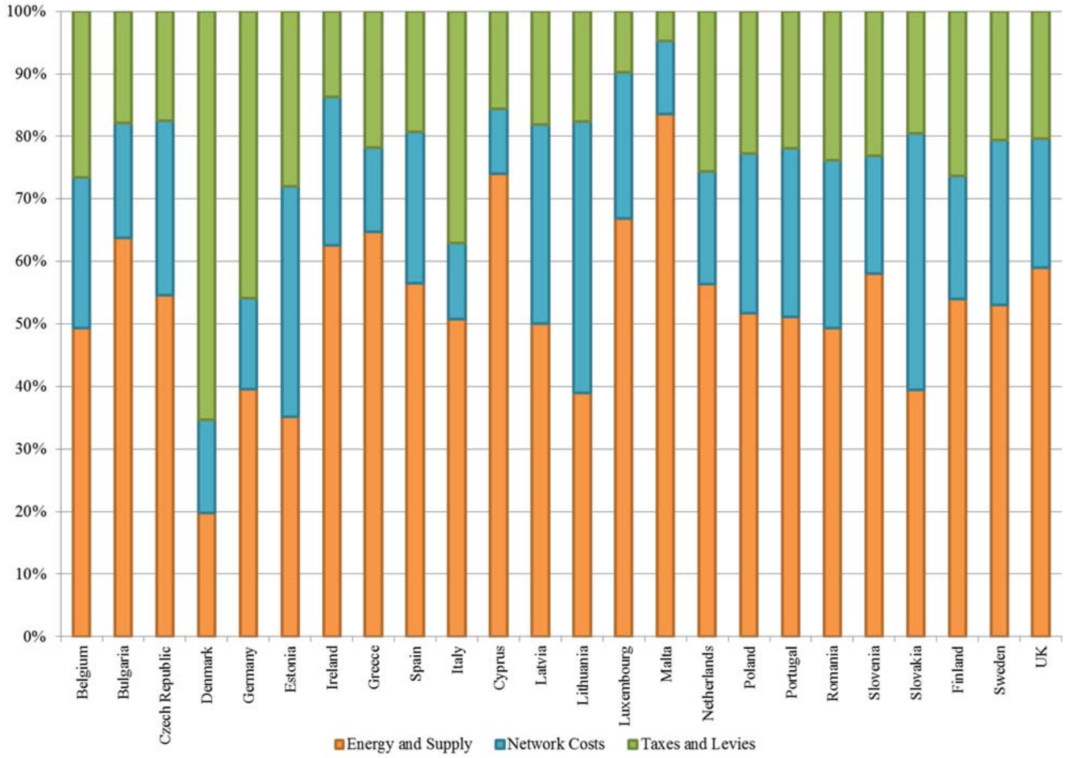

Figure 2.17: Breakdown of retail electricity prices for industry by cost in 2011. Data source: Eurostat.

2.5 Summary

The objectives of this chapter were to provide an overview of the legislative framework and of the structure of the European electricity industry. Since the middle of the 1980's, the EU energy policy has aimed to ensure the uninterrupted physical availability of energy products and services on the market, at a price which is affordable for households and businesses and in a way which is environmentally sustainable. Over the past 20 years, three major electricity packages have been enacted to radically reform the electricity industries of Europe Former vertically integrated monopolies have been dismantled and wholesale and retail markets have been established.

To achieve the common energy policy goals a single electricity market is necessary by the ambitious deadline of 2014; by this time Member States should have fully implemented the EU measures. However, the generation market is highly concentrated. In eight Member States more than 80% of power generation is still dominated by the historic incumbent. The opening of wholesale traded markets in almost all Member States has increasingly led electricity prices to be determined by demand and supply. Traded volumes of electricity increased almost continuously between 2005 and 2011. Liquidity and transparency in traded electricity markets gradually improved, as result of market coupling between Member States. Market coupling, which started in North and Central Western Europe in 2006, have led to increased cross-border trade and price convergence across Europe. The future EU-wide implementation of the Target Models for capacity calculation and allocation rules is expected to deliver full integration between EU wholesale electricity markets.

At retail level however, there are greater disparities between prices, for both household and industrial electricity consumers, persisted throughout the EU. This seemed to occur even between countries where integration of wholesale markets reduced the wholesale price differentials. This can be explained by differences in network costs and taxation, the latter of which falls within the remit of the national legislations. Moreover, the presence of regulated prices in many countries did not allow changes in prices at the wholesale level to be reflected at retail level. Switching rates for household customers remained low in most countries. The picture emerging from EU retail markets is that of lack of maturity of many markets, which suggests that, in many Member States, consumers have not yet reaped with all the potential benefits of the single EU market.

In Chapter 3 an in-depth welfare analysis of the impact of a fully integrated electricity market in the area comprising Italy, France, Germany, Switzerland, Austria, Slovenia and Greece is presented. The chapter evaluates the effect for the Italian electricity market when market coupling is introduced.

3 Measuring the impact of market coupling on the Italian electricity market using ELFO++™♣

3.1 Introduction

Since 2009 there has been significant progress towards the creation of the IEM thanks to the projects implemented by the ERI and to the enactment of the Third Legislative Package. Important achievements have been reached in the field of cross-border trade of electricity and several actions have been taken by different stakeholders, (i.e. European Commission, transmission system operators and energy regulators), to improve the management of the interconnections so as to increase the amount of available transmission capacity between several countries. As discussed in Chapter 2, the limited amount of available interconnection capacity is closely related to the mechanism used to address the problem of network congestion. In particular, one of the most significant sources of inefficiency stems from the use of the explicit auction mechanism to allocate the daily available cross-border capacities to market participants. At the European level, the solution devised for this problem consists of replacing the explicit auction mechanism with the implicit auction mechanism, so-called market coupling. By internalizing the cross-border capacity allocation in the day-ahead energy market, market coupling is able to guarantee the efficient use of the interconnectors.

The economic literature on market integration stresses that countries with high-variable cost generation capacity are expected to obtain a positive welfare gain from integration. The Italian electricity market represents a suitable case-study to test this assumption. In particular, this chapter evaluates the welfare effects of introducing market coupling to

♣ The results presented in this chapter are published as Pellini, E. (2012)."Measuring the impact of market coupling on the Italian electricity market". *Energy Policy* 48, 322-333. The paper was presented at the 9th International Conference on the European Energy Market (10th -12th May 2012, Florence, Italy). I acknowledge EPEX SPOT for providing me with the electricity price data.

allocate the daily available cross-border interconnection capacity between Italy and its neighbouring countries, namely France, Switzerland, Austria, Slovenia and Greece[14]. Two alternative market scenarios are simulated for the year 2012[15], using the optimal dispatch model ELFO++™. The first scenario, called the *Reference Scenario*, reflects the characteristics and the dynamics most likely to occur in the marketplace, namely an electricity demand that remains weak over the year, reflecting a climate of uncertainty surrounding the Italian economy, and overcapacity on the supply side of the market. In contrast, the alternative *High Scenario* sets out the key variables of the electricity market assuming tighter market fundamentals, namely higher demand and higher cost of producing electricity. For each scenario, four alternative cases are modelled, namely Perfect Competition, Business As Usual, Market Coupling and Market Coupling with producers of Northern Italy acting as price takers[16]. These four cases feature alternative models of allocating cross-border transmission capacity, that is, explicit auctioning and market coupling, and alternative market structures (perfect and imperfect competition).

The remainder of the chapter is organized as follows. Section 3.2 provides an overview of the cross-border congestion management methods used in Europe, highlighting the weaknesses of the current methods and the strengths of those proposed. Section 3.3 reviews the main economic literature on market integration, comparing the results of both theoretical and empirical work. Section 3.4 summarises the structure of the markets included in this study and explains the rationale for choosing Italy as the object of this welfare analysis. Section 3.5 describes the electricity market simulation model ELFO++™, while Section 3.6 presents the assumptions used to build the alternative market scenarios. Section 3.7 reports

[14] Since January 2011, a mechanism of market coupling has been implemented on the Italy-Slovenia border.
[15] Considering 2012 allows the best reflection of actual Italian electricity market fundamentals, adopting either 2010 or 2011 would result in biased outcomes, given that over these two years the electricity market fundamentals have been significantly affected by the recession of the Italian economy. Forecasting beyond 2012 would require knowing how the capacity payment, introduced with Resolution ARG/elt 98/11, should be incorporated into the simulation model.
[16] Northern Italy is the zone that would be most largely affected by market coupling given that it borders all the neighbouring countries except for Greece.

the results of the simulations and carries out the welfare analysis. Section 3.8 concludes and provides a brief outline of questions for further work.

3.2 Criticisms of market integration: cross-border congestion management methods

The economic literature addressing the issue of market integration, (see for instance Turvey, 2006; Domanico, 2007 and Creti et al., 2010), highlights that increasing the level of interconnection between separated electricity markets is expected to bring several benefits. First, market integration would enhance economic efficiency, because if a more diversified plant mix can be dispatched, the probability that demand is met by the least-cost producer increases. Second, it would reduce market concentration, given that cross-border trade opens the national markets to foreign participants and hence it would also diminish the probability of national incumbents exercising market power. Third, it would strengthen security of supply, as several interconnected systems work as back-up for each other. Finally, it would mean a reduction in the required reserve capacity, because at any given point in time an interconnected country could rely on its neighbours' capacity, thus decreasing the internal level of spare capacity. However, all these benefits can only be exploited if the national TSOs coordinate and actively cooperate with each other when dispatching their respective systems.

Despite these potential benefits, the EU-wide market integration has proved to be a complicated target to achieve. Since the enactment of the Directive 96/92/EC, the liberalization reforms have not been implemented uniformly in Member States, with the result that alternative market designs have emerged across Europe (Vasconcelos, 2009). In addition, there has been a problem of insufficient interconnection and of inefficient congestion management methods between Member States, as the interconnectors were historically built to provide back-up for sudden faults rather than to facilitate trade between countries (EC, 2007b).

As described in Chapter 2, in Europe, interconnection capacity allocation is carried out using explicit auctions of PTR for the year-ahead and the month-ahead timeframe, and either explicit auctions of PTR or market coupling[17] for the day-ahead timeframe. The procedure of capacity allocation is as follows. First, the national TSOs cooperate to determine the Net Transfer Capacity (NTC) of the interconnector for each direction separately[18]. The TSOs then split the NTC into three tranches to be allocated in subsequent phases, namely yearly, monthly and daily allocation phases. More precisely, the capacity available for each time frame is called Available Transfer Capacity (ATC) and it is calculated as the difference between the NTC and the capacity allocated in the previous phases, the so-called Already Allocated Capacity (AAC):

$$ATC = NTC - AAC \qquad (3.1)$$

In addition, in the monthly allocation phase, the TSO augments the ATC for each direction by the amount of capacity that has not been sold in the yearly phase and also by the amount of capacity allocated in the opposite direction in the yearly phase. The same also occurs for the daily allocation. In the case of the explicit auction the amount of daily ATC is sold separately for each direction, while in the case of market coupling no separated auctions take place and the flows on the interconnectors are determined simultaneously with the clearing of the energy markets.

Thus, the main advantages of market coupling consist of flows-netting and of eliminating imperfect arbitrage. Flows-netting, also known as the superposition principle, implies that

[17] In this chapter the term market coupling is used as synonym for price coupling.
[18] NTC is defined as the "maximum exchange programme between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions" (ETSO 2001, p.7).

power flows scheduled in opposite directions cancel out, therefore allowing the interconnector to be used up to full capacity. By contrast, explicit auctions, featuring a separated allocation of PTR for each direction, deny flows-netting and determine an inefficient use of cross-border capacity. The only netting provision implemented in the day-ahead timeframe under explicit auctions refers to the amount of capacity sold in a previous allocation phase and nominated in one direction that can be used to increment the ATC of the opposite direction. Moreover, market coupling, allocating the cross-border capacity simultaneously with the clearing of the energy markets, is able to eliminate the imperfect arbitrage that may arise under explicit auctions. Imperfect arbitrage occurs when power flows against price differentials, and it is due to that market participants have to bid for capacity and energy in two different markets.

Though in theory market coupling could determine an efficient use of interconnection capacity, its adoption requires the preliminary elimination of major technical barriers relating to the non-harmonised market designs of the different EU countries. Amongst the major barriers, EuroPEX (2003) and Creti et al. (2010) mention the following. All the power exchanges involved in market coupling need to have the same gate closure time for the day-ahead auction, the same computation time for running the market clearing algorithm and the same deadline for publishing the results. Bidding arrangements need to be harmonised as there is a potential difficulty with the likes of the French and German markets allowing for block bidding[19], while others including Italy allow trading only for hourly or half-hourly products. Internal congestion management methods can vary across countries, given that some countries use redispatching through counter-purchases by TSOs to relieve the congestion, while others implement a market splitting algorithm, which in turn determines the calculation of different prices for the several nodes or zones of the grid. In addition, there are also some cases, i.e. Italian and Greek markets, where the price that clears the demand side of the market is different from that of the supply side. Finally, in markets using pay-as-

[19] Block bidding means offering a given amount of power at a fixed price for a number of consecutive hours.

bid day-ahead auctions, it is necessary to introduce a reference price for the determination of cross-border flows direction. Addressing all these difficulties is essential to implementing a market coupling mechanism that can be rolled out across the EU member states.

3.3 Literature review

There is a growing economic literature on electricity market integration that can be summarized in three main streams. The first stream consists of theoretical work that analyses the impact of integration on market power in electricity generation. The second stream includes empirical work that highlights the inefficiencies of the explicit auction mechanism to allocate day-ahead cross-border interconnection capacities. The third stream groups empirical analysis of the impact of introducing implicit auctions or additional cross-border transmission capacity on the social welfare of the newly integrated markets.

There are several theoretical papers analysing the impact of integration on the extent of market power in electricity markets. Borenstein et al. (2000) show that the introduction of a transmission line between two separated symmetric monopoly markets fosters competition, even when the connecting line has a small capacity. The literature also addresses whether alternative market designs for energy and transmission markets (i.e. integrated energy and transmission market design and separated energy and transmission market design) have a different impact on the degree of market power. The integrated energy and transmission market design typically refers to the nodal spot pricing mechanism, as proposed by Schweppe et al. (1988)[20], complemented with FTR, as defined by Hogan (1992). The unbundled or separated energy and transmission market design[21] features bilateral contracts for energy trade and PTR to access the transmission facilities. Chao and Peck (1996)

[20] Nodal spot pricing is a method for managing network congestion that allows for calculating different spot prices when the lines are congested. Under perfect competition, nodal price represents the marginal cost of delivering power to a certain node, while the difference between prices represents the opportunity cost of constraints.

[21] The integrated energy and transmission market design corresponds to the case of implicit auction, while the separated design corresponds to the case of explicit auction.

demonstrate that separated energy and transmission markets, where PTR are defined as flow-gate rights[22], determines a welfare maximizing outcome in a perfectly competitive market with no uncertainty and perfect information, just as nodal spot pricing complemented by FTR. Joskow and Tirole (2000) confirm the result of Chao and Peck (1996) of equivalence of PTR and FTR for perfectly competitive energy and transmission markets. However, once the assumption of perfect competition is dropped, they show that both PTR and FTR enhance or mitigate market power depending on the market power configuration and on the microstructure of transmission rights market. Physical rights may determine a worse welfare outcome than financial rights, because they can be strategically withheld from the market. Thus, Joskow and Tirole (2000) suggest the introduction of either "use-it-or-lose-it" or "use-it-or-get-paid-for-it" provisions to prevent strategic withholding of transmission rights by market participants.

In contrast to Joskow and Tirole (2000), Neuhoff (2003), assuming that all PTR are acquired by traders, demonstrates that integrated energy and transmission markets reduce market power relative to the separated market design. Gilbert et al. (2004) extend the analysis of Joskow and Tirole (2000) examining the impact of alternative allocation rules and auction designs of transmission contracts on market power. They also evaluate whether subsequent trading of transmission contracts can solve the problem of incorrect initial allocation of rights. Efficiently arbitraged uniform-price auctions may mitigate market power, while grandfathering and pay-as-bid auctions may increase it. Moreover, they show that contract trading cannot correct the outcome of an inefficient initial allocation.

Parisio and Bosco (2008) evaluate the welfare effect of introducing cross-border trade between two isolated countries. They model transmission rights allocation according to an implicit auction mechanism and show that cross-border trade may lead to price convergence

[22] Transmission rights can be defined according to either a point-to-point approach, which defines the right to inject power in a point and to withdraw in another point, or a flow-gate model, which defines the right to use the lines on which power flows (Hogan, 2000).

between countries. Welfare gains and losses across countries are determined by a volume effect and a strategic effect of the interconnection. In the importing country, the volume effect leads consumers' surplus to increase and producers' rent to decrease, while in the exporting country the opposite occurs. The strategic effect implies that the reduced demand in the importing country flattens the supply curve in that market, which can further increase consumers' surplus in the importing country, but can also reduce the consumers' surplus in the exporting country. Ehrenmann and Neuhoff (2009) analyse the difference between explicit and implicit auctions for oligopolistic markets. For a simple two-node network, an implicit auction reduces the ability of strategic generators to exercise market power. Moreover, a numerical simulation for the case of the North-western European Network shows that integrated markets lead to lower electricity prices than separated markets.

In partial contrast, Boffa and Scarpa (2009) stress that integration may facilitate collusion and reduce the aggregate welfare of the newly integrated markets. They model the case of two markets, one where a collusive monopoly price prevails and a second one where some excess capacity exists. They show that when markets are integrated, the excess capacity in the second market can be used to satisfy the demand in the first market. If the first market is able to absorb the new capacity without decreasing the price, and if the second market experiences a price increase as a consequence of the reduced level of spare capacity, it is possible that interconnection leads to an aggregate social welfare reduction.

The second stream of literature provides an assessment of the inefficiencies of explicit auctions in allocating cross-border transmission capacities. Newbery and Mc Daniel (2002), analysing the results of the auctions held for the Dutch-German interconnector and for the French-England interconnector, find that under explicit auctions capacities are underused, as a result of no flows-netting. Moreover, imperfect arbitrage is present, as the average price of daily capacity is lower than the monthly and annual prices. Similarly, Kristiansen (2007), assesses the performance of the Kontek cable and of the interconnector between West

Denmark and Germany, and finds evidence of imperfect arbitrage. Höffler and Wittmann (2007) show analytically that flows-netting maximizes the physical usage of cross-border capacity and decreases the incentive for the auctioneer (TSO) to withhold capacity for increasing his profits. Bunn and Zachmann (2010) demonstrate that under the explicit auction, a generator, which is both a dominant player in one market and a competitive player in the other, has an incentive to acquire transmission rights to export against price differential, thus resulting in an inefficient use of cross-border interconnections. In addition, Bunn and Zachmann (2010) provide a measure of the inefficiency generated by the use of an explicit auction on the Anglo-French Interconnector. The results highlight that electricity tends to flow against the price differential mainly in peak-time hours, whilst in off-peak hours flows are nominated correctly. Moreover, the results show that the French incumbent, which is a competitive player in UK, exports to UK even when prices in France are higher. Meeus (2011) computes a performance indicator for different auction mechanisms on the Kontek Cable between Denmark and Germany, and finds that one-way price coupling is able to outperform both the no-coupling and the volume coupling. However, because price coupling has been implemented only in one direction from Denmark to Germany, this mechanism fails to completely eliminate cross-border trade inefficiency.

The third stream of literature includes several studies regarding the impact of either market coupling or additional cross-border transmission capacity on the social welfare of the newly integrated markets. Hobbs et al. (2005) analyse the potential impact of market coupling for the Belgian and the Dutch markets, before the start of the Trilateral Coupling project among Belgium, France and the Netherlands. The authors estimate the welfare effect of the project simulating a Cournot-Nash equilibrium model under five alternative market settings[23]. The results show that if the Belgian incumbent plays strategically the change in aggregate social surplus due to market coupling is quite significant, but it occurs at the expense of the Dutch

[23] These are: all firms acting as price-takers in every market; the Belgian incumbent, Electrabel, acting as Cournot player everywhere under both usual transmission allocation and market coupling; Electrabel acting as price-taker in Belgium but as a strategic player outside, under both usual transmission allocation and market coupling.

consumers. On the other hand, when the Belgian incumbent acts as a price-taker, market coupling brings a smaller increase in the aggregate social surplus, which is more equally distributed among Belgian and Dutch consumers. Finally, Hobbs et al. (2005) highlight that market coupling could induce the incumbent to become a Cournot player, given that the opening of the market to foreign competition could lead to a diminished threat of regulatory intervention.

Finon and Romano (2009) demonstrate for France the principle of trade theory that, ceteris paribus, consumers living in countries with high-variable cost capacity enjoy a price fall at the expense of consumers living in countries of low-cost capacity. Malaguzzi Valeri (2009) evaluates the effect of additional interconnection capacity between Ireland and Great Britain simulating a model of optimal dispatch. The author finds that aggregate social surplus increases when more interconnection capacity is available, though at a decreasing rate. Moreover, the paper highlights that the size of the interconnector needed to make Ireland and Great Britain a single market depends on the differences in the production mix between the two countries. In particular, as the cost of the CO_2 allowances increases, the two systems become similar and need less additional interconnection capacity to reach integration.

An empirical evaluation of the effect of market integration for the Italian market is still to be carried out (Creti et al., 2010). The only study providing some evidence of the inefficiency of the explicit auction mechanism is that of Gestore dei Mercati Energetici (GME, 2008)[24]. GME (2008) identifies four potential efficiency gains from the adoption of implicit auctions, namely lower operational risk[25], lower trading risk/cost[26], increased liquidity in less mature energy markets[27] and an efficient use of interconnection capacity[28].

[24] GME (2008) estimates the value of unused cross-border capacity between Italy and France, Italy and Switzerland, Italy and Austria for year 2007 is approximately 162 M€.
[25] This should stem from a single bidding procedure for both the energy and the interconnection capacity.
[26] This is because operators no longer need to forecast energy price before bidding for capacity and can save the costs of participating on different trading platforms.
[27] This is what happened to Finland when it joined NordPool in 1998 and to Belgium after the launch of Trilateral Market Coupling (TLC) between France, Belgium and Netherlands in 2006.

This chapter provides a contribution to the empirical literature on market integration, presenting a comprehensive investigation of the welfare effect of introducing price coupling in the Italian electricity market. In particular, the change in social welfare is measured with respect to the change in the productive efficiency of the electricity market. As in Hobbs et al. (2005) and in Malaguzzi Valeri (2009), the evaluation of the welfare changes are carried out over a specific year, in this case 2012, and results are obtained by using a structural simulation model. A brief overview of the electricity markets included in the Central South Europe area is presented in Section 3.4.

3.4 The electricity markets of Central South Europe

Italy, together with France, Germany, Austria, Slovenia and Greece make up the Central South Europe (CSE) electricity regional initiative. In what follows, Switzerland, although not part of the CSE is included in the analysis of the CSE area, as it borders Italy, France, Germany and Austria.

The Italian electricity market is the highest priced area in the CSE region. Figure 3.1 shows the dynamics of the monthly average electricity spot (i.e. day-ahead) prices of France, Germany Switzerland, Austria, Italy and Greece over the period 2007-2010. Spot prices of France, Germany and Switzerland are provided by EPEX SPOT, which is the power exchange in charge of managing the day-ahead spot market for these countries. Data of the Austrian, Italian and Greek markets are publicly available on the website of the Austrian Energy Exchange (EXAA), of the Italian Power Exchange (IPEX) and of the Hellenic Transmission System Operator (HTSO) respectively. Slovenia is excluded from the analysis as the day-ahead market opened in 2010.

A distinguishing feature of both the Italian and the Greek markets is that the demand and the supply side of the market are cleared by different prices, namely zonal prices for the supply

[28] Efficient use of interconnection capacity means that facilities are always fully used and that the net cross-border flows always go from the low-price area to the high-price area.

side and a single price for the demand side. The demand side price is the reference market price and included in the analysis. The reference price for Italy is the Prezzo Unico Nazionale (PUN)[29], while that of Greece is referred to as the System Marginal Price (SMP). In both cases the reference price is computed as an average of the zonal prices weighted by the respective zonal load[30]. In Figure 3.1 the IPEX-PUN price has consistently been above the other spot prices over the whole period. The gap, of about 18-20 €/MWh over the period, is particularly evident with the prices of the countries on the northern border of Italy, namely France, Switzerland, Germany and Austria. By contrast, the price differential between Italy and Greece has become significant, i.e. around 12-16 €/MWh, only since the beginning of 2009, partly reflecting the deepening of the recession of the Greek economy.

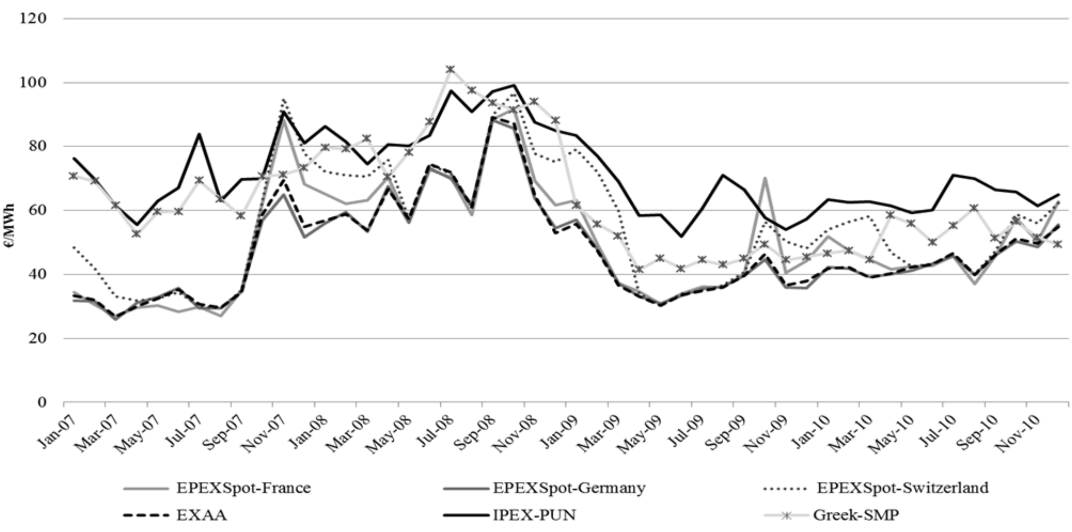

Figure 3.1: European monthly average electricity spot prices. Data source EPEX SPOT, GME and HTSO.

The price differentials are due primarily to the differing generation mixes between the countries. Given that the short-run variable cost of generating electricity essentially reflects the cost of fuel, countries with a generation mix based on low-cost fuels (nuclear, hydro, lignite and coal) have a cost advantage relative to countries with high-cost capacity (burning

[29] To be precise, as highlighted by Creti et al. (2010), the PUN is not only a weighted average of zonal prices calculated ex-post, but it is also the reference price below which no demand bid is accepted.
[30] The Italian market is divided in the zones as listed in Section 3.6, while the Greek market is divided into two zones, namely Northern Greece and Central-Southern Greece.

natural gas and fuel oils)[31]. In addition, the heterogeneity of the production mix matters when determining the spot price. A well-diversified production mix includes an efficient amount of both base-load generation, mid-merit and peak-load capacity[32].

The generation mix of the CSE area markets as of 31st December 2010, the latest data available from ENTSO-E[33], is presented in Figure 3.2. Total net installed capacity[34], stands at about 438 GW, of which 43% of capacity is fossil fuels power plants. Germany has the largest net installed capacity (about 152 GW) and the most diversified production mix of the area. Fossil fuel plants account for 45% of total net installed capacity (69 GW) and include mainly coal-fired plants (45 GW) and natural gas plants (21 GW).

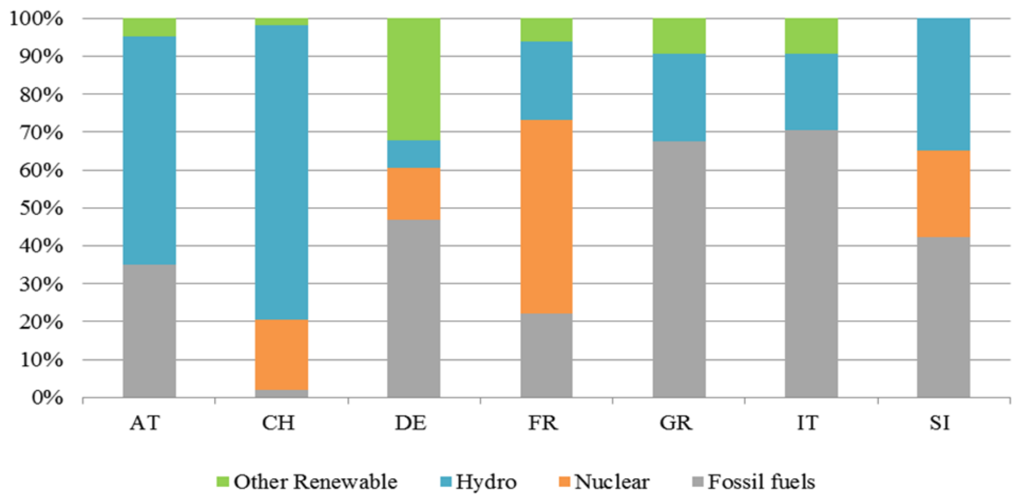

Figure 3.2: Generation capacity mix in Central South Europe as of 31st December 2010. Data source: ENTSO-E.

Nuclear power plants (20 GW) represented a large share of the net installed capacity until March 2011, when the German government introduced a Nuclear Moratorium in the

[31] Burning natural gas can be cheaper than using coal, as the price of the CO_2 allowances rises.
[32] Base-load plants feature high fixed costs but low variable costs, thus they are suitable for running over the majority of the hours of the year, while peak-load plants have low fixed cost and high variable costs, so that they are mainly used to cover the consumption peaks. Mid-merit capacity is in between.
[33] For Switzerland the data is as of 31st December 2009.
[34] Net installed capacity is defined in the ENTSO-E's glossary as:" the maximum electrical net active power that a power station can produce continuously throughout a long period of operation in normal conditions", where: net means "the difference between the gross generating capacity of the alternator(s) and the auxiliary equipments' load and the losses in the main transformers of the power station".

aftermath of the Fukushima disaster. Hydro power plants (including pumped storage) account for 7% (11GW) of installed capacity, while non-hydro renewables account for 31% (47 GW) of capacity. France is Europe's second largest electricity market after Germany. The market is dominated by the state-owned utility EDF, which manages the country's 58 nuclear power plants and owns 85% of installed capacity (IEA, 2009). The total net installed capacity of France as of 31st December 2010 is about 123 GW, of which about 50 % comes from nuclear plants (63 GW), 21% from hydro power plants (25 GW) and about 22% are conventional thermal plants (27 GW). Among fossil fuel plants, 10 GW are from fuel oil plants, 8 GW from coal-fired power stations and 9 GW from natural gas plants. Other renewables represent only 6% (8 GW) of capacity. Switzerland largely relies on the hydropower and nuclear plants, which represent 76% (13 GW) and 18% (3 GW) respectively of its total net installed capacity (18 GW). Austria has a total net installed capacity of about 21 GW, with hydro accounting for about 60% (13 GW), and fossil fuels for about 35% (7 GW). Slovenia's total net installed capacity is negligible compared to the other countries of the region. It has 3 GW of capacity, of which 24% is nuclear, 45% is fossil fuels (mainly lignite) and 30% is hydro. There is no nuclear generating capacity in Greece, which does the majority of its generation with fossil fuels (9 GW out 14 GW of total net installed capacity). Italy is the third largest market of CSE area, accounting for about 106 GW of net installed capacity; 75 GW of which is fossil fuels (30 GW are of plants fuelled by natural gas only and 19 GW are of plants using both natural gas and oil derivatives) while hydro represents about 20% (21 GW). Other renewables account for 9% of total net installed capacity (10 GW). As in Austria and Greece, Italy has no nuclear capacity.

Figure 3.3 shows a map of both physical and commercial exchanges of electricity within the CSE region, also reporting the production and consumption data of the 2010 electricity balances for the region. The data is taken from the ENTSO-E statistical database. Germany and France are the first and the second largest markets of CSE[35], with a net production[36] of more than 500 TWh in 2010. Italy ranks third in the CSE area, with a total net production of about 286 TWh, while Austria, Switzerland, Greece and Slovenia are comparatively small markets. Moreover, Germany, France and Slovenia are net exporters of electricity, while all the other countries are net importers.

The focus is on the exchange of electricity that take place in the CSE area. Figure 3.3 reports the data for both the net physical flows and the net commercial flows of energy between the relevant countries of the region. As defined in ENTSO-E's glossary, physical flows of energy represent the real movements of energy between neighbouring countries as metered on the interconnectors, while commercial flows are exchange programs of electricity between adjacent areas stemming from contractual agreements signed by market participants[37]. In highly meshed grids, programmed exchanges often differ from physical flows because power moves between two points following every available parallel path between the two points, rather than a unique predetermined path. In this analysis we are only concerned with commercial flows.

The most important commercial flows of energy occur from Switzerland to Italy (22.4 TWh), from France to Switzerland (19.5 TWh) and from France to Italy (16.2 TWh). Trade between Austria and Italy and between Slovenia and Italy is comparatively small, accounting for 1.6 TWh and 2.8 TWh respectively. Figure 3.3 also reveals that the flows from Switzerland to Italy originate in France, while those on the north-eastern Italian border come directly from Germany. Thus the modelling can be simplified to an analysis of cross-border exchanges between Italy and France as well as the exchanges between Italy and Germany.

[35] Germany and France are also the largest markets in Europe.
[36] According to ENTSO-E glossary, net production is the gross generation less the electricity absorbed by Generating Auxiliaries and the losses in the main generator transformers.
[37] Furthermore, physical flows include the flows resulting from all the electricity markets, namely the day-ahead market, the intra-day market, the market for ancillary services, and correspond to the electricity metered less the imbalances. Commercial flows represent only the flows resulting from the day-ahead market.

The methodology followed to model the cross-border exchanges of electricity between Italy and its neighbours is set out in Section 3.6.1.

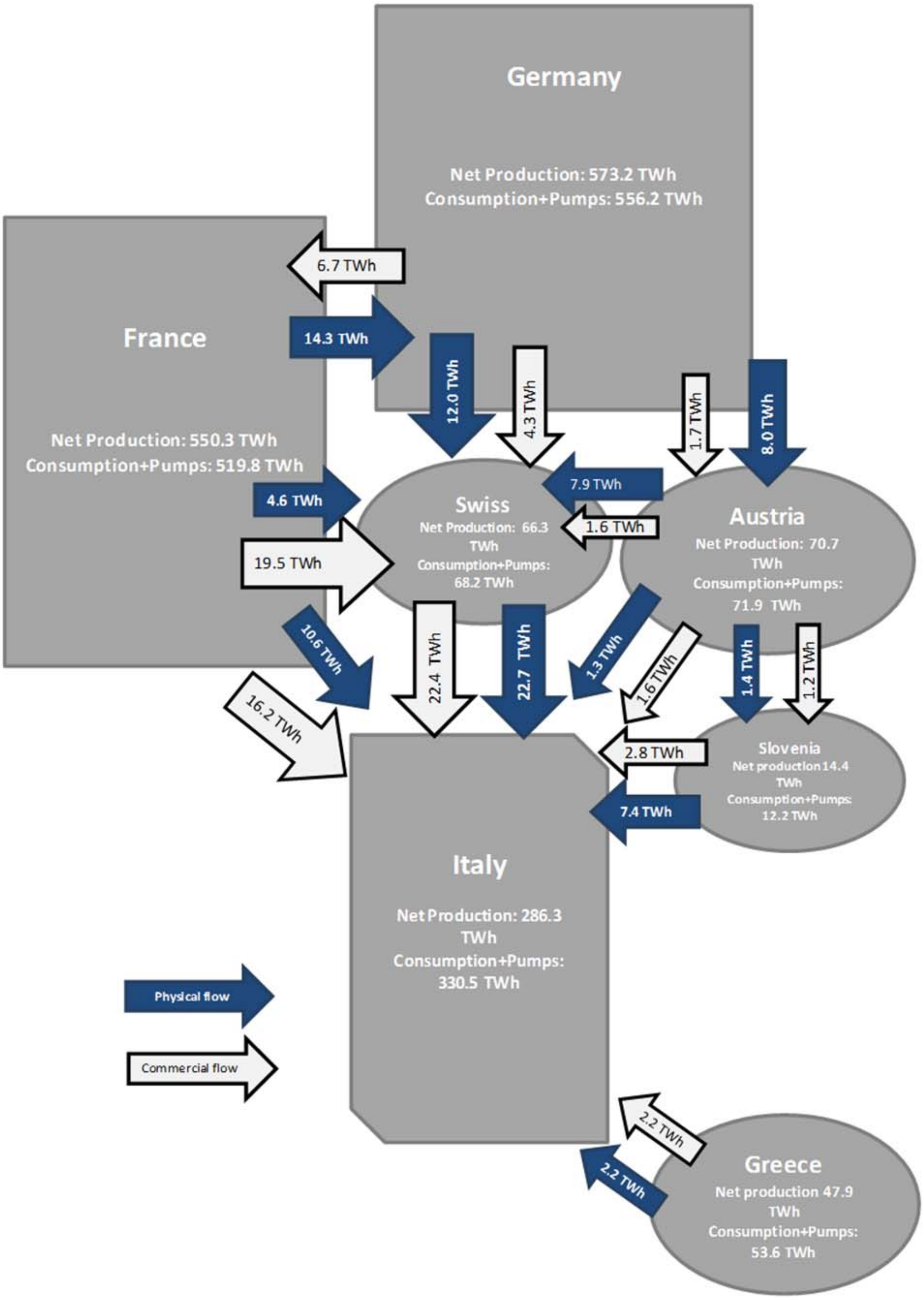

Figure 3.3: Map of physical and commercial net energy flows across Central South Europe in 2010. Data source: ENTSO-E.

3.5 Methodology

The methodology used to evaluate the welfare effect of introducing market coupling between Italy and its neighbouring countries is based on the deterministic simulation of the Italian day-ahead electricity market under two alternative scenarios, while the foreign electricity markets are not explicitly simulated. The two alternative scenarios, the *Reference* and the *High* scenarios, largely reflect those specified by the Italian company Ricerche per l'Economia e la Finanza (henceforth ref.) in March 2011. Ref's scenarios include the most up to date information of the Italian power system and realistic assumptions about the evolution of the Italian electricity market, which are validated and adopted by several market operators[38].

The *Reference Scenario* is so called because it is based on assumptions and market features that are intended to replicate those which are most likely to occur in the market place. The internal consumption of electricity is assumed to exhibit only a small increase with respect to 2010, due to the enduring recession of the Italian economy. By contrast, the yearly average crude oil price, which represents the key driver in determining the variable cost of generating electricity, is assumed to be considerably higher than in 2010, when it was about 79 $/bbl, reaching the value of 97 $/bbl[39]. This in turn is expected to determine a substantial increase in the Italian wholesale electricity price with respect to that registered in 2010. Moreover, subject to similar market dynamics, also Italy's neighbours are expected to see their respective electricity prices increase significantly.

In the *High Scenario,* national demand is assumed to show a more pronounced increase with respect to 2010, as a consequence of an assumed hypothetical recovery of the Italian economy over the year. Furthermore, the oil price is expected to jump to the value of 122 $/bbl. Such a rise in oil price is expected, and therefore assumed in the modelling, to have a

[38] Ref.'s scenarios and ELFO++™ model are currently adopted by major Italian electricity market operators such as ENEL, Edison, Acea, ERG, and Iren.
[39] All the variables forecast for 2012 are expressed in 2010 real terms.

massive impact on the level of the Italian electricity prices. At the same time, the wholesale electricity prices across the borders are expected to suffer from the rise in input prices and also rise.

The simulations are carried out using ref's model ELFO++™, the Italian market leader tool for simulating the outcomes of a liberalised electricity market, which models the Italian power system with a very high level of detail and implements a robust algorithm for the solution of the day-ahead market[40]. The ELFO++™ model and its database are presented below. The two 2012 scenarios and their underlying hypothesis are described in Section 3.6.

ELFO++™ of ref. is a production cost-based model for simulating the outcomes of a competitive day-ahead electricity market, where several generation companies sell their power output either offering it to a centralised power exchange or signing OTC contracts. ELFO++™ is a structural model that simulates the results of the Italian day-ahead electricity market using a deterministic approach, where all the parameters and the constraints of the power system are taken as inputs to the system's scheduling optimization problem. The model delivers the optimal scheduling of the Italian hydrothermal power system over a yearly time horizon with hourly discretization. The optimal scheduling of a hydrothermal power system is an optimization problem well known in the literature, first addressed in the early 1960s[41]. Mathematically, the optimal hydrothermal scheduling problem is a nonlinear mixed integer optimization problem, including two separate sub-problems: the Unit Commitment (UC) of the thermal units and the Dispatch (DS) problem.

The UC problem aims at determining the optimal hourly sequence of start-up and shut-down manoeuvres for all the thermal units of the power system, together with a preliminary hourly

[40] ELFO++™ is programmed in FORTRAN and features an interface built in Microsoft Access.

[41] Yamin (2004), among others, offers a review on the topic. In the pre-liberalization era, the prevailing paradigm of organizing the electricity supply industry was by either regulated or state-owned vertically integrated utilities, which operated the power system with the target of supplying load, maximizing security and minimizing cost. By contrast, since the introduction of the restructuring reforms of the last twenty years, the decisions of production have been taken by decentralized competitive markets, in which several competitors act so as to maximize their own profits. Thus, nowadays, the main approaches for simulating the results of competitive electricity markets include, in addition to production cost-based models, equilibrium models, featuring mainly either Cournot or Supply Function Equilibrium (SFE) competition, and agent based models (Ventosa et al. 2005).

dispatch schedule for all the units in the system. It is a non-convex optimization problem with discrete variables. The constraints to the problem are given by: load to be served, minimum run time and minimum down time restrictions, transmission lines limits. A Dynamic Programming algorithm is implemented in ELFO++**™** to solve the UC problem[42]. Dynamic Programming evaluates alternative sequences of thermal units statuses with the objective of minimising the operating cost of the power system.

The DS problem aims at determining the power output (MW) of each generating unit that minimises system operating costs under several technical constraints, provided that the unit commitment schedule for thermal units is already fixed. The DS is a convex quadratic programming problem with continuous variables, where the objective function consists of a quadratic cost function with constraints including: load to be served, minimum and maximum power output restrictions for both thermal and hydro units, hydro plants reservoirs limits and transmission lines limits. The method used to solve this problem requires the implementation of the Kuhn-Tucker optimality conditions using the most suitable algorithm to take into account the size of the problem.

The overall problem is solved via an iterative procedure that is summarized in the flow chart in Figure 3.4.

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[42] Dynamic programming is largely used in the literature to address this kind of problem (see, among others, Snyder et al. 1987).

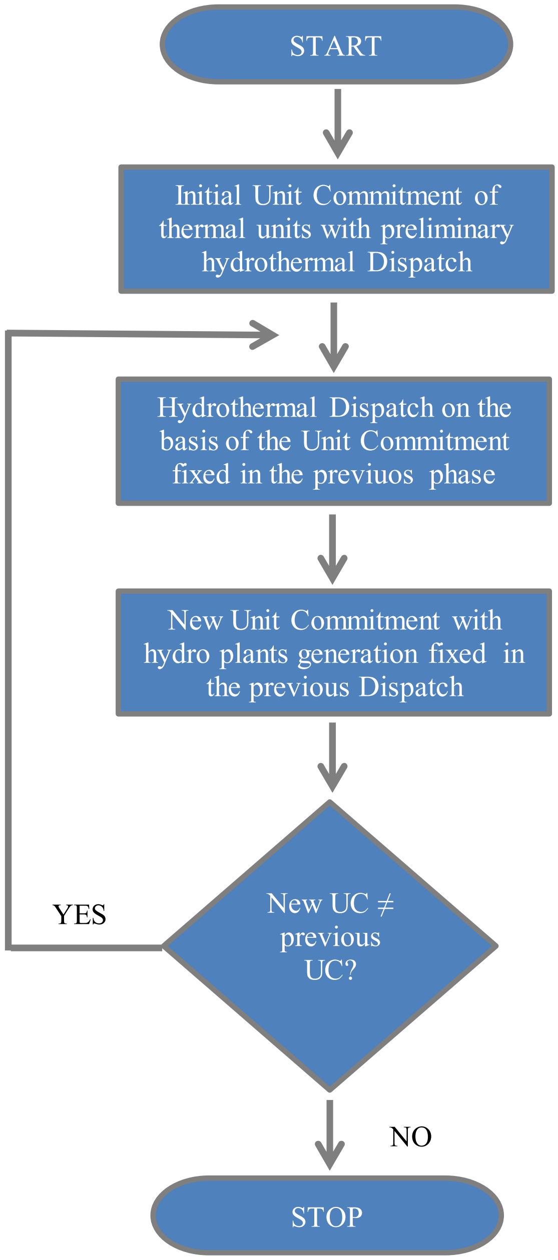

Figure 3.4: Flow chart of the algorithm implemented in ELFO++™.

The hydrothermal scheduling problem is modelled as follows. Given a power system consisting of G thermal units, H hydro plants, L transmission lines connecting Z zones of the grid, the model is set to find the sequence of start-up and shut-down manoeuvres of the thermal units and the power output of all the units over T time periods to minimise the power system expenditure subject to several constraints. The minimisation equation is given in equation (3.2) below:

$$\min \varphi = \sum_{t\in T}\sum_{g\in G}\left[\left(A_{2gt}p_{gt}^2 + \left(A_{1gt}+F_{gt}+B_{gt}\right)p_{gt} + A_{0gt}u_{gt}\right) + W_g\delta\left(u_{gt}-u_{gt-1}\right)\right] + \sum_{t\in T}\sum_{h\in H}F_{ht}p_{ht} \quad (3.2)$$

where A_{2gt} is the 2nd degree coefficient [€/MW^{2}h] of the hourly cost curve for the thermal unit g at time-step t, p_{gt} is the power output [MW] of the thermal unit g at time-step t, A_{1gt} is the 1st degree coefficient [€/MWh] of the hourly cost curve for the thermal unit g at time-step t, F_{gt} is a coefficient [€/MWh] used to control the production of thermal unit g at time-step t, B_{gt} is the bid-up [€/MWh] on the marginal cost used to determine the offer price of the thermal unit g at time-step t, A_{0gt} is the 0 degree coefficient [€/h] of the hourly cost curve for the thermal unit g at time-step t, u_{gt} is the status (1=on / 0=off) of the thermal unit g at time-step t, W_g is the start-up cost [€] of the thermal unit g, $\delta(x)$ is a step function $\delta = 0$ for $x < 0$ and $\delta = 1$ for $x > 0$, F_{ht} is the coefficient [€/MWh] used to control the production of hydro plant h at time-step t, p_{ht} is the power output [MW] in generation (+) or the power absorbed in pumping (–) from the hydro plant h at time-step t.

Subject to the following constraints:

thermal units power output constraint:

$$P_{mgt} \le p_{gt} \le P_{Mgt} \qquad [\, g\in G \,,\, t\in T \,], \quad (3.3)$$

where P_{mgt} is the minimum power output [MW] of the thermal unit g at time-step t and P_{Mgt} is the maximum power output [MW] of the thermal unit g at time-step t;

hydro plants power output constraint:

$$P_{mht} \le p_{ht} \le P_{Mht} \qquad [\, h\in H \,,\, t\in T \,], \quad (3.4)$$

where P_{mht} is the minimum power output [MW] in generation/pumping of the hydro plant h at time-step t and P_{Mht} is the maximum power output [MW] in generation/pumping of the hydro plant h at time-step $t;$

storage volume of hydro plants basins constraint:

$$V_{mht} \leq v_{ht} \leq V_{Mht} \qquad [\, h \in H \,,\, t \in T \,], \tag{3.5}$$

where V_{mht} is the minimum storage volume [$10^3 m^3$] of the reservoir of the hydro plant h at the end of the time-step t, v_{ht} is the actual storage volume [$10^3 m^3$] of the reservoir of the hydro plant h at the end of the time-step t and V_{Mht} is the maximum storage volume [$10^3 m^3$] of the reservoir of the hydro plant h at the end of the time-step $t;$

hydro plants basins balance equation:

$$v_{ht} - v_{h(t-1)} = a_{ht} + \Sigma_{\mu \in \Omega h} q_{\mu t} - q_{ht} \qquad [\, h \in H \,,\, t \in T \,], \tag{3.6}$$

where a_{ht} is the natural inflow [$10^3 m^3/h$] to the reservoir of the hydro plant h at time-step t, q_{ht} is the discharge [$10^3 m^3/h$] of the hydro plant h at time-step t, μ is the hydro plant upstream the h hydro plant and Ω is the number of hydro plants of which the discharge flows in the reservoir of the hydro plant h;

compatibility of capacity/power of the hydro plants:

$$q_{ht} = p_{ht} \left(\delta(p_{ht})/c_{h+} + (1-\delta(p_{ht}))/c_{h-} \right) \qquad [\, h \in H \,,\, t \in T \,], \tag{3.7}$$

where $ch+$ is the energy coefficient [$MWh/10^3 m^3$] for generation of hydro plant $h,$ $ch-$ is the energy coefficient [$MWh/10^3 m^3$] for pumping of hydro plant h;

zones balance equation:

$$i_{zt} = \Sigma_{g \in Gz} p_{gt} + \Sigma_{h \in Hz} p_{ht} - (C_{zt} - E_{zt}) \qquad [\, z \in Z \,,\, t \in T \,], \tag{3.8}$$

where i_{zt} is the grid injection [MW] of the zone z at the time-step t, C_{zt} is the load [MW] of the zone z at time-step t and E_{zt} is the equivalent generation [MW] in the zone z at the time-step t;

power reserve constraint:

$$\Sigma_{g\in Gz}\,(P_{Mgt}\,u_{gt}-p_{gt}) \ \geq \ max\,(r_{zt}-r_{Hzt}\,,\,0)\ [\ z\in Z\ ,\ t\in T\ ], \tag{3.9}$$

where r_{zt} is the minimum total spinning reserve [MW] for the zone z at time-step t, r_{Hzt} is the available hydro spinning reserve [MW] in the zone z at time-step t;

transmission lines constraint:

$$S_{mlt} < \ s_{lt} < \ S_{Mlt} \quad [\ l\in L\ ,\ t\in T\ ], \tag{3.10}$$

where S_{mlt} is the minimum transit [MW] on the equivalent interconnection l at time-step t, s_{lt} is the actual transit [MW] on the equivalent interconnection l at time-step t *and* S_{Ml} is the maximum transit [MW] on the equivalent interconnection l at time-step t;

transmission lines balance equation:

$$s_{lt} \ = \ \Sigma_{z\in Z}\sigma_{lz}\,i_{zt} \quad [\ l\in L\ ,\ t\in T\ ], \tag{3.11}$$

where σ_{lz} is the sensitivity coefficient of the interconnection l to the injection of the zone z;

network balance equation:

$$\Sigma_{z\in Z}i_{zt} = 0 \qquad [\ t\in T\ ] \tag{3.12}$$

In ELFO++^{TM} database, all the major thermal units (with a capacity larger than 15MW) are modelled individually including the information specified in the above equations, namely location in the grid, minimum and maximum net efficient power output, production technology, fuels mix, quadratic fuel consumption curve, fuels costs, constraints about start-up and shut-down manoeuvres, and also commissioning and decommissioning dates, maintenance schedules, company owner, rate of accidental unavailability and pollution emissions.

Hydro units are modelled as grouped in hydropower stations distributed in the different zones. Each station is described according to: type of facility (run of river, reservoir, pumped storage), location in the grid, owner company, maximum and minimum net efficient power output, energy coefficients for both generating and pumping activities, rate of accidental unavailability, daily profile of natural inflows in the reservoirs, storage volume of the reservoirs. Power output from hydro plants is offered to the market at zero price, according to a peak-shaving allocation. This implies that during peak-load times hydro plants are used to generate electricity, while during night hours they pump water to the upstream basins.

The transmission network or grid is modelled as a radial network, where each node represents a given zone of the Italian market. The zones correspond to those identified in the Decision ARG/elt 116/08 by the Italian Authority for Electricity and Gas and they are classified as: Geographical Zones (Northern Italy, including Aosta Valley, Piedmont, Liguria, Lombardy, Trentino Alto Adige, Veneto, Friuli Venezia Giulia, Emilia Romagna; Central-Northern Italy, including Tuscany, Umbria, Marche; Central-Southern Italy, including Lazio, Abruzzo, Campania; Southern Italy, including Molise, Apulia, Basilicata, Calabria and two separated zones for Sicily and Sardinia); National Virtual Zones (Monfalcone, Rossano, Brindisi, Priolo and Foggia, which are only points of injection and are called limited production points); Neighbouring Countries' Virtual Zones (France, Switzerland, Austria, Slovenia, Corsica, Corsica AC and Greece). The power exchange limits among zones are modelled with hourly detail and refer to the values imposed by the TSO Terna.

System load represents the electricity demand net of pumped storage plants consumption, export, power plants' auxiliary services consumption and gross of network losses. ELFO++™ considers the day-ahead market demand, which corresponds to the system load less the amount of self-consumption[43]. Market demand is assumed to be completely inelastic to price and it is modelled separately for each of the above geographical zones, with hourly detail. This assumption is consistent with the empirical evidence found in Chapter 5, where the estimate of the short-run (impact) price elasticity of Italy's residential electricity demand is zero given it is statistically insignificant.

In ELFO++**™**, all power plants granted dispatching priority by the Italian legislation, namely renewables, CHP units and plants incentivised with the CIP6 mechanism[44], as well as electricity produced by self-producers not used for self-consumption, are assigned a predefined hourly power output schedule. For each hour of the day, the total amount of production from these sources is subtracted from market demand to simulate dispatching priority. Net imports from neighbouring countries can also be modelled via a fixed production schedule. Alternatively, it is possible to model cross-border exchanges of electricity by extending the transmission network so as to include foreign countries' zones.

ELFO++**™** can simulate the electricity market according to either perfect or imperfect competition. In order to simulate imperfect competition, the modeller has to set out exogenously the hourly profile of strategic behaviour for the several market competitors[45]. In particular, the variable describing the player's strategic behaviour takes the form of an additional component (called bid-up) that shifts up the offer curve that the player i submits to the day-ahead market for producing electricity in the hour t using the thermal unit g[46].

[43] Self-consumption is the consumption of electricity made by self-producers. These in turn can be either natural persons or companies that own a generating facility for covering their own power needs.
[44] The Interministerial Price Committee (CIP) Resolution 6 of 29 April 1992, known as CIP6 mechanism, envisages incentives for the production of electricity from both renewable sources and from the so-called assimilated to renewable sources, namely some cogeneration units, power plants using refinery or industrial residues.
[45] This is due to the fact that ELFO++**™** follows a production cost-based approach rather than a neoclassical game-theoretic one.
[46] In the day-ahead market, the market operator holds 24 separated auctions for procuring power for each of the 24 hours of the following day. Thus, generators submit a different offer curve for each plant, for each hour of the day.

The offer curve of the thermal unit *g* for the hour *t* is a linear function[47] that relates the price of the electricity produced by the unit *g*, e_g [€/MWh], to the power output p_g [MW]. If the player *i* offers the power output of the unit *g* for the hour *t* at a price equal to marginal cost, then the offer curve for the hour *t* is given by the marginal cost curve of the unit *g*, as follows[48].

$$e_{gt}=MC_{gt}=2A_{2gt}p_{gt}+A_{1gt} \tag{3.13}$$

By contrast, if the player *i* offers the power output of the unit *g* adding a bid-up to marginal cost B_{gt}, then the offer curve for the hour *t* becomes,

$$e_{gt}=2A_{2gt}p_{gt}+A_{1gt}+B_{gt} \tag{3.14}$$

To set out the bid-up profiles, the modeller has to fix ex-ante the desired outcome of the simulation, for instance the desired electricity price or the desired plant's operating margin, and then has to construct the bid-up profiles so as to achieve the designed target. In this chapter, the bid-up profiles for the year 2012 are constructed to achieve a target value of yearly average clean spark spread[49]. Moreover, the bid-up profiles are set to reproduce the typical hourly electricity price dynamics, which implies very low or negative bid-up values for the off-peak hours and very large bid-up values for peak-load times. Finally, the bid-up values are differentiated for each of the above Geographical and National Virtual zones, so as to reproduce zonal prices differentials very similar to those of the year 2010[50]. As no major changes are expected to the transmission lines or to the number of power plants on line between 2010 and 2012, this seems a reasonable assumption to make.

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[47] The function is linear because it is the first derivative of the quadratic hourly cost curve of the unit *g*.
[48] The term F_{gt} in equation (3.2) is neglected in this formulation.
[49] Clean spark spread is a measure of gross margin of a gas-fired power plant from selling a unit of electricity. In this analysis, it is calculated as the difference between national single price PUN and the variable cost (inclusive of fuel, EU-ETS allowances and green certificates) of generating electricity for a combined cycle gas turbine plant with 53% average efficiency.
[50] Bid-up profiles can be modelled with different degrees of complexity. In addition to modelling different bid-up profiles for each zone, it is possible also to set out a single bid-up profile for each generating unit in the system, or alternatively to assume a common profile for each production company or technology.

The bid-up calibration procedure developed by ref. consists of the following steps. First, a preliminary simulation without bid-up, i.e. where generators offer at marginal cost, is carried out. This simulation yields the system marginal cost of generating electricity for the Italian power system for the simulated year. Second, the modeller computes the difference between the yearly value of system marginal price needed to achieve the target value of clean spark spread, and the yearly average system marginal cost found in the preliminary simulation, so as to obtain a yearly average bid-up value. Third, the yearly average bid-up is used to build an hourly profile of bid-up for each zone of the market and a new simulation including this new variable is run. Finally, if the resulting system marginal price matches its target value, the calibration procedure ends. Otherwise, the bid-up profiles are adjusted[51] and further simulations are run until the target is achieved.

3.6 Data and assumptions

All the variables included in the scenarios, with exception of those related to the model of cross-border exchanges of electricity, which are detailed in Section 3.6.1, are prepared by ref. and reflect ref.'s view about the expected evolution of the Italian electricity market as of March 2011. The two scenarios account for different values of market demand, fuel prices, participants' strategies and foreign countries' electricity prices. By contrast, all other inputs listed below are held constant across the two scenarios.

Large hydro power stations (with a capacity larger than 10MW) including reservoir and run of river facilities are assumed to generate about 38 TWh in 2012, while pumped storage stations are expected to produce about 4.7 TWh and to consume 6.2 TWh.

Electricity generated both from renewable sources (namely small hydro, solar, wind, geothermal biomass and waste plants) and from assimilated to renewable sources (namely some cogeneration units, power plants using refinery or industrial residues) is granted

[51] The adjustment consists of adding or subtracting an offset value.

dispatching priority by the Italian legislation, thus it is modelled via a predefined production schedule that accounts for about 37 TWh, and 18 TWh respectively.

Internal network constraints are modelled as power exchange limits among the zones of the Italian grid. The model closely follows the limits determined by the Italian TSO for the year 2011: REV15 “Valori dei limiti di scambio fra le zone di mercato”, Terna.

The distinguishing features of the *Reference Scenario* can be summarised as follows. In 2012, due to the economic recession, the Italian system load is assumed to grow only modestly with respect to 2010 (330.45 TWh), reaching 332.16 TWh. The amount of self-consumption is expected to be in line with the values registered in the recent years, namely about 13.51 TWh. The day-ahead market demand, given by the difference between the system load and the self-consumption, is therefore equal to 318.65 TWh. The main component of the variable cost of generating electricity, namely crude oil price, is expected to show substantial increase with respect to 2010, mainly driven by a rise in oil demand by non-OECD Asia, Middle East and Latin America. Thus, oil price is assumed to average around 97 $/BBL, with the €/$ exchange rate at about 1.42 €/$. Other fuels prices, namely coal, fuel oil, diesel and natural gas prices, are expected to increase in the same proportion as the crude oil price, given that they display a long-run relationship with oil price. Bid-up profiles are calibrated so as to reflect the structure and dynamics of the competition observed in the Italian marketplace since 2009. In addition, these bid-up profiles allow generators to gain profits that are consistent with the low level of electricity demand and with the situation of substantial overcapacity of the power system expected in 2012. In particular, it is assumed that participants act so as to reach a value of the clean spark spread of 2 €/MWh in the simulation of the Business As Usual case[52].

[52] These bid-up profiles are able to produce a price result for the Business As Usual case which is in line with that quoted on the Italian forward market in June 2011.

The key assumptions underlying the *High Scenario* are the following**.** The Italian economy is assumed to show a moderate recovery in 2012 with respect to 2010 and consequently the Italian system load is expected to grow up to 335.61 TWh. Thus, considering the same level of self-consumption of the *Reference Scenario* (13.51 TWh), day-ahead market demand is assumed to reach 322.10 TWh. Oil price is expected to increase steeply with respect to the 2010, up to the yearly average value of 122 $/BBL (with the €/$ exchange rate about 1.42 €/$ as in the *Reference Scenario)*, due to a higher oil demand by non-OECD Asia, Middle East, Latin America, Europe and Northern America. Other fuel prices, namely coal, fuel oil, diesel and natural gas prices, follow the crude price escalation. Participants' strategies are more pronounced than in the *Reference Scenario*, as the electricity demand and the general economic situation allow an improvement in generators' profit margins. In particular, bid-up profiles are calibrated so that generators get a clean spark spread of 5 €/MWh in the simulation of the Business As Usual case.

For each scenario the following four alternative cases are simulated. Perfect Competition (PC) case: in this baseline case, market participants are assumed to act as price-takers, offering their power output at marginal cost. The allocation of rights for using cross-border interconnection capacity is carried out via explicit auctions that take place yearly, monthly and daily. Business As Usual (BAU) case: market participants compete with each other offering their power output at a price higher than marginal cost. As in the previous case, the allocation of rights for using cross-border interconnection capacity is carried out via explicit auctions that take place yearly, monthly and daily. Market Coupling (MC) case: the daily available cross-border interconnection capacity is allocated via market coupling, while explicit auctions are held for the allocation of long-term capacity. As in the BAU case, market participants are assumed to offer their power output at a price higher than marginal cost. Moreover, they are assumed to repeatedly keep offering with the same hourly bid-up profiles. Market Coupling with producers of Northern zone offering at their marginal costs (MCNO) case: the allocation of the daily available cross-border interconnection capacity is carried out via market coupling as before, but now generators located in the Northern zone of the Italian market fear the threat of potential sharper competition with market participants in bordering countries, and hence are assumed to behave as price-takers.

3.6.1 Cross-border exchanges of electricity

Two alternative settings of cross-border interconnection capacity allocation between Italy and its neighbouring countries are considered. The first, which is set out in the PC and BAU cases, features explicit auctions for allocating both long term and day-ahead interconnection capacity. The second, which is assumed for the remaining cases, includes explicit auctions for the allocation of long-term capacity and market coupling for the day-ahead capacity.

The foreign electricity markets are not explicitly simulated rather, they are represented by several foreign zones. Each foreign zone includes an equivalent[53] generator, which can produce an amount of power output at most equal to the interconnector's maximum NTC in import to Italy, and a load, which is at most equal to the interconnector's maximum NTC in export from Italy. Each equivalent generator is assumed to offer a share of its production via long-term bilateral contracts and to participate in the day-ahead electricity market for selling the remaining energy. The amount of power output sold under bilateral contracts by each equivalent generator corresponds to a predefined hourly power output schedule, which is assumed to be the same across all cases. Equivalent foreign generators offer in the Italian day-ahead market at their respective foreign day-ahead electricity prices.

ELFO++**TM** works as follows. The power output from bilateral contracts is always entirely dispatched, as it is granted dispatching priority. Then, the model determines the daily import/export balance across each border according to the price differential between the Italian and the foreign market.

[53] Equivalent means fictitious generator that groups different generators summing all the respective production capacities.

Although the CSE region includes several countries, it is worth simplifying the modelling of cross-border trade between Italy and its neighbours, grouping the different bordering countries in broader foreign zones. Figure 3.3 shows that the net commercial flows from Switzerland to Italy originate in France, while those on the north-eastern Italian border come directly from Germany. Given that net commercial flows follow price differentials between countries, there is evidence of converging behaviour in the pattern of the French and Swiss electricity prices, as well as in that of Austrian and German prices and of Slovenian and German prices. This convergence allows the modelling of trade across the several borders to be simplified to only two main interconnections: a north-western interconnection with France, which sums the flows of both France and Switzerland; and a north-eastern interconnection with Germany, which accounts for the flows of both Austria and Slovenia. An in-depth price convergence analysis suggesting that this simplification to the modelling is appropriate is reported in Appendix A.

For the *Reference Scenario*, the forecasts of the foreign electricity prices for 2012, namely the French EPEXSpotFR, the German EPEXSpotDE and the Greek System Marginal Price, are based on the following assumptions. Due to the decision taken by the German government in June 2011 to shut-down the seven oldest nuclear plants in the country, the German electricity price is forecast to increase considerably with respect to 2010 (44.49 €/MWh), reaching 59.59 €/MWh. The annual average French spot electricity price is expected to rise, with respect to 2010 (47.50 €/MWh), to the yearly average of 59.24 €/MWh, driven by a higher demand for exports to Germany and by the persistent structural imbalance between base-load and peak-load capacity described in IEA (2009). Also the Greek spot electricity price is forecast upward, as a consequence of the surge in fuel prices, reaching 62.94 €/MWh.

The methodology implemented to achieve the forecasts is as follows. First of all, for the French and the German prices, the hourly price profile of 2010 is selected and adjusted[54] to the 2012 calendar. Second, the values are scaled[55] so as to obtain quarterly average prices equal to the French Power Futures and the German Power Futures respectively as quoted by EEX on the 7th of June 2011 (http://www.eex.com/en/). Table 3.1 reports the quarterly futures values.

	French Power Futures €/MWh	***German Power Futures €/MWh***
1st Quarter 2012	68.50	65.02
2nd Quarter 2012	51.00	54.43
3rd Quarter 2012	50.61	55.59
4th Quarter 2012	66.90	63.44

Table 3.1: Quarterly French Power Futures and German Power Futures quotation as of 7th June 2011. Data source: EEX.

Given that for the Greek SMP there are no futures quoted, the Greek SMP is forecast using the following model, a parsimonious simplification of the autoregressive distributed lags (ARDL) of order 12:

$$GreekPrice_t = \alpha_0 + \alpha_1 Trend + \beta_0 GreekPrice_{t-1} + \beta_1 GreekPrice_{t-3} + \beta_2 GreekDemand_t$$

$$+\beta_3 OilPrice_{t-1} + \varepsilon_t \tag{3.15}$$

where the variable *GreekPrice* is the monthly average Greek SMP in €/MWh, while *GreekDemand* is the monthly average Greek system load in MWh, both available online at:

[54] The price profile of a given year is unique, because each day of the week has its own specific profile. For example, if we want to build the price profile for the 2nd of January 2012, which was a Monday, we cannot replicate the profile of the 2nd January 2010, which was a Saturday; rather we have to consider the price profile of Monday 4th January 2010.

[55] The values of the quarterly futures are divided by the quarterly averages of the price series of 2010, so as to obtain four scaling factors, one for each quarter. Each hourly value of the series of 2010, as adjusted to the calendar of 2012, is then multiplied by the scaling factor so to build the new 2012 price series.

www.desmie.gr/content/values_xls.asp?lang=2. *OilPrice* ($/bbl) is the same included in the ELFO++™ database of the *Reference Scenario*, provided by ref.

This model is estimated by employing monthly average data over the period from January 2006 to March 2011. The forecast for the year 2012 is extrapolated assuming that the monthly Greek system load grows linearly by 0.2%, with respect to the same month of the previous year, between April 2011 and December 2012. Then, in order to obtain the hourly price series for 2012, the values of the 2010 Greek price profile are rescaled using the forecasted monthly average prices. The results of the OLS regression are reported in Table 3.2.

Dependent variable: GreekPrice			
	Coefficient		**p-value**
α_0	-12.34		0.15
Trend	-0.18		0.05
GreekPrice (t-1)	0.48		0.00
GreekPrice (t-3)	0.22		0.01
GreekDemand	0.00		0.03
OilPrice (t-1)	0.27		0.00
R^2	0.89	***Adj.*** R^2	0.88
	Statistics		**p-value**
ARCH 1-1 test: F(1,57)	0.17		0.68
AR 1-2 test: F(2,52)	0.92		0.40
Jarque-Bera Normality test:	0.55		0.76

Table 3.2: Estimation of the Autoregressive Distributed Lags model of Greek price.

In the *High* Scenario, the foreign electricity prices are expected to be more pronounced than in the *Reference Scenario*. In particular, both the German and the French prices are expected to be driven by an increased electricity demand that reflects an improvement in general economic situation of their countries. Moreover, the large increase in fuel prices also determines a significant impact on these electricity prices. Therefore, the annual average

French electricity price is forecast to reach 76.84 €/MWh, while the German price is forecast to average around 76.77 €/MWh. The main driver of the surge in Greek electricity price, forecast at 78.09 €/MWh, is the fuel price, given that, contrary to the leading European countries, the Greek economy is expected to remain in a deep recession during 2012.

For all cases of the *High Scenario* all the foreign electricity prices are forecast using equations (3.16)-(3.18) reported below, which represent the parsimonious versions of ARDL models of order 12. As before, the three equations are estimated over the period from January 2006 to March 2011, assuming both the French and the German monthly system loads increase linearly by 1.7%, with respect to the same month of the previous year, between April 2011 and December 2012. The monthly Greek system load is instead assumed to grow by 1%, with respect to the same month of the previous year, from April 2011 to December 2012. The results of estimations are reported in Table 3.3.

$$EPEXSpotFR_t=\alpha_0+\beta_0 EPEXSpotFR_{t-1}+\beta_1 FrenchDemand_t+\beta_2 OilPrice_{t-3}+\varepsilon_t \qquad (3.16)$$

where *EPEXSpotFR* is the monthly average French electricity price in €/MWh as provided by EPEXSpot, *FrenchDemand* is the French system load in MW as provided by ENTSO-E. *OilPrice* ($/bbl) is the same included in the ELFO++**TM** database for the *High Scenario*, provided by ref.

$$EPEXSpotDE_t=\alpha_0+\beta_0 EPEXSpotDE_{t-1}+\beta_1 GermanDemand_{t-1}+\beta_2 OilPrice_t$$
$$+\beta_3 OilPrice_{t-1}+\beta_4 OilPrice_{t-3}+\varepsilon_t \qquad (3.17)$$

where *EPEXSpotDE* is the monthly average German electricity price in €/MWh as provided by EPEXSpot, *GermanDemand* is the German system load in MW as provided by ENTSO-E. *OilPrice* ($/bbl) is the same included in the ELFO++**TM** database for the *High Scenario*, provided by ref.

$$GreekPrice_t=\alpha_0+\alpha_1 Trend+\beta_0 GreekPrice_{t-1}+\beta_1 GreekPrice_{t-3}+\beta_2 GreekDemand_t$$

$$+\beta_3 OilPrice_{t-1}+\varepsilon_t \tag{3.18}$$

where the variable *GreekPrice* and *GreekDemand* are as defined above and *OilPrice* (\$/bbl) is the same included in the ELFO++**TM** database for the *High Scenario*, provided by ref. Finally, for each of the relevant series, the 2010 price profiles are scaled using the forecast monthly average values.

Dependent variable: EPEXSpotFR				*Dependent variable: EPEXSpotDE*				*Dependent variable: GreekPrice*			
	Coefficient		**p-value**		**Coefficient**		**p-value**		**Coefficient**		**p-value**
				α_0	25.02		0.09	α_0	-12.34		0.15
				EPEXSpotDE (t-1)	0.35		0.00	***Trend***	-0.18		0.00
α_0	-15.80		0.09	***GermanDemand (t-1)***	0.00		0.05	***GreekPrice (t-1)***	0.48		0.00
EPEXSpotFR (t-1)	0.25		0.03	***OilPrice***	0.37		0.02	***GreekPrice (t-3)***	0.22		0.01
FrenchDemand	0.00		0.03	***OilPrice (t-1)***	-0.41		0.05	***GreekDemand***	0.00		0.03
OilPrice (t-3)	0.44		0.00	***OilPrice (t-3)***	0.51		0.00	***OilPrice (t-1)***	0.27		0.00
R^2	0.63	Adj. R^2	0.61	R^2	0.74	Adj. R^2	0.72	R^2	0.89	Adj. R^2	0.88
	Statistics		**p-value**		**Statistics**		**p-value**		**Statistics**		**p-value**
ARCH 1-1 test: F(1,59)	0.39		0.53	***ARCH 1-1 test: F(1,57)***	0.03		0.87	***ARCH 1-1 test: F(1,57)***	0.17		0.68
AR 1-2 test: F(2,56)	0.99		0.38	***AR 1-2 test: F(2,52)***	0.14		0.87	***AR 1-2 test: F(2,52)***	0.92		0.40
Jarque-Bera Normality test:	46.63		0.0	***Jarque-Bera Normality test:***	37.71		0.0	***Jarque-Bera Normality test:***	0.55		0.8

Table 3.3: Estimation of the Autoregressive Distributed Lags models of French, German and Greek electricity prices.

With respect to the NTC values for 2012, it is reasonable to assume for both scenarios the same exchange limits as of 2011, given that no changes to the interconnectors are expected in future years. The NTC values for exchanges of electricity between Italy and its bordering countries are set by the TSO Terna[56]. This data is used to construct the NTC time series for 2012 in the following way. The France-Italy NTC time series is built summing the NTC values between France and Italy and between Switzerland and Italy, for each flow direction. The Germany-Italy NTC time series is calculated by summing the NTC values between Austria and Italy and between Slovenia and Italy, for each flow direction. The Greece-Italy NTC time series is the same as defined by Terna, for flow in each direction. Table 3.4 and Table 3.5 report the values of the interconnection capacity as constructed above.

		Winter		Summer	
		7h-23h	23h-7h	7h-23h	23h-7h
*Monday until Saturday **	***France***	6740	6135	5710	5240
	Germany	800	755	680	650
	Greece	500	500	500	500
*Sunday **	***France***	6135	6135	5258	5240
	Germany	755	755	632	650
	Greece	500	500	500	500
		0h-24h			
*Bank Holidays***	***France***	2682			
	Germany	319			
	Greece	500			

**these values hold with exception of Bank Holidays.*

*** The following Bank Holidays of 2012 are considered only: periods from 1st to 8th January, 8th and 9th of April, 25th of April, 1st of May, 2nd of June, 1st of November, 8th and 9th of December, 25th and 26th of December*

Table 3.4: Indicative and not binding NTC values on the France, Germany and Greece to Italy Interconnection in MW, as an aggregation of the original values in Terna, 2011.

[56] The data refers to Terna, 2011. Access rule to FRANCE-ITALY, SWITZERLAND-ITALY, AUSTRIA-ITALY, SLOVENIA-ITALY, GREECE-ITALY interconnections. (Capacity Allocation Auction Rules), with the exclusion of the values for the so-called low-consumption weekends.

		Winter		Summer	
		7h-23h	23h-7h	7h-23h	23h-7h
Monday until Saturday	***France***	2805	3070	2310	2715
	Germany	245	280	190	235
	Greece	500	500	500	500
Sunday and Bank Holidays	***France***	3070	3070	2715	2715
	Germany	280	280	235	235
	Greece	500	500	500	500

Table 3.5: Indicative and not binding NTC values on the Italy to France, Germany and Greece Interconnection in MW, as aggregation of the original values in Terna, 2011.

Once the maximum hourly values of exchange programs between Italy and the foreign zones have been defined, it is assumed that for each interconnector a portion of the respective NTC for importing to Italy is allocated in long-term auctions and it is used by holders of bilateral importing contracts. In particular, it is expected that on the France-Italy interconnector about the 25% of capacity is used to deliver 12.40 TWh of net import under bilateral contracts, on the Germany-Italy interface about 50% of capacity is reserved to deliver 1 TWh of net imports, while on the Greece-Italy interface about 16% of capacity is allocated to deliver 0.7 TWh of importing contracts. The total amount of net imports via bilateral contracts (about 14 TWh) is estimated to be lower than the value registered in 2010 (about 16.7 TWh). All these conjectures are justified by the expected reduction in availability of both German and French exporters, due to the nuclear shut-down decision, to sign long-term bilateral contracts. Thus, the amount of interconnection capacity available for the daily allocation towards Italy, via either explicit auction or market coupling, corresponds to the total NTC less the capacity allocated to fulfil the obligations stemming from the bilateral contracts.

In the no-coupling cases of both scenarios, BAU and PC, to simulate under-usage of interconnectors, it is assumed that interconnectors are at most used at capacity utilisation rates similar to those of 2010[57]. The interconnector with France is expected to be used for about 90% of its capacity in the direction from France to Italy and for about 45% in the

[57] The utilisation rates are similar to those that occurred when the flows were scheduled consistently with the price differentials.

opposite direction. The German interconnector is assumed to be used for about 75% of its capacity in the direction from Germany to Italy, which is less than in 2010 (98%) so as to reflect an Italian-German price differential much smaller than in 2010, and for about 45% in the opposite direction. The interconnector with Greece is expected to be used for about 80% of its capacity in both directions. The non-economical use of the interconnectors, namely when power flows against the price differential, cannot be simulated with ELFO++™.

3.7 Welfare analysis

The simulation results are presented in Table 3.6. It is useful to compare each of the alternative cases of the *Reference Scenario* before considering the results for each of the cases in the *High Scenario*.

The Italian day-ahead electricity price (€/MWh) is reported in the first row of Table 3.6 (System Marginal Price, PUN). The hourly value of the PUN is calculated as an average of the hourly zonal prices weighted for the respective hourly zonal load. Market demand (TWh) is the Italian system load less the amount of self-consumption. Market demand less net import yields the value of internal production of electricity. Generation costs (M€/year) represent the yearly sum of variable costs of generating electricity for the Italian power system. They include three components: fuel cost, EU-ETS allowances cost and green certificates cost. Welfare indicators (M€/year) consist of TSO's surplus (internal congestion rent), consumers' surplus and producers' surplus, while social surplus is the sum of the three components. The last row of Table 3.6 shows the difference in social surplus (M€/year) relative to the PC case.

Given that demand is assumed to be inelastic to price, in order to provide a quantitative measure of consumers' surplus, a reasonably high value of the demand intercept is assumed. Specifically, the values are 300 €/MWh for the *Reference Scenario* and 400 €/MWh for the

High Scenario[58]. Consumers' surplus is calculated by summing over a year the product of the difference between the assumed intercept and the PUN times the market demand, as specified in (3.19) below. Producer's surplus is the generator's gross margin from producing electricity, as fixed costs are not incorporated in this model. Producers' surplus is calculated by summing over a year the difference between consumers' expenditure for internal production ($CEIP_t$), congestion rent and generation costs, as shown in (3.20) below. Congestion rent is the sum for all the internal transmission lines of the product of the differences in the zonal prices (P_{zt},$P_{\theta t}$) times the net flow on the constrained transmission lines, as specified in (3.21) below.

$$\textit{Consumer Surplus}=\sum_{t\in T}\left[\left(Intercept_t\text{-}PUN_t\right) Demand_t\right] \tag{3.19}$$

$$\textit{Producer Surplus}=\sum_{t\in T}\left(CEIP_t\text{-}Congestion\ Rent_t\text{-}Generation\ Costs_t\right) \tag{3.20}$$

$$\textit{Congestion Rent}=\sum_{t\in T}\sum_{l\in L}\left[(P_{zt}\text{-}P_{\theta t})Net\ Flow_{lt}\right] \qquad [z,\theta \in Z \text{ and } z\neq\theta] \tag{3.21}$$

where t=1,…,T (T=8784) is the number of hours in 2012, and l=1,..L (L=11) is the equivalent transmission line[59], and z and θ represent a given zone with Z the full set of zones. In this analysis, given the assumption of completely inelastic demand, welfare changes account only for changes in the productive efficiency of the electricity market. Further, welfare indicators do not take into account other potential benefits generated by the introduction of market coupling, such as increased security of supply and a reduced need of reserve capacity.

[58] The choice of 300 €/MWh stems from that the highest value of PUN of the Reference Scenario is 160.82 €/MWh, while 400 €/MWh refers to the maximum value of 229.32 €/MWh of the PUN of *High Scenario*.

[59] The physical transmission lines of the Italian grid are grouped in fictitious or equivalent lines, which connect the zones of the Italian market.

Columns (i-iv) of Table 3.6 contain the results of the simulations carried out for the *Reference Scenario*. As expected, the PC case yields the lowest PUN (65.31 €/MWh). The PUN from the PC case represents the system marginal cost of producing electricity for the Italian power system. The Italian electricity demand is covered by internal production for 285.91 TWh out of 318.65 TWh, while net imports account for the remaining 32.75 TWh. Net imports are positive because foreign prices, which are assumed to be in the 59-63 €/MWh range, are lower than the internal system marginal cost.

When generators are allowed to exercise market power, as in the BAU case, the PUN goes up by 16% with respect to the PC case, reaching the value of 75.62 €/MWh. As the price of electricity rises, the Italian power system reduces the level of the internal production, which falls to 280 TWh, increasing the share of net import from abroad, which goes up to 38.67 TWh. Congestion rent increases from 37 M€/year of the PC case to 121 M€/year of the BAU case[60]. This is because under imperfect competition, generators located in zones with a scarce level of interconnection, find it profitable to induce congestion into their areas, so as to exert market power on the local residual demand. Imperfect competition determines consumers' surplus to decline by 4366 M€/year (approximately -6%) with respect to the PC case, while producers' surplus increases by 3608 M€/year (81% with respect to the PC case). In total, the change in social surplus with respect to the PC case is a net loss of 674 M€/year.

The impact of market coupling on the Italian electricity market is assessed by comparing the results of the simulations of the MC case against those of the BAU case, reported in the third and in the second columns of Table 3.6 respectively. As market coupling is introduced, the PUN decreases by 0.70 €/MWh with respect to the BAU case (-1% approximately). As expected, market coupling, maximising the use of the available day-ahead interconnection capacity, allows more power from abroad to flow into the Italian market. In particular, net

[60] The value of congestion rent resulting from all the simulations are comparable with the actual values and relating to the most recent years, i.e. over the period 2007-2010. In particular, GME (2011) reports that the congestion rent in the Italian electricity market ranged between 121-238 M€ over the period 2007-2010. Further, congestion in 2012 is expected to be slightly smaller than the values registered before 2010, due to the new transmission line between Sardinia and Continental Italy and to the low level of demand.

imports rise to 47 TWh from 39 TWh in the BAU case. The competitive effect brought by market coupling determines an increase of Italian consumers' surplus with respect to the BAU case of 210 M€/year (0.30%), whereas producers see their margins reduced by 187 M€/year (-2%). Congestion rent (130M€/year) rises by 10 M€/year with respect to the BAU case. Table 3.7 reports the values of congestion rent for each congested transmission line. Congestion rent increases for the zones directly exposed to market coupling, namely Northern and Southern Italy, as it exerts a pronounced downward pressure on their prices. Specifically, congestion rent increases by 12 M€/year between Southern and Central-Southern Italy, and by 1 M€/year both on the line between Foggia and Southern Italy and on that linking Northern and Central-Northern Italy. By contrast, congestion rent decreases by 4 M€/year on the transmission line between Central Northern and Central-Southern Italy.

Summing the impact on consumers' surplus, producers' surplus and TSO's surplus, it emerges that market coupling determines a net welfare gain of 33 M€/year with respect to the BAU case. However, though market coupling increases the competition in the Italian electricity market, it may not be able to exert sufficient pressure to drive price down to the level of perfect competition. The results show that the PUN of the MC case is still well above the system marginal cost of the PC case (15% higher), with the consequence that social surplus continues to be lower than in the PC case by 641 M€/year.

Column (iv) of Table 3.6 reports the results of the MCNO case. Here, it is assumed that the introduction of market coupling, representing a credible threat of tighter competition on the Northern border, pushes Northern Italy producers to become price-takers so as to increase their market share. The results highlight that under the MCNO case, the PUN decreases by 2.80 €/MWh with respect to the BAU case (-4%). Net import (40.41 TWh) return approximate the level of the BAU case (38.67 TWh), but it does not decrease further as foreign power is still much cheaper than the locally produced power. Consumers' surplus increases by 1208 M€/year with respect to the BAU case (2%), whereas producers' surplus declines by 833 M€/year (-10%). Given that demand is inelastic to price, the drop in producers' surplus is remarkable because Northern Italy's producers, decreasing their offer price, can only increase their production by a limited amount. In particular, by reducing their margins, producers can at most re-appropriate of the market share they had before the start of coupling. Therefore, Northern Italy's producers have a strong incentive to continue to charge the usual level of mark-up, following the so-called "passive output strategy" of Borenstein et al. (2000). This strategy implies that the incumbent, aware of the limited amount of energy that can be shipped into its market, finds it more profitable to accommodate imports so as to congest the interconnectors and hence be able to act as price-makers on the residual demand. A low electricity price in the Northern zone has a major impact also on congestion rent, as shown in Table 3.7. With respect to the BAU case, congestion rent increases by 19 M€/year on the line between Northern and Central-Northern Italy, and by 17 M€/year on the line between Central-Northern and Central-Southern Italy. By contrast, congestion rent falls by 19 M€/year on the line between Southern and Central-Southern Italy. Overall, considering also the changes in the congestion rent on the transmission lines between Rossano and Southern Italy and between Rossano and Sicily, congestion rent rises by 21 M€/year with respect to the BAU case. The change in social surplus with respect to the BAU case becomes important, accounting for about 396 M€/year. However, this improvement is still far from the result of the PC case, given that social surplus is 278 M€/year lower than in the PC case.

Columns (v-viii) of Table 3.6 report the results of the simulation of the four cases for the *High Scenario*. The results of the PC case show the impact on the cost structure of the Italian power system of a major change in market fundamentals, with respect to the *Reference Scenario*. The system marginal cost of producing electricity reaches the value of 79.48 €/MWh, thus 22% higher than the PUN of the PC case of the *Reference Scenario*. Given that also foreign electricity prices largely increase with respect to the *Reference Scenario*, net imports (25.65 TWh) is lower than in the *Reference Scenario* (32.75 TWh), though the level of demand is higher.

	Reference Scenario				*High Scenario*			
	Perfect Competition PC	***Business As Usual BAU***	***Market Coupling MC***	***Market Coupling North Producers Competitive MCNO***	***Perfect Competition PC***	***Business As Usual BAU***	***Market Coupling MC***	***Market Coupling North Producers Competitive MCNO***
	(i)	***(ii)***	***(iii)***	***(iv)***	***(v)***	***(vi)***	***(vii)***	***(viii)***
System Marginal Price PUN €/MWh	65.31	75.62	74.92	72.82	79.48	94.52	93.61	89.76
Demand TWh	318.65	318.65	318.65	318.65	322.10	322.10	322.10	322.10
Net Import TWh	32.75	38.67	47.19	40.41	25.65	34.79	44.39	35.86
Internal Production TWh	285.91	279.99	271.46	278.24	296.45	287.31	277.71	286.24
Internal Expenditure M€	18921	22320	21540	21297	23868	28615	27554	27090
Total Expenditure M€	20996	25361	25151	24153	25824	32239	31951	30174
Generation Cost M€	14405	14111	13509	13901	18012	17412	16506	17211
TSO's Surplus (Congestion Rent) M€	37	121	131	142	42	180	186	208
Consumers' Surplus M€	74601	70235	70445	71443	103016	96601	96889	98666
Producers' Surplus M€	4479	8087	7900	7254	5814	11023	10861	9671
Social Surplus M€	79117	78443	78476	78839	108872	107804	107936	108545
Change in Social Surplus wrt PC case M€		-674	-641	-278		-1068	-936	-327
Change in Social Surplus brought by coupling wrt to BAU case M€			33	396			132	741

Table 3.6: Simulations results under the four alternative cases of the Reference and High Scenario.

Comparing the results of the BAU case against those of the PC case, imperfect competition leads price to rise by 19%, reaching the value of 94.52 €/MWh. As the Italian price surges, the relative convenience of power from abroad increases, with the result that net imports goes from 25.65 TWh of the PC case to 34.79 TWh of the BAU case. Congestion rent in the BAU case quadruples with respect to the PC case, going from 42 M€/year to 180 M€/year. This pronounced increase reflects, even more than in the *Reference Scenario*, that generators make strategic use of the bottleneck on the internal transmission lines. In *High Scenario*, the change from perfect to imperfect competition leads consumers' surplus to fall by 6415 M€/year (-6%), while producers are better off by 5209 M€/year (90%). In total, social surplus shrinks by 1068 M€/year.

As in the *Reference Scenario*, the introduction of market coupling has a beneficial impact on the level of the PUN. In particular, under the MC case, the PUN drops by 0.91 €/MWh with respect to the BAU case. Consumers' surplus grows with respect to the BAU case by about 288 M€/year, while producers' surplus declines by 162 M€/year. Congestion rent increases with respect to the PC case by a small amount with the introduction of coupling (6 M€/year). Thus, the aggregate welfare impact with respect to the BAU case is 132 M€/year. At the same time, the change in social surplus with respect to the PC remains remarkably high (936 M€/year).

Under the MCNO case, where Northern Italy producers reduce their margins, so as to increase their output, PUN declines by 4.76 €/MWh with respect to the BAU case. In the MCNO case, the gain for Italian consumers with respect to the BAU is of 2065 M€/year (2%), while the fall in producers' surplus accounts for 1352 M€/year (-12%). Moreover, the fall in producers' surplus with respect to the BAU case is larger than that observed when comparing the MC case against the BAU case. This confirms the conclusion that under market coupling Northern producers are better off if they continue to charge their usual margins so as to follow the "passive output strategy" outlined above.

As for the *Reference Scenario*, a reduced Northern zone price determines a significant impact on the internal congestion rent. Table 3.7 shows that, with respect to the BAU case, congestion rent increases by 23 M€/year between Northern and Central-Northern Italy, by 28 M€/year between Central-Southern to Central-Northern Italy and by 5 M€/year on the transmission line between Rossano and Sicily. By contrast, congestion rent decreases by 28 M€/year between Central Southern and Southern Italy. Given that the overall congestion rent is 208 M€/year, the change in aggregate surplus of the MCNO case with respect to the BAU case accounts for about 742 M€/year. Nonetheless, social surplus is still 326 M€/year below the level of the PC case. Thus, though market coupling contributes considerably to the increase of social surplus with respect to the BAU case, it is not alone able to exert competitive pressure as to replicate the results of the PC case.

	Reference Scenario			*High Scenario*		
	Business As Usual BAU	***Market Coupling MC***	***Market Coupling NORTH producers competitive MCNO***	***Business As Usual BAU***	***Market Coupling MC***	***Market Coupling NORTH producers competitive MCNO***
	Congestion Rent M€	*Congestion Rent M€*	*Congestion Rent M€*	*Congestion Rent M€*	*Congestion Rent M€*	*Congestion Rent M€*
North-Central North	1	2	20	1	2	24
Central North-Central South	13	9	30	22	17	50
Central South-South	64	76	45	93	103	65
Foggia-South	4	5	4	7	9	7
Rossano-South	0	0	1	1	0	2
Rossano-Sicily	36	35	38	52	52	57
Priolo-Sicily	4	4	4	3	3	3
Total Congestion Rent M€	121	131	142	180	186	208

Table 3.7: Congestion rent by transmission lines for the Reference and the High Scenario.

3.8 Conclusions

The main aim of this chapter was to evaluate the impact on the Italian electricity market of the introduction of market coupling to allocate the daily available cross-border interconnections with its neighbouring countries. Market coupling maximizes the use of interconnection capacity between countries, allowing for flows-netting and the elimination of inefficient arbitrage that may occur under the explicit auction mechanism. Simulations of two states of the Italian market, a *Reference Scenario* which is based on current market fundamentals and a *High Scenario* which accounts for rises in demand and in fuel prices, support the theoretical expectation that market coupling would determine a net welfare gain for market participants. In the *Reference Scenario*, the net welfare gain with respect to the Business As Usual case ranges between 33 M€/year and 396 M€/year, depending on whether Northern Italy producers act as oligopolists rather than as price-takers. The increase in social surplus brought by the introduction of market coupling is particularly evident when market fundamentals are tight, as in the instance of the *High Scenario*. Here, the net welfare gain is estimated to range between 132 M€/year and 741 M€/year. The analysis in this chapter, that employs the robust and highly detailed simulation model ELFO++™, has the merit of providing a sound measure of the minimum gains that could be achieved by market participants.

The welfare results in this chapter can also be compared against those shown in ACER (2013b) and in Booz & Co. et al. (2013). In particular, ACER (2013b) reports the results of simulation analyses of integrating the day-ahead electricity markets, performed by major power exchanges in Europe to establish the welfare gain of increasing cross-border trade. The results of the simulation for the Italian electricity market for 2012 highlight that improved integration between Italy and France (the only border for which the analysis is carried out) would yield a cumulative welfare gain of 26M€/year as compared to their historical scenario. Booz & Co. et al (2013) use available data between 2004 and 2013 to directly estimate the economic effects of market coupling. Scaling is then used to determine the additional impact assuming that market coupling is introduced as planned by 2015[61]. Once market coupling is fully implemented across the EU Booz & Co et al. estimate that the benefits will range between 2.5bn€/year and 4bn€/year.

Comparing the assumptions and the results of the simulations of the *Reference Scenario* with the actual 2012 data, it is possible to further evaluate the impact of market coupling on the Italian electricity market. The 2012 average spot electricity price was 75.48 €/MWh, which is very close to the results of the simulation of the BAU case of the *Reference Scenario* (75.62 €/MWh). A large system overcapacity combined with lower than expected electricity demand (325.3 TWh versus 332.2 TWh forecast) had the impact of mitigating the higher than expected oil price (111.7 $/bbl versus 97 $/bbl forecast) that occurred in 2012, and therefore produced an electricity price result in line with that of the simulation. The actual foreign electricity prices were much lower than what was assumed in the *Reference Scenario*. The German price did not increase due to the shut-down of several nuclear plants (forecast price was 59.59 €/MWh), but the actual price was 42.60 €/MWh due to a combination of factors including an unexpected abundance of wind and solar power generation, high levels of the hydro reservoirs, milder weather conditions in periods of high demand for heating (January, March and December) and sluggish economic growth. The French electricity spot price also turned out to be much lower than assumed in the model (59.24 €/MWh), recording an average value of 46.94 €/MWh. Throughout the year, the French price remained constantly above the German price, showing a marked premium to the German price in February (27.53 €/MWh) and in December (6.47 €/MWh), and only a modest differential for the remaining months (on average around 2 €/MWh). The large price differential recorded in February was due to the temperature drop during the first two weeks of the month, which were the coldest of the year and which caused French electricity

[61] Between 2015 and 2030 scenario modelling is used to assess the benefit of a fully integrated EU electricity market.

demand for domestic heating to peak. In December, lower than expected availability of nuclear power in France and a large amount of renewable electricity production in Germany caused the electricity prices of France and Germany to diverge more than usual. The fortunes of the Greek economy meant that the Greek electricity price averaged at 56.60 €/MWh, which is lower than assumed. The dramatic impact of the recession hitting the Greek economy determined a reduction in power consumption throughout 2012. As the foreign prices turned out to be between 20 €/MWh and 30 €/MWh lower than the Italian price, the amount of net imports (43.1 TWh) was obviously higher than that resulting from the simulation of the BAU case of the *Reference Scenario* (38.7 €/MWh). From these stylised facts it appears evident that even in a situation of substantial overcapacity of the electricity production system, the Italian electricity market remains the highest-priced area in Europe due to a production mix that is constantly more expensive than that of its neighbours. Differently from Germany, which has largely invested in renewable technologies in the last decade, Italy has increased the number of CCGT plants between the 2004 and 2012, with the result that the current production mix mainly consists of thermoelectric plants that have a long life ahead. Moreover, the presence of several bottlenecks on the internal transmission grid, due to the historical delay in the construction of additional lines between some regions of the country, often prevents the electricity system from being dispatched in the most efficient way, which translates into an increased electricity price. The recent stream of investment in new gas-fired technology and the bureaucracy associate with building new transmission capacity are an obstacle to a fall in the price, which is difficult to overcome. Therefore, it seems that, at least in the short term, only stronger integration with neighbouring countries, in particular with the northern bordering regions, could help reduce the Italian wholesale electricity price.

The analysis in this chapter can be developed further. The gains for market participants determined the by the elimination of imperfect arbitrage of explicit auctions could be accounted for. Moreover, all the markets in the CSE area could be explicitly simulated and an aggregate welfare analysis could be carried out for all the countries. Finally, it would be interesting to extend this short-term analysis over a longer-term horizon, so as to consider the benefits generated by both the increased security of supply and the reduced need for investment in reserve capacity, and the costs of harmonisation and coordination of the national markets for the implementation of market coupling. These extensions are left for future research.

As market integration is welfare enhancing for Italian market participants, it is important to evaluate if and to what extent a single electricity market has been attained throughout Europe. In Chapter 4 an assessment of the level of electricity market integration between major European electricity markets is undertaken.

4 Convergence across European electricity wholesale spot markets: still a way to go♦

4.1 Introduction

Given the efforts of the European Union to restructure the electricity industry and to implement ad-hoc projects to remove barriers to cross-border trade, it is important to empirically assess the level of integration of European electricity markets. This chapter contributes to the literature on electricity market integration by analysing the behaviour of wholesale electricity spot prices for 15 European power exchanges, the broadest set of European countries for which prices series are available, up to January 2012. The national electricity markets of Austria, Belgium, Czech Republic, France, Germany, Greece, Ireland, Italy, Poland, Portugal, Scandinavia, Spain, Switzerland, the Netherlands and the UK are included in this study.

Market integration is assessed in a more comprehensive way than previously undertaken. The general framework of fractional integration and fractional cointegration is used to test for perfect market integration (i.e. achieved convergence), while time-varying pairwise relations are estimated to evaluate whether market integration is an ongoing process (i.e. ongoing convergence). Multivariate GARCH (MGARCH) estimates provide an indication of returns volatility transmission between markets belonging to each electricity region.

The remainder of this chapter is organized as follows. Section 4.2 reviews the economic literature on electricity market integration and convergence. Section 4.3 presents the dataset

♦ The results in this chapter are presented in a paper which is under review at *The Energy Journal*. It was presented at the 12th IAEE European Energy Conference (9th-12th September 2012, Venice, Italy), where it also won a Best Student Paper Award, and to the Energy Finance Conference (4th-5th October 2012, Trondheim, Norway). I acknowledge EPEX SPOT and Nord Pool Spot for providing me with the electricity price data.

employed in the analysis. Section 4.4 describes the empirical analysis performed to measure market integration. Section 4.5 concludes and sets out key issues for the future.

4.2 Literature review

Over the past two decades, the introduction of competitive electricity markets in Europe, Australia and the United States has generated a growing literature on the empirical evaluation of regional and national electricity market integration. The means of assessing market integration have become more sophisticated ranging from a simple data exploratory approach, to cointegration analysis, to MGARCH models. Evidence of electricity market integration is repeatedly found in the literature between markets with sufficient interconnection capacity. Often, but not in every instance, these countries are geographically close.

Among the first studies, De Vany and Walls (1999) examine the behaviour of peak and off-peak daily spot electricity prices of 11 regional markets in the western United States for evidence of market integration between 1994 and 1996. The authors test market integration, strong market integration and perfect market integration, applying the Johansen cointegration procedure to 55 pairs of markets. In the authors' terminology, market integration only requires the presence of cointegration between two price series p_{it} and p_{jt}. Strong market integration implies testing for the null hypothesis of $\beta=1$ in the cointegration relation $p_{it} = \alpha + \beta p_{jt} + \varepsilon_{it}$, while perfect integration, often referred to as achieved convergence, requires both $\alpha=0$ and $\beta=1$. The results highlight that cointegration is present for almost all peak and off-peak price pairs, while strong integration and perfect integration are mainly an off-peak phenomenon. For a later period, 1998–2002, Park et al. (2006) estimate a vector autoregression model to measure short-term price correlations between 11 US electricity markets located in the Western Interconnected System, in the Eastern Interconnected System and in the Texas Interconnected System. The analysis of the contemporaneous innovation correlation matrix of the vector autoregression model shows that price correlations between markets of the western area, and between those of the central and the eastern US are found to be high (on average above 0.7). By contrast, price correlations between the Texas market and all other markets appear weak (ranging from 0.03 to 0.46). Moreover, forecast error variance decompositions and impulse response function analysis shows that non-western markets help to explain price variation in western markets at 30-day time horizon.

In Europe, Bower (2002) employs the Engle and Granger (1987) procedure to test for cointegration between Norway, Sweden, Finland, Denmark, England & Wales, Germany, Spain and the Netherlands, using daily spot prices for 2001. The results show that cointegration is present between the majority of the countries, except between Germany and Norway, the Netherlands and Norway and between Spain and all other countries. Bower concludes that market integration exists where cross-border interconnection capacity is not limited. Using a data exploratory approach, Armstrong and Galli (2005) find convergence in hourly spot prices for France, Germany, Spain and the Netherlands over the period 2002-2004. In the Nord Pool area, between 2000 and 2003, Haldrup and Nielsen (2006) show that market integration depends on whether the transmission grid is congested or not, as they find evidence of fractional cointegration between electricity prices only when there is no congestion.

Zachmann (2008) evaluates both achieved integration and convergence[62] between Austria, Czech Republic, France, Germany, East Denmark, West Denmark, Poland, Spain, Sweden, the Netherlands and the United Kingdom, between 2002 and 2006. Principal Component Analysis (PCA) is used to test for achieved market integration, while, convergence is measured using time-varying regression models for log price differences. The PCA provides evidence that a single market had not been attained by mid-2006. The results of the time-

[62] Zachmann (2008, pp.1662-1663) defines market integration as “the static degree to which the single European market is attained”, while for convergence he means the “reduction of international price level dispersion over time”.

varying regression models highlight that countries sharing a geographical border experienced price convergence, and that convergence occurred mostly during off-peak hours when there was no congestion on the interconnectors. Nitsche et al (2010) apply the Johansen cointegration analysis to test for pairwise integration between the German spot market and those of Austria, France and the Netherlands. The empirical findings show that Germany and its neighbouring countries form an integrated market. Bunn and Gianfreda (2010) demonstrate that market integration is not only due to the geographical proximity of two markets, as they find integration between the German and UK markets as well as between the German and Spain markets. Further evidence of wider European electricity market integration is found by Bosco et al. (2010). A multivariate cointegration analysis of prices for 6 European power exchanges, including Germany, France, Austria, the Netherlands, Spain and Nordic countries, up to 2007 accounting for leptokurtosis, additive outliers and seasonality reveals the German, French, Austrian and Dutch markets to be cointegrated, and the German and French markets to be strongly integrated[63]. Moreover, they find that both the Spanish and the Nordic markets, which are peripheral zones with different electricity use characteristics, market rules and more limited interconnection, do not share common trends with the other countries. This is also the case for the Irish Single Electricity Market (SEM). Nepal and Jamasb (2011) evaluate the degree of convergence between the Irish Single Electricity Market (SEM) and major continental markets of Germany, the Netherlands, Belgium, Austria and Scandinavia, between 2008 and 2011. Using the same time-varying approach as Zachmann (2008), they find convergence between SEM and other European markets to be low, due to the poor level of interconnection capacity between Ireland and Great Britain.

An alternative means of determining electricity market integration is to determine the existence of pricing-to-market (PTM) behaviour using a fixed-effects model of export prices across destinations. Balaguer (2011) measures electricity market integration between

[63] As defined in De Vany and Walls (1999).

Denmark and Sweden, and between France, Germany and Italy, testing for the existence of PTM[64] behaviour from Norwegian and Swiss exporters, between 2003 and 2009. There is evidence that Norwegian exporters' pricing behaviour is consistent with market integration between Denmark and Sweden, while the pricing behaviour of Swiss exporters highlights market segmentation between France, Germany and Italy over this period.

In contrast to the methodologies employed by much of the literature, in this chapter, a further level of sophistication to the analysis of electricity market integration is added by carrying out fractional integration and cointegration analysis. This allows testing for perfect European electricity market integration, defined in this chapter also as achieved convergence. Moreover, as in Zachmann (2008) and in Nepal and Jamasb (2011), ongoing convergence is tested using a time-varying approach.

An issue not previously tested in the literature on EU electricity market integration is that of volatility transmission between markets. Transmission of volatility has however been investigated in the National Electricity Market of Australia (NEM). Worthington et al. (2005) find that both own and cross-volatility spillovers are statistically significant across the five state based markets of the NEM. Higgs (2009) extends the work of Worthington et al. (2005) employing three alternative MGARCH models, namely the constant conditional correlation model of Bollerslev (1990), the dynamic conditional correlation model of Tse and Tsui (2002) and the dynamic conditional correlation model of Engle (2002). Electricity price volatilities spillovers between the markets of the NEM are strongest between the states that are geographically close and best interconnected. Market integration in this chapter is measured with MGARCH models akin to those used by Higgs (2009).

[64] First defined by Krugman (1987), this from of price discrimination occurs when exporters find it optimal to set destination-specific mark-ups and adjust them in response to exchange rate fluctuations. In Balaguer (2011), acceptance of the hypothesis of PTM behaviour is evidence of market segmentation, while rejection implies market integration.

4.3 Data

The dataset consists of wholesale electricity prices as quoted by the following power exchanges: APX Power NL (Netherlands), APX Power UK (Great Britain), BELPEX (Belgium), EPEX SPOT (clearing the French, German and Swiss markets), EXAA (Austria), HTSO (Greece), IPEX (Italy), Nord Pool Spot (system price for Scandinavia), OMIE (Spain and Portugal), OTE (Czech Republic), POLPX (Poland), SEM (Ireland). Table 4.1 reports summary information of each of the markets. The wholesale spot markets considered in this analysis operate as day-ahead auction markets, featuring double-sided multi-unit uniform price sealed bid auctions of electricity. In this type of auction, which is held the day-ahead of the physical exchange of electricity, buyers and sellers submit to the market operator sealed bids and offers specifying how many units of electricity they are willing to buy and/or sell at every price, for each of the 24 hours of the following day[65].

[65] For the SEM market only, the market operator holds 48 auctions for each of the 48 half-hours of the following day.

Power exchange	*Country*	*Day-ahead price series name*	*1st day-ahead price series observation*	*Average day-ahead price in 2011 (€/MWh)*	*Total consumption 2011 (TWh)*	*Day-ahead market volume 2011 (TWh)*	*Share of power traded in day-ahead market %*
APX Power NL (Amsterdam Power Exchange)	Netherlands	*APXNL*	03/01/2000	51.91	117.84	40.4	34%
APX Power UK (Amsterdam Power Exchange)*	Great Britain	*APXUK*	27/03/2001	55.12	320.08	10.4	3%
BELPEX (Belgian Power Exchange)	Belgium	*BELPEX*	22/11/2006	49.37	86.49	12.4	14%
EPEX SPOT (European Power Exchange)	Germany	*EPEXDE*	08/02/2005	51.12	544.27	224.6	41%
EPEX SPOT (European Power Exchange)	France	*EPEXFR*	22/04/2005	48.89	478.22	59.7	12%
EPEX SPOT (European Power Exchange)	Switzerland	*SWISSIX*	12/12/2006	56.18	64.41	12.1	19%
EXAA (Energy Exchange Austria)	Austria	*EXAA*	22/03/2002	51.80	68.57	7.6	11%
HTSO (Hellenic Transmission System Operator)	Greece	*HTSO*	01/10/2005	59.36	52.92	*Not Available*	*Not Available*
Ipex (Italian Power Exchange)	Italy	*IPEX*	01/04/2004	72.23	328.09	180.4	55%
Nord Pool Spot	Scandinavia+Estonia	*NORDPOOL*	01/07/1999	47.05	387.78	288.1	74%
OMIE (Operador del Mercado Ibérico de Energía)	Spain	*OMIEES*	02/01/1998	49.92	261.66	185.1	71%
OMIE (Operador del Mercado Ibérico de Energía)	Portugal	*OMIEPT*	01/07/2007	50.45	50.51	31.0	61%
OTE (Czech Electricity and Gas Market Operator)	Czech Republic	*OTE*	01/01/2002	50.56	62.98	10.0	16%
POLPX (Polish Power Exchange)	Poland	*POLPX*	01/07/2000	49.61	145.70	19.7	14%
SEM-O (Single Electricity Market Operator)	Republic of Ireland and Northern Ireland	*SEM*	01/11/2007	61.75	35.10	33.57	96%

**Data refer to APX Power UK Spot.*
Day-ahead price of 2011 are comparable with those of the pre-crisis 2006.

Table 4.1: Power Exchanges in Europe. Data source: Consumption data from ENTSO-E, with the exception of SEM-O data which was provided by EirGrid. All day-ahead volumes and prices are from each respective power exchanges' website, except APXNL price data which was supplied by Bloomberg.

The market operator aggregates bids and offers so as to construct 24 demand and supply curves, and determines hourly equilibrium prices and quantities that are compatible with all the technical constraints of the related power system, including congestion on the transmission grid. Therefore, all day-ahead prices employed in this study correspond either to the region uncongested price, as is the case of NORDPOOL[66], or to the average of the internal zonal prices, as in the cases of IPEX[67] and HTSO, or to the final single price that is found after internal congestion is relieved via re-dispatching, as is the case in all remaining markets.

The APX Power UK spot market is the only market in this study that does not operate as a day-ahead auction market. It is a continuous trading market where participants trade both half-hourly and blocks of hours products (in lots of 1 MW of constant flow of electricity) posting their orders on an electronic platform[68]. Trades are cleared continuously and participants get the price they have bid.

Day-ahead markets have opened gradually across Europe since the end of the 1990's and are in operation in Hungary, Romania, Serbia, Slovakia and Slovenia[69] in addition to the countries listed in Table 4.1. The level of liquidity of each exchange, as measured by the ratio between volumes traded on the spot market and total consumption, varies considerably as participation in the day-ahead markets is not compulsory in most countries. As reported in Table 4.1, in 2011, the most liquid day-ahead markets were Nord Pool Spot (74%), OMIE Spain (71%) and OMIE Portugal (61%) and IPEX (55%), while the least liquid markets included the APX Power UK (3%), EXAA (11%) and EPEX SPOT France (12%). There is large variation of wholesale electricity prices between countries, the IPEX market was the

[66] NORDPOOL price is defined by Nord Pool Spot as "The average daily price that disregards bottlenecks in the day ahead market. The reference price for the financial market" http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/Price-calculation/
[67] The IPEX price corresponds to the Italian national single price, which is defined as: "average of Zonal Prices in the Day-Ahead Market, weighted for total purchases and net of purchases for Pumped-Storage Units and of purchases by Neighbouring Countries' Zones". http://www.mercatoelettrico.org/en/Tools/Glossario.aspx#P
[68] Though APX launched a UK day-ahead market in late 2008, the spot market price represents the reference wholesale price.
[69] Romanian data was not available in a suitable format, while Hungary, Serbia, Slovakia and Slovenia have been excluded from this analysis because their markets opened between 2009 and 2010.

most expensive power exchange in 2011 (72.23 €/MWh) and the Nord Pool Spot was the cheapest (47.05 €/MWh). These differences in spot prices reflect the differing characteristics of the production mix and also the degree of internal competition that exists in each country.

The price series used in the study has been constructed using the original hourly prices for the Netherlands, Belgium, France, Germany, Austria, Greece, Italy, Scandinavia, Spain, Portugal, Czech Republic and Poland; and the original half hourly prices, for Ireland and the UK, as quoted by each respective power exchange. The reported market prices have been aggregated to obtain daily arithmetic averages, which is the same as considering the so-called baseload prices of each market, and then transformed into natural logarithms. Using baseload prices rather than hourly prices is necessary as hourly electricity prices cannot be regarded as a pure time series process, since in day-ahead markets hourly prices are set in 24 different auctions that take place at the same time. This means that the information set used to determine prices is the same for all the auctions, while it differs over days. Therefore in order to perform a time series analysis, the raw data must be aggregated in daily averages (Huisman et al., 2007).

The electricity prices that are not quoted in euros (APXUK, OTE, POLPX) have been converted to euros using the daily official exchange rates of European Central Bank as reported at: http://www.ecb.eu/stats/exchange/eurofxref/html/index.en.html. Descriptive statistics of log daily prices are reported in Table 4.2, while plots of the series are shown in Figure 4.1. Every price series is analysed using the whole sample available, reported in column 4 of Table 4.1, with the exception of the POLPX series, for which the observations from 01/07/2000 to 15/10/2002 were eliminated, since the market failed to determine prices for several days of the first two years of operation. The descriptive statistics highlight that log daily electricity prices exhibit high volatility and non-normality. In particular, it emerges that all series except for APXUK, HTSO, POLPX and SEM are leptokurtic; while all series but APXUK, EPEXFR, POLPX and SEM are left-skewed (i.e. low extreme prices are more likely to occur than high extreme prices).

	APXNL	*APXUK*	*BELPEX*	*EPEXDE*	*EPEXFR*	*EXAA*	*HTSO*	*IPEX*	*NORDPOOL*	*OMIEES*	*OMIEPT*	*OTE*	*POLPX*	*SEM*	*SWISSIX*
Mean	3.704	3.713	3.820	3.801	3.825	3.655	4.033	4.198	3.404	3.577	3.843	3.453	3.562	4.052	3.946
Median	3.692	3.712	3.844	3.823	3.831	3.672	4.051	4.214	3.437	3.602	3.850	3.547	3.449	4.068	3.999
Maximum	6.493	5.582	5.750	5.709	6.418	5.181	4.770	4.960	4.904	4.642	4.536	5.004	4.787	4.994	5.192
Minimum	-2.303	2.602	1.818	-2.303	2.253	1.815	3.024	0.191	1.358	0.904	0.904	-3.488	2.799	3.254	2.546
Std. Dev.	0.478	0.437	0.394	0.403	0.393	0.438	0.301	0.260	0.498	0.392	0.357	0.717	0.308	0.285	0.364
Skewness	-0.183	0.392	-0.098	-2.829	0.028	-0.327	-0.263	-2.466	-0.527	-0.398	-1.791	-3.981	0.482	0.002	-0.421
Kurtosis	9.962	2.997	4.143	44.285	4.444	3.651	2.597	30.934	3.455	4.103	12.251	34.145	2.227	2.684	3.172
Jarque-Bera	8935	102	106	184422	216	128	42	95952	253	396	6873	158587	216	6	58
Probability	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.045	0.000
Observations	4412	3963	1897	2549	2476	3603	2314	2862	4598	5143	1676	3683	3395	1492	1877

Table 4.2: Descriptive statistics of log daily electricity prices.

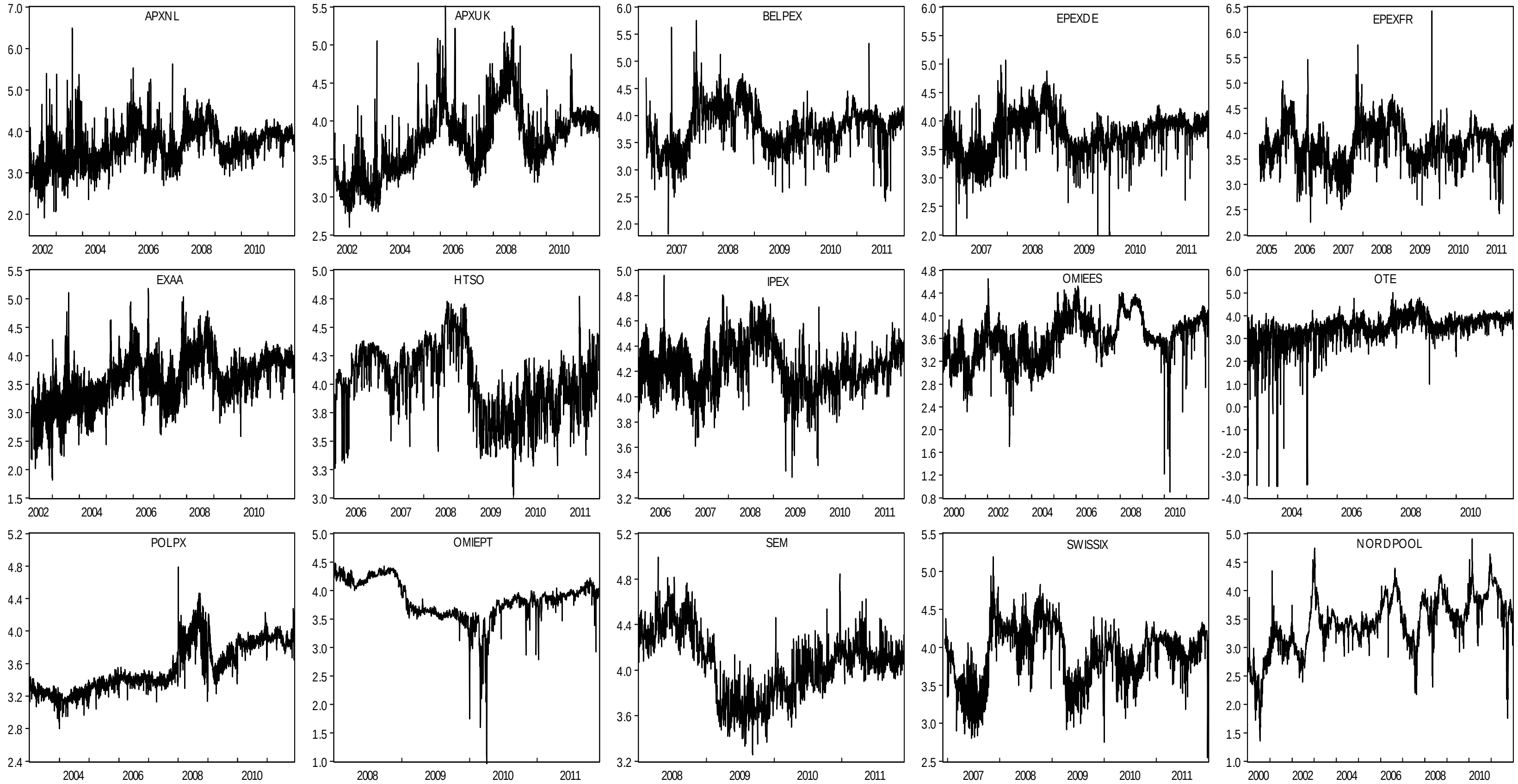

Figure 4.1: Daily electricity spot prices in Europe.

4.4 Empirical analysis

The empirical evaluation of EU electricity markets integration is carried out using a multi-step analysis. Section 4.4.1 reports the fractional cointegration analysis that aims at finding evidence of perfect market integration between the European markets. Section 4.4.2 provides estimates of time-varying relations for all market pairs to explore ongoing convergence. Section 4.4.3 employs MGARCH models to measure returns volatility spillovers between national markets.

4.4.1 Testing for perfect market integration (i.e. achieved convergence)

Cointegration analysis has often been used to assess market integration among electricity markets. The first step in this analysis is therefore to establish whether the price series are individually integrated and if so, to what degree. Table 4.3 reports the Phillips and Perron (1988) unit root test (PP), the KPSS test of Kwiatkowski et al. (1992), and the Gaussian semi-parametric (GSP) test (Robinson and Henry, 1998) for long memory. The PP tests the null hypothesis H_0: $y_t \sim I(1)$, while the KPSS tests the null of H_0: $y_t \sim I(0)$. Both the tests are carried out using the Barlett kernel and the Newey-West automatic bandwidth selection method. The results of the PP test show that the null hypothesis of unit root can be rejected for all series, while the KPSS test results show that all series except for BELPEX, EPEXDE, EPEXFR and SWISSIX are *I(1).* Contradictory evidence about the order of integration of electricity prices is well documented in the literature. Escribano et al. (2002), Lucia and Schwartz (2002), Knittel and Roberts (2005), Worthington et al. (2005), Higgs (2009) and Bunn and Gianfreda (2010) all find electricity prices to be *I(0)*, while others including De Vany and Walls (1999), Bosco et al. (2010) find electricity prices to be *I(1)*. Long memory and mean reversion are observed by Haldrup and Nielsen (2006), Koopman et al. (2007) and Haldrup et al. (2010). The results of the GSP test in the last row of Table 4.3 clearly indicate that all series display long memory and non-stationarity, as the memory parameters *d* are estimated to lie in the interval [0.5, 1). Given that daily electricity prices feature outlying observations and within-week seasonality, the robustness of the results is confirmed by the same unit root and long memory tests being performed for logarithms of weekly medians[70]. The non-stationarity of price series allows the investigation into whether market integration of the European markets had been achieved. Two markets are said to be perfectly integrated if their price series are cointegrated together such that their difference is statistically equal to zero (De Vany and Walls, 1999). Therefore, for each of the N(N-1)/2 (i.e. 105) pairs of prices the following OLS regression is estimated, using the longest available common sample to 31 January 2012.

$$\ln p_t^i - \ln p_t^j = \alpha + \varepsilon_t \tag{4.1}$$

Two fractionally integrated series are said to be fractionally cointegrated if the memory parameter of the cointegrating error (d_ε) is estimated to be smaller than those of the parent series (d_i and d_j with $i \neq j$). Perfect market integration is achieved if the constant α is not statistically different from zero.

Table 4.4 reports the results of GSP estimates of the d_ε for all the fractional cointegration relationships estimated, while Table 4.5 shows the estimates of the α, which represent the log differences between electricity prices. The results in Table 4.4 highlight that all the 105 pairs of prices are fractionally cointegrated, however from Table 4.5 it emerges that the null hypothesis of α=0, i.e. perfect integration, is rejected for all market pairs except for the pairs APXNL-APXUK, EPEXFR-OMIEES, EPEXDE-OMIEPT, EPEXFR-EXAA, EXAA-OMIEES and EXAA-OMIEPT[71]. Perfect integration can be attributed to cross-border trade for EPEXFR-OMIEES only, these are the only two countries that share a direct geographical border. By contrast, the remaining five cases (APXNL-APXUK, EPEXDE-OMIEPT, EPEXFR-EXAA, EXAA-OMIEES and EXAA-OMIEPT), which achieved convergence as a

[70] The results are reported in Appendix B.
[71] Figures for the calculated pairwise prices differences are reported in Appendix B.

result of the using of the same marginal generation technology combined with a similar degree of competition and common institutional arrangements. Therefore, the majority of European electricity markets are far from being perfectly integrated.

	APXNL	*APXUK*	*BELPEX*	*EPEXDE*	*EPEXFR*	*EXAA*	*HTSO*	*IPEX*	*NORDPOOL*	*OMIEES*	*OMIEPT*	*OTE*	*POLPX*	*SEM*	*SWISSIX*
PP test	-46.335**	-12.539**	-25.535**	-41.085**	-28.649**	-33.181**	-20.15**	-43.378**	-5.306**	-21.673**	-8.277**	-37.704**	-9.252**	-15.044**	-18.414**
Bandwith	44	32	36	39	40	48	33	43	17	40	21	37	40	28	38
KPSS test	2.589**	3.871**	0.362	0.213	0.225	3.494**	0.941**	1.479**	4.392**	3.713**	1.141**	5.554**	5.901**	0.992**	0.305
Bandwith	50	50	33	39	39	45	38	42	53	54	32	42	44	31	33
GSP estimate of d	0.629**	0.696**	0.649**	0.612**	0.653**	0.605**	0.84**	0.696**	0.837**	0.678**	0.832**	0.518*	0.82**	0.84**	0.73**

**, ** denote 5% and 1% level of significance respectively.*

For PP, null hypothesis H_0: series=non stationary. Critical values -3.43 for 1% level of significance and -2.86 for 5% level of significance.

For KPSS, null hypothesis H_0: series= stationary. Critical values 0.739 for 1% level of significance and 0.463 for 5% level of significance.

For GSP, Wald test is performed to test the null hypothesis H_0: d=0.49. X^2 critical value 3.84 for 5% level of significance and 6.64 for 1% level of significance.

Table 4.3: Unit root and long memory tests on log daily electricity prices. Unit root tests are performed with Eviews 7, GSP test with G@rch 6.

To evaluate whether the process of convergence towards the single market is ongoing, the α parameters are further investigated to check for potential instability over the respective sample periods. For all the fractional cointegration relationships, CUSUM tests suggest that all the α except that of EPEXDE-EXAA are unstable over their respective sample periods[72].

4.4.2 Testing for ongoing convergence

To explore the time-varying behaviour of the several α, state space models are set up for the pairwise relationships specified above.

$$\ln p_t^i - \ln p_t^j = \alpha_t + \varepsilon_t \qquad \varepsilon_t \sim N(0, \sigma^2{}_{\varepsilon}) \tag{4.2}$$

$$\alpha_t = \alpha_{t-1} + \upsilon_t \qquad \upsilon_t \sim N(0, \sigma^2{}_{\upsilon}) \tag{4.3}$$

Where equation (4.2) is known as the signal or measurement equation and equation (4.3) is known as the state or transfer equation. Equation (4.3) captures the impact of the unobservable variable α_t, which represents the time-varying factors that determine convergence, i.e. presence of cross-border trade, use of the same marginal generation technology and of a common regulatory framework. In this set up, α_t is assumed to follow a random walk process. The time-varying relationships are estimated via the Kalman filter and smoother algorithm (Kalman, 1960), which is a recursive procedure for calculating the optimal estimator of the state vector α_t using all the information available up to time *t*.

[72] The results are reported in in Appendix B.

	APXNL	*APXUK*	*BELPEX*	*EPEXDE*	*EPEXFR*	*EXAA*	*HTSO*	*IPEX*	*NORD POOL*	*OMIEES*	*OMIEPT*	*OTE*	*POLPX*	*SEM*	*SWISSIX*
APXNL		0.367 (0.011)	0.294 (0.016)	0.166 (0.014)	0.373 (0.014)	0.341 (0.012)	0.489 (0.015)	0.385 (0.013)	0.395 (0.011)	0.418 (0.011)	0.470 (0.017)	0.372 (0.012)	0.420 (0.012)	0.261 (0.018)	0.404 (0.016)
APXUK			0.326 (0.016)	0.198 (0.014)	0.310 (0.014)	0.332 (0.012)	0.521 (0.015)	0.386 (0.013)	0.557 (0.011)	0.501 (0.011)	0.501 (0.017)	0.396 (0.012)	0.486 (0.012)	0.279 (0.018)	0.433 (0.016)
BELPEX				0.194 (0.016)	0.261 (0.016)	0.309 (0.016)	0.461 (0.016)	0.404 (0.016)	0.477 (0.016)	0.436 (0.016)	0.443 (0.017)	0.300 (0.016)	0.393 (0.016)	0.294 (0.018)	0.344 (0.016)
EPEXDE					0.251 (0.014)	0.016 (0.014)	0.380 (0.015)	0.314 (0.014)	0.380 (0.014)	0.305 (0.014)	0.346 (0.017)	0.271 (0.014)	0.300 (0.014)	0.172 (0.018)	0.274 (0.016)
EPEXFR						0.382 (0.014)	0.514 (0.015)	0.423 (0.014)	0.467 (0.014)	0.398 (0.014)	0.463 (0.017)	0.390 (0.014)	0.388 (0.014)	0.341 (0.018)	0.354 (0.016)
EXAA							0.488 (0.015)	0.398 (0.013)	0.490 (0.012)	0.456 (0.012)	0.482 (0.017)	0.359 (0.012)	0.440 (0.012)	0.299 (0.018)	0.497 (0.016)
HTSO								0.447 (0.015)	0.673 (0.015)	0.505 (0.015)	0.488 (0.017)	0.425 (0.015)	0.536 (0.015)	0.446 (0.018)	0.514 (0.016)
IPEX									0.474 (0.013)	0.412 (0.013)	0.495 (0.017)	0.351 (0.013)	0.347 (0.013)	0.382 (0.018)	0.479 (0.016)
NORDPOOL										0.631 (0.010)	0.651 (0.017)	0.436 (0.012)	0.660 (0.012)	0.542 (0.018)	0.550 (0.016)
OMIEES											0.370 (0.017)	0.403 (0.012)	0.512 (0.012)	0.449 (0.018)	0.510 (0.016)
OMIEPT												0.442 (0.017)	0.544 (0.017)	0.455 (0.018)	0.527 (0.017)
OTE													0.406 (0.012)	0.285 (0.018)	0.427 (0.016)
POLPX														0.364 (0.018)	0.486 (0.016)
SEM															0.408 (0.018)

Table 4.4: Estimates of the memory parameter d for the residuals of the fractional cointegration relationships. Estimations are carried out with G@rch 6.

	APXNL	*APXUK*	*BELPEX*	*EPEXDE*	*EPEXFR*	*EXAA*	*HTSO*	*IPEX*	*NORD POOL*	*OMIEES*	*OMIEPT*	*OTE*	*POLPX*	*SEM*	*SWISSIX*
APXNL		-0.002	0.022	0.074	0.053	0.094	-0.150	-0.372	0.268	0.068	0.038	0.283	0.218	-0.159	-0.104
		(0.005)	(0.003)	(0.005)	(0.004)	(0.004)	(0.008)	(0.006)	(0.008)	(0.006)	(0.007)	(0.01)	(0.007)	(0.005)	(0.004)
APXUK			0.109	0.142	0.121	0.102	-0.081	-0.307	0.183	0.102	0.138	0.308	0.232	-0.053	-0.016
			(0.006)	(0.006)	(0.006)	(0.005)	(0.007)	(0.006)	(0.007)	(0.005)	(0.007)	(0.01)	(0.005)	(0.005)	(0.007)
BELPEX				0.031	-0.007	0.012	-0.213	-0.435	0.164	0.052	0.025	0.054	0.052	-0.174	-0.126
				(0.006)	(0.003)	(0.004)	(0.009)	(0.007)	(0.009)	(0.008)	(0.009)	(0.005)	(0.007)	(0.007)	(0.005)
EPEXDE					-0.021	-0.018	-0.224	-0.432	0.148	-0.014	-0.009	0.109	0.131	-0.198	-0.156
					(0.005)	(0.004)	(0.009)	(0.007)	(0.008)	(0.007)	(0.01)	(0.006)	(0.007)	(0.008)	(0.007)
EPEXFR						0.003	-0.199	-0.414	0.163	0.011	0.036	0.120	0.145	-0.161	-0.117
						(0.004)	(0.009)	(0.006)	(0.008)	(0.007)	(0.009)	(0.006)	(0.007)	(0.007)	(0.004)
EXAA							-0.205	-0.431	0.081	0.000	0.010	0.205	0.130	-0.181	0.137
							(0.008)	(0.005)	(0.007)	(0.005)	(0.008)	(0.009)	(0.006)	(0.006)	(0.005)
HTSO								-0.222	0.351	0.231	0.178	0.300	0.330	-0.047	-0.084
								(0.005)	(0.01)	(0.007)	(0.007)	(0.008)	(0.008)	(0.007)	(0.008)
IPEX									0.579	0.430	0.420	0.583	0.576	0.205	-0.308
									(0.007)	(0.006)	(0.007)	(0.008)	(0.005)	(0.006)	(0.007)
NORDPOOL										-0.081	-0.135	0.125	0.049	-0.298	0.290
										(0.008)	(0.013)	(0.012)	(0.006)	(0.01)	(0.008)
OMIEES											-0.050	0.206	0.130	-0.250	0.175
											(0.002)	(0.011)	(0.006)	(0.007)	(0.008)
OMIEPT												0.026	0.026	-0.219	0.142
												(0.008)	(0.009)	(0.007)	(0.009)
OTE													-0.076	-0.213	0.179
													(0.01)	(0.007)	(0.006)
POLPX														-0.192	0.174
														(0.006)	(0.007)
SEM															-0.051
															(0.007)

Table 4.5: Estimates of the log differences between electricity prices (α) with standard errors in parenthesis. Estimations are carried out with Eviews 7.

From a visual inspection of the smoothed estimates of the state vectors ($\hat{\alpha}_t$), it is possible to classify the pairwise time-varying relations into four groups according to the degree of convergence displayed. These groups include markets that display: 1) clear evidence of ongoing convergence, i.e. convergence is more frequent than divergence and it becomes quite stable and clear from a given date onwards; 2) mixed evidence of convergence, i.e. convergence periods alternate with divergence periods without regularity; 3) seasonal convergence, i.e. convergence periods alternate with divergence periods according to a regular pattern; and 4) no convergence. Table 4.6 reports the classification of market pairs, while Figures 4.2-4.5 show some illustrative examples of the behaviour of the smoothed convergence indicators[73].

Market pairs displaying clear evidence of ongoing convergence all belong to the areas of Central-Western and Central-Eastern Europe; 20 pairs (or approximately 19% of pairs) are included in this group. Among them are the market pairs of BELPEX-EPXFR and OMIEES-OMIEPT (see Figure 4.2) for which convergence can be attributed to the introduction of market coupling/splitting projects in 2006 and 2007 respectively. Cross-border trade and use of the same marginal generation technology is the driver of convergence between APXNL-EPEXDE and also for EPEXDE-OTE. Ongoing convergence is present also between markets that do not share a common geographical border, such as APXNL-EXXA and APXUK-OTE, but that, in the largest majority of cases, share at least one border with Germany. Approximately 16% of market pairs (17 pairs) show mixed evidence of convergence and include both markets that are directly interconnected, such as EPEXFR-SWISSIX, EPEXDE-EPEXFR and markets that are geographically distant, such as BELPEX-EXAA and BELPEX-POLPX (see Figure 4.3). For these latter market pairs, convergence is driven by similarity in the production structure.

[73] The full set of figures is reported in in Appendix B.

	APXNL	*APXUK*	*BELPEX*	*EPEXDE*	*EPEXFR*	*EXAA*	*HTSO*	*IPEX*	*NORD POOL*	*OMIEES*	*OMIEPT*	*OTE*	*POLPX*	*SEM*	*SWISSIX*
APXNL		**on-going**	mixed	**on-going**	**on-going**	**on-going**	no	no	no	mixed	mixed	**on-going**	**on-going**	no	seasonal
APXUK			no	no	no	no	no	no	no	mixed	mixed	**on-going**	no	no	no
BELPEX				mixed	**on-going**	mixed	no	no	no	no	no	mixed	mixed	no	no
EPEXDE					mixed	**on-going**	no	no	no	mixed	mixed	**on-going**	**on-going**	no	seasonal
EPEXFR						**on-going**	no	no	no	mixed	mixed	**on-going**	**on-going**	no	mixed
EXAA							no	no	no	mixed	mixed	**on-going**	**on-going**	no	seasonal
HTSO								no	no	no	no	no	no	no	no
IPEX									no	no	no	no	no	no	no
NORDPOOL										no	no	**on-going**	no	no	no
OMIEES											**on-going**	**on-going**	no	no	no
OMIEPT												no	no	no	no
OTE													**on-going**	no	seasonal
POLPX														no	no
SEM															no

Table 4.6: Summary of results for the convergence analysis.

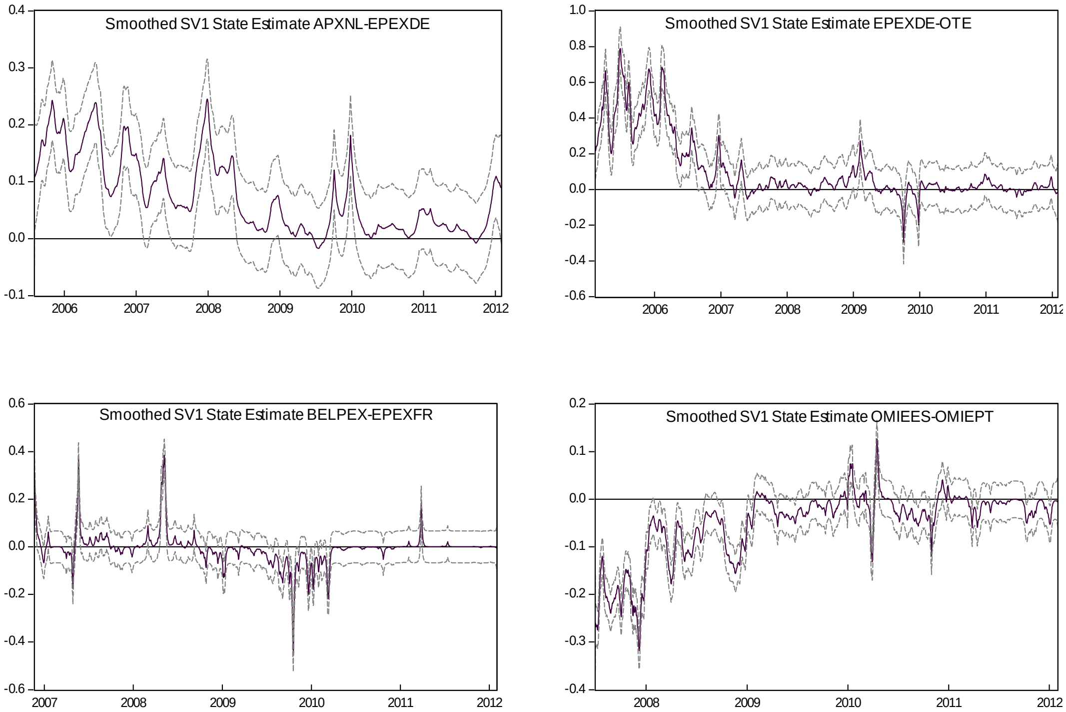

Figure 4.2: Smoothed convergence indicators for selected European electricity markets pairs displaying clear evidence of ongoing convergence. Black line smoothed indicator, grey lines ± 2 RMSE.

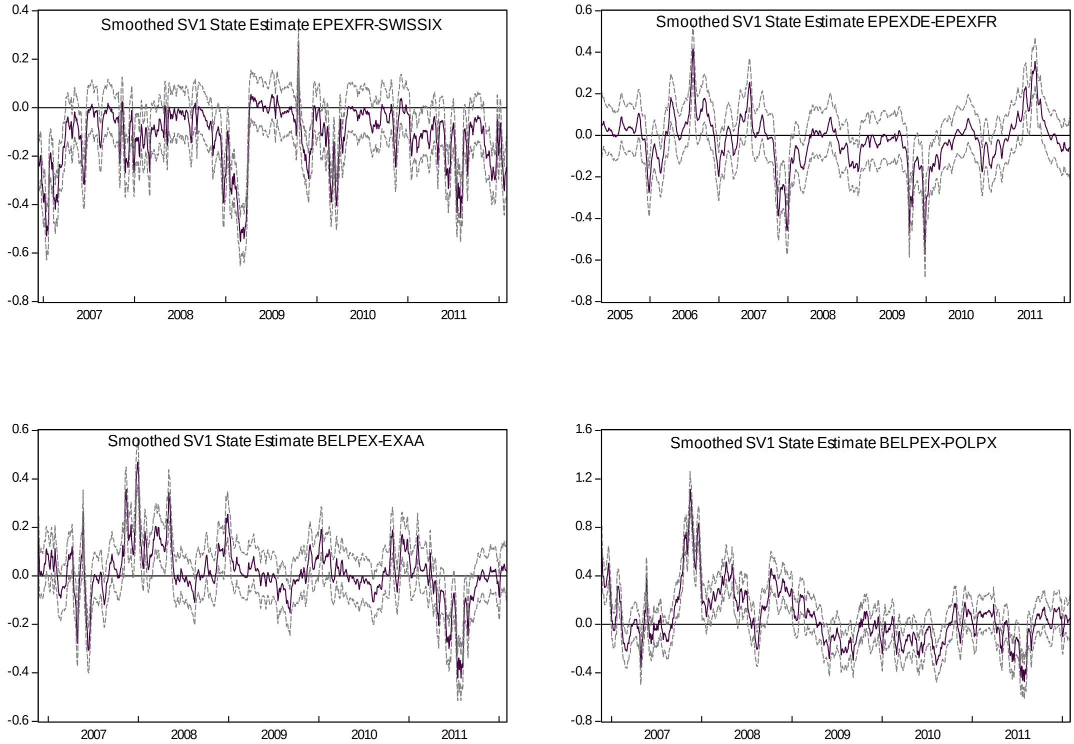

Figure 4.3: Smoothed convergence indicators for selected European electricity market pairs displaying mixed evidence of convergence. Black line smoothed indicator, grey lines ± 2 RMSE.

The third group of market pairs, reported in Figure 4.4, displays a mixed evidence of convergence featuring a seasonal pattern. This is a Swiss phenomenon, since it involves the pairs EXAA-SWISSIX, EPEXDE-SWISSIX, APXNL-SWISSIX and OTE-SWISSIX. Electricity demand is at its highest in Switzerland during the winter months while, the level of hydro reservoirs is at its lowest. Consequently the average price is higher than prices of many EU electricity markets (around 63 €/MWh). By contrast in spring and summer the country enjoys an oversupply of cheap hydroelectricity, which pushes the wholesale electricity price down to an average price of around 47 €/MWh and results in the Swiss price convergence with other European electricity markets.

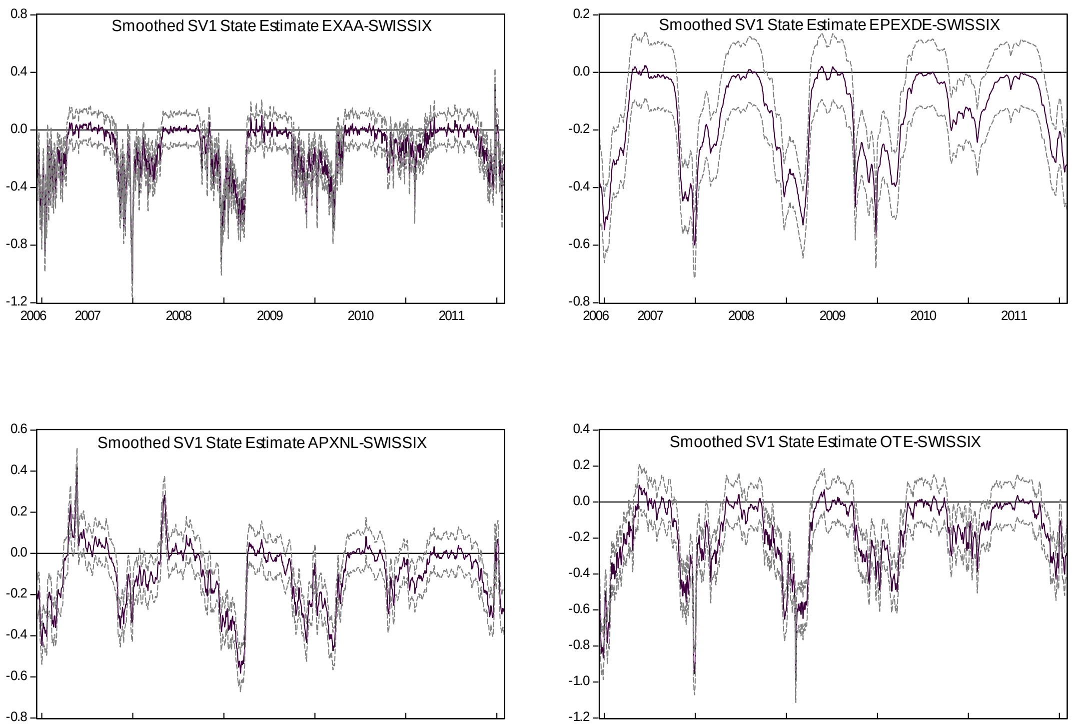

Figure 4.4: Smoothed convergence indicators for selected European electricity market pairs displaying evidence of seasonal convergence. Black line smoothed indicator, grey lines ± 2 RMSE.

Four representative pairs (of the 64 market pairs) that do not show any evidence of convergence are presented in Figure 4.5. An analysis of these pairs, reveals that the Greek market (HTSO), the Italian market (IPEX) and the Irish market (SEM) do not converge to any other market in our sample; while NORDPOOL converges only to Czech market OTE.

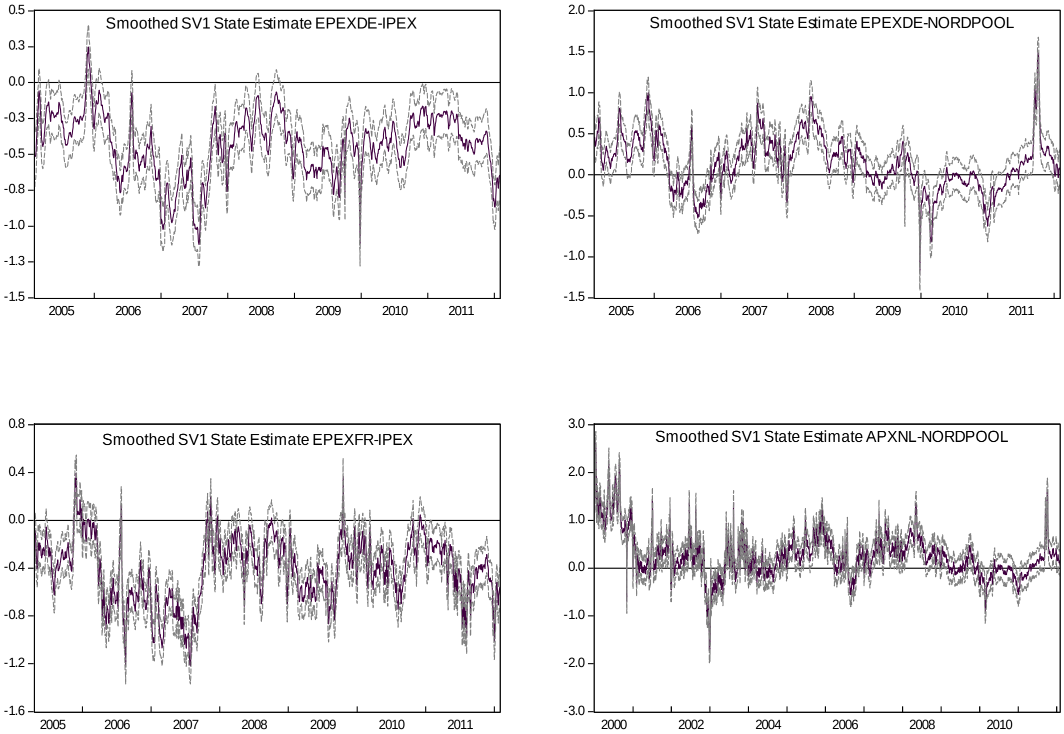

Figure 4.5: Smoothed convergence indicators for selected European electricity market pairs displaying no evidence of convergence. Black line smoothed indicator, grey lines ± 2 RMSE.

This result is not surprising given that SEM and HTSO are isolated from the major markets of continental Europe, and given that the Nordic market, though well interconnected with Germany, has a predominance of hydropower plants in the production mix making it the least expensive power exchange in Europe. The Italian market, although geographically near to the central European markets of France, Switzerland and Austria, does not exhibit evidence of convergence to other markets because its production mix is biased towards fossil fuel plants. It is natural gas plants which turn out to be the marginal plant much more frequently than in other countries[74].

[74] In 2011 combined cycle gas turbine technology was the marginal plant for about 65% of the time.

4.4.3 Returns volatility transmission between European electricity markets

Another method of assessing market integration consists of analysing the returns volatility transmission across markets. This can be done by estimating MGARCH models. The decision to model returns volatility rather than price volatility is based on the non-stationarity feature of the price series. As convergence has been shown to be a regional phenomenon, the estimate of MGARCH models for volatility transmission is carried out on markets in the same geographical area. Therefore, the 15 markets are grouped into three areas: North-Western Europe, including Ireland, the UK, the Netherlands, Belgium, France, Germany and Scandinavia; Central-Southern Europe, including Germany, France, Spain, Portugal, Italy, Switzerland, Austria and Greece; Central-Eastern Europe, including Austria, Czech Republic, Germany and Poland.

As a first step, univariate GARCH (1,1) and EGARCH(1,1)[75] are estimated for each electricity market[76].

The GARCH (1,1), introduced by Bollerslev (1986), specifies the conditional variance of ε_t as an ARMA(1,1) process:

$$h_t = \alpha_0 + \alpha_1 \varepsilon_{t-1}^2 + \beta_1 h_{t-1} \tag{4.4}$$

where h_t is the conditional variance of the error term ε_t , α_1 measures the impact on current volatility of shocks occurring in the previous period and β_1 measures previous period's volatility impact on current volatility.

An EGARCH (1,1) model, originally proposed by Nelson (1991), allows shocks to the price series to have an asymmetric impact on volatility, as defined by the following specification:

$$\ln(h_t) = \alpha_0 + \alpha_1 (\varepsilon_{t-1}/h_{t-1}^{0.5}) + \lambda_1 \left|\varepsilon_{t-1}/h_{t-1}^{0.5}\right| + \beta_1 \ln(h_{t-1}) \tag{4.5}$$

[75] Among the several GARCH models these two have been selected because they are the most used to describe the conditional variance of electricity prices in the literature, see among others Escribano et al. (2002), Knittel and Roberts (2005) and Higgs (2009).
[76] The results are reported in in Appendix B.

If the standardised shock in the previous period $\varepsilon_{t-1}/h_{t-1}^{0.5}$ is positive, the impact of the shock on the log of conditional variance is given by $\alpha_1 + \lambda_1$. If $\varepsilon_{t-1}/h_{t-1}^{0.5}$ is negative the impact of a shock on the conditional variance is $-\alpha_1 + \lambda_1$.

A comparison of the Akaike Information Criterion (AIC) and the Schwartz Bayesian Criterion (SBC), statistics of each estimation reveals that the EGARCH (1,1) models fit the data best. Therefore, the conditional variances from the univariate EGARCH (1,1) are used to calculate the conditional correlation matrices for constant conditional correlations (CCC) and dynamic conditional correlations (DCC) models. The CCC model of Bollerslev (1990) is defined as:

$$H_t = D_t R D_t = \left(\rho_{ij}\sqrt{h_{iit}h_{jjt}}\right) \tag{4.6}$$

where,

$$D_t = diag\left(h_{11t}^{0.5} \dots h_{NNt}^{0.5}\right) \tag{4.7}$$

and h_{iit} is, in this case, a univariate EGARCH (1,1) model while $R = \left(\rho_{ij}\right)$ is a symmetric positive definite matrix, containing the constant conditional correlations ρ_{ij}.

The assumption of constant conditional correlations is then checked via the tests proposed by Tse (2000) and by Engle and Sheppard (2001). Table 4.7 reports the results of these tests. The null hypothesis of constant correlations is rejected for all the correlations considered.

	North-Western Europe	*Central-South Europe*	*Central-Eastern Europe*
LMC Tse (2000)	262.073 (0.000)	357.171 (0.000)	170.557 (0.000)
Engle and Sheppard (2001) test (5)	498.567 (0.000)	161.184 (0.000)	40.5650 (0.000)
Engle and Sheppard (2001) test (10)	883.196 (0.000)	240.079 (0.000)	136.914 (0.000)

P-value in parenthesis. LMC~$X^2(N*(N-1)/2)$ under H_0: CCC model, with N= number of series
P-values in parenthesis. E-S Test(j)~$X^2(j+1)$ under H_0: CCC model

Table 4.7: Constant conditional correlations tests. Estimations are carried out with G@RCH 6.

The DCC model of Engle (2002) is specified as follows:

$$H_t = D_t R_t D_t \tag{4.8}$$

where D_t is the same as in equation (4.7), while R_t

$$R_t = diag\left(q_{11t}^{-0.5} \dots q_{NNt}^{-0.5}\right) Q_t \, diag\left(q_{11t}^{-0.5} \dots q_{NNt}^{-0.5}\right) \tag{4.9}$$

where Q_t is a NxN symmetric positive definite matrix $Q_t = (q_{ijt})$ given by:

$$Q_t = (1 - \alpha - \beta)\bar{Q} + \alpha u_{t-1} u'_{t-1} + \beta Q_{t-1} \tag{4.10}$$

where $u_t = (u_{1t}\, u_{2t} \dots u_{Nt})'$ and the elements $u_{it} = \varepsilon_{it} / \sqrt{h_{iit}}$. $\bar{Q}$ is the NxN unconditional variance matrix of standardised residuals u_t and α and β are non-negative scalar parameters satisfying α+β<1. Given that electricity prices were found to be leptokurtic, returns are assumed to be distributed according to the Student *t* distribution.

The estimations of the DCC models indicate the presence of significant and positive volatility spillovers across Europe, since the estimated correlations are all positive and significant at 1% level. Table 4.8 reports some descriptive statistics of the estimated DCC, while Figures 4.6-4.8 show the respective plots.

North-Western Europe	Mean	Maximum	Minimum	Std. Dev.
EPEXFR-BELPEX	0.971	0.994	0.496	0.048
APXNL-BELPEX	0.917	0.992	0.530	0.047
APXNL-EPEXFR	0.893	0.954	0.415	0.063
APXNL-EPEXDE	0.807	0.913	0.285	0.067
EPEXDE-BELPEX	0.795	0.901	0.258	0.063
EPEXFR-EPEXDE	0.788	0.888	0.272	0.062
APXNL-NORDPOOL	0.665	0.845	-0.003	0.064
EPEXDE-NORDPOOL	0.659	0.860	-0.264	0.071
NORDPOOL-BELPEX	0.655	0.832	0.027	0.068
EPEXFR-NORDPOOL	0.631	0.820	0.143	0.066
APXUK-BELPEX	0.380	0.686	-0.206	0.081
APXUK-APXNL	0.375	0.674	-0.098	0.080
APXUK-EPEXFR	0.360	0.717	-0.383	0.083
APXUK-NORDPOOL	0.340	0.684	-0.138	0.075
APXUK-EPEXDE	0.335	0.595	-0.086	0.073
NORDPOOL-SEM	0.234	0.638	-0.041	0.078
APXNL-SEM	0.230	0.616	-0.134	0.081
BELPEX-SEM	0.221	0.601	-0.158	0.082
APXUK-SEM	0.211	0.695	-0.148	0.087
EPEXFR-SEM	0.200	0.552	-0.189	0.079
EPEXDE-SEM	0.191	0.554	-0.289	0.082
Central-Southern Europe	*Mean*	*Maximum*	*Minimum*	*Std. Dev.*
EXAA-SWISSIX	0.854	0.986	0.448	0.131
OMIEES-OMIEPT	0.809	0.963	0.439	0.113
EXAA-EPEXFR	0.800	0.918	0.473	0.088
EXAA-EPEXDE	0.775	0.885	0.405	0.070
EPEXFR-SWISSIX	0.771	0.927	0.444	0.109
EPEXFR-EPEXDE	0.742	0.884	0.392	0.085
EPEXDE-SWISSIX	0.701	0.873	0.349	0.111
EXAA-IPEX	0.465	0.759	0.082	0.119
IPEX-SWISSIX	0.439	0.758	-0.081	0.135
EPEXFR-IPEX	0.421	0.758	-0.051	0.128
SWISSIX-OMIEPT	0.401	0.602	-0.083	0.099
EXAA-OMIEPT	0.398	0.583	0.046	0.095
EPEXDE-IPEX	0.397	0.727	-0.057	0.130
EPEXFR-OMIEPT	0.384	0.591	-0.044	0.102
OMIEES-SWISSIX	0.374	0.579	-0.050	0.094
EXAA-HTSO	0.372	0.623	0.014	0.090
EXAA-OMIEES	0.366	0.638	0.090	0.095
HTSO-SWISSIX	0.364	0.613	-0.044	0.096
EPEXFR-OMIEES	0.360	0.719	0.052	0.105
EPEXFR-HTSO	0.348	0.588	0.032	0.094
IPEX-HTSO	0.328	0.565	-0.004	0.101
EPEXDE-OMIEPT	0.320	0.539	0.005	0.093
EPEXDE-HTSO	0.309	0.534	0.018	0.083
EPEXDE-OMIEES	0.291	0.499	-0.025	0.088
OMIEES-IPEX	0.276	0.536	-0.029	0.104
IPEX-OMIEPT	0.275	0.629	-0.127	0.116
HTSO-OMIEPT	0.248	0.521	-0.118	0.095
OMIEES-HTSO	0.244	0.502	-0.200	0.105
Central-Eastern Europe	*Mean*	*Maximum*	*Minimum*	*Std. Dev.*
EXAA-EPEXDE	0.769	0.885	0.405	0.074
EXAA-OTE	0.737	0.907	0.289	0.146
EPEXDE-OTE	0.633	0.846	0.209	0.143
EXAA-POLPX	0.537	0.797	0.138	0.126
POLPX-OTE	0.491	0.764	0.136	0.142
EPEXDE-POLPX	0.469	0.711	0.141	0.097

Table 4.8: Descriptive statistics of DCC between returns of electricity prices of North-Western Europe, Central-Southern Europe and Central-Eastern Europe. Estimates of DCC are performed with G@RCH 6.

In the North-Western area, APEXNL-BELPEX, APEXNL-EPEXDE, APEXNL-EPEXFR, EPEXDE-BELPEX, EPEXFR-BELPEX, EPEXFR-EPEXDE exhibit strong returns volatility spillovers. In this case, correlations are on average equal to or larger than 0.8, with corresponding standard deviations ranging from 0.047 to 0.067. The correlations between SEM (Ireland) and all the other markets are the weakest, always smaller than 0.3, while exhibiting standard deviations around 0.08. Volatility spillovers between APXUK and the continental markets are rather modest, since correlations average around 0.35, with the standard deviations being about 0.08. NORPOOL displays an intermediate level of correlation with other European continental markets (on average around 0.65, with standard deviations around 0.07). These results suggest that within the markets of the North-Western region the best interconnected markets (i.e. those of continental Europe) are also the most integrated, while geographically peripheral markets exhibit limited integration with the core of Europe.

In Central-Southern Europe, the pairs EPEXDE-SWISSIX, EPEXFR-EPEXDE, EPEXFR-SWISSIX, EXAA-EPEXDE, EXAA-EPEXFR, EXAA-SWISSIX and OMIEES-OMIEPT feature the strongest correlations (on average above 0.7, with standard deviations ranging from 0.07 to 0.13). Moreover, there is a clear seasonal pattern, with high correlations in spring, summer and in the first part of autumn, and low correlations in winter, between EPEXFR and SWISSIX and between EXAA and SWISSIX, as depicted in Figure 4.7. Volatility spillovers between the Greek market HTSO, the Spanish OMIEES, the Portuguese OMIEPT and the rest of Central-Southern Europe, are rather weak, with correlations always below 0.4, with standard deviations ranging between 0.08 and 0.13. IPEX shows slightly stronger correlations with those countries to which it is directly interconnected (around 0.4), namely France, Austria, Switzerland and Greece, than with Spain and Portugal that are geographically distant. These results confirm that even for Central-Southern Europe the best interconnected markets are the most integrated. Moreover, standard deviations are more similar across the pairs of Central-Southern countries than across North-Western countries, ranging between 0.070 of EXAA-EPEXDE to 0.135 of IPEX-SWISSIX, and also higher than those of the North-Western area. In particular, it emerges that the correlations of market pairs including Italy (EPEXDE-IPEX, EPEXFR-IPEX, IPEX-SWISSIX) are particularly volatile, since standard deviations are around 0.13.

In Central-Eastern Europe, EXAA-EPEXDE and EXAA-OTE feature strong volatility spillovers, with correlations above 0.70, which in the case of EXAA-OTE also display a high standard deviation of 0.146. EPEXDE-OTE, EPEXDE-POLPX and POLPX-OTE show an intermediate level of correlations, between 0.47 and 0.63, with an average standard deviation of 0.13. Moreover, the correlations between EPEXDE-OTE and EXAA-OTE show an upward trend in their behaviour (see Figure 4.8). As for Central-Western and Central-Southern Europe, here again the level of interconnectivity and geographical proximity play the most important role in explaining volatility spillovers across markets.

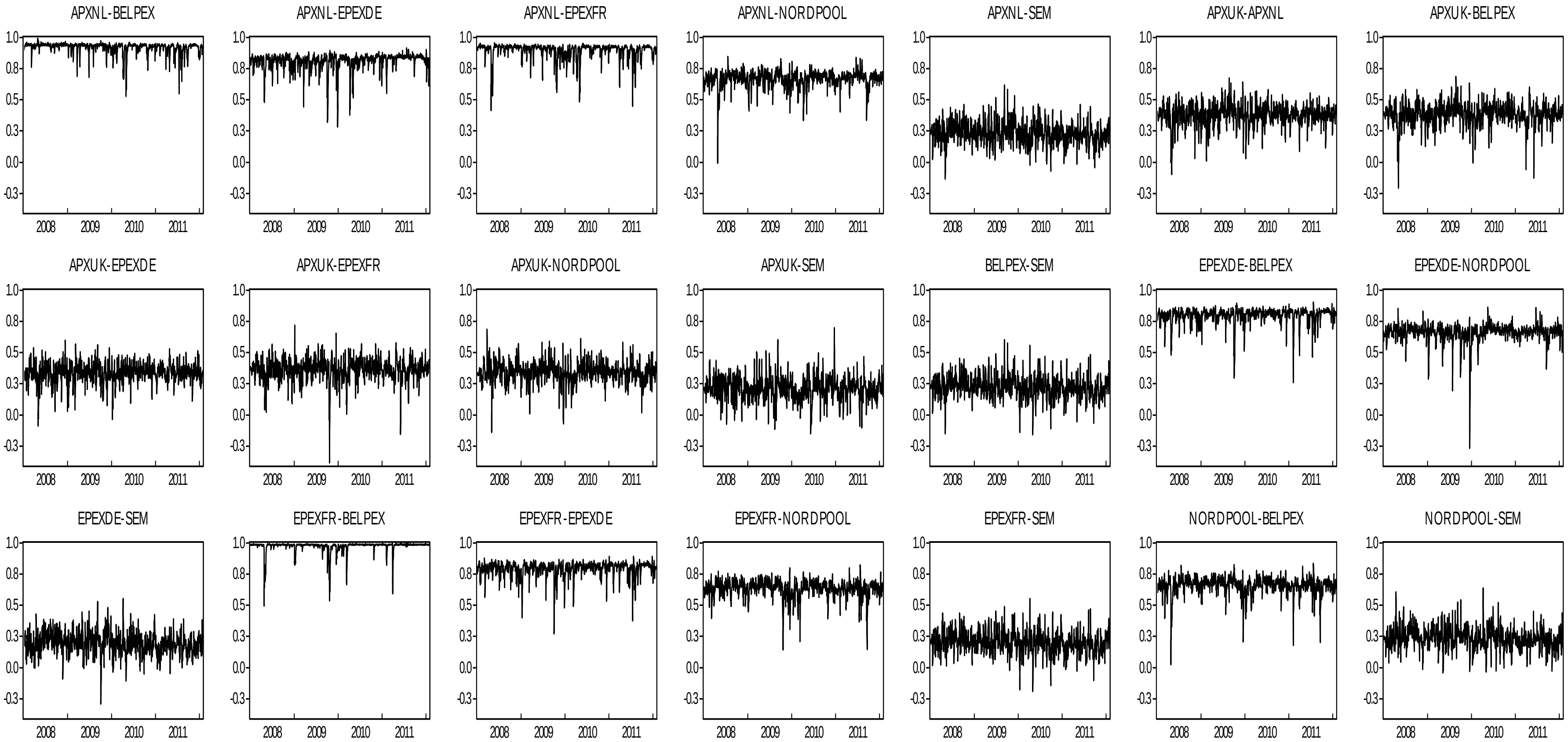

Figure 4.6: DCC between returns of electricity prices of North-Western Europe 2008-2011. Estimations of DCC are performed with G@RCH 6.

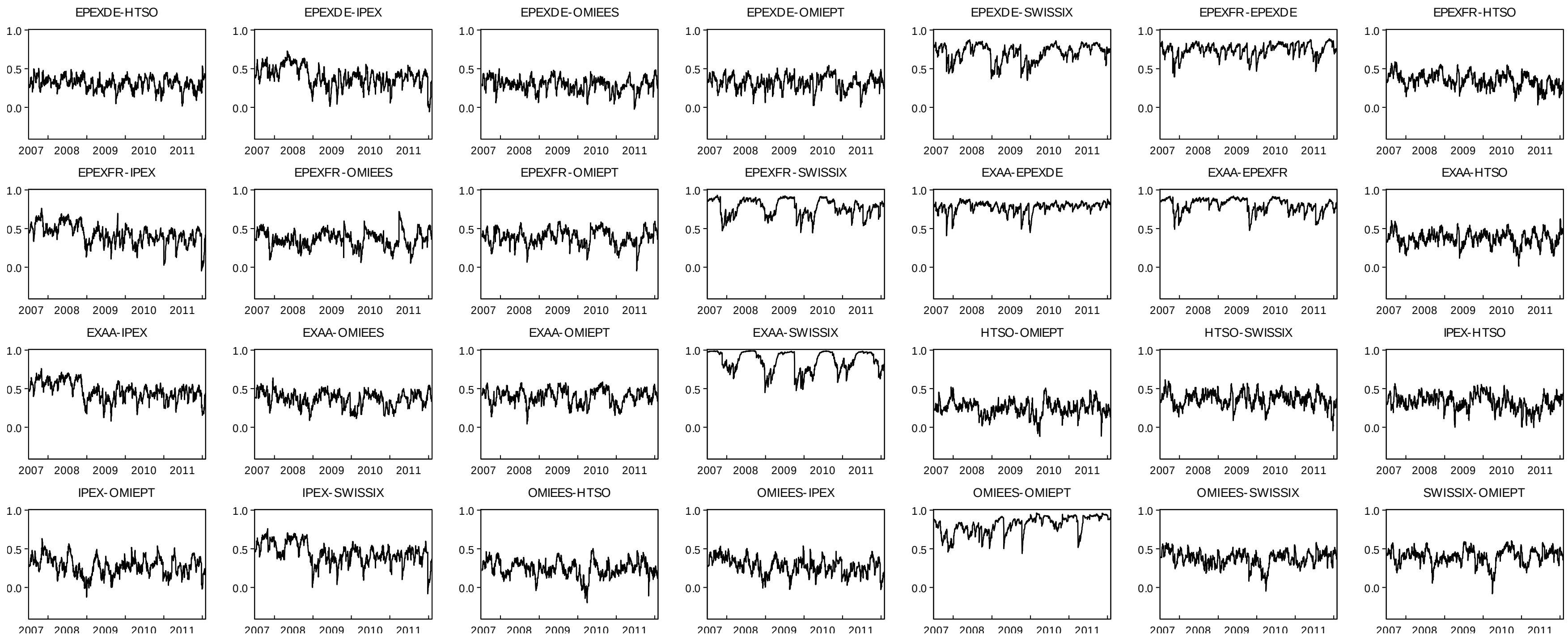

Figure 4.7: DCC between returns of electricity prices of Central-Southern Europe 2007-2011. Estimations of DCC are performed with G@RCH 6

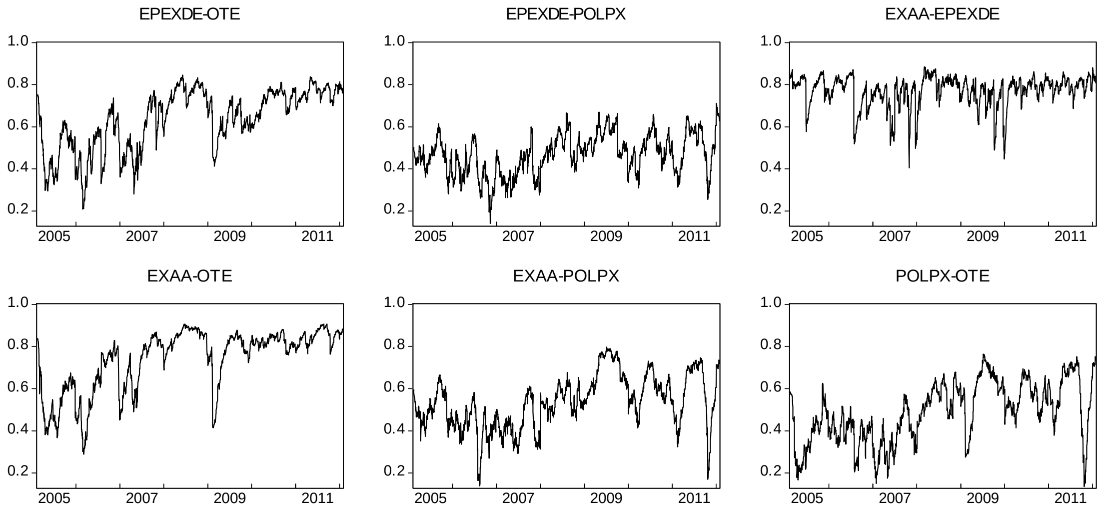

Figure 4.8: DCC between returns of electricity prices of Central-Eastern Europe 2005 - 2011. Estimations of DCC are performed with G@RCH 6.

4.5 Conclusions

This chapter provides a comprehensive investigation of market integration between European electricity markets. The spot market prices generated by the power exchanges of Austria, Belgium, Czech Republic, France, Germany, Greece, Ireland, Italy, Poland, Portugal, Scandinavia, Spain, Switzerland, the Netherlands and the UK are used to test for market integration. Fractional cointegration analysis reveals that only a limited number of markets were perfectly integration by the end of January 2012 and consequently full Europe wide market integration is still a way off. However, evidence of convergence was found in 41 of the 105 market pairs (39% of market pairs tested), almost all belonging to countries at the geographical core of continental Europe. The remaining 64 market pairs (about 61%) showed no sign of market convergence. In particular, the peripheral electricity markets of Greece, Ireland, Italy and Scandinavia showed little evidence of convergence to other markets. The major determinants of this lack of convergence seems to be attributable to both the geographical distance from continental European markets, for Greece and Ireland, and the composition of the national electricity portfolio mixes, especially for Italy and Scandinavia.

Positive and significant DCC estimates suggest the presence of volatility spillovers across regional markets, including North-Western Europe, Central-Southern Europe and Central-Eastern Europe. Analysis of returns volatility spillovers confirmed that the level of interconnectivity and geographical proximity play the most important role in explaining volatility transmissions across regional markets and hence market integration.

Overall, the findings highlight that the policy measures undertaken by the European Commission have only been partially successful in delivering the internal electricity market. This is in line with the conclusions of previous studies on European electricity market integration. Zachmann (2008), analysing hourly price series from 2002 to 2006, shows that a fully integrated market had not been achieved by mid-2006, though some market pairs did exhibit an increasing price convergence over time. In particular, as in this study, market pairs such as Spain–France and Germany–the Netherlands experienced a substantial price convergence, while for other market pairs including Poland–Czech Republic, Germany–Czech Republic, Germany–Poland and Germany–Denmark convergence only occurred in some (off-peak) hours of the day. The results presented here also concur with the findings of Bosco et al. (2010), who show that the European electricity market is not yet fully integrated. Like Bosco et al. (2010) the results presented here show that markets at the core of continental Europe, in particular the French and German markets, are strongly integrated, while more peripheral markets such as the Spanish and the Nordic markets are prevented from a complete integration with the major continental markets. Nitsche et al. (2010) also find geographical proximity to be key for market integration[77] as do Nepal and Jamasb (2011), who find a poor level of convergence between the Irish and other European markets, due to the limited interconnection capacity between Ireland and the continent.

Given these results, the most important challenges ahead include the complete diffusion of market coupling to manage cross-border congestion efficiently, and more effective oversight

[77] The German market and those of Austria, France and the Netherlands are found to form an integrated market.

by energy regulators so as to increase competition, particularly in poorly interconnected markets. Over a longer time horizon, the European Commission must ensure investment in new interconnection capacity is undertaken so as to eliminate bottlenecks that prevent price convergence and, more importantly, to reach the 2020 and 2050 targets of delivering a secure and sustainable electricity supply to all European consumers.

It must be stresses, however, that a fully integrated electricity market could not be sufficient to achieve the long-term sustainability objective, if European citizens do not modify their electricity consumption behaviour. It is therefore crucial for EU energy policy makers to have an accurate model of the determinants of electricity demand to evaluate which tools are best employed to induce electricity conservation. Chapter 5 proposes a novel econometric approach to estimate the determinants of residential electricity demands for nine major European countries.

5 Modelling residential electricity demand in Europe with Autometrics™♠

5.1 Introduction

Building a fully integrated European electricity market is crucial to move to a low carbon economy by 2050. Curbing residential electricity demand would contribute to reaching the 2020 and 2050 emissions reduction targets, given that, in 2010, CO_2 emissions[78] from electricity generation were about the 32% of total emissions of the EU-27 area (IEA, 2012) and that residential consumption accounted for about the 30% of total final electricity consumption (Eurostat, 2013).

EU policy makers can encourage energy conservation by employing alternative tools including energy taxes, mandatory energy efficiency standards for new appliances, incentive schemes for substituting old and inefficient electrical equipment, advertising campaigns to promote environmentally friendly behaviours and demand side management. Energy taxes can be seen as the most direct option to pursue, however their effectiveness of curbing consumption can be limited if electricity demand turns out to be very price inelastic. Legislation to impose energy efficiency standards for household appliances may deliver important energy savings[79], though it must be recognised that the positive results of the diffusion of more efficient appliances could be offset or even more than offset by a change in households' tastes towards a more electricity-intensive lifestyle, the so-called rebound effect (Khazzoom, 1980). Therefore, together with the introduction of new efficiency standards, it is important to educate and draw people's attention to environmental issues and to

♠ The results in this chapter are presented in a paper which is under review at *The Energy Journal*. The paper was presented at the 2nd International PhD-Day and 14th YEEES Seminar (21st -22nd March 2013, Vienna Institute of Technology, Austria), at the International Conference "Econometrics, Energy and Finance" (8th April 2013, Cass Business School, London) and at the 13th IAEE European Energy Conference (18th-21st August 2013, Dusseldorf, Germany), where it received a Best Student Paper Award.

78 In 2010, CO_2 emissions represented about the 81% of total greenhouse gas emissions (IEA, 2012).

79 In recent years, the EU Commission has enacted ad-hoc legislation, such as Directive 2009/125/EC and Directive 2010/30/EC to introduce the eco-design efficiency standards and energy labels.

implement demand side management (DSM). DSM refers to all the actions and technologies that enable consumers to monitor their electricity usage in real-time and that help utilities to ensure an even supply of electricity (Eurelectric, 2011). Among these technologies, smart meters[80] and smart grids[81] are the key instruments of DSM that the European Union has introduced (Directive 2009/72/EC) to ensure the transition to a low-carbon economy.

An accurate model of the determinants of residential electricity demand for European countries would allow understanding the degree of similarities of consumption behaviour across European households and hence could correctly inform EU policy makers as to which tools are best employed to achieve a reduction in households' electricity demand. Over the past two decades, several studies have applied different econometric techniques, in particular cointegration analysis and structural time-series modelling (STSM), to estimate a stable relationship between residential electricity demand and its determinants. These typically include: household income, electricity price, price of substitute goods (e.g. natural gas, fuel oil), price of complement goods (i.e. appliances), climate, technical progress (i.e. improvements in the energy efficiency of the appliances), and consumers' preferences (encompassing socio-demographic and economic characteristics of the population). However, difficulties in quantifying some of the potential explanatory variables has led the majority of scholars to employ only a reduced number of factors (i.e. income, electricity price, substitute good's price and climate variable) when estimating residential electricity demand; while technical progress and consumers' preferences have been either ignored or proxied via a linear time trend or proxied via a non-linear stochastic trend within the STSM framework.

Ignoring or incorrectly modelling these factors results in inconsistent estimates of long-run income and price elasticities, which means providing policy makers with unreliable tools for

[80] A smart meter is an electricity meter that enables consumers to control and manage their individual consumption in real-time. The information recorded by the smart meter is instantaneously transmitted to the grid operator, who can plan the use of infrastructure and balance the system (EC, 2011b).
[81] A smart grid is defined as an upgraded electricity network to which two-way digital communication between supplier and consumer, intelligent metering and monitoring systems have been added (EC, 2011b).

conducting policy simulations (see for instance Beenstock and Willcocks (1981), Kouris (1983), Welsch (1989), Jones (1994), Hunt et al. (2000, 2003a,b), Hunt and Ninomiya (2003), Dimitropoulos et al. (2005), Griffin and Schulman (2005), Sa'ad (2009), Adeyemi et al. (2010), Broadstock and Hunt (2010), and Dilaver and Hunt (2011a,b,c). Moreover, incorrect modelling of these factors could lead to incorrect rejection of a meaningful cointegration relationship between residential electricity demand and its determinants.

This chapter proposes a novel econometric approach to correctly model all the relevant variables that may influence residential electricity demand and it is applied to estimate residential electricity demand for nine European countries, namely Austria, Belgium, France, Germany, Italy, Spain, Switzerland, the Netherlands and the UK, using annual data for the period 1978-2009. These countries' electricity sectors accounted for about 67% of total CO_2 emissions due to electricity generation in the area comprising EU-27 and Switzerland in 2010 (IEA, 2012). The methodological approach is to specify a general unrestricted error correction mechanism (ECM) featuring Impulse Indicator Saturation (IIS) (Hendry, 1999; Hendry et al., 2008; Johansen and Nielsen, 2009; and Castle et al., 2012) and its related extensions (Ericsson, 2011, 2012, 2013; Bergamelli and Urga, 2013) to estimate the cointegrating relationship between electricity demand, gross domestic product (GDP), electricity price, and all other potential factors that are difficult to measure but that have to be accounted for to get consistent estimates of the long-run price and income elasticities. The models are estimated with the search algorithm *Autometrics™*. This potentially provides more accurate estimation than techniques previously employed in the literature as it is based on the theory of cointegration and its dynamic error correction representation counterpart, which guarantees the correct specification of long-run equilibrium and short-run dynamics. In addition, the approach has the appealing advantage of giving an insight as to the location and the potential determinants of the change in the electricity demand trend and the estimated relationship is stable.

The remainder of this chapter is organized as follows. Section 5.2 reviews the economic literature on electricity demand modelling. Section 5.3 presents the dataset employed in the analysis and Section 5.4 describes the robust unit root analysis performed. The methodology used to model electricity demands in Europe is reported in Section 5.5, while estimation results are presented in Section 5.6. Section 5.7 concludes.

5.2 Literature review

According to the neoclassical household production theory, electricity can be seen as an input together with electricity-using capital stock into the production of services, such as lighting, cooling, heating and cooking that generate some utility to the consumer[82]. Therefore, the demand of electricity is derived demand, as it comes from the consumer's optimal choice of a certain service.

Residential electricity consumption is ultimately a function of household income, electricity price, price of substitute goods (i.e. natural gas or fuel oil), price of complement goods (i.e. appliances), energy efficiency of the appliances, climate, environmental regulations and other economic, social and demographic factors that may define consumers' preferences (e.g. age of the population, size of the household, size of the dwelling, degree of urbanization). In the short run, capital stock size and technology are fixed, hence the consumer can respond to changes in variables such as electricity price, income and climate only by adjusting the capital utilisation rate. In the long run, the consumer can fully adjust to changes in electricity price and/or income by varying the stock of appliances.

One of the most problematic aspects when estimating electricity demand functions is how to account for the impact of technical progress of capital equipment, as this is a non-observable factor. Early research on the broader topic of modelling aggregate energy demand has pointed out that improved technical efficiency can be induced by sustained price rises, but

[82] For a description of the neoclassical household production theory see for instance Becker (1965) and Muth (1966). Theoretical models formulated for electricity are presented in Flaig (1990) and in Filippini (1999).

also by other exogenous factors including environmental regulations, mandatory energy efficiency standards, substitution of labour, capital or raw materials inputs for energy inputs and changes in consumers' preferences towards less energy intensive goods and services (Kouris, 1983 and Jones, 1994). In addition, Jones (1994) stresses that the effect of price induced technical progress has to be distinguished from the long-term adjustment to price increases that consumers make as they replace their appliances stock. The price-driven technical progress determines in the long-run a shift to the left of the energy demand curve, while the normal long-term adjustment to price increases only implies that the long-run energy demand curve is flatter (i.e. more price elastic) than its short-run counterpart. Hunt et al. (2000) further argue that improvement in technical efficiency may even be induced by increases in income, and therefore that the technical progress effect has to be distinguished also from the long-run income effect.

Irrespective of which factors drive technical progress, it is important not to ignore it and to attempt to model it correctly in order to avoid bias in the elasticities estimation and hence getting policy wrong. However, only a few papers in the electricity demand literature have considered this as an important model specification issue. Focusing on aggregate energy demand, Beenstock and Willcocks (1981), Welsch (1989), Jones (1994), De Vita et al. (2006) include a linear time trend as a proxy for technical progress, while Kouris (1983) criticises this approach arguing that a poor approximation, such as a linear trend, could still result in biased elasticities estimates. Hunt et al. (2000, 2003a, b), Hunt and Ninomiya (2003), Dimitropoulos et al. (2005), Sa'ad (2009), Adeyemi et al. (2010), Broadstock and Hunt (2010), Dilaver and Hunt (2011a,b,c) attempt to address this issue by using STSM of Harvey (1989)[83]. This approach allows the specification of a dynamic behavioural model of electricity (and/or energy) demand, in particular an ARDL model, which also includes a latent variable (i.e. a non-linear stochastic trend) to proxy for technical progress and other

[83] Hunt et al. (2000, 2003a, b), Dimitropoulos et al. (2005) and Adeyemi et al. (2010) focus on energy demand; while Hunt and Ninomiya (2003) and Broadstock and Hunt (2010) consider transport oil demand. Sa'ad (2009) refers to residential electricity demand. Dilaver and Hunt (2011a,b,c) study industrial, residential and aggregate electricity demand, respectively.

exogenous and non-observable factors such as consumers' preferences, encompassing family size and structure, gender, work status, age and density of the population, changes in urbanization (Hunt and Ninomiya, 2003, p.65) and economic structure[84]. The use of a specification including a non-linear stochastic trend has the advantage of allowing consumers' preferences and economic structure to change over time in directions that may be opposite to that of technical progress. At the same time, however, neglecting the role of cointegration theory in modelling economic relationships and just testing down an over-parameterised ARDL model on the basis of statistical fit, may result in a selected specification that does not include the correct dynamic effect. This is what happens in Ditropoulos et al. (2005), Broadstock and Hunt (2010) and Dilaver and Hunt (2011a,c). A final alternative is that used by Blázquez et al. (2013), who employ a series of time dummy variables, which in a panel framework play a similar role to the non-linear stochastic trend in the STSM approach.

A large part of the literature has paid little attention to the modelling of technical progress and other exogenous factors, mainly focusing on measuring the impact of income, electricity price, substitute goods prices and climate on short- ad long-run electricity consumption. Among the earliest studies of residential electricity demand, Fisher and Kaysen (1962) are the first to distinguish explicitly between short-run demand and long-run demand of electricity, using time-series aggregate data for the period 1946-1957 for 47 US states. In particular, the authors estimate for each of the 47 states a two-stage model, where in the short-run electricity consumption is a function of electricity price and income; while for the long run they explain the growth rate of appliances stock with income, price of appliances, price of gas-using substitute, price of electricity, price of gas, number of wired households and number of marriages.

[84] Hunt et al. (2003a) introduce the concept of Underling Energy Demand Trend (UEDT) to model the impact of technical progress, consumers' preferences and economic structure.

Severe data limitations for the stock of appliances have led the subsequent research to abandon the two-stage approach in favour of dynamic modelling to capture the effect that, in the short run, actual electricity consumption can differ from the desired equilibrium level because it requires a change in the capital stock. The first class of dynamic models, mainly used in the 1970's and in the 1980's, is that of the partial adjustment specification. Houthakker and Taylor (1970) are among the first to estimate residential electricity demand via a partial adjustment model (also known as flow-adjustment model) using aggregate data of the US between 1947 and 1964. In this model, current consumption of electricity is explained by its past value, total consumption expenditure and price of electricity. Houthakker et al. (1974) use the same flow-adjustment model as in Houthakker and Taylor (1970), modifying the analysis by pooling time-series of annual aggregate data for 48 individual US states from 1960 to 1971 using an error component technique.

Sutherland (1983) measures the adjustment of electricity consumption to changes in electricity price, income and price of natural gas for the US fitting three alternative distributed lag specifications (Almon polynomial model, partial adjustment model and unconstrained distributed lag model). The models are estimated using aggregate data of 48 states pooled over the period 1961-1980, and for two sub-periods 1961-1973 and 1974-1980 to test the stability of the electricity demand function before and after the 1973 oil embargo. Chern and Bouis (1988) also employ a partial adjustment model to explain US residential electricity consumption, using aggregate data from 1955-1978 for 48 individual US states. As regressors the authors include electricity price, income, number of residential customers, household size, heating and cooling degree days and natural gas price. The model is estimated via OLS with 47 dummies, both over the whole sample period and over 15 windows of ten-year intervals each, to test for structural changes in the demand function.

Error correction models represent an alternative and novel class of dynamic models that have gained a large popularity for estimating residential electricity demand since the introduction of the theory of cointegration (Engle and Granger, 1987; Johansen, 1988). Silk and Joutz (1997) estimate US residential consumption with the multivariate approach to cointegration of Johansen (1988), using aggregate data over the period 1949-1993. Residential electricity consumption is regressed on income, electricity price, fuel oil price, cooling and heating degree days interacted with cooling and heating stock of appliances indices, and mortgage interest rate. Similarly, Holtedahl and Joutz (2004), Hondroyiannis (2004) and Jamil and Ahmad (2011) employ the Johansen multivariate approach to estimate Taiwan's, Greece's and Pakistan's residential electricity demand, respectively[85]. Beenstock et al. (1999) estimate residential electricity demand for Israel with aggregate data for the period 1973-1994 comparing the dynamic regression model, the two-step Engle and Granger procedure (Engle and Granger, 1987) and the Johansen multivariate approach. The regressors employed are consumer spending, electricity price, cooling and heating degree days. Narayan and Smyth (2005), Halicioglu (2007) and Dergiades and Tsoulfideis (2008) adopt the ARDL bounds testing approach to cointegration developed by Pesaran and Shin (1999) and Pesaran et al. (2001), to model residential electricity demand for Australia, Turkey and the US, respectively[86].

Among the studies that employ cointegration analysis using panel data, Narayan et al. (2007) estimate a panel cointegration model of residential electricity demand with aggregate data for Canada, France, Germany, Italy, Japan, United Kingdom and United States, between 1978-2003, using OLS and dynamic ordinary least squares (DOLS). The explanatory variables employed are income, price of electricity and price of natural gas. Blázquez et al. (2013) employ a dynamic partial adjustment specification that is estimated via the

[85] Holtedahl and Joutz (2004) use aggregate data over the period 1955-1995 for electricity price, disposable income, world oil price, urbanization, cooling degree days. Hondroyiannis (2004) regresses residential electricity consumption on income, electricity price and climate, using aggregate data from 1986 to 1999. Jamil and Ahmad (2011) model Pakistan's residential electricity demand as a function of private consumption expenditure, electricity price, diesel price, capital stock (gross fixed capital formation), heating and cooling degree days, employing aggregate data for 1961-2008.

[86] Narayan and Smyth (2005) use aggregate data from 1969 to 2000 and include as regressors income, electricity price and gas price. Halicioglu (2007) employs income, electricity price and urbanization rate for the period 1968-2005. Dergiades and Tsoulfideis (2008) use aggregate data from 1965 to 2006 for all the variables employed by Silk and Joutz (1997), with the exception that the mortgage interest rate is replaced with the per capita occupied stock of housing.

generalized method of moments (GMM) estimator of Blundell and Bond (1998) to investigate Spain's residential electricity demand considering a panel of aggregate data for 47 provinces between 2000-2008. The authors use as predictors disposable income, electricity price, size of households, population, proportion of households that have access to natural gas, heating and cooling degree days and time dummies to account for technical progress and consumers' behaviour.

The estimates of the long- and short-run income and price elasticities of residential electricity demand reported in the literature are summarised in Table 5.1

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Study	*Country*	*Sample and frequency*	*Methodology*	*Short-run income elasticity*	*Short-run price elasticity*	*Long-run income elasticity*	*Long-run price elasticity*
Fischer and Kaysen (1962)	USA	1946-1957 (annual series)	Two-stage model (time series)	0.10	-0.15	---	---
Houthakker and Taylor (1970)	USA	1947-1964 (annual series)	Partial adjustment model	0.13	-0.13	1.93	-1.89
Houthakker et al. (1974)	USA	1960-1971 (annual series)	Pooled time series error component technique	from 0.13 to 0.15	from -0.09 to -0.03	from 1.64 to 2.20	from -1.2 to -0.45
Sutherland (1983)	USA	1961-1973 (annual series)	Almon polynomial model, partial adjustment model and unconstrained distributed lag model	---	---	from 0.30 to 0.53	from -1.73 to -1.12
"	"	1974-1980 (annual series)	"	---	---	from -0.09 to 0.39	from -1.08 to 0.78
"	"	1961-1980 (annual series)	"	---	---	from 0.23 to 0.50	from -2.12 to -1.08
Chern and Bouis (1988)	USA	1955-1978 (annual series)	Partial adjustment model	from 0 to 0.22	from -0.80 to -0.10	from 0 to 0.82	from -1.36 to -0.50
Silk and Joutz (1997)	USA	1949-1993 (annual series)	Johansen ML	0.39	-0.63	0.52	-0.48
Beenstock et al.(1999)	Israel	1973-1994 (quarterly series)	Dynamic regression model, two-step Engle and Granger and Johansen ML	---	---	from 1.0 to 1.09	from -0.58 to -0.21
Holtedahl and Joutz (2004)	Taiwan	1955-1995 (annual series)	Johansen ML	0.23	-0.15	1.57	-0.15
Hondroyiannis (2004)	Greece	1986-1999 (monthly series)	Johansen ML	0.2	statistically insignificant	1.56	-0.41
Narayan and Smyth (2005)	Australia	1969-2000 (annual series)	ARDL bounds testing	statistically insignificant	-0.26	0.32	-0.54
Halicioglu (2007)	Turkey	1968-2005 (annual series)	ARDL bounds testing	from 0.37 to 0.44	from -0.46 to -0.33	from 0.49 to 0.70	from -0.63 to -0.52
Narayan et al. (2007)	Panel of G7 countries	1978-2003 (annual series)	Panel cointegration OLS and DOLS	statistically insignificant	-0.11	from 0.25 to 0.31	from -1.56 to -1.45
"	Canada	"	Individual country DOLS estimator	statistically insignificant	statistically insignificant	0.81	-0.30
"	France	"	"	statistically insignificant	statistically insignificant	1.49	-0.50
"	Germany	"	"	statistically insignificant	statistically insignificant	statistically insignificant	-4.20
"	Italy	"	"	statistically insignificant	-0.10	statistically insignificant	statistically insignificant
"	Japan	"	"	statistically insignificant	statistically insignificant	statistically insignificant	-1.49
"	UK	"	"	statistically insignificant	statistically insignificant	statistically insignificant	statistically insignificant
"	USA	"	"	0.37	statistically insignificant	statistically insignificant	statistically insignificant
Dergiades and Tsoulfidis (2008)	USA	1965-2006 (annual series)	ARDL bounds testing	0.1	-0.39	0.27	-1.07
Sa'ad (2009)	South Korea	1973-2007 (annual series)	STSM	0.56	-0.14	1.33	-0.27
Dilaver and Hunt (2011b)	Turkey	1960-2008 (annual series)	STSM	0.38	-0.09	1.57	-0.38
Jamil and Ahmad (2011)	Pakistan	1961-2008 (annual series)	Johansen ML	statistically insignificant	statistically insignificant	1.97	-1.22
Blazquez et al. (2013)	Spain	2000-2008 (annual series)	Panel two-step GMM estimator	0.23	-0.07	0.61	-0.19

Table 5.1: Residential electricity demand: long-run and short-run elasticities in the literature.

Income and price elasticities vary significantly across the studies due in part to the different econometric techniques used as well as to the heterogeneity of the countries and the periods considered. Short-run income elasticity ranges between being statistically insignificant to 0.56, while short-run price elasticity varies between -0.80 and statistically insignificant. On average long-run elasticities are larger than short-run elasticities. In particular, long-run income elasticity is estimated to vary between -0.09 to 2.20, while long-run price elasticity range between -4.20 to 0 (when it is statistically insignificant).

To avoid the possibility of inconsistent estimates of price and income elasticities resulting from omitting technical progress and other important factors, this chapter proposes a novel econometric approach consisting of specifying a general unrestricted ECM featuring the IIS framework (Hendry, 1999; Hendry et al., 2008; Johansen and Nielsen, 2009; and Castle et al., 2012) and its related extensions (Ericsson, 2011, 2012, 2013; Bergamelli and Urga, 2013), to estimate the cointegrating relationship between residential electricity demand and its determinants. The specification includes GDP, electricity price and deterministic components, which proxy for technical progress and all other factors that may be relevant in explaining residential electricity demand, but that are difficult to measure/find. In contrast to previous literature, the deterministic components include not only a constant and linear trend but also three sets of dummies, as defined in the IIS framework and extensions, which in correcting the constant and the slope of the trend, allow the variables non explicitly modelled to have an impact that may vary over time in a non-deterministic way. Similar to the STSM framework used by Hunt et al. (2000, 2003a, b), Hunt and Ninomiya (2003), Dimitropoulos et al. (2005), Sa'ad (2009), Adeyemi et al. (2010), Broadstock and Hunt (2010), Dilaver and Hunt (2011a,b,c), our approach can capture the overall effect of several variables that may work in opposite directions. However, the approach used in this chapter differs from this literature, as it is based on the theory of cointegration and its dynamic error correction representation counterpart, which guarantees the correct specification of long-run equilibrium and short-run dynamics. In addition, the approach has the appealing advantage of giving an insight about the location and the potential determinants of the change in the electricity demand trend. Finally, the IIS framework and extensions make sure that the estimated relationship does not suffer from any instability.

5.3 Data

The dataset used in this chapter consists of annual time series data (transformed in natural logarithms) of residential electricity consumption in GWh (*<<Country Name>> EC)*, GDP expressed in national currency[87] at 2005 constant prices *(<<Country Name>> GDP)* and real electricity price index with base year 2005=100[88] *(<<Country Name>> PRICE)* for the following countries: Austria (AT), Belgium (BE), Switzerland (CH), Germany (DE), Spain (ES), France (FR), Italy (IT), the Netherlands (NL) and the United Kingdom (UK). The data spans the period 1978-2009 and is obtained from the International Energy Agency database (IEA, 2012).

The descriptive statistics of the data are reported in Table 5.2. The series feature low variability and they appear to follow a Gaussian distribution, given that the null hypothesis of normality is always accepted with the exception of IT PRICE (test Jarque-Bera). IT PRICE exhibits leptokurtosis, which denotes the presence of extreme values, and negative skewness, which indicates that extremely low values are more likely to occur than extremely high values.

[87] Since the 1 January 2002, the Euro is the currency for Austria, Belgium, Germany, Spain, France, Italy and the Netherlands. GDP data referring to the period 1978-2001 are converted into Euros with the fixed conversion rates established in the Council Regulation (EC) No 2866/98,31 December 1998. British Pound Sterling and Swiss Franc are used for the UK and Switzerland, respectively.

[88] The real electricity price index is calculated from the average nominal end-use electricity price (including taxes) paid by households (IEA, 2012).

	Mean	*Maximum*	*Minimum*	*Std. Dev.*	*Skewness*	*Kurtosis*	*Jarque-Bera*	*Probability*
AT EC	9.413	9.773	8.900	0.303	-0.436	1.783	2.988	0.224
BE EC	9.862	10.187	9.391	0.240	-0.466	1.952	2.624	0.269
CH EC	9.535	9.794	9.079	0.207	-0.633	2.281	2.825	0.244
DE EC	11.775	11.860	11.595	0.073	-0.824	2.753	3.699	0.157
ES EC	10.465	11.200	9.679	0.445	0.113	1.945	1.553	0.460
FR EC	11.557	12.045	10.895	0.311	-0.544	2.326	2.182	0.336
IT EC	10.883	11.141	10.440	0.206	-0.602	2.190	2.809	0.245
NL EC	9.841	10.120	9.572	0.186	0.158	1.494	3.156	0.206
UK EC	11.527	11.743	11.324	0.137	0.077	1.712	2.244	0.326
AT GDP	12.143	12.496	11.782	0.221	0.028	1.684	2.314	0.314
BE GDP	12.377	12.687	12.058	0.200	-0.001	1.681	2.321	0.313
CH GDP	12.870	13.139	12.587	0.157	-0.078	2.030	1.286	0.526
DE GDP	14.426	14.694	14.109	0.186	-0.287	1.647	2.878	0.237
ES GDP	13.357	13.803	12.973	0.278	0.131	1.722	2.271	0.321
FR GDP	14.119	14.404	13.797	0.192	-0.073	1.723	2.203	0.332
IT GDP	13.983	14.216	13.641	0.172	-0.397	1.898	2.458	0.293
NL GDP	12.858	13.239	12.499	0.247	0.027	1.571	2.725	0.256
UK GDP	13.697	14.102	13.330	0.259	0.112	1.676	2.405	0.300
AT PRICE	4.799	4.993	4.582	0.125	-0.368	1.867	2.431	0.296
BE PRICE	4.835	5.095	4.605	0.154	0.295	1.832	2.283	0.319
CH PRICE	4.730	4.866	4.529	0.089	-0.905	2.945	4.371	0.112
DE PRICE	4.615	4.829	4.414	0.094	0.011	2.918	0.010	0.995
ES PRICE	4.904	5.115	4.605	0.195	-0.324	1.374	4.084	0.130
FR PRICE	4.838	5.098	4.532	0.184	-0.252	1.589	2.995	0.224
IT PRICE	4.650	4.806	4.327	0.108	-1.367	5.101	15.856	0.000
NL PRICE	4.443	4.710	4.161	0.171	-0.040	1.696	2.276	0.320
UK PRICE	4.792	4.975	4.517	0.139	-0.779	2.325	3.845	0.146

Table 5.2: Descriptive statistics of residential electricity consumption, GDP and electricity price series in natural logarithms.

Figure 5.1 shows the plot of the normalised[89] series of residential electricity consumption, GDP and electricity price for each of the nine EU countries. All the consumption and GDP series, with the exception of *DE EC*, feature a strong deterministic trend component; while in all price series the trend exhibits stochastic behaviour. In addition, the majority of the series display one or more shifts in mean and trend.

[89] The original series are normalised, by subtracting the mean and dividing by the standard deviation, thus allowing the plots to be more easily read.

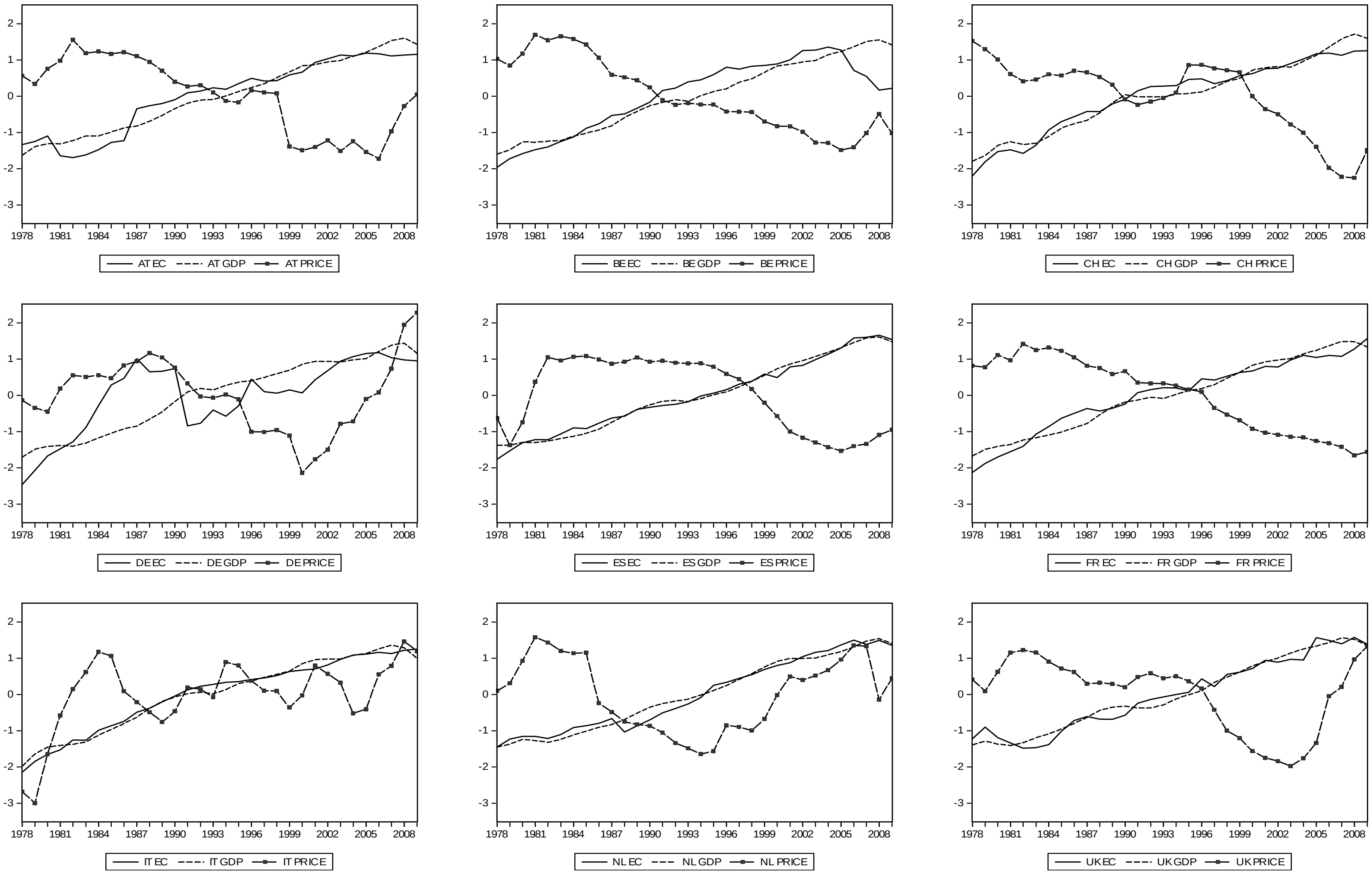

Figure 5.1: Residential electricity consumption, GDP and electricity price index for European countries 1978-2009 (normalised data). Data source: IEA, 2012.

AT EC has shifts in 1981 and 1987, AT PRICE in 1983, 1999 and 2007; BE EC and BE PRICE in 2006; CH PRICE in 1995, 2000; DE EC in 1991, DE PRICE in 1981, 1989, 1996 and 2001; ES PRICE in 1983 and 2006; NL EC in 1988, NL PRICE in 1982 and 1995; UK EC in 1983, UK PRICE in 1983 and 2004.

Visual inspection of the data suggests the possibility of having structural breaks in many series, it becomes crucial to undertake cointegration analysis to ascertain rigorously whether breaks are a long-run feature of the data. If the presence of breaks were confirmed, the application of standard unit root tests (i.e. Dickey-Fuller test) to identify the order of integration of the series would be questionable. Therefore, modelling the residential electricity demand of the nine EU countries begins with a robust unit root test analysis (Section5.4) that allows the identification of possible structural breaks in the series.

5.4 Unit root tests

Perron (1989), in a seminal paper, demonstrates that a standard Dickey-Fuller (DF) unit root test fails to reject the null of unit root, when the alternative is a stationary process with a break in the slope of the trend function. In particular, Perron (1989) proposes a modified DF test that includes a dummy variable to account for one exogenous structural change. Subsequent literature introduces modification to the Perron's procedure to allow for endogenous (or unknown) structural breaks under the alternative hypothesis. Zivot and Andrews (1992, ZA henceforth) analyse the case of one unknown break, while Lumsdaine and Papell (1997, LP henceforth) extend this methodology to the case of two unknown breaks. Lee and Strazicich (2003) point out that the main drawback of the ZA and LP tests is that they assume breaks only under the alternative hypothesis. This determines that the rejection of the null implies rejection of unit root without breaks rather than the rejection of unit root per se. Carrion-I-Silvestre et al. (2009) solve this problem by proposing robust versions for a battery of tests originally developed by Ng and Perron (2001), which allow for multiple structural breaks under both the null and the alternative hypotheses. However, given that the robust tests are affected by size distortions when applied to series where no breaks occur, Carrion-I-Silvestre et al. (2009) suggest implementing a pretesting procedure to assess whether a series has structural change in level and or slope.

Therefore, following the strategy outlined in Carrion-I-Silvestre et al. (2009), each series is pretested with the Perron and Yabu (2009) procedure to check for the presence of structural change, without prior knowledge of the series' order of integration. If structural change is found, the robust unit root tests of Carrion-I-Silvestre et al. (2009) are employed. If no breaks occur, standard unit root tests can be used.

The Perron and Yabu (2009) procedure starts by considering a data-generating process for a scalar random variable y_t as follows:

$$y_t = \boldsymbol{x_t}\boldsymbol{\psi} + u_t \tag{5.1}$$

$$u_t = \alpha u_{t-1} + A^*(L)\Delta u_{t-1} + e_t \quad where\ A^*(L) = \sum_{i=0}^{\infty} a_i^* L^i \ \ and\ a_i^* = -\sum_{J=i+1}^{\infty} a_j \tag{5.2}$$

where $\boldsymbol{x_t}$ is a *(r x 1)* vector of deterministic components and $\boldsymbol{\psi}$ is a *(r x 1)* vector of parameters. Perron and Yabu (2009) are interested in testing the null hypothesis $\boldsymbol{R\psi} = \boldsymbol{\gamma}$, where **R** is a *(q x r)* full rank matrix, $\boldsymbol{\gamma}$ is a *(q x 1)* vector of restrictions and q is number of restrictions. The restrictions relate to the type of structural change affecting the model. The types of structural change considered are:

Model I structural change in the intercept: $\boldsymbol{x_t} = (1, DU_t, t)'$ and $\boldsymbol{\psi} = (\mu_0, \mu_1, \beta_0)'$, where $DU_t = 1(t > T_1)$. The null hypothesis is the absence of break in the intercept or $\mu_1 = 0$.

Model II structural change in the slope: $\boldsymbol{x_t} = (1, t, DT_t)'$ and $\boldsymbol{\psi} = (\mu_0, \beta_0, \beta_1)'$, where $DT_t = 1(t > T_1)(t - T_1)$. The null hypothesis is the absence of break in the slope or $\beta_1 = 0$.

Model III structural change in the intercept and in the slope: $\boldsymbol{x_t} = (1, DU_t, t, DT_t)'$ and $\boldsymbol{\psi} = (\mu_0, \mu_1, \beta_0, \beta_1)'$. The null hypothesis is the absence of break(s) in both the intercept and in the slope or $\mu_1 = \beta_1 = 0$.

The testing procedure consists of regressing y_t on $\boldsymbol{x_t}$ so as to get the residuals series $\hat{u}_t$and then in estimating the following autoregression of order *k:*

$$\hat{u}_t = \alpha\hat{u}_{t-1} + \sum_{i=1}^{k} \zeta_i \Delta\hat{u}_{t-1} + e_{tk} \tag{5.3}$$

The regression in equation (5.3) provides an estimate of the α parameter defined as $\tilde{\alpha}_{MS}$, which is then used in equation (5.1) as follows

$$(1 - \tilde{\alpha}_{MS}L)y_t = (1 - \tilde{\alpha}_{MS}L)\boldsymbol{x}_t'\boldsymbol{\psi} + (1 - \tilde{\alpha}_{MS}L)u_t \tag{5.4}$$

so as to get a feasible GLS estimate of the parameters in the vector $\boldsymbol{\psi}$**.** The Wald statistic for testing the null hypothesis relating to the parameters in the vector $\boldsymbol{\psi}$ specified above is defined as:

$$W_{RQF}(\lambda_1) = [\boldsymbol{R}(\widetilde{\boldsymbol{\psi}} - \boldsymbol{\psi})]'[\tilde{h}_v \boldsymbol{R}(\boldsymbol{X}'\boldsymbol{X})^{-\mathbf{1}}\boldsymbol{R}']^{-1}[\boldsymbol{R}(\widetilde{\boldsymbol{\psi}} - \boldsymbol{\psi})] \tag{5.5}$$

where $\widetilde{\boldsymbol{\psi}}$ is feasible GLS estimate of the parameters in the vector $\boldsymbol{\psi}$**,** $\tilde{h}_v$ is an estimate of $v_t = (1 - \alpha L)u_t$, and $\mathbf{X} = \{\boldsymbol{x}_t^{\tilde{\alpha}_{MS}}\}$, where $\boldsymbol{x}_t^{\tilde{\alpha}_{MS}} = (1 - \tilde{\alpha}_{MS}L)\boldsymbol{x}_t$.

The final statistic used to implement the testing procedure is the Exp functional of the Wald test in equation (5.5).

From the visual inspection of the electricity demand, GDP and price series the presence of shifts in both the intercept and in the slope of the trend component are evident therefore, the testing procedure is implemented using Model III[90].

Table 5.3 reports the results of the Perron and Yabu (2009) pretesting procedure. The results highlight that the null hypothesis of no break is rejected for the majority of the series (17 out of 27). For the remaining 10 series, (AT EC, CH EC, CH GDP, CH PRICE, ES GDP, FR EC, FR PRICE, NL EC, NL GDP and UK GDP), the trend function turns out to be stable, as the null hypothesis of no breaks is accepted.

Exp test Statistic (W-RQF^a)													
AT EC	AT GDP	AT PRICE	BE EC	BE GDP	BE PRICE	CH EC	CH GDP	CH PRICE	FR EC	FR GDP	FR PRICE	DE EC	DE GDP
0.187	183.870**	18.914**	71.841**	423.667**	3.514*	2.997	1.421	2.464	2.771	33.386**	1.65	54.134**	11.819**
DE PRICE	ES EC	ES GDP	ES PRICE	IT EC	IT GDP	IT PRICE	NL EC	NL GDP	NL PRICE	UK EC	UK GDP	UK PRICE	
13.200**	6.345**	1.124	7.838**	72.656**	11.225**	18.691**	1.069	1.736	5.189**	3.522*	2.045	23.202**	

*a W-RQF stands for Wald robust quasi feasible generalised least squares test. **, * denote 1% and 5% significance values respectively. Critical values for H_0 = no break, H_1 : one break, are 5%=3.36, 1%=4.78 (trimming parameter is set at 0.05).*

Table 5.3: Perron and Yabu (2009) pretesting procedure.

The second step of this procedure consists of applying the Carrion-I-Silvestre et al. (2009) battery of robust tests to the series that feature a break in the trend function. The battery of robust tests includes: the Elliot et al. (1996) feasible point optimal test (P_T^{GLS}) and its modified version (MP_T^{GLS}), the Phillips (1987) modified test (MZ_α^{GLS}), the modified Sargan and Bhargava (1983) test (MSB^{GLS}) and the modified Phillips and Perron (1988) test (MZ_t^{GLS}). The superscript GLS indicates that all the series are GLS detrended

The description of these tests starts by defining y_t as a stochastic process generated according to:

$$y_t = d_t + u_t \tag{5.6}$$

[90] The GAUSS code for computing the Perron and Yabu (2009) test developed by the authors is available at http://people.bu.edu/perron/code.html

$$u_t = \alpha u_{t-1} + \upsilon_t \tag{5.7}$$

The deterministic component d_t featuring *m* breaks in the level and in the slope is defined as:

$$d_t = z'_t(T_0^0)\psi_0 + z'_t(T_1^0)\psi_1 + \cdots + z'_t(T_m^0)\psi_m \equiv z'_t(\lambda^0)\psi \tag{5.8}$$

where $z_t(T_0^0) = (1, t)'$, $\psi_0 = (\mu_0, \beta_0)'$, and $z_t(T_j^0)$ corresponding to either a break in the level (DU_t) or in the slope (DT_t) or in both. Consequently, $z_t(\lambda^0) = [z'_t(T_0^0), \dots, z'_t(T_m^0)]'$ and $\psi = (\psi'_0, \dots, \psi'_m)'$.

The GLS-detrended unit root tests feature the use of quasi-differenced variables $y_t^{\bar{\alpha}}$ and $z_t^{\bar{\alpha}}(\lambda^0)$ defined as follows:

$$y_t^{\bar{\alpha}} = (1 - \bar{\alpha}L)y_t \tag{5.9}$$

$$z_t^{\bar{\alpha}}(\lambda^0) = (1 - \bar{\alpha}L)z_t(\lambda^0) \tag{5.10}$$

where $\bar{\alpha} = 1 + \bar{c}/T$, where $\bar{c}$ is a parameter depending on the number of structural breaks and their positions.

The GLS-detrended series is defined as

$$\tilde{y}_t = y_t - \widehat{\psi'} z_t(\lambda_0) \tag{5.11}$$

where $\hat{\psi}$ minimises the sum of the squared residuals obtained by estimating the (5.6) with quasi-differenced variables. Denoting the minimum of the sum of the squared residuals as $S(\bar{\alpha}, \lambda^0)$, the feasible point optimal test of the null hypothesis $\alpha = 1$ in equation (5.7) against the alternative $\alpha = \bar{\alpha}$ is the statistic:

$$P_T^{GLS}(\lambda^0) = \frac{\{S(\bar{\alpha}, \lambda^0) - \bar{\alpha}S(1, \lambda^0)\}}{s(\lambda^0)^2} \tag{5.12}$$

where $s(\lambda^0)^2$ is an estimate of the spectral density at zero frequency of υ_t in (5.7) and it is defined as :

$$s(\lambda^0)^2 = \frac{s_{ek}^2}{\left(1 - \sum_{j=1}^{k} \hat{b}_j\right)^2} \tag{5.13}$$

where $s_{ek}^2 = (T-k)^{-1} \sum_{t=k+1}^{T} \hat{e}_{t,k}^2$ and $\{\hat{b}_j, \hat{e}_{t,k}\}$ are obtained from the following OLS regression:

$$\Delta\tilde{y}_t = b_0 \tilde{y}_{t-1} + \sum_{j=1}^{k} b_j \Delta\tilde{y}_{t-j} + e_{t,k} \tag{5.14}$$

The modified version of the feasible point optimal test (MP_T^{GLS}) is defined as:

$$MP_T^{GLS}(\lambda^0) = \frac{[\bar{c}^2 T^{-2} \sum_{t=1}^{T} \tilde{y}_{t-1}^2 + (1-\bar{c}) T^{-1} \tilde{y}_T^2]}{s(\lambda^0)^2} \tag{5.15}$$

The modified Phillips (1987) test (MZ_α^{GLS}) is defined as:

$$MZ_\alpha^{GLS}(\lambda^0) = (T^{-1}\tilde{y}_T^2 - s(\lambda^0)^2)\left(2T^{-2} \sum_{t=1}^{T} \tilde{y}_{t-1}^2\right)^{-1} \tag{5.16}$$

The modified Sargan and Bhargava (1983) test (MSB^{GLS}) is defined as:

$$MSB^{GLS}(\lambda^0) = \left(s(\lambda^0)^{-2} T^{-2} \sum_{t=1}^{T} \tilde{y}_{t-1}^2\right)^{1/2} \tag{5.17}$$

The modified Phillips and Perron (1988) test (MZ_t^{GLS}) is defined as:

$$MZ_t^{GLS}(\lambda^0) = (T^{-1}\tilde{y}_T^2 - s(\lambda^0)^2)\left(4s(\lambda^0)^2 T^{-2} \sum_{t=1}^{T} \tilde{y}_{t-1}^2\right)^{-1/2} \tag{5.18}$$

Table 5.4 reports the results of the Carrion-I-Silvestre et al. (2009) unit root tests[91]. From the analysis of the results, it emerges that the null hypothesis of unit root with break is accepted for all the series considered.

[91] The GAUSS code for computing the unit root test statistics and the relevant critical values for the Carrion-I-Silvestre et al. (2009) tests is provided by the authors at http://people.bu.edu/perron/code.html

	P_T^{GLS}	MP_T^{GLS}	MZ_α^{GLS}	MSB^{GLS}	MZ_t^{GLS}
AT GDP	10.276	10.802	-10.208	0.218	-2.229
	(5.628)	*(5.628)*	*(-19.803)*	*(0.159)*	*(-3.137)*
AT PRICE	21.718	20.799	-6.576	0.257	-1.691
	(6.286)	*(6.286)*	*(-22.749)*	*(0.148)*	*(-3.355)*
BE EC	11.837	11.940	-9.807	0.225	-2.211
	(5.545)	*(5.545)*	*(-21.505)*	*(0.154)*	*(-3.256)*
BE GDP	11.036	11.342	-9.666	0.226	-2.181
	(5.628)	*(5.628)*	*(-19.803)*	*(0.159)*	*(-3.137)*
BE PRICE	17.486	15.582	-6.996	0.267	-1.864
	(5.870)	*(5.870)*	*(-18.96)*	*(0.161)*	*(-3.082)*
DE EC	16.578	16.754	-9.931	0.217	-2.153
	(6.978)	*(6.978)*	*(-23.953)*	*(0.143)*	*(-3.444)*
DE GDP	15.455	14.168	-13.031	0.171	-2.232
	(7.020)	*(7.020)*	*(-24.028)*	*(0.143)*	*(-3.449)*
DE PRICE	29.973	27.991	-4.811	0.317	-1.526
	(6.185)	*(6.185)*	*(-22.503)*	*(0.149)*	*(-3.337)*
ES EC	10.676	9.331	-12.828	0.194	-2.492
	(5.862)	*(5.862)*	*(-20.416)*	*(0.156)*	*(-3.185)*
ES PRICE	26.796	25.273	-4.925	0.314	-1.548
	(6.194)	*(6.194)*	*(-21.053)*	*(0.153)*	*(-3.217)*
FR GDP	13.417	14.293	-7.629	0.256	-1.951
	(5.87)	*(5.87)*	*(-18.96)*	*(0.161)*	*(-3.082)*
IT EC	13.734	12.797	-12.879	0.195	-2.512
	(6.931)	*(6.931)*	*(-23.857)*	*(0.143)*	*(-3.437)*
IT GDP	22.014	19.217	-5.643	0.294	-1.659
	(5.628)	*(5.628)*	*(-19.803)*	*(0.159)*	*(-3.137)*
IT PRICE	13.293	13.417	-11.908	0.201	-2.390
	(6.756)	*(6.756)*	*(-23.715)*	*(0.144)*	*(-3.423)*
NL PRICE	23.609	22.521	-7.167	0.264	-1.889
	(6.908)	*(6.908)*	*(-23.8)*	*(0.143)*	*(-3.432)*
UK EC	10.852	11.193	-15.374	0.169	-2.600
	(6.823)	*(6.823)*	*(-23.537)*	*(0.144)*	*(-3.412)*
UK PRICE	24.679	21.719	-6.019	0.263	-1.584
	(6.054)	*(6.054)*	*(-22.921)*	*(0.149)*	*(-3.362)*

Null hypothesis H_0 = unit root with break. For all tests the null hypothesis is rejected if the test statistic is smaller than the relevant critical value. Critical values 5% in brackets.

Table 5.4: Carrion-I-Silvestre et al. (2009) robust unit root tests.

For the series where no breaks were detected, the standard Phillips and Perron (1988) unit root test (PP) is carried out. The results of the PP test presented in Table 5.5 indicate that the null hypothesis of unit root is accepted for all the series analysed.

	AT EC	*CH EC*	*CH GDP*	*CH PRICE*	*ES GDP*	*FR EC*	*FR PRICE*	*NL EC*	*NL GDP*	*UK GDP*
Phillips and Perron (1988) statistic	-1.939	-2.860	-2.345	-1.798	-1.849	-3.308	-3.250	-1.707	-1.849	-2.162

Null hypothesis H_0 = unit root. Critical values are 5% = -3.56, 1% = -4.28.

Table 5.5: Phillips and Perron (1988) unit root test.

Having ascertained that all series are *I(1)* processes, and in most cases with breaks, it is now possible to investigate whether a cointegrating relationship between residential electricity consumption and its determinants exists. It must be noted that the presence of breaks in marginal processes of residential electricity consumption, GDP and electricity price of several countries implies that breaks may be a long-run feature of the cointegration relationship, unless the series co-break (Hendry and Massmann, 2007). The use of the IIS framework and extensions, however, guarantees that not only omitted variables are incorporated in the modelling but also that any unmeasured break is accounted for.

5.5 Methodology: unrestricted ECM with IIS

The strategy used to estimate the cointegrating relationship between residential electricity and its determinants for the nine European countries consists of specifying an unrestricted ECM featuring the IIS framework (originally proposed by Hendry, 1999 and developed in Hendry et al., 2008; Johansen and Nielsen, 2009; and Castle et al., 2012) and the related extensions Super Saturation and Ultra Saturation, as defined by Ericsson (2011, 2012, 2013).

The application of IIS and extensions foresees saturating a standard unrestricted ECM specification by adding a dummy variable for every observation in the sample. The dummy variables considered are: *impulse indicator dummies*, which are defined as $I_{i,t} = 1$ for $t = i$, zero otherwise; *step dummies*, which capture changes in the electricity demand trend level and are defined as $S_{i,t} = 1$ for $t \geq i$, zero otherwise; and *step trend dummies*, which control for changes in the slope of the trend function and are defined as $T_{i,t} = t - i + 1$ for $t \geq i$, zero otherwise. For all dummies, i is the index for indicators and t is the index for time, so that $S_{1980,t}$ stands for step dummy 1980, which assumes value 1 from 1980 and zero prior to 1980.

The procedure of adding up to three sets of T dummies has the problematic consequence of formulating a model with more variables than observations. This implies that standard procedures to get estimates of unknown parameters, such as OLS, cannot be performed due to the lack of degrees of freedom. To solve this problem, the estimation of the three models is carried out using the algorithm *Autometrics™*, included in OxMetrics6.2™ (see Doornik, 2009a,b). *Autometrics™* is a search algorithm that performs automatic general-to-specific model selection when there are more regressors than observations. The starting point for this procedure is to specify a general unrestricted model (GUM) containing all the variables that are assumed to be relevant for explaining electricity demand. *Autometrics™* uses a tree-search to remove the insignificant variables so as to select a final model that encompasses the GUM. A brief description of *Autometrics™* is provided in Appendix C.

The modelling strategy involves specifying three alternative models of electricity demand, each of which features a different combination of impulse dummies, step dummies and step trend dummies, as follows.

The GUM for the unrestricted ECM model saturated with impulse indicator dummies is:

$$\begin{aligned}\Delta EC_t &= \alpha_0 + \alpha_1 t + \alpha_2 \Delta EC_{t-1} + \alpha_3 \Delta GDP_t + \alpha_4 \Delta GDP_{t-1} + \alpha_5 \Delta PRICE_t + \alpha_6 \Delta PRICE_{t-1} \\ &+ \alpha_7 EC_{t-1} + \alpha_8 GDP_{t-1} + \alpha_9 PRICE_{t-1} + \sum_{i=1}^{T} \beta_i I_{i,t} + \varepsilon_t \qquad (5.19)\end{aligned}$$

Where ΔEC_t is the first difference of residential electricity consumption, α_0 is the constant, t is the linear time trend, ΔGDP_t is the first difference of the GDP and $\Delta PRICE_t$ is the first difference of the electricity price index for residential consumers. ΔEC_{t-1}, ΔGDP_{t-1} and $\Delta PRICE_{t-1}$ are the one-year lagged variables in first difference, while $EC_{t-1}, GDP_{t-1}, PRICE_{t-1}$ are the one-year lagged variables in levels, which identify the cointegrating relationship.

The GUM for the unrestricted ECM model saturated with impulse dummies and step dummies, also known as Super Saturation model, is:

$$\Delta EC_t = \alpha_0 + \alpha_1 t + \alpha_2 \Delta EC_{t-1} + \alpha_3 \Delta GDP_t + \alpha_4 \Delta GDP_{t-1} + \alpha_5 \Delta PRICE_t + \alpha_6 \Delta PRICE_{t-1}$$
$$+ \alpha_7 EC_{t-1} + \alpha_8 GDP_{t-1} + \alpha_9 PRICE_{t-1} + \sum_{i=1}^{T} \beta_i I_{i,t} + \sum_{i=1}^{T} \gamma_i S_{i,t} + \varepsilon_t \qquad (5.20)$$

The GUM for the unrestricted ECM model saturated with impulse dummies, step dummies, step trend dummies, also known as Ultra Saturation (also referred to as Super-Duper Saturation in Ericsson, 2011) model, is:

$$\Delta EC_t = \alpha_0 + \alpha_1 t + \alpha_2 \Delta EC_{t-1} + \alpha_3 \Delta GDP_t + \alpha_4 \Delta GDP_{t-1} + \alpha_5 \Delta PRICE_t + \alpha_6 \Delta PRICE_{t-1}$$
$$+ \alpha_7 EC_{t-1} + \alpha_8 GDP_{t-1} + \alpha_9 PRICE_{t-1} + \sum_{i=1}^{T} \beta_i I_{i,t} + \sum_{i=1}^{T} \gamma_i S_{i,t} + \sum_{i=1}^{T} \delta_i T_{i,t} + \varepsilon_t \qquad (5.21)$$

The models specified in Equations (5.19), (5.20) and (5.21) can include *T* impulse indicator dummies, *T* step dummies and *T* step trend dummies in addition to the constant α_0 and the linear trend *t*, because *Autometrics*™ can handle non-orthogonal regressors.

The modelling strategy proceeds as follows. The three GUMs are estimated for each country and the preferred final model is selected by comparing the Akaike Information Criterion (AIC) and Schwarz Criterion (SC). The variables that enter the long-run relationship, namely constant α_0, time trend *t*, EC_{t-1}, GDP_{t-1} and $PRICE_{t-1,}$ are held fixed in the search algorithm to avoid potential elimination by *Autometrics*™. The presence of a meaningful long-run relationship between the variables is then checked, verifying that the coefficient associated with the lagged dependent variable in levels (EC_{t-1}) is statistically significant with negative sign (Dufour, 1997). The correct specification of the selected model is evaluated using a battery of misspecification tests, including the *AR* test (Breusch and Godfrey, 1981) where the null hypothesis is no serial correlation in the residuals; the *ARCH* test (Engle, 1982) where the null hypothesis is no serial correlations in the squares of the residuals; the *Normality* test (Bera and Jarque, 1982) where the null hypothesis is normality in the residuals; the *Hetero* test (Breusch and Pagan, 1979) where the null hypothesis is homoscedasticity in the residuals and the *RESET23* (Ramsey, 1974) where the null hypothesis is linearity in the functional form of the regression. In case of misspecification or if any of the coefficients of the error correction terms are insignificant or have an unexpected sign, the model is re-specified with a longer lag structure, (i.e. with either 2 or 3 lags) and the misspecification tests are re-run. Finally, the long-run income and price elasticities are calculated.

5.6 Estimation results

Tables 5.6 - 5.14 report the results of the estimated models for the nine European countries. A preferred specification is identified for each country. In particular, it emerges that the Ultra Saturation model is the preferred model for six out of nine countries (Austria, Belgium, Switzerland, France, Italy and the UK), while the Super Saturation model is selected for Germany, Spain and the Netherlands. For each final model, the dummies selected by *Autometrics*™ help to explain the variation in electricity demand that is not due to price or income, but to some other factors not explicitly modelled (e.g. technical progress, changes in consumers' preferences and climate). Although this is fundamental in order to get consistent estimates of the price and income coefficients, it is not possible to identify the specific contribution of each of these factors.

The results highlight that cointegration between residential electricity consumption and its determinants exists for all nine countries, as the coefficients associated with the lagged dependent variable in levels (EC_{t-1}) are always negative and statistically significant. Moreover, the estimated coefficients associated with economic variables GDP and price in levels are all statistically significant and have the expected sign (i.e. positive for GDP and negative for price). In a preliminary exercise reported in Appendix D, an unrestricted ECM without IIS and extensions was estimated for all nine countries. The results show that cointegration is rejected for Austria, Belgium, Germany, Spain, Switzerland and the Netherlands. For France, Italy and the UK cointegration is found, but the estimates of the long-run coefficients of price and income are not statistically significant. The results for each of the nine countries are discussed in turn.

Austria

The preferred model for Austria's electricity demand is a Ultra Saturation specification (Table 5.6). The selected model (Ultra Saturation I) is re-specified with a longer lag structure (i.e. two lags), so as to eliminate a minor problem of residual autocorrelation (AR 1-2 test). The final model (Ultra Saturation II) includes the one-period lagged growth rate of price, a step dummy for 2007, a step trend dummy for 1989, three impulse dummies, relating to years 1986, 1987 and 1997 and the variables entering the long-run relationship. All the dummies selected by *Autometrics™* help to explain the variation in electricity demand that is not due to price or income, but to some other factors not explicitly modelled (e.g. technical progress, changes in consumers' preferences, climate). Among the impulse dummies, *I:1987* has a large positive coefficient (0.129) and captures the large shift in the level of the electricity demand that is only partially explained by the price decrease of the same year (this is also evident in Figure 5.1). One possible interpretation for this dummy is that 1987 was a particularly cold year for Austria (see Eurostat, 2013). The misspecification tests reported at the bottom of Table 5.6 suggest that the final model is correctly specified.

Belgium

Table 5.7 shows the estimation results of the electricity demand for Belgium. For this country the preferred model is the Ultra Saturation specification. As the coefficient of the variable GDP in the level is negative, the model is re-estimated with a longer dynamic structure (i.e. two lags). The final model (Ultra Saturation II) includes the growth rate of price, a step dummy for 2002, seven step trend dummies, two impulse dummies and the economic variables in levels. Among the several step trend dummy variables, *T:2005* has the largest coefficient (-0.102) and it captures the change in the slope of Belgium's demand that is visible in Figure 5.1 and that is not explained by the economic variables included in the model. Dummy *T:1997* picks up the slowdown in electricity consumption (coefficient -0.038) that occurred between 1997 and 2000, while *T:2001* and *S:2002* capture the recovery of the following years (up to 2004). The misspecification tests reported at the bottom of Table 5.7 reveal that the model is correctly specified.

Switzerland

The Ultra Saturation model is the preferred specification for modelling Switzerland's electricity demand, as reported in Table 5.8. As residual autocorrelation is detected (AR 1-2 test), the model is re-estimated with a longer dynamic structure (i.e. two lags). The final selected model (Ultra Saturation II) includes the one-period lagged growth rate of price, one step dummy for 2002, three step trends for 1983, 1985 and 2006 and the variables electricity price and GDP in levels. The step trend *T:1983* is of particular importance (coefficient 0.10) as it picks up the sudden increase in the slope of demand that is also visible in Figure 5.1. Diagnostic tests reported at the bottom of Table 5.8 confirm that the model Ultra Saturation II is correctly specified.

Germany

The estimated models for Germany's electricity demand are presented in Table 5.9. The Ultra Saturation model is the specification that fits the data best yet again. However, given that the diagnostic tests highlight the presence of residual autocorrelation (AR 1-2 test), the Ultra Saturation model is re-estimated adding two extra lags and eliminating the restriction on the *Trend* variable, given that Germany's demand series does not exhibit a pronounced deterministic trend (see Section 5.3). The final selected model corresponds to a Super Saturation specification, where the lag structure includes up to three lags. The results show that Germany's electricity consumptions is explained by the growth rate of GDP and the growth rate of GDP three-period lagged; a set of step dummies for 1984, 1991, 1992, 1997 and 2003; two impulse dummies for 1987 and 2005, and the variables electricity price and GDP in levels. Among the step dummies, *S:1991* is of particular importance since it captures the dramatic fall in the electricity demand level that is clearly not explained by price and income (see Figure 5.1), but by some other factors that are omitted from the model. The following recovery of electricity demand is captured by *S:1992*. The impulse dummy *I:1987* picks up the impact of a positive temporary shock on Germany's electricity consumption (coefficient 0.038), which may be interpreted as a temperature shock given that 1987 was a particularly cold year for Germany (see Eurostat, 2013). The model passes the misspecification tests, though the residuals are still weakly autocorrelated.

Spain

The estimates of Spain's electricity demand are reported in Table 5.10. The preferred specification is the Super Saturation model and includes the one-period lagged dependent variable, the GDP growth rate, two step dummies for 1993 and 2004, seven impulse dummies for 1982, 1984, 1985, 1988, 1991, 2000, 2006 and the variables electricity price and GDP in levels. The several impulse dummies reveal the presence of many temporary shocks to the electricity demand series, some of which are of important magnitude, like *I:1982*, *I:2000* and *I:2006*, having coefficients that range between 0.055 and 0.095 (in absolute value). In this case, where the price series shows an extremely low variability for many years (from 1982 to 1995), the impulse dummies are particularly helpful to model all the variability in the demand that is not explained by price. The model passes all the misspecification tests, as confirmed by the diagnostics box at the bottom of Table 5.10.

France

The demand of electricity for France is best estimated via a Ultra Saturation model (Table 5.11). The model includes step dummies for 1983, 1991 and 2009, two step trends relating to 1988 and 1989, impulse dummies for 1985, 1995, 1996, 2002, 2004, 2007 and the usual economic variables in levels. *S:1983* and *S:1991* capture the two small increases in the level of France's electricity consumption that are visible in Figure 5.1. *T:1988* and *T:1989* explain the two subsequent changes in the slope of the demand's trend, which starts as positive then becomes negative and then positive again. The several impulse dummies are added by *Autometrics™* to model the effect of temporary shocks on France's electricity consumption that are due to some omitted variables. For example, *I:1985* and *I:1996* may capture the impact of two particularly cold years, while *I:2002* and *I:2007* could reflect two particularly mild years (see Eurostat, 2013). The model is correctly specified.

Italy

The preferred specification to describe Italy's residential demand of electricity is a Ultra Saturation model that features a dynamic structure with three lags, as the original model with only one lag presents problems of misspecification. The final selected model (Ultra Saturation II) comprehends the one-period lagged GDP growth rate, two step dummies for 1984 and 2003, one step trend for 1985, six impulse dummies with small coefficients (*I:1987, I:1995, I:1996, I:1999, I:2004, I:2007*) and the variables electricity price and GDP in levels (Table 5.12). Several impulse dummies are selected by *Autometrics™* to capture the discrepancy between Italy's electricity demand series and the price series, given that the latter has a very high variability not reflected by the demand series. The model is correctly specified.

Netherlands

The Super Saturation model is the specification selected for modelling Netherlands's electricity demand (Table 5.13). The regressors of the final selected model are six step dummies for 1983, 1994, 1997, 1999, 2002 and 2005; six impulse dummies for 1984, 1988, 1991, 1995, 2007 and 2009; and the variables electricity price and GDP in levels. Among the step dummies, *S:1995* explains the increase in the electricity demand that occurs despite the price rise which is obvious in Figure 5.1. Of the impulse dummies, *I:1988* and *I:2009* are the most important picking up two sudden drops in the Dutch electricity demand series that do not find explanation in the behaviour of price and income variables. The final preferred model is correctly specified.

United Kingdom

UK's electricity demand is best fitted by a Ultra Saturation specification (Table 5.14). The final selected model includes the one-period lagged dependent variable, the one-period lagged growth rate of price; six step dummies for 1983, 1985, 1988, 1991, 1998 and 2004; six impulse dummies for 1985, 1989, 1991, 1996, 2001 and 2004; plus the economic variables in levels. The step dummies *S:1985* and *S:1991* pick up three major breaks in the level of the demand's trend function that are also visible in Figure 5.1. As for all other countries, the dummies are selected by *Autometrics*™ to capture the effect on electricity consumption of some variables that are not explicitly modelled. The model passes all the misspecification tests.

Dependent variable $\Delta AT\ EC$

Model Impulse Indicator Saturation			
	Coefficient	**Std.Error**	**p-value**
I:1981	-0.215	0.026	0.000
I:1982	-0.057	0.024	0.029
I:1987	0.239	0.024	0.000
I:2001	0.057	0.024	0.028
Constant F	-3.342	4.250	0.440
Trend F	-0.008	0.008	0.324
$AT\ EC_{t-1}$ ***F***	-0.014	0.053	0.794
$AT\ GDP_{t-1}$ ***F***	0.301	0.335	0.379
$AT\ PRICE_{t-1}$ ***F***	-0.003	0.081	0.967
R^2	0.915	***Adj.*** R^2	0.883
AIC	-4.601	***SC***	-4.180

	Statistics	**p-value**
AR 1-2 test: F(2,19)	4.389	0.027
ARCH 1-1 test: F(1,28)	0.105	0.749
Normality test: $\chi^2(2)$	0.028	0.986
Hetero test: F(8,17)	0.767	0.636
RESET23 test: F(2,19)	0.789	0.469

Model Super Saturation			
	Coefficient	**Std.Error**	**p-value**
S:1995	0.058	0.012	0.000
S:1997	-0.056	0.013	0.001
S.1999	0.063	0.015	0.001
I:1981	-0.223	0.016	0.000
I:1982	-0.044	0.015	0.009
I:1985	0.044	0.015	0.012
I:1987	0.256	0.015	0.000
I:1991	0.041	0.014	0.009
I:2001	0.056	0.014	0.001
Constant F	-6.897	2.780	0.025
Trend F	-0.016	0.005	0.010
$AT\ EC_{t-1}$ ***F***	0.091	0.042	0.048
$AT\ GDP_{t-1}$ ***F***	0.453	0.216	0.052
$AT\ PRICE_{t-1}$ ***F***	0.168	0.061	0.014
R^2	0.977	***Adj.*** R^2	0.958
AIC	-5.573	***SC***	-4.918

	Statistics	**p-value**
AR 1-2 test: F(2,14)	7.510	0.006
ARCH 1-1 test: F(1,28)	0.754	0.393
Normality test: $\chi^2(2)$	1.020	0.600
Hetero test: F(11,12)	2.288	0.085
RESET23 test: F(2,14)	1.299	0.304

Model Ultra Saturation I			
	Coefficient	**Std.Error**	**p-value**
$\Delta AT\ PRICE_{t-1}$	0.185	0.071	0.019
S:1982	-0.252	0.021	0.000
S:1987	0.254	0.012	0.000
S:2007	-0.053	0.016	0.005
T:1986	-0.034	0.005	0.000
T:2001	0.019	0.005	0.002
T:2004	-0.025	0.008	0.008
I:1981	-0.218	0.016	0.000
I:1996	0.034	0.011	0.008
Constant F	0.304	2.800	0.915
Trend F	0.033	0.006	0.000
$AT\ EC_{t-1}$ ***F***	-0.947	0.042	0.000
$AT\ GDP_{t-1}$ ***F***	0.778	0.216	0.002
$AT\ PRICE_{t-1}$ ***F***	-0.209	0.080	0.019
R^2	0.986	***Adj.*** R^2	0.974
AIC	-6.048	***SC***	-5.394

	Statistics	**p-value**
AR 1-2 test: F(2,14)	4.362	0.034
ARCH 1-1 test: F(1,28)	0.189	0.667
Normality test: $\chi^2(2)$	1.762	0.414
Hetero test: F(18,8)	1.223	0.403
RESET23 test: F(2,14)	0.162	0.852

Model Ultra Saturation II (preferred model)			
	Coefficient	**Std.Error**	**p-value**
$\Delta AT\ PRICE_{t-1}$	0.307	0.078	0.001
S:2007	-0.055	0.013	0.001
T:1989	-0.045	0.004	0.000
I:1986	-0.077	0.015	0.000
I:1987	0.129	0.017	0.000
I:1997	-0.035	0.014	0.026
Constant F	0.031	2.910	0.992
Trend F	0.042	0.006	0.000
$AT\ EC_{t-1}$ ***F***	-0.627	0.050	0.000
$AT\ GDP_{t-1}$ ***F***	0.561	0.234	0.028
$AT\ PRICE_{t-1}$ ***F***	-0.272	0.081	0.003
R^2	0.972	***Adj.*** R^2	0.956
AIC	-5.514	***SC***	-4.996

	Statistics	**p-value**
AR 1-2 test: F(2,16)	1.148	0.342
ARCH 1-1 test: F(1,27)	0.392	0.537
Normality test: $\chi^2(2)$	0.240	0.887
Hetero test: F(13,12)	0.880	0.591
RESET23 test: F(2,16)	0.465	0.637

Note: the variables marked with F are held fixed in the search algorithm to avoid potential elimination by Autometrics.

Table 5.6: Estimation output and misspecification tests for alternative models of Austria's electricity demand.

Dependent variable Δ ***BE EC***

Model Impulse Indicator Saturation

	Coefficient	Std.Error	p-value
Δ ***BE*** EC_{t-1}	-0.423	0.102	0.001
Δ ***BE PRICE***	-0.595	0.084	0.000
I:1982	-0.057	0.014	0.001
I:1996	0.030	0.013	0.032
I:2002	0.058	0.013	0.000
I:2004	0.043	0.014	0.006
I:2006	-0.106	0.014	0.000
Constant F	-9.720	2.820	0.003
Trend F	-0.023	0.004	0.000
BE EC_{t-1} ***F***	0.115	0.049	0.031
BE GDP_{t-1} ***F***	0.727	0.193	0.002
BE $PRICE_{t-1}$ ***F***	-0.002	0.087	0.986
R^2	0.948	***Adj.*** R^2	0.916
AIC	-5.657	***SC***	-5.096

	Statistics	p-value
AR 1-2 test: F(2,16)	0.172	0.843
ARCH 1-1 test: F(1,28)	0.195	0.662
Normality test: $\chi^2(2)$	0.976	0.614
Hetero test: F(12,12)	0.221	0.993
RESET23 test: F(2,16)	0.067	0.936

Model Super Saturation

	Coefficient	Std.Error	p-value
Δ ***BE*** EC_{t-1}	-0.400	0.106	0.001
Δ ***BE GDP***	-0.497	0.214	0.033
Δ ***BE PRICE***	-0.554	0.088	0.000
S:2005	-0.042	0.015	0.012
I:1982	-0.043	0.015	0.010
I:2002	0.047	0.014	0.004
I:2006	-0.094	0.016	0.000
Constant F	-0.531	3.580	0.884
Trend F	-0.009	0.005	0.097
BE EC_{t-1} ***F***	0.008	0.064	0.899
BE GDP_{t-1} ***F***	0.131	0.243	0.597
BE $PRICE_{t-1}$ ***F***	-0.201	0.101	0.063
R^2	0.944	***Adj.*** R^2	0.910
AIC	-5.587	***SC***	-5.027

	Statistics	p-value
AR 1-2 test: F(2,16)	1.079	0.363
ARCH 1-1 test: F(1,28)	0.027	0.872
Normality test: $\chi^2(2)$	5.484	0.065
Hetero test: F(15,11)	0.485	0.904
RESET23 test: F(2,16)	0.045	0.957

Model Ultra Saturation I

	Coefficient	Std.Error	p-value
Δ ***BE GDP***	-0.767	0.023	0.000
Δ ***BE PRICE***	-0.403	0.010	0.000
S:1982	-0.026	0.002	0.000
S:1999	-0.010	0.002	0.001
S:2002	0.045	0.002	0.000
T:1997	-0.025	0.001	0.000
T:2003	-0.020	0.001	0.000
T:2006	-0.070	0.003	0.000
I:1984	0.005	0.001	0.006
I:1985	0.018	0.001	0.000
I:1991	0.023	0.002	0.000
I:1992	0.010	0.002	0.000
I:2004	0.042	0.002	0.000
I:2005	0.015	0.003	0.001
I:2006	-0.036	0.002	0.000
Constant F	18.483	0.515	0.000
Trend F	0.046	0.001	0.000
BE EC_{t-1} ***F***	-1.222	0.022	0.000
BE GDP_{t-1} ***F***	-0.421	0.032	0.000
BE $PRICE_{t-1}$ ***F***	-0.382	0.013	0.000
R^2	1.000	***Adj.*** R^2	0.999
AIC	-10.482	***SC***	-9.548

	Statistics	p-value
AR 1-1 test: F(1,9)	4.400	0.065
ARCH 1-1 test: F(1,28)	0.426	0.519
Normality test: $\chi^2(2)$	2.150	0.341
Hetero test: not enough observations		
RESET23 test: F(2,8)	0.284	0.760

Model Ultra Saturation II (preferred model)

	Coefficient	Std.Error	p-value
Δ ***BE PRICE***	-0.167	0.083	0.065
S:2002	0.052	0.009	0.000
T:1987	-0.019	0.004	0.001
T:1991	0.042	0.006	0.000
T:1992	-0.030	0.007	0.001
T:1997	-0.038	0.004	0.000
T:2001	0.014	0.004	0.005
T:2005	-0.102	0.006	0.000
T:2009	0.062	0.014	0.001
I:1987	0.015	0.007	0.055
I:2005	0.060	0.007	0.000
Constant F	8.322	2.210	0.002
Trend F	0.041	0.003	0.000
BE EC_{t-1} ***F***	-1.362	0.077	0.000
BE GDP_{t-1} ***F***	0.488	0.137	0.004
BE $PRICE_{t-1}$ ***F***	-0.290	0.083	0.004
R^2	0.994	***Adj.*** R^2	0.987
AIC	-7.447	***SC***	-6.693

	Statistics	p-value
AR 1-1 test: F(2,11)	2.087	0.171
ARCH 1-1 test: F(1,27)	0.224	0.640
Normality test: $\chi^2(2)$	4.902	0.086
Hetero test: not enough observations		
RESET23 test: F(2,11)	0.897	0.436

Note: the variables marked with F are held fixed in the search algorithm to avoid potential elimination by Autometrics.

Table 5.7: Estimation output and misspecification tests for alternative models of Belgium's electricity demand.

Dependent variable $\Delta CH\,EC$															
Model Impulse Indicator Saturation				***Model Super Saturation***				***Model Ultra Saturation I***				***Model Ultra Saturation II (preferred model)***			
	Coefficient	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**
								S:1984	0.069	0.008	0.000				
				S:1984	0.046	0.010	0.000	***S:1988***	-0.029	0.009	0.004				
				S:2007	-0.043	0.010	0.000	***S:1997***	-0.043	0.009	0.000				
				I:1981	-0.030	0.011	0.014	***S:2007***	-0.029	0.012	0.034				
I:1981	-0.046	0.015	0.005	***I:1982***	-0.064	0.011	0.000	***T:1983***	0.028	0.006	0.000	$\Delta\,CH\,PRICE_{t-1}$	0.518	0.111	0.000
I:1982	-0.074	0.015	0.000	***I:1988***	-0.027	0.009	0.009	***T:1993***	-0.010	0.002	0.001	***S:2002***	-0.031	0.010	0.005
I:1984	0.038	0.015	0.019	***I:1995***	0.024	0.009	0.017	***T:2006***	-0.012	0.005	0.021	***T:1983***	0.100	0.015	0.000
I:1988	-0.031	0.014	0.036	***I:1997***	-0.025	0.010	0.023	***I:1982***	-0.026	0.010	0.016	***T:1985***	-0.052	0.005	0.000
I:1997	-0.043	0.014	0.007	***I:2002***	-0.022	0.009	0.027	***I:2002***	-0.021	0.007	0.010	***T:2006***	-0.034	0.004	0.000
Constant F	-0.418	1.780	0.817	***Constant F***	0.929	1.150	0.433	***Constant F***	4.890	1.460	0.004	***Constant F***	1.260	1.380	0.375
Trend F	0.000	0.002	0.950	***Trend F***	0.003	0.001	0.024	***Trend F***	-0.005	0.005	0.327	***Trend F***	-0.043	0.012	0.002
$CH\,EC_{t-1}$ ***F***	-0.183	0.073	0.020	$CH\,EC_{t-1}$ ***F***	-0.518	0.068	0.000	$CH\,EC_{t-1}$ ***F***	-0.975	0.075	0.000	$CH\,EC_{t-1}$ ***F***	-0.796	0.076	0.000
$CH\,GDP_{t-1}$ ***F***	0.153	0.151	0.325	$CH\,GDP_{t-1}$ ***F***	0.328	0.108	0.008	$CH\,GDP_{t-1}$ ***F***	0.356	0.100	0.003	$CH\,GDP_{t-1}$ ***F***	0.631	0.128	0.000
$CH\,PRICE_{t-1}$ ***F***	0.047	0.060	0.448	$CH\,PRICE_{t-1}$ ***F***	-0.059	0.044	0.206	$CH\,PRICE_{t-1}$ ***F***	-0.079	0.050	0.132	$CH\,PRICE_{t-1}$ ***F***	-0.355	0.069	0.000
R^2	0.801	*Adj.* R^2	0.712	R^2	0.926	*Adj.* R^2	0.874	R^2	0.957	*Adj.* R^2	0.923	R^2	0.913	*Adj.* R^2	0.872
AIC	-5.600	***SC***	-5.133	***AIC***	-6.390	***SC***	-5.782	***AIC***	-6.874	***SC***	-6.220	***AIC***	-6.454	***SC***	-5.982
	Statistics	**p-value**			**Statistics**	**p-value**			**Statistics**	**p-value**			**Statistics**	**p-value**	
AR 1-2 test: F(2,18)	0.479	0.627		***AR 1-2 test: F(2,15)***	6.283	0.010		***AR 1-2 test: F(2,14)***	4.150	0.038		***AR 1-2 test: F(2,17)***	1.562	0.239	
ARCH 1-1 test: F(1,28)	0.001	0.972		***ARCH 1-1 test: F(1,28)***	0.475	0.496		***ARCH 1-1 test: F(1,28)***	0.024	0.877		***ARCH 1-1 test: F(1,27)***	0.235	0.632	
Normality test: $\chi^2(2)$	0.385	0.825		***Normality test:*** $\chi^2(2)$	0.438	0.803		***Normality test:*** $\chi^2(2)$	0.682	0.711		***Normality test:*** $\chi^2(2)$	0.363	0.834	
Hetero test: F(8,16)	1.024	0.458		***Hetero test: F(10,13)***	1.686	0.187		***Hetero test: F(18,9)***	0.571	0.851		***Hetero test: F(15,12)***	1.339	0.309	
RESET23 test: F(2,18)	0.547	0.588		***RESET23 test: F(2,15)***	0.352	0.709		***RESET23 test: F(2,14)***	1.774	0.206		***RESET23 test: F(2,17)***	0.366	0.699	

Note: the variables marked with F are held fixed in the search algorithm to avoid potential elimination by Autometrics.

Table 5.8: Estimation output and misspecification tests for alternative models of Switzerland's electricity demand.

Dependent variable Δ DE EC															
Model Impulse Indicator Saturation				***Model Super Saturation I***				***Model Super Saturation II (preferred model)***				***Model Ultra Saturation***			
	Coefficient	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**
				S:1983	0.023	0.005	0.000					***S:1991***	-0.108	0.004	0.000
				S:1984	0.033	0.005	0.000					***S:1998***	-0.016	0.003	0.000
				S:1985	0.030	0.006	0.000					***S:2002***	0.009	0.003	0.005
				S:1991	-0.091	0.009	0.000					***T:1984***	0.033	0.003	0.000
				S:2002	0.015	0.004	0.002	Δ ***DE GDP***	-0.490	0.080	0.000	***T:1986***	-0.037	0.002	0.000
				S:2007	-0.017	0.005	0.002	Δ ***DE*** GDP_{t-3}	-0.837	0.087	0.000	***T:2004***	-0.009	0.001	0.000
				I:1987	0.035	0.004	0.000	***S:1984***	0.030	0.007	0.001	***I:1987***	0.036	0.003	0.000
				I:1991	-0.024	0.008	0.011	***S:1991***	-0.112	0.008	0.000	***I:1992***	0.008	0.004	0.045
I:1988	-0.044	0.016	0.011	***I:1993***	0.016	0.005	0.005	***S:1992***	0.046	0.010	0.000	***I:1993***	0.023	0.003	0.000
I:1991	-0.123	0.016	0.000	***I:1994***	-0.013	0.004	0.011	***S:1997***	-0.037	0.006	0.000	***I:1994***	-0.013	0.003	0.001
I:1996	0.046	0.014	0.004	***I:1996***	0.048	0.004	0.000	***S:2003***	0.020	0.005	0.001	***I:1996***	0.043	0.003	0.000
I:1997	-0.036	0.014	0.020	***I:2000***	-0.017	0.004	0.002	***I:1987***	0.038	0.006	0.000	***I:2000***	-0.018	0.003	0.000
Constant F	2.199	2.160	0.322	***Constant F***	12.862	1.220	0.000	***I:2005***	-0.012	0.006	0.081	***Constant F***	18.629	0.731	0.000
Trend F	0.002	0.002	0.543	***Trend F***	0.010	0.001	0.000	***Constant F***	2.852	0.544	0.000	***Trend F***	0.022	0.001	0.000
DE EC_{t-1} ***F***	-0.016	0.081	0.844	***DE*** EC_{t-1} ***F***	-0.837	0.052	0.000	***DE*** EC_{t-1} ***F***	-0.405	0.060	0.000	***DE*** EC_{t-1} ***F***	-1.007	0.024	0.000
DE GDP_{t-1} ***F***	-0.126	0.108	0.262	***DE*** GDP_{t-1} ***F***	-0.201	0.062	0.007	***DE*** GDP_{t-1} ***F***	0.188	0.039	0.000	***DE*** GDP_{t-1} ***F***	-0.480	0.045	0.000
DE $PRICE_{t-1}$ ***F***	-0.046	0.035	0.199	***DE*** $PRICE_{t-1}$ ***F***	-0.061	0.015	0.001	***DE*** $PRICE_{t-1}$ ***F***	-0.159	0.022	0.000	***DE*** $PRICE_{t-1}$ ***F***	-0.037	0.016	0.036
R^2	0.857	***Adj.*** R^2	0.802	R^2	0.993	***Adj.*** R^2	0.984	R^2	0.983	***Adj.*** R^2	0.969	R^2	0.997	***Adj.*** R^2	0.994
AIC	-8.013	***SC***	-5.122	***AIC***	-6.634	***SC***	-7.219	***AIC***	-7.271	***SC***	-6.653	***AIC***	-8.937	***SC***	-8.143
	Statistics	**p-value**			**Statistics**	**p-value**			**Statistics**	**p-value**			**Statistics**	**p-value**	
AR 1-2 test: F(2,19)	0.093	0.911		***AR 1-2 test: F(2,11)***	2.319	0.144		***AR 1-2 test: F(2,13)***	4.959	0.025		***AR 1-2 test: F(2,11)***	10.131	0.003	
ARCH 1-1 test: F(1,28)	0.288	0.596		***ARCH 1-1 test: F(1,28)***	1.383	0.25		***ARCH 1-1 test: F(1,28)***	0.085	0.773		***ARCH 1-1 test: F(1,28)***	0.070	0.794	
Normality test: χ_2 ***(2)***	0.474	0.789		***Normality test:*** χ_2 ***(2)***	0.556	0.757		***Normality test:*** χ_2 ***(2)***	2.079	0.354		***Normality test:*** χ_2 ***(2)***	0.903	0.637	
Hetero test: F(8,17)	1.281	0.316		***Hetero test: not enough observation***				***Hetero test: F(14,10)***	1.398	0.301		***Hetero test: not enough observation***			
RESET23 test: F(2,19)	1.194	0.325		***RESET23 test: F(2,11)***	0.322	0.731		***RESET23 test: F(2,13)***	0.783	0.478		***RESET23 test: F(2,11)***	0.975	0.408	

Note: the variables marked with F are held fixed in the search algorithm to avoid potential elimination by Autometrics.

Table 5.9: Estimation output and misspecification tests for alternative models of Germany's electricity demand.

Dependent variable Δ ***ES EC***											
Model Impulse Indicator Saturation				***Model Super Saturation (preferred model)***				***Model Ultra Saturation***			
	Coefficient	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**
				Δ $\boldsymbol{ES\ EC_{t-1}}$	-0.439	0.052	0.000	***S:1991***	-0.046	0.016	0.011
				Δ $\boldsymbol{ES\ GDP}$	1.450	0.097	0.000	***S:1996***	-0.042	0.013	0.007
				S:1993	0.040	0.010	0.001	***S:2000***	-0.096	0.016	0.000
Δ $\boldsymbol{ES\ EC_{t-1}}$	-0.379	0.075	0.000	***S:2004***	0.028	0.008	0.004	***S:2009***	-0.086	0.024	0.003
Δ $\boldsymbol{ES\ GDP}$	1.189	0.141	0.000	***I:1982***	-0.055	0.008	0.000	***T:1982***	-3.345	0.733	0.000
I:1982	-0.050	0.014	0.002	***I:1984***	0.049	0.008	0.000	***T:1992***	-0.038	0.010	0.002
I:1984	0.044	0.013	0.004	***I:1985***	-0.022	0.008	0.020	***T:1994***	0.049	0.010	0.000
I:1985	-0.030	0.014	0.050	***I:1988***	-0.036	0.008	0.000	***T:2006***	0.096	0.017	0.000
I:1988	-0.039	0.013	0.009	***I:1991***	-0.019	0.008	0.035	***T:2007***	-0.130	0.021	0.000
I:2000	-0.097	0.013	0.000	***I:2000***	-0.095	0.008	0.000	***I:1980***	3.314	0.725	0.000
I:2006	0.067	0.013	0.000	***I:2006***	0.058	0.008	0.000	***I:1984***	0.042	0.014	0.008
Constant F	4.292	1.550	0.014	***Constant F***	-0.728	1.430	0.619	***Constant F***	0.000	--	--
Trend F	0.014	0.004	0.002	***Trend F***	0.000	0.005	0.987	***Trend F***	3.414	0.741	0.000
$\boldsymbol{ES\ EC_{t-1}}$ ***F***	-0.342	0.077	0.000	$\boldsymbol{ES\ EC_{t-1}}$ ***F***	-0.313	0.072	0.001	$\boldsymbol{ES\ EC_{t-1}}$ ***F***	-1.505	0.113	0.000
$\boldsymbol{ES\ GDP_{t-1}}$ ***F***	-0.018	0.130	0.889	$\boldsymbol{ES\ GDP_{t-1}}$ ***F***	0.331	0.098	0.004	$\boldsymbol{ES\ GDP_{t-1}}$ ***F***	0.153	0.197	0.452
$\boldsymbol{ES\ PRICE_{t-1}}$ ***F***	-0.137	0.022	0.000	$\boldsymbol{ES\ PRICE_{t-1}}$ ***F***	-0.082	0.016	0.000	$\boldsymbol{ES\ PRICE_{t-1}}$ ***F***	-0.155	0.069	0.042
$\boldsymbol{R^2}$	0.953	***Adj.*** $\boldsymbol{R^2}$	0.919	$\boldsymbol{R^2}$	0.987	***Adj.*** $\boldsymbol{R^2}$	0.972	$\boldsymbol{R^2}$	0.960	***Adj.*** $\boldsymbol{R^2}$	0.916
AIC	-5.698	***SC***	-5.091	***AIC***	-6.763	***SC***	-6.016	***AIC***	-5.657	***SC***	-4.910
	Statistics	**p-value**			**Statistics**	**p-value**			**Statistics**	**p-value**	
AR 1-2 test: F(2,15)	1.841	0.193		***AR 1-2 test: F(2,12)***	2.778	0.102		***AR 1-2 test: F(2,12)***	4.283	0.040	
ARCH 1-1 test: F(1,28)	0.009	0.925		***ARCH 1-1 test: F(1,28)***	2.004	0.168		***ARCH 1-1 test: F(1,28)***	0.145	0.706	
Normality test: $\boldsymbol{\chi_2(2)}$	0.713	0.700		***Normality test:*** $\boldsymbol{\chi_2(2)}$	5.164	0.076		***Normality test:*** $\boldsymbol{\chi_2(2)}$	0.024	0.988	
Hetero test: F(12,11)	0.403	0.933		***Hetero test: not enough observations***				***Hetero test: not enough observations***			
RESET23 test: F(2,15)	0.478	0.629		***RESET23 test: F(2,12)***	0.95358	0.413		***RESET23 test: F(2,12)***	0.086	0.918	

Note: the variables marked with F are held fixed in the search algorithm to avoid potential elimination by Autometrics.

Table 5.10: Estimation output and misspecification tests for alternative models of Spain's electricity demand.

Dependent variable Δ FR EC

Model Impulse Indicator Saturation

	Coefficient	Std.Error	p-value
I:1995	-0.063	0.025	0.020
I:2007	-0.062	0.026	0.029
I:2009	0.061	0.028	0.039
Constant F	-5.911	4.580	0.211
Trend F	0.012	0.008	0.116
$FR\ EC_{t-1}$ ***F***	-0.494	0.101	0.000
$FR\ GDP_{t-1}$ ***F***	0.621	0.322	0.067
$FR\ PRICE_{t-1}$ ***F***	0.552	0.139	0.001
R^2	0.672	***Adj.*** R^2	0.567
AIC	-4.400	***SC***	-4.026
	Statistics	**p-value**	
AR 1-2 test: F(2,20)	2.221	0.134	
ARCH 1-1 test:F(1,28)	2.737	0.109	
Normality test: $\chi_2(2)$	1.425	0.490	
Hetero test: F(8,18)	1.172	0.367	
RESET23 test: F(2,20)	0.003	0.997	

Model Super Saturation

	Coefficient	Std.Error	p-value
S:2005	-0.062	0.016	0.001
I:1995	-0.077	0.021	0.001
I:1997	-0.059	0.022	0.014
I:2009	0.085	0.023	0.001
Constant F	-2.124	3.900	0.593
Trend F	0.025	0.007	0.002
$FR\ EC_{t-1}$ ***F***	-0.615	0.094	0.000
$FR\ GDP_{t-1}$ ***F***	0.396	0.273	0.162
$FR\ PRICE_{t-1}$ ***F***	0.673	0.120	0.000
R^2	0.786	***Adj.*** R^2	0.705
AIC	-4.763	***SC***	-4.342
	Statistics	**p-value**	
AR 1-2 test: F(2,19)	2.125	0.147	
ARCH 1-1 test:F(1,28)	0.062	0.805	
Normality test: $\chi_2(2)$	4.567	0.102	
Hetero test: F(9,17)	0.526	0.836	
RESET23 test: F(2,19)	0.243	0.787	

Model Ultra Saturation (preferred model)

	Coefficient	Std.Error	p-value
S:1983	0.064	0.012	0.000
S:1991	0.077	0.009	0.000
S:2009	0.078	0.009	0.000
T:1988	-0.096	0.011	0.000
T:1989	0.060	0.008	0.000
I:1985	0.024	0.009	0.016
I:1995	-0.050	0.009	0.000
I:1996	0.030	0.010	0.009
I:2002	-0.033	0.009	0.002
I:2004	0.036	0.008	0.001
I:2007	-0.037	0.009	0.001
Constant F	6.051	2.774	0.047
Trend F	0.046	0.007	0.000
$FR\ EC_{t-1}$ ***F***	-0.999	0.084	0.000
$FR\ GDP_{t-1}$ ***F***	0.406	0.146	0.015
$FR\ PRICE_{t-1}$ ***F***	-0.161	0.077	0.057
R^2	0.979	***Adj.*** R^2	0.957
AIC	-6.628	***SC***	-5.881
	Statistics	**p-value**	
AR 1-2 test: F(2,12)	1.018	0.391	
ARCH 1-1 test: F(1,28)	0.248	0.623	
Normality test: $\chi_2(2)$	5.502	0.064	
Hetero test: not enough observations			
RESET23 test: F(2,12)	1.459	0.271	

Note: the variables marked with F are held fixed in the search algorithm to avoid potential elimination by Autometrics.

Table 5.11: Estimation output and misspecification tests for alternative models of France's electricity demand.

Dependent variable Δ IT EC															
Model Impulse Indicator Saturation				***Model Super Saturation***				***Model Ultra Saturation I***				***Model Ultra Saturation II (preferred model)***			
	Coefficient	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**
I:1980	-0.034	0.007	0.000												
I:1981	-0.039	0.005	0.000					$\Delta\ IT\ GDP_{t-1}$	-0.541	0.083	0.000	$\Delta\ IT\ GDP_{t-1}$	-0.646	0.067	0.000
I:1983	-0.036	0.004	0.000					***S:1982***	0.038	0.008	0.000	***S:1984***	0.081	0.006	0.000
I:1984	0.019	0.004	0.001	$\Delta\ IT\ GDP_{t-1}$	-0.563	0.116	0.000	***S:1984***	0.054	0.009	0.000	***S:2003***	0.017	0.002	0.000
I:1987	0.021	0.004	0.000	***S:1984***	-2.959	1.000	0.009	***S:1987***	0.021	0.005	0.002	***T:1985***	0.021	0.004	0.000
I:1991	0.010	0.004	0.023	***S:2003***	0.014	0.005	0.009	***S:1999***	0.011	0.004	0.022	***I:1987***	0.016	0.003	0.000
I:2000	-0.010	0.004	0.020	***I:1980***	-2.998	1.000	0.008	***S:2003***	0.017	0.004	0.001	***I:1995***	0.015	0.003	0.001
I:2001	-0.017	0.004	0.001	***I:1981***	-3.017	1.000	0.008	***T:1985***	0.029	0.004	0.000	***I:1996***	0.014	0.003	0.001
I:2003	0.013	0.004	0.005	***I:1982***	-2.987	1.000	0.009	***T:1992***	-0.019	0.004	0.001	***I:1999***	0.011	0.003	0.001
I:2004	0.015	0.004	0.002	***I:1983***	-3.015	1.000	0.008	***T:2004***	0.014	0.004	0.002	***I:2004***	0.007	0.003	0.027
I:2007	-0.016	0.004	0.001	***I:1987***	0.017	0.006	0.011	***T:2006***	-0.023	0.005	0.001	***I:2007***	-0.007	0.003	0.025
Constant F	-0.750	0.607	0.237	***Constant F***	0.000	--	--	***Constant F***	7.739	2.280	0.004	***Constant F***	-2.780	0.459	0.000
Trend F	0.000	0.001	0.672	***Trend F***	-0.004	0.001	0.014	***Trend F***	-0.002	0.008	0.822	***Trend F***	-0.024	0.004	0.000
$IT\ EC_{t-1}$ ***F***	-0.326	0.034	0.000	$IT\ EC_{t-1}$ ***F***	-0.495	0.064	0.000	$IT\ EC_{t-1}$ ***F***	-1.085	0.118	0.000	$IT\ EC_{t-1}$ ***F***	-0.596	0.038	0.000
$IT\ GDP_{t-1}$ ***F***	0.322	0.060	0.000	$IT\ GDP_{t-1}$ ***F***	0.615	0.097	0.000	$IT\ GDP_{t-1}$ ***F***	0.256	0.104	0.027	$IT\ GDP_{t-1}$ ***F***	0.695	0.048	0.000
$IT\ PRICE_{t-1}$ ***F***	-0.038	0.013	0.012	$IT\ PRICE_{t-1}$ ***F***	-0.034	0.022	0.141	$IT\ PRICE_{t-1}$ ***F***	0.054	0.022	0.025	$IT\ PRICE_{t-1}$ ***F***	-0.063	0.012	0.000
R^2	0.976	***Adj.*** R^2	0.950	R^2	0.932	***Adj.*** R^2	0.883	R^2	0.976	***Adj.*** R^2	0.953	R^2	0.989	***Adj.*** R^2	0.977
AIC	-8.121	***SC***	-7.373	***AIC***	-7.278	***SC***	-6.671	***AIC***	-8.172	***SC***	-7.472	***AIC***	-8.892	***SC***	-8.179
	Statistics	**p-value**			**Statistics**	**p-value**			**Statistics**	**p-value**			**Statistics**	**p-value**	
AR 1-2 test: F(2,12)	0.038	0.963		***AR 1-2 test: F(2,15)***	1.393	0.279		***AR 1-2 test: F(2,13)***	9.376	0.003		***AR 1-2 test: F(2,11)***	1.505	0.264	
ARCH 1-1 test: F(1,28)	1.657	0.209		***ARCH 1-1 test: F(1,28)***	0.227	0.638		***ARCH 1-1 test: F(1,28)***	1.857	0.184		***ARCH 1-1 test: F(1,26)***	0.494	0.488	
Normality test: $\chi_2(2)$	4.397	0.111		***Normality test:*** $\chi_2(2)$	1.153	0.562		***Normality test:*** $\chi_2(2)$	2.447	0.294		***Normality test:*** $\chi_2(2)$	0.632	0.729	
Hetero test: not enough observations				***Hetero test: F(11,13)***	1.3694	0.292		***Hetero test: not enough observations***				***Hetero test: not enough observations***			
RESET23 test:F(2,12)	0.987	0.401		***RESET23 test:F(2,15)***	0.565	0.58		***RESET23 test:F(2,13)***	8.828	0.004		***RESET23 test:F(2,11)***	0.884	0.441	

Note: the variables marked with F are held fixed in the search algorithm to avoid potential elimination by Autometrics.

Table 5.12: Estimation output and misspecification tests for alternative models of Italy's electricity demand.

Dependent variable $\Delta NL\ EC$											
Model Impulse Indicator Saturation				***Model Super Saturation (preferred model)***				***Model Ultra Saturation***			
	Coefficient	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**
				S:1983	0.037	0.004	0.000				
				S:1994	0.016	0.003	0.000				
				S:1997	0.012	0.003	0.001				
				S:1999	0.007	0.003	0.020				
				S:2002	0.027	0.003	0.000				
I:1982	-0.020	0.007	0.006	***S:2005***	0.025	0.003	0.000				
I:1984	0.019	0.006	0.009	***I:1984***	0.017	0.003	0.000				
I:1988	-0.087	0.006	0.000	***I:1988***	-0.087	0.003	0.000				
I:1995	0.036	0.006	0.000	***I:1991***	0.007	0.003	0.024				
I:2004	-0.013	0.006	0.058	***I:1995***	0.035	0.003	0.000				
I:2007	-0.044	0.007	0.000	***I:2007***	-0.037	0.003	0.000	***T:1996***	-0.006	0.003	0.024
I:2009	-0.056	0.006	0.000	***I:2009***	-0.056	0.003	0.000	***I:1988***	-0.087	0.016	0.000
Constant F	1.568	0.579	0.015	***Constant F***	-0.567	0.549	0.321	***Constant F***	0.663	1.460	0.655
Trend F	0.004	0.001	0.011	***Trend F***	-0.006	0.001	0.000	***Trend F***	0.005	0.003	0.152
$NL\ EC_{t-1}$ ***F***	-0.147	0.044	0.003	$NL\ EC_{t-1}$ ***F***	-0.159	0.025	0.000	$NL\ EC_{t-1}$ ***F***	-0.129	0.107	0.241
$NL\ GDP_{t-1}$ ***F***	-0.011	0.054	0.839	$NL\ GDP_{t-1}$ ***F***	0.192	0.041	0.000	$NL\ GDP_{t-1}$ ***F***	0.032	0.130	0.809
$NL\ PRICE_{t-1}$ ***F***	-0.004	0.009	0.686	$NL\ PRICE_{t-1}$ ***F***	-0.061	0.006	0.000	$NL\ PRICE_{t-1}$ ***F***	0.036	0.034	0.306
R^2	0.963	***Adj.*** R^2	0.940	R^2	0.996	***Adj.*** R^2	0.991	R^2	0.697	***Adj.*** R^2	0.617
AIC	-7.183	***SC***	-6.622	***AIC***	-9.047	***SC***	-8.253	***AIC***	-5.423	***SC***	-5.096
	Statistics	**p-value**			**Statistics**	**p-value**			**Statistics**	**p-value**	
AR 1-2 test: F(2,16)	4.380	0.030		***AR 1-1 test: F(1,12)***	0.726	0.410		***AR 1-2 test: F(2,21)***	2.527	0.104	
ARCH 1-1 test: F(1,28)	0.174	0.680		***ARCH 1-1 test: F(1,28)***	2.479	0.127		***ARCH 1-1 test: F(1,28)***	0.085	0.773	
Normality test: $\chi^2(2)$	0.332	0.847		***Normality test:*** $\chi^2(2)$	1.482	0.477		***Normality test:*** $\chi^2(2)$	0.163	0.922	
Hetero test: F(8,14)	1.811	0.158		***Hetero test: not enough observations***				***Hetero test: F(10,18)***	2.112	0.081	
RESET23 test: F(2,16)	0.444	0.649		***RESET23 test: F(2,11)***	1.980	0.184		***RESET23 test: F(2,21)***	0.960	0.399	

Note: the variables marked with F are held fixed in the search algorithm to avoid potential elimination by Autometrics.

Table 5.13: Estimation output and misspecification tests for alternative models of Netherlands's electricity demand.

Dependent variable Δ UK EC											
Model Impulse Indicator Saturation				***Model Super Saturation***				***Model Ultra Saturation (preferred model)***			
	Coefficient	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**
								Δ ***UK*** $\boldsymbol{EC_{t-1}}$	-0.162	0.016	0.000
				Δ ***UK*** $\boldsymbol{EC_{t-1}}$	-0.148	0.032	0.001	Δ ***UK*** $\boldsymbol{PRICE_{t-1}}$	-0.134	0.008	0.000
				Δ ***UK*** $\boldsymbol{GDP_{t-1}}$	0.126	0.044	0.014	***S:1983***	-0.008	0.002	0.002
				S:1986	0.066	0.004	0.000	***S:1985***	0.071	0.002	0.000
				S:1988	-0.034	0.004	0.000	***S:1988***	-0.034	0.002	0.000
				S:1991	0.075	0.006	0.000	***S:1991***	0.076	0.002	0.000
				S:2002	-0.014	0.004	0.002	***S:1998***	0.005	0.002	0.024
				S:2004	0.069	0.004	0.000	***S:2004***	0.073	0.002	0.000
				S:2008	0.025	0.005	0.000	***I:1985***	-0.032	0.002	0.000
				I:1985	0.041	0.004	0.000	***I:1989***	-0.011	0.002	0.000
				I:1989	-0.015	0.004	0.003	***I:1991***	-0.032	0.002	0.000
				I:1991	-0.030	0.006	0.000	***I:1996***	0.036	0.002	0.000
I:1996	0.038	0.018	0.046	***I:1996***	0.038	0.003	0.000	***I:2001***	0.013	0.001	0.000
I:2005	0.053	0.019	0.010	***I:2004***	-0.082	0.005	0.000	***I:2004***	-0.085	0.002	0.000
Constant F	7.645	1.930	0.001	***Constant F***	7.536	0.718	0.000	***Constant F***	6.621	0.303	0.000
Trend F	0.009	0.003	0.010	***Trend F***	-0.001	0.001	0.412	***Trend F***	-0.002	0.001	0.008
UK $\boldsymbol{EC_{t-1}}$ ***F***	-0.635	0.126	0.000	***UK*** $\boldsymbol{EC_{t-1}}$ ***F***	-0.891	0.041	0.000	***UK*** $\boldsymbol{EC_{t-1}}$ ***F***	-0.906	0.023	0.000
UK $\boldsymbol{GDP_{t-1}}$ ***F***	-0.015	0.124	0.903	***UK*** $\boldsymbol{GDP_{t-1}}$ ***F***	0.257	0.063	0.002	***UK*** $\boldsymbol{GDP_{t-1}}$ ***F***	0.307	0.024	0.000
UK $\boldsymbol{PRICE_{t-1}}$ ***F***	-0.057	0.035	0.124	***UK*** $\boldsymbol{PRICE_{t-1}}$ ***F***	-0.175	0.017	0.000	***UK*** $\boldsymbol{PRICE_{t-1}}$ ***F***	-0.088	0.005	0.000
R^2	0.704	***Adj.*** R^2	0.626	R^2	0.994	***Adj.*** R^2	0.986	R^2	0.999	***Adj.*** R^2	0.998
AIC	-5.124	***SC***	-4.797	***AIC***	-8.355	***SC***	-7.514	***AIC***	-10.155	***SC***	-9.268
	Statistics	**p-value**			**Statistics**	**p-value**			**Statistics**	**p-value**	
AR 1-2 test: F(2,21)	0.819	0.455		***AR 1-2 test: F(2,10)***	4.375	0.043		***AR 1-1 test: F(1,10)***	3.884	0.077	
ARCH 1-1 test: F(1,28)	0.213	0.648		***ARCH 1-1 test: F(1,28)***	0.768	0.388		***ARCH 1-1 test: F(1,28)***	0.033	0.858	
Normality test: $\chi^2(2)$	1.424	0.491		***Normality test:*** $\chi^2(2)$	10.838	0.004		***Normality test:*** $\chi^2(2)$	5.139	0.077	
Hetero test: F(8,19)	1.087	0.413		***Hetero test: not enough observations***				***Hetero test: not enough observations***			
RESET23 test: F(2,21)	0.263	0.771		***RESET23 test: F(2,10)***	1.469	0.276		***RESET23 test: F(2,9)***	0.013	0.987	

Note: the variables marked with F are held fixed in the search algorithm to avoid potential elimination by Autometrics.

Table 5.14: Estimation output and misspecification tests for alternative models of UK's electricity demand.

5.6.1 Long-run elasticities and electricity demand trends

This section reports the long-run income and price elasticities, calculated as long-run solutions of the final selected unrestricted ECM specifications presented in Section 5.6, and describes the main features of the electricity demand trends. All the income and price elasticities are statistically significant, given that the estimated coefficients of these variables in levels were all found to be statistically significant, and have the correct sign, i.e. positive for income elasticity and negative for price elasticity (Table 5.15). The elasticity estimates highlight some similarities between the nine European countries. Income elasticities are less than one or close to one for all countries, which is consistent with the story that electricity is a necessity good rather than a luxury good for developed nations (see for instance Sutherland, 1983; Chern and Bouis, 1988; Silk and Joutz ,1997; Narayan and Smyth, 2005; Narayan et al., 2007; Dergiades and Tsoulfideis, 2008; Blázquez et al., 2013). Residential electricity demand in Europe is price inelastic, as the price elasticities always have an absolute value of less than one. This finding is also in line with what is found in the literature, in particular Silk and Joutz (1997), Beenstock et al. (1999), Holtedahl and Joutz (2004), Hondroyiannis (2004), Narayan and Smyth (2005); Halicioglu (2007), Sa'ad (2009), Dilaver and Hunt (2011b), Blázquez et al. (2013). Long-run income elasticities range between 0.34 (UK) and 1.20 (Netherlands), and price elasticities range between -0.45 (Switzerland) and -0.10 (UK). Income and price elasticities are quite alike for Austria and Switzerland and for France and Belgium, this is perhaps due to the geographical and cultural proximity of these countries.

	Selected model	*Long-run income elasticity*	*Long-run price elasticity*
Austria	Ultra Saturation	0.89	-0.43
Belgium	Ultra Saturation	0.36	-0.21
Switzerland	Ultra Saturation	0.79	-0.45
Germany	Super Saturation	0.46	-0.39
Spain	Super Saturation	1.06	-0.26
France	Ultra Saturation	0.41	-0.16
Italy	Ultra Saturation	1.17	-0.11
Netherlands	Super Saturation	1.20	-0.38
UK	Ultra Saturation	0.34	-0.10

Table 5.15: Long-run income and price elasticities.

These estimates differ from those presented in Blázquez et al. (2013) and Narayan et al. (2007). The estimates of Spain's income and price elasticities presented here are larger than those found by Blázquez et al. (2013), which are 0.61 and -0.19 for income and price elasticity respectively. This discrepancy may be explained by the difference in the data used, given that Blázquez et al. (2013) analyse a panel of 47 Spanish provinces over the period 2000-2008. A marked difference is found with the results of Narayan et al. (2007), who obtain 1.49 and -0.50 for income and price elasticity of France's residential electricity demand, 0 and -4.20 for income and price elasticity of Germany's demand, and non-significant coefficients for both income and price elasticity of Italy and UK demand.

Using the dummies selected by *Autometrics™* it is possible to construct the underlying electricity demand trends which capture all the non-stationary components omitted from the long-run relationship. Figure 5.2 shows the estimated trends for the nine European countries. All trends feature structural breaks in both the level and the slope, suggesting alternation between periods when technical progress and consumers' environmentally friendly behaviour may have led to energy saving (ceteris paribus) and periods when consumers' preferences towards a larger use of electrical appliances (i.e. higher demand of lighting and heating services) has more than offset any progress in energy efficiency. Of course, the precise identification of the impact of each of the omitted variables is impossible given that the trends capture the overall effect of the omitted variable mentioned above. For Austria, Italy and the Netherlands, the periods in which the trend slopes downward, implying that residential electricity demand declines even after controlling for price and income effects, slightly prevails over the periods in which the opposite occurs. Germany's demand trend features a large negative shift from 1991 onwards, which may be attributed to a permanent increase in energy efficiency for both electrical appliances and space heating and to an increased sensitivity to and improvement of German households energy conservation. By contrast, for Belgium and Switzerland the trend is upward sloping up to 2005 and 2006, respectively. Then, a break in the slope suggests that technical progress and a more environmentally conscious attitude may have prevailed and have led to a reduction in consumption.

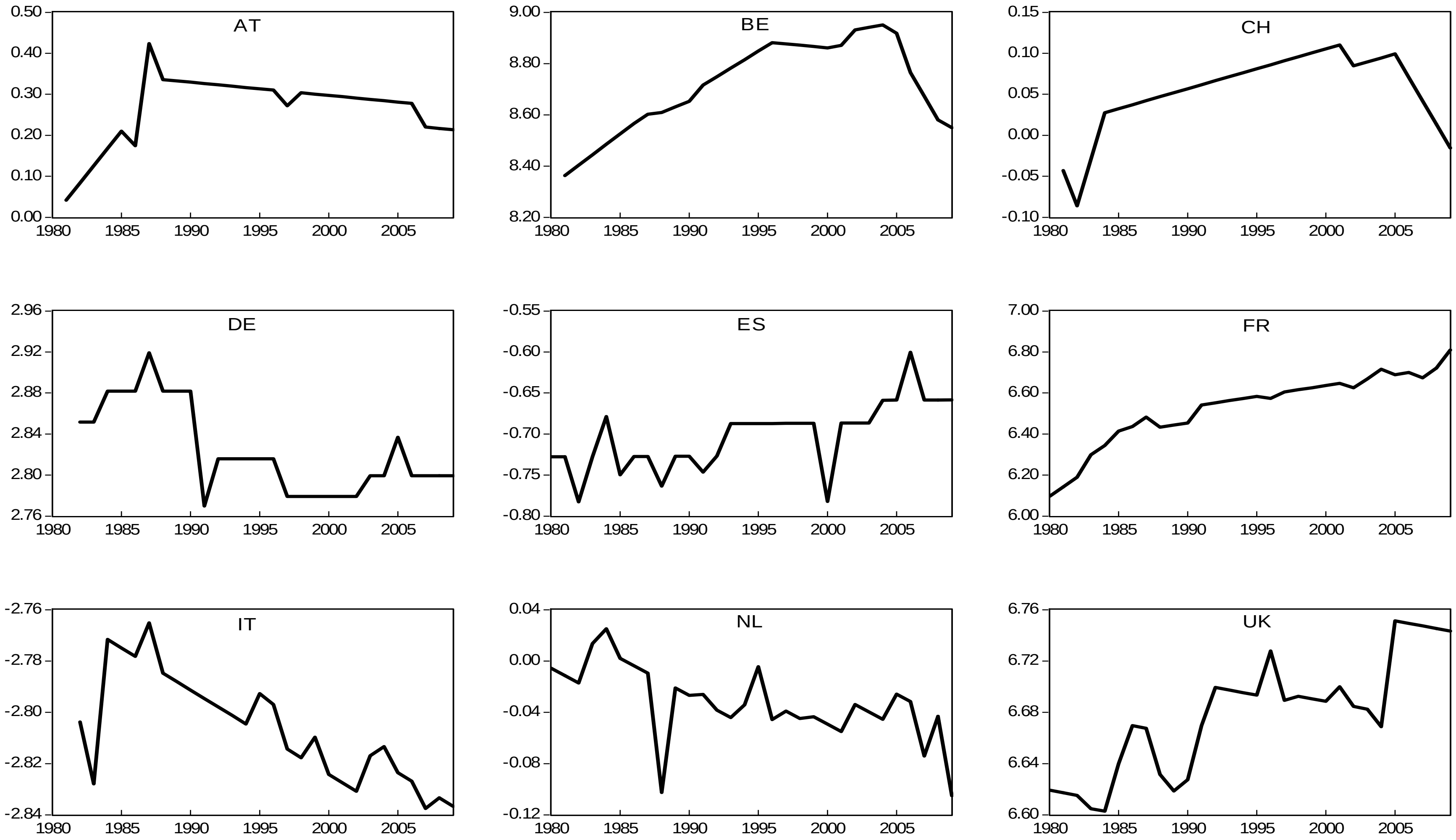

Figure 5.2: Electricity demand trends.

France's electricity demand trend is clearly upward sloping and shows that over the past thirty years French households have exhibited an increasing demand of lighting, cooling and heating services that has more than offset the impact of improved technical efficiency of appliances. UK's electricity demand trend features two large positive shifts in the level (in 1991 and in 2004), which may be attributed to important changes in households' attitude towards electricity-intensive goods usage. In Spain, the trend exhibits two small breaks in the level (in 1993 and in 2004) and may indicate that changes in consumers' preferences towards a more comfortable lifestyle have counterbalanced any improvement in technical efficiency.

Given that the residential sectors of the countries analysed accounted for about the 67% of total CO_2 emissions due to electricity generation in the area comprising EU-27 and Switzerland in 2010, the results presented in this chapter have implications for EU energy policy makers. In particular, as residential electricity demand is price inelastic for all nine countries, any policy aimed at energy conservation using only price increase as an instrument would have a limited effect on reducing consumption, while causing a loss in consumer welfare. Hence, to meet the long-term goals of decarbonisation, the EU policy makers should continue on the pathway of increasing energy efficiency of appliances and buildings, and of improving consumers' awareness, given that for the majority of the countries in this study (Austria, Belgium, Switzerland, Germany, Italy and the Netherlands) these actions seem to have been quite effective in delivering electricity conservation.

Directive 2009/125/EC and Directive 2010/30/EU, which have introduced the eco-design efficiency standards and energy labels for new household appliances, are two examples of provisions that have the potential to deliver substantial energy savings in the near future. Several countries in Europe have also considered monetary incentives, such as rebates, subsidies and tax credits to encourage the substitution of old appliances for more energy efficient appliances. At the same time, however, it is important to increase consumers' awareness of actual electricity usage via the roll-out of smart meters to all EU households and with the building of smart grids (Directive 2009/72/EC). Moreover, European Commission's initiatives, set up to further educate and promote households' environmentally friendly habits[92], can greatly contribute to energy conservation.

5.7 Conclusions

This chapter estimated residential electricity demand for Austria, Belgium, France, Germany, Italy, Spain, Switzerland, the Netherlands and the UK, using a novel econometric approach to get consistent estimates of the long-run relationship between electricity demand and its determinants. Residential electricity demand can be explained by several factors such as household income, electricity price, substitute goods prices, technical progress, climate and changes in consumers' socio-demographic and economic characteristics influencing preferences. Only for some of these variables are data available, while technical progress and changes in consumers' preferences are typically not observable. Correctly modelling the unobservable factors is fundamental to obtaining consistent estimates of income and price elasticities so as to provide policy makers with an indication of the impact that variables such as energy efficiency and households' tastes may have on the demand of electricity.

Previous studies that have addressed this model specification issue have proposed the use of either a linear deterministic trend or a non-linear stochastic trend estimated combining the STSM approach with ARDL modelling. Both approaches, however, suffer from potential drawbacks. A linear deterministic specification disregards the fact that some potential unobservable factors may exert opposite impacts on the electricity demand trend. While a non-linear stochastic trend may better describe these opposite impacts, its combination with ARDL modelling may not correctly model dynamic effects.

[92] An example of such projects is that of the "EU Sustainable Energy Week", which is an EU wide event started in 2006 and organised across Europe to showcase activities to promote energy efficiency and renewable energy, http://www.eusew.eu/index.php.

The chapter offers a novel solution to this problem, employing a general unrestricted ECM with IIS framework to estimate the cointegrating relationship between electricity demand, GDP, electricity price, and all other potential factors that are difficult to measure/find. Potential omitted factors were modelled using the IIS framework and its extensions Super-Saturation and Ultra Saturation. The estimation of the residential demand models was carried out with the search algorithm *Autometrics™*, which allows for general-to-specific model selection when there are more regressors than observations.

The empirical findings highlighted that once non-observable factors are correctly proxied, a meaningful cointegrating relationship between residential electricity consumption and all its determinants exists for all nine EU countries. In particular, the Ultra Saturation model turned out to be the preferred specification for the electricity demand in six out of nine countries (i.e. Austria, Belgium, Switzerland, France, Italy and the UK), while the Super Saturation model was selected for the remaining three countries (Germany, Spain and the Netherlands). The long-run income and price elasticities of residential demand unveiled important similarities between major European countries, given that electricity was found to be a normal good and price inelastic for all nine countries. In particular, long-term income elasticities were estimated to range between 0.34 (UK) and 1.20 (Netherlands), while long-term price elasticities between -0.45 (Switzerland) and -0.10 (UK). These results are in line with those found in previous studies. Moreover, the electricity demand trends for six out of nine countries (i.e. Austria, Belgium, Switzerland, Italy, Germany and the Netherlands) showed that improvements in energy efficiency and a more environmentally friendly attitude of EU households may have contributed to a reduction of electricity consumption after controlling for income and price effects.

Residential electricity demand being price inelastic, and with a downward sloping trend for many countries, bears important consequences for the choice of the most effective policy tool to promote energy conservation in Europe. Any policy based exclusively on price increases (e.g. energy taxes) could produce a heavy loss in consumers' welfare, discouraging consumption and hence having an adverse impact on CO_2 emissions. EU decision makers should therefore continue to focus on promoting alternative energy efficiency policies to increase residential energy saving. In particular, the key challenge for the near future is the full deployment of the smart grids project, which is anticipated to provide EU consumers with cheaper, greener and a more secure electricity system (EC, 2011b).

The analysis conducted in this chapter can be extended to all countries in the EU to investigate further whether and to what extent similarities in households' electricity consumption exist across the EU-27 area. In addition, the results of this study could be used to build a full cost-benefit analysis to evaluate alternative policy options to achieve the EU's long-term decarbonisation target. These developments are left for future work.

6 Conclusions and further work

The main objective of this thesis was to empirically evaluate the benefit of integrating the electricity markets of Europe and to assess whether and to what extent the EU reforms of the last two decades have been effective in delivering a single electricity market. In addition, as market integration requires integration of policy making to facilitate the efficient operation of the physical interconnections, the thesis aimed to analyse the determinants of residential electricity demand in Europe, so as to provide central policy makers with insights as to the likely effectiveness of various policy tools in promoting electricity savings that could contribute in reaching the EU 2020 and 2050 de-carbonisation targets.

Since 2009 there has been significant progress towards the creation of the single electricity market thanks to the enactment of the Third Legislative Package and to the set-up of projects for intraregional cooperation on specific themes. Major advances have been made to improve the management of the cross-border interconnections so as to increase the historically limited amount of available transmission capacity between countries. In particular, ACER requires all Member States to have replaced the explicit auction mechanism with the target model of market coupling, as a mean to allocate interconnection capacity across their borders by 2014. This replacement is expected to guarantee the efficient use of all the interconnectors across Europe and to bring a net welfare gain to countries with high-variable cost generation capacity. In Chapter 3, the market simulation model ELFO++™ was used to estimate the welfare gains of integrating the Italian wholesale electricity market with those of neighbouring countries France, Switzerland, Austria, Slovenia and Greece. The results of simulations of two states of the Italian market for 2012, a *Reference Scenario* and a *High Scenario*, supported the theoretical expectation that the introduction of market coupling would determine a net welfare gain for market participants. The Italian electricity market remains the highest-priced area in Europe due to a production mix that is constantly more expensive than that of its neighbours. This is likely to continue as the increase in generating capacity within Italy since 2004 has been via the construction of CCGT plants resulting in a production mix for the foreseeable future which mainly consists of thermoelectric plants. Bottlenecks on the internal transmission grid, due to the delays in the construction of additional lines between some regions of the country, often prevents the electricity system from being dispatched efficiently resulting in higher electricity prices. In the short term therefore only improved integration with neighbouring electricity markets, in particular with the northern bordering regions, is likely to reduce the Italian wholesale electricity price. Therefore Italian policy makers are well advised in the short-term to pursue both demand and supply side policy measures that facilitate cross boarder transmission and efficient dispatch along existing interconnections. In the longer term however, policy makers should turn their attention to improvements in interconnection infrastructure and diversifying the domestic production mix.

Moreover, as argued in Chapter 4, the complete diffusion of market coupling is a pre-requisite for the wholesale electricity prices of Europe to converge. The analysis in Chapter 4, carried out with three alternative econometric approaches, allowed to assess the degree of integration between wholesale electricity markets of Austria, Belgium, Czech Republic, France, Germany, Greece, Ireland, Italy, Poland, Portugal, Scandinavia, Spain, Switzerland, the Netherlands and the UK. The first approach, fractional cointegration analysis, revealed that, as of the end of January 2012, only six out of 105 market pairs were already perfectly integrated. However, the second approach of time-varying regression models showed evidence of convergence for the 39% of market pairs tested, almost all belonging to countries, which either feature very similar characteristics in the production mix or have been already coupled. For the remaining 61% market pairs no sign of market convergence were found. In particular, the peripheral electricity markets of Greece, Ireland, Italy and Scandinavia displayed little evidence of convergence to other markets. The major determinants of this lack of convergence seems to be attributable to both the geographical distance from continental European markets, for Greece and Ireland, and the composition of the national electricity portfolio mixes, especially for Italy and Scandinavia. The third econometric approach for evaluating the degree of integration between electricity markets consisted of estimating multivariate GARCH models (dynamic conditional correlation models) to measure returns volatility spillovers between countries. The results of this analysis pointed out that strong volatility spillovers exist between markets well interconnected and geographically close to each other, with the markets of continental Europe exhibiting the highest returns correlations and hence the best integration.

As discussed in Chapter 5, the single market is not only an objective per se, but it is a mean to reach the EU 2020 and 2050 de-carbonisation targets. However, full market integration could not be sufficient to reach these targets, if EU citizens do not increase the efficiency of their appliances stock and modify their consumption behaviour. It is therefore crucial for EU energy policy makers to have an accurate model of the determinants of electricity demand to evaluate which tools is best to employ to induce electricity conservation. The analysis in Chapter 5 aimed at building such a model for residential electricity demand of nine European countries, namely Austria, Belgium, France, Germany, Italy, Spain, Switzerland, the Netherlands and the UK, using annual data for the period 1978-2009. A novel econometric approach was used to correctly model all the relevant variables that may influence residential electricity demand. A general unrestricted error correction mechanism featuring Impulse Indicator Saturation was specified to estimate the cointegrating relationship between electricity demand, gross domestic product, electricity price, and all other potential factors that are difficult to measure but that have to be accounted for to get consistent estimates of the long-run price and income elasticities. The models were estimated with the search algorithm *Autometrics*™. The results highlighted that residential electricity demand was found to be price inelastic for all countries analysed and with a downward sloping trend for 6 out of 9 countries. These results imply therefore that any policy based exclusively on price increases (e.g. energy taxes) could produce a heavy loss in consumers' welfare, discouraging consumption and hence CO_2 emissions only marginally. EU decision makers should therefore continue to focus on promoting alternative energy efficiency policies to increase energy saving.

There are several areas for further research. Since the results of this work have demonstrated that market integration is beneficial especially for consumers located in high-priced areas, it would be interesting to extend the welfare analysis in Chapter 3 simulating explicitly the impact of market coupling on all other markets in Europe. This requires the building of a market simulation model that incorporates the features of all European electricity markets. Such a model would allow the evaluation of the distribution of gains and losses between market participants of different countries. Moreover, it would be important to consider the benefits generated by both the increased security of supply and the lower need of investing in reserve capacity, and the costs of harmonisation of the national markets for the implementation of market coupling.

As far as the convergence analysis is concerned, it would be interesting to explore the change in spikes and volatility of wholesale spot price before and after the deployment of coupling between markets, so as to understand whether and to what extent the riskiness of the market may have changed.

In Chapter 5, the examination of the determinants of residential electricity for nine major European countries was carried out. Therefore, the analysis can be extended to all countries in the EU, featuring different levels of GDP and infrastructure, to investigate further whether and to what extent similarities in households' electricity consumption exist across the EU-27 area. Increasing the number of countries would also allow considering alternative estimation approaches, as a dynamic panel data model and a vector-autoregressive system. In addition, the results of this study could be used to build a full cost-benefit analysis to evaluate alternative policy options to achieve the EU's long-term decarbonisation target.

We leave these developments to future research.

7 Appendices

7.1 Appendix A

In order to identify the presence of common trends in the behaviour of the CSE wholesale electricity spot prices, a cointegration analysis between the German EPEXSpotDE and the Austrian EXAA prices and between the French EPEXSpotFR and the Swiss EPEXSpotCH prices is performed with data over from 1st January 2007 to 31st December 2010[93]. Given the large amount of noise in the hourly and daily price series, natural logarithms of weekly averages of the prices are taken. Figure 7.1 shows the four price series as transformed in natural logarithms of weekly averages (over a total of 209 weeks). Descriptive statistics of the series are reported in Table 7.1 below.

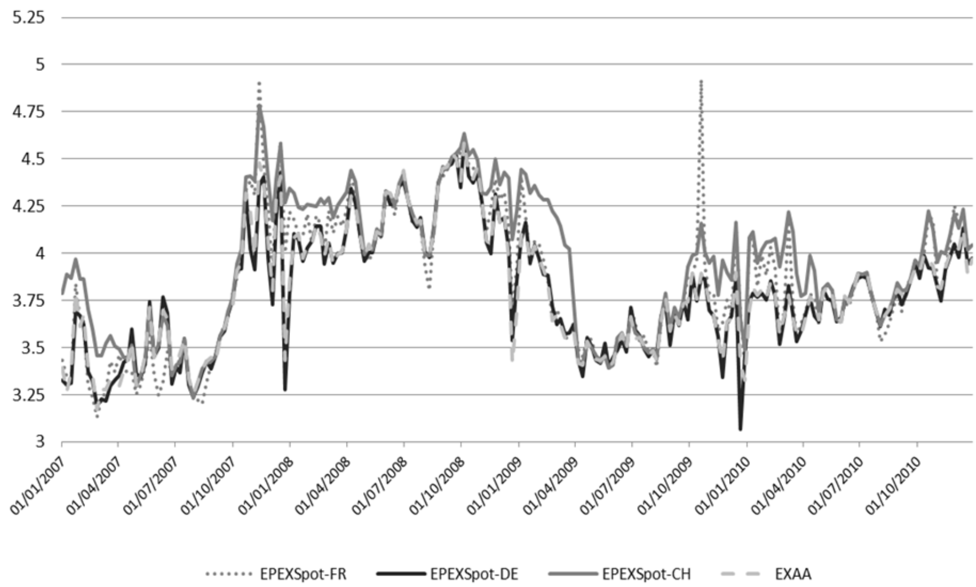

Figure 7.1: Log of weekly averages of EPEXSpotFR, EPEXSpotDE, EPEXSpotCH and EXAA, over the period 2007-2010. Data source: EPEX SPOT and EXAA.

[93] The data used is that described in Section 3.4. The exclusion of Slovenia is due to the fact that its day-ahead auction market only opened in March 2010. In the second step of the cointegration analysis reported below, a further exercise is carried out including only the weeks from the 18th of March 2010 to the end of 2010 to evaluate whether there is convergence between the Slovenian and German electricity spot price.

	EPEXSpotDE	*EXAA*	*EPEXSpotFR*	*EPEXSpotCH*
Mean	3.79	3.80	3.85	3.94
Median	3.76	3.78	3.82	3.96
Maximum	4.60	4.59	4.92	4.78
Minimum	3.07	3.17	3.13	3.23
Std. Dev.	0.32	0.32	0.37	0.35
Skewness	0.26	0.34	0.29	-0.01
Kurtosis	2.41	2.34	2.44	1.98
Jarque-Bera	5.50	7.80	5.62	9.09
Probability	0.06	0.02	0.06	0.01
Observations	209	209	209	209

Table 7.1: Descriptive statistics of log of weekly averages of EPEXSpotDE, EXAA, EPEXSpotFR and EPEXSpotCH. Data source: EPEX SPOT and EXAA.

In order to establish the order of the integration of the series, the Dickey-Fuller (DF) and the Augmented Dickey-Fuller (ADF) statistics are applied to the log transformation of the price series. The results are reported in Table 7.2. The log level of each of the four variables is non-stationary. The EPEXSpotDE, EXAA, EPEXSpotFR and EPEXSpotCH prices can be regarded as *I(1)* variables, given that the first difference of the series are found to be stationary.

Variable	***t-adf***	***Lag order***
EPEXSpotDE	-2.20	4
EXAA	-2.30	2
EPEXSpotFR	-2.53	2
EPEXSpotCH	-2.27	3
DEPEXSpotDE	-13.02	2
DEXAA	-15.89	1
DEPEXSpotFR	-15.49	1
DEPEXSpotCH	-8.82	2
5% significance level =-2.88		

Table 7.2: ADF unit root tests on level and on first differenced series.

Thus, it is possible to check whether EXAA converges to EPEXSpotDE and whether EPEXSpotCH converges to EPEXSpotFR. The following equation is estimated for the two relations:

$$P_{i,t}=\alpha+\beta P_{j,t}+\varepsilon_{i,t} \qquad i=EPEXSpotDE,\ EPEXSpotFR \qquad (7.1)$$

$$j=EXAA,\ EPEXSpotCH \qquad i\neq j$$

Following De Vany and Walls (1999), market integration requires the presence of cointegration, while strong market integration implies testing for the null hypothesis of β =1 in the cointegration relation $p_{i,t}=\alpha+\beta p_{j,t}+\varepsilon_{i,t}$. Perfect integration, that is achieved convergence, requires that both α=0 and β=1.

Table 7.3 reports the result of estimating equation (7.1) for EPEXSpotDE, from which it emerges evidence of convergence between the Austrian and the German markets, as the null hypothesis of α=0 and β=1 is accepted. Cointegration only occurs if the residuals of the regression are stationary. Using the ADF statistics to evaluate the stochastic process underlying the residuals, it turns out shows that the residuals series is stationary at the conventional 5% level (as reported at the bottom of Table 7.3).

Dependent variable EPEXSpotDE					
	Coefficient	**Std. Error**	**t-stat**		**t-adf**
			α=0	β=1	
α	0.03	0.04	0.79		
EXAA	0.99	0.01		1.10	
ADF(3)					-5.24

Table 7.3: Convergence analysis of EXAA towards EPEXSpotDE.

Table 7.4 reports the result of estimating equation (7.1) for EPEXSpotFR. The Swiss price is found to converge to the French one, given that the null of α=0 and β=1 are both accepted. The ADF test confirms that the residuals from this regression are stationary.

Dependent variable EPEXSpotFR					
	Coefficient	**Std. Error**	**t-stat**		**t-adf**
			α=0	β=1	
α	0.08	0.11	0.72		
EPEXSpotCH	0.95	0.03		1.67	
ADF(2)					-4.35

Table 7.4: Convergence analysis of EPEXSpotCH towards EPEXSpotFR.

The ADF test on the logarithm of the weekly average Slovenian price rejects stationarity also for this series (i.e *t-adf -2.309, lag order 0*). Thus, equation (7.1) is estimated for this relation as well and the results are reported in Table 7.5 below.

Dependent variable EPEXSpotDE					
	Coefficient	**Std. Error**	**t-stat**		**t-adf**
			α=0	β=1	
α	0.18	0.17	1.06		
SI price	0.95	0.04		1.14	
DF(0)					-4.85

Table 7.5: Convergence analysis of Slovenian price towards EPEXSpotDE.

The Slovenian price converges to the EPEXSpotDE price, as the null of α=0 and β=1 are both accepted. Again, the ADF test highlights that the residuals of this regression are stationary.

It therefore makes sense to reduce the complexity of the interconnections of northern Italy assuming only France and Germany to be the bordering countries.

7.2 Appendix B

	APXNL	*APXUK*	*BELPEX*	*EPEXDE*	*EPEXFR*	*EXAA*	*HTSO*	*IPEX*	*NORDPOOL*	*OMIEES*	*OMIEPT*	*OTE*	*POLPX*	*SEM*	*SWISSIX*
PP test	-11.573**	-3.092*	-3.775**	-5.975**	-5.46**	-6.066**	-4.117**	-5.415**	-3.587**	-5.397**	-2.859	-17.288**	-1.841	-2.653**	-3.322*
Bandwith	15	6	4	4	6	8	3	4	13	2	2	15	11	1	5
KPSS test	1.074**	1.566**	0.164	0.097	0.105	1.358**	0.434	0.38	1.801**	1.457**	0.464*	2.199**	2.142**	0.406	0.140
Bandwith	19	18	12	14	14	17	14	15	21	21	11	16	17	11	12
GSP estimate of d	0.467	0.652**	0.632**	0.549	0.617**	0.574**	0.589*	0.617**	0.81**	0.649**	0.641**	0.301	0.782**	0.632**	0.699**

**, ** denote 5% and 1% level of significance respectively.*
For PP, null hypothesis H_0: series=non stationary. Critical values -3.43 for 1% level of significance and -2.86 for 5% level of significance.
For KPSS, null hypothesis H_0: series= stationary. Critical values 0.739 for 1% level of significance and 0.463 for 5% level of significance.

Table 7.6: Unit root and long memory tests on log weekly medians of European electricity prices. Unit root tests are performed with Eviews 7, GSP test with G@rch 6.

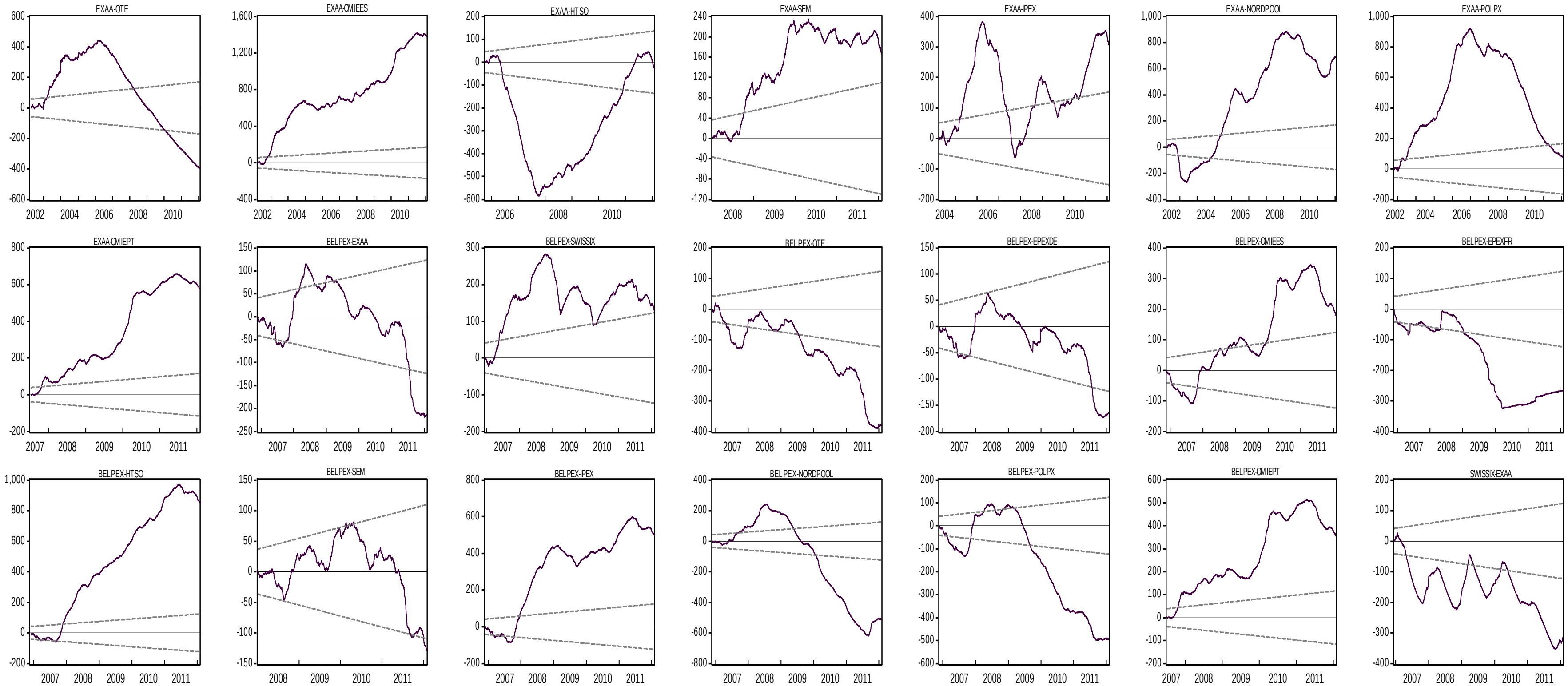

Figure 7.2: CUSUM analysis (I): solid line CUSUM, dashed lines 5% significance level. Estimations are performed with Eviews 7.

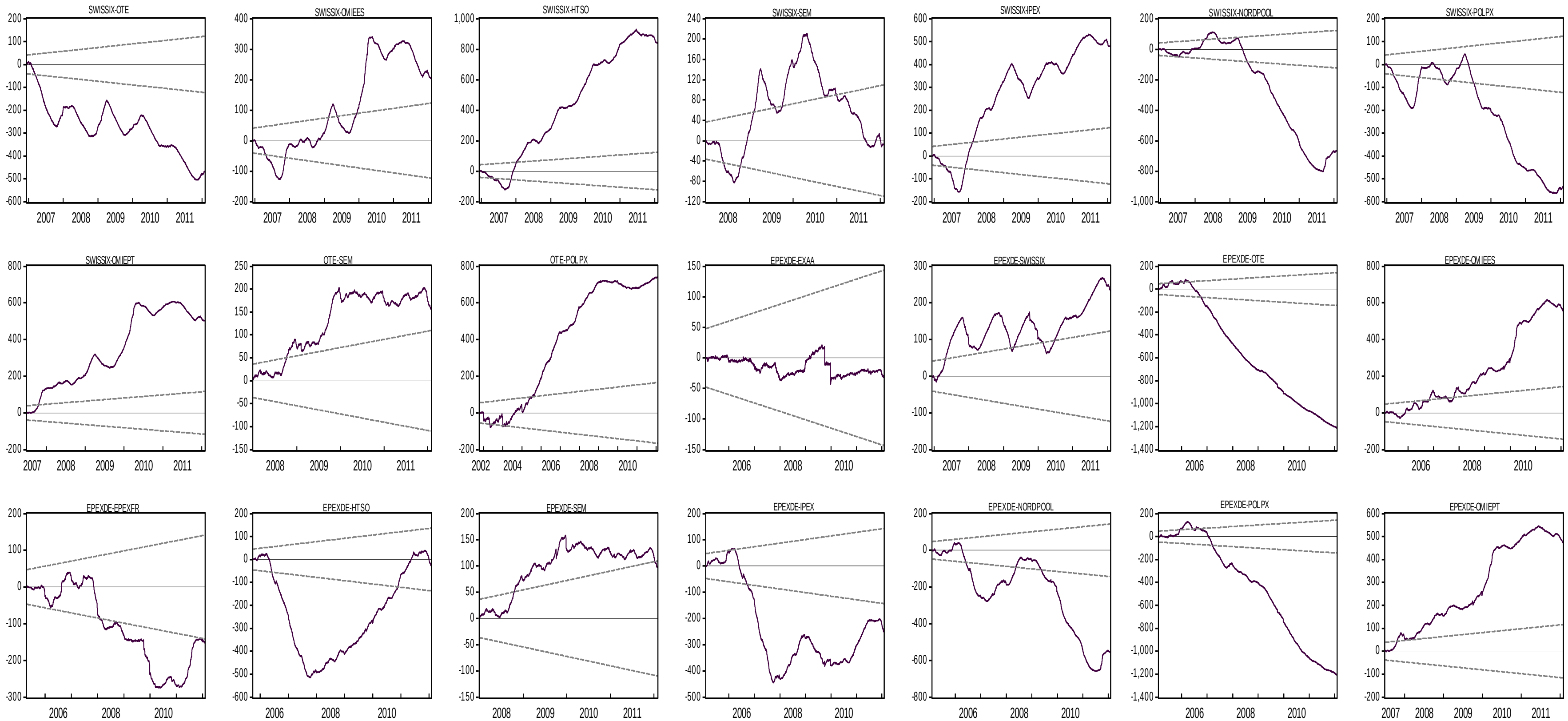

Figure 7.3: CUSUM analysis (II): solid line CUSUM, dashed lines 5% significance level. Estimations are performed with Eviews 7.

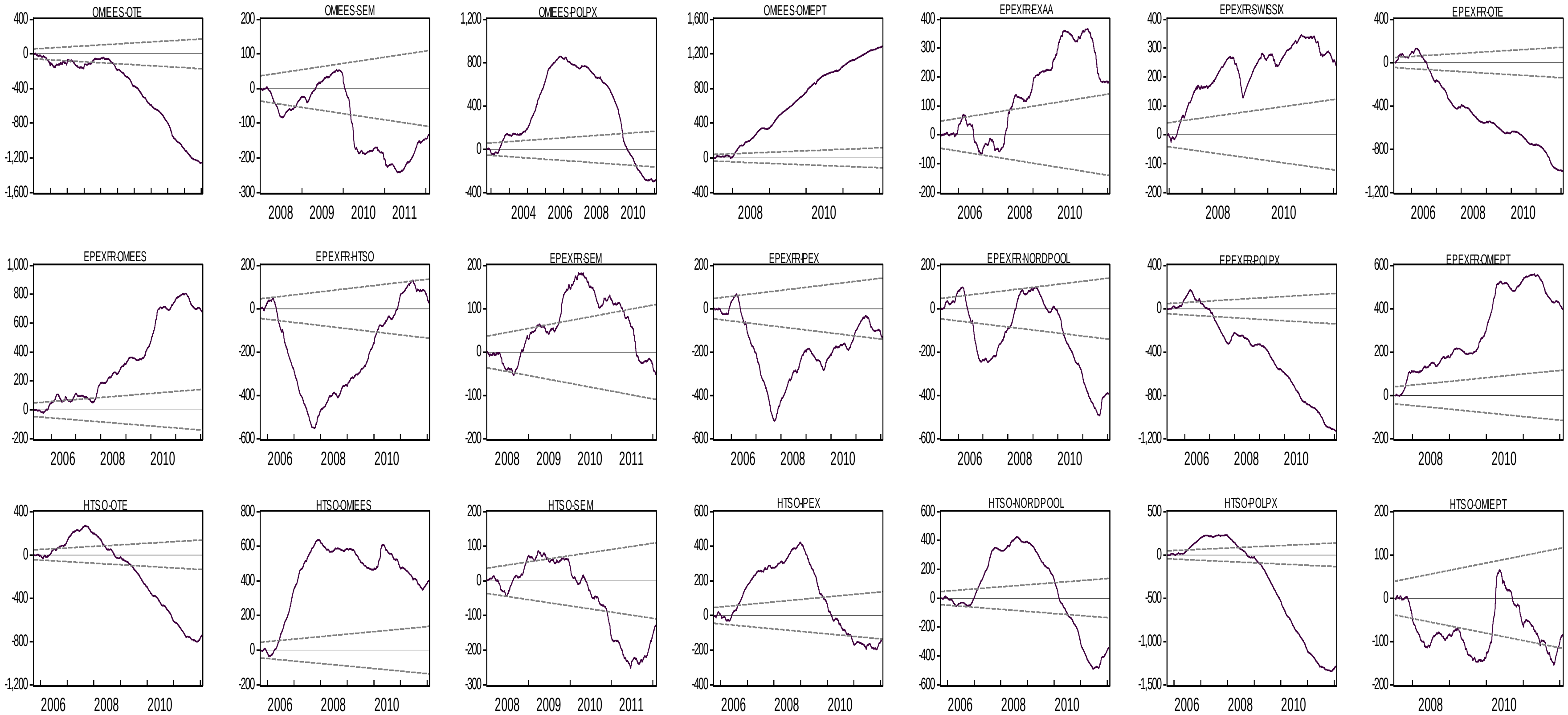

Figure 7.4: CUSUM analysis (III): solid line CUSUM, dashed lines 5% significance level. Estimations are performed with Eviews 7.

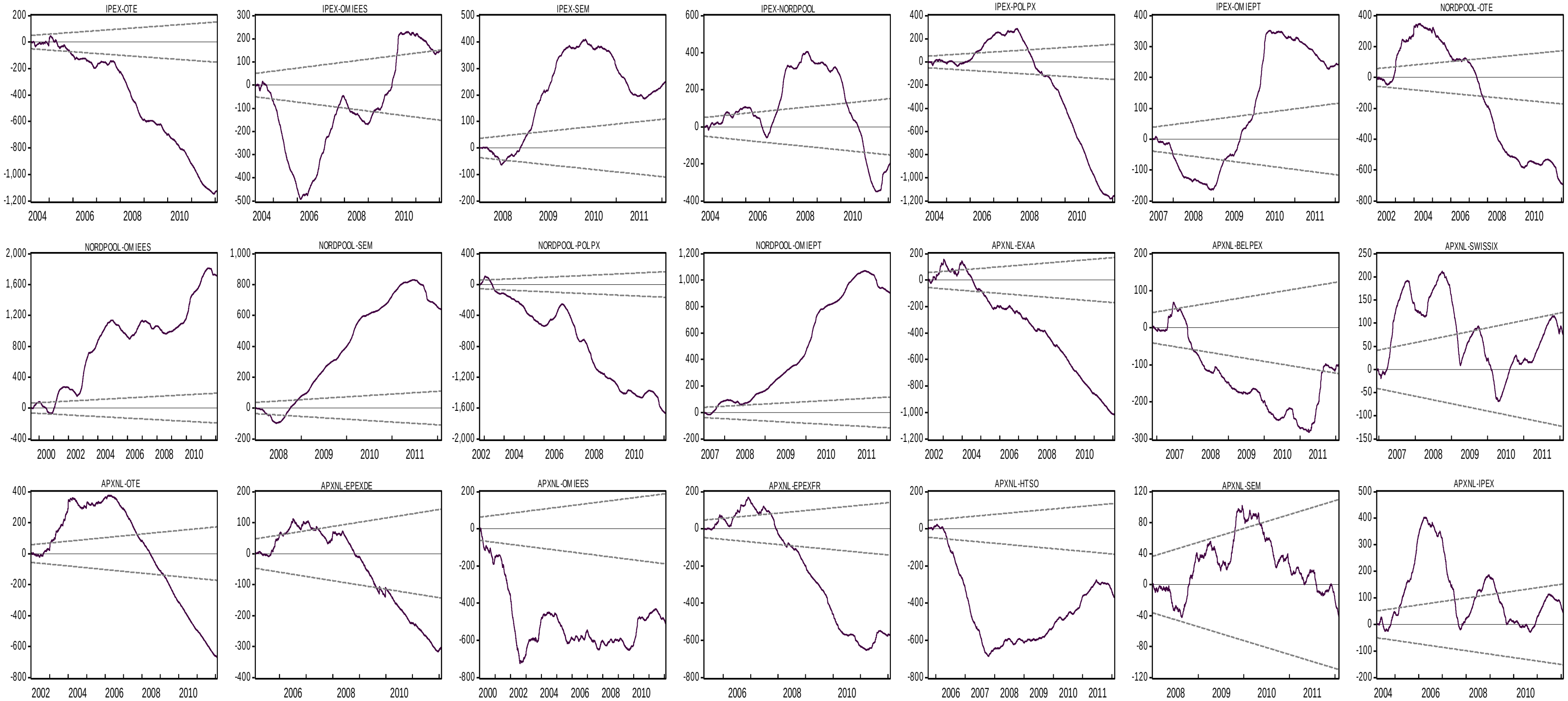

Figure 7.5: CUSUM analysis (IV): solid line CUSUM, dashed lines 5% significance level. Estimations are performed with Eviews 7.

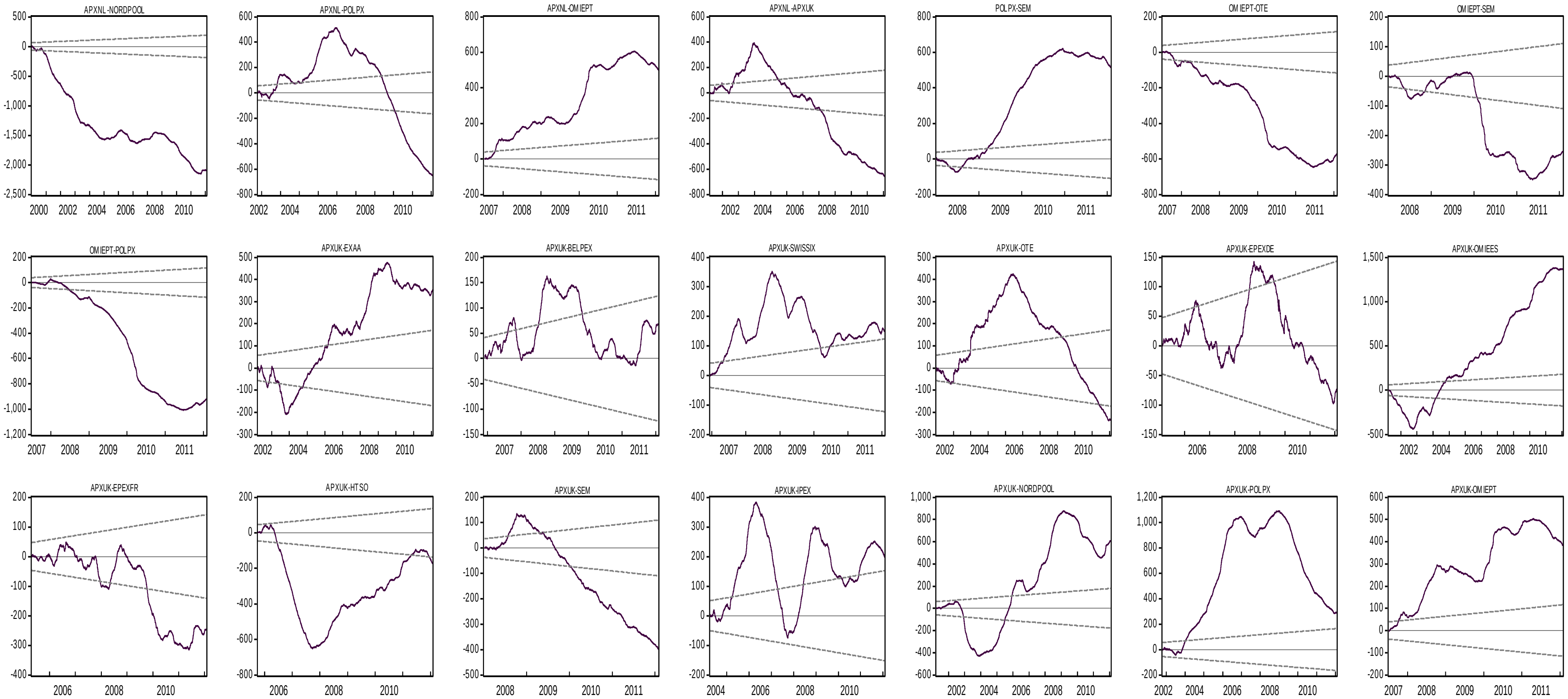

Figure 7.6: CUSUM analysis (V): solid line CUSUM, dashed lines 5% significance level. Estimations are performed with Eviews 7.

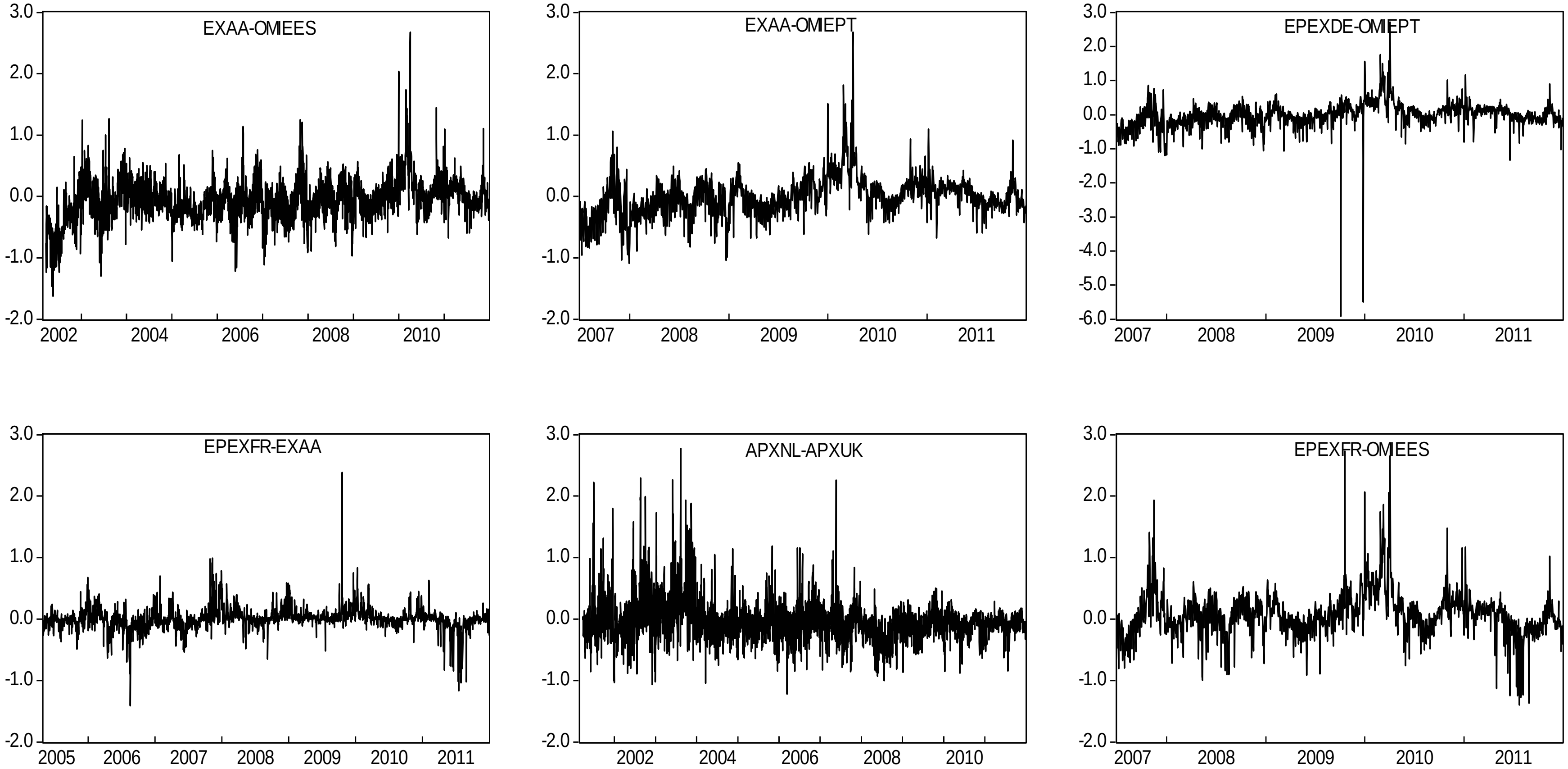

Figure 7.7: Calculated differences between the prices series of the perfectly integrated markets.

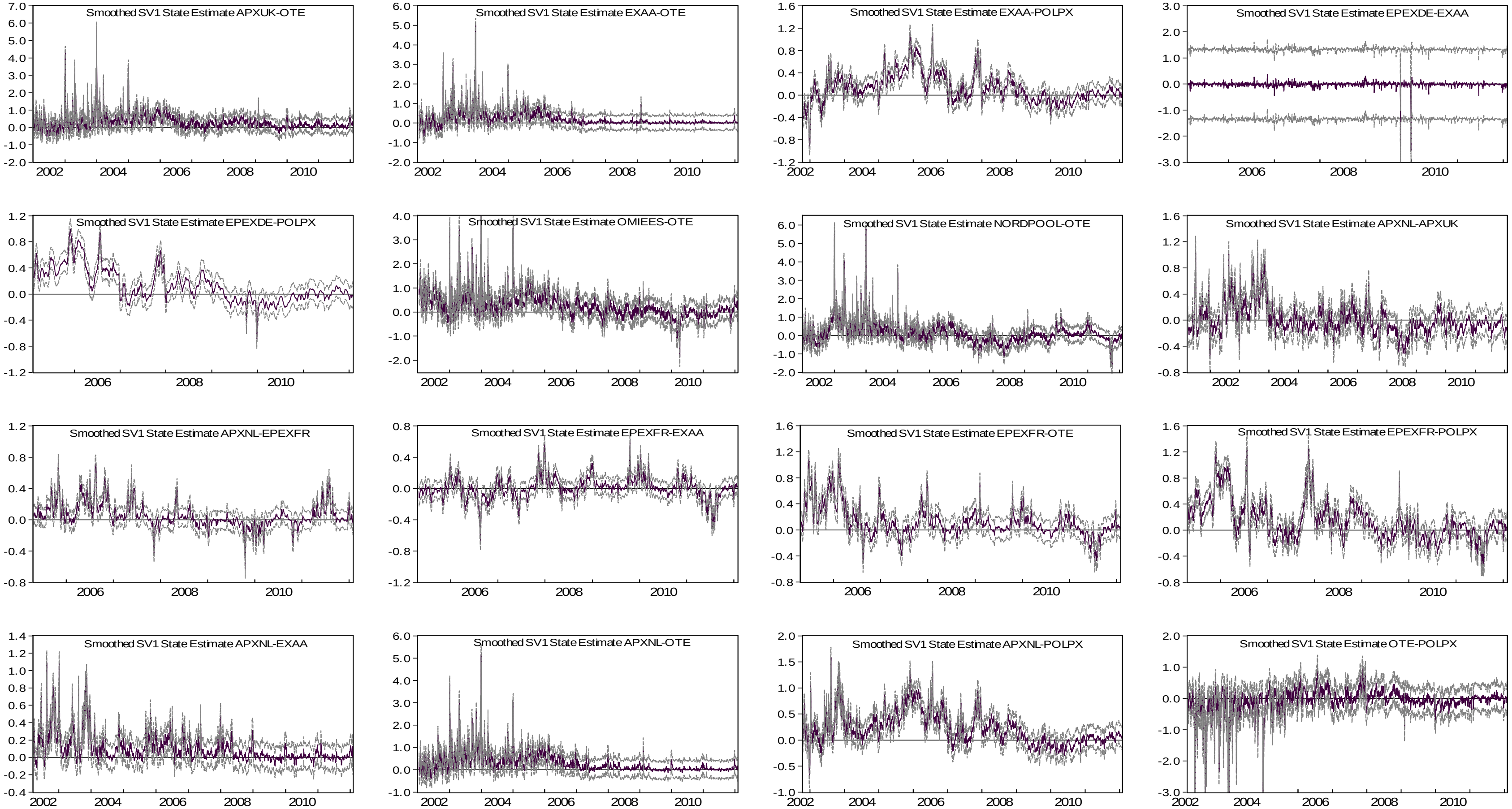

Figure 7.8: Smoothed convergence indicators for European electricity markets pairs displaying evidence of ongoing convergence. Black line smoothed indicator, grey lines ± 2 RMSE.

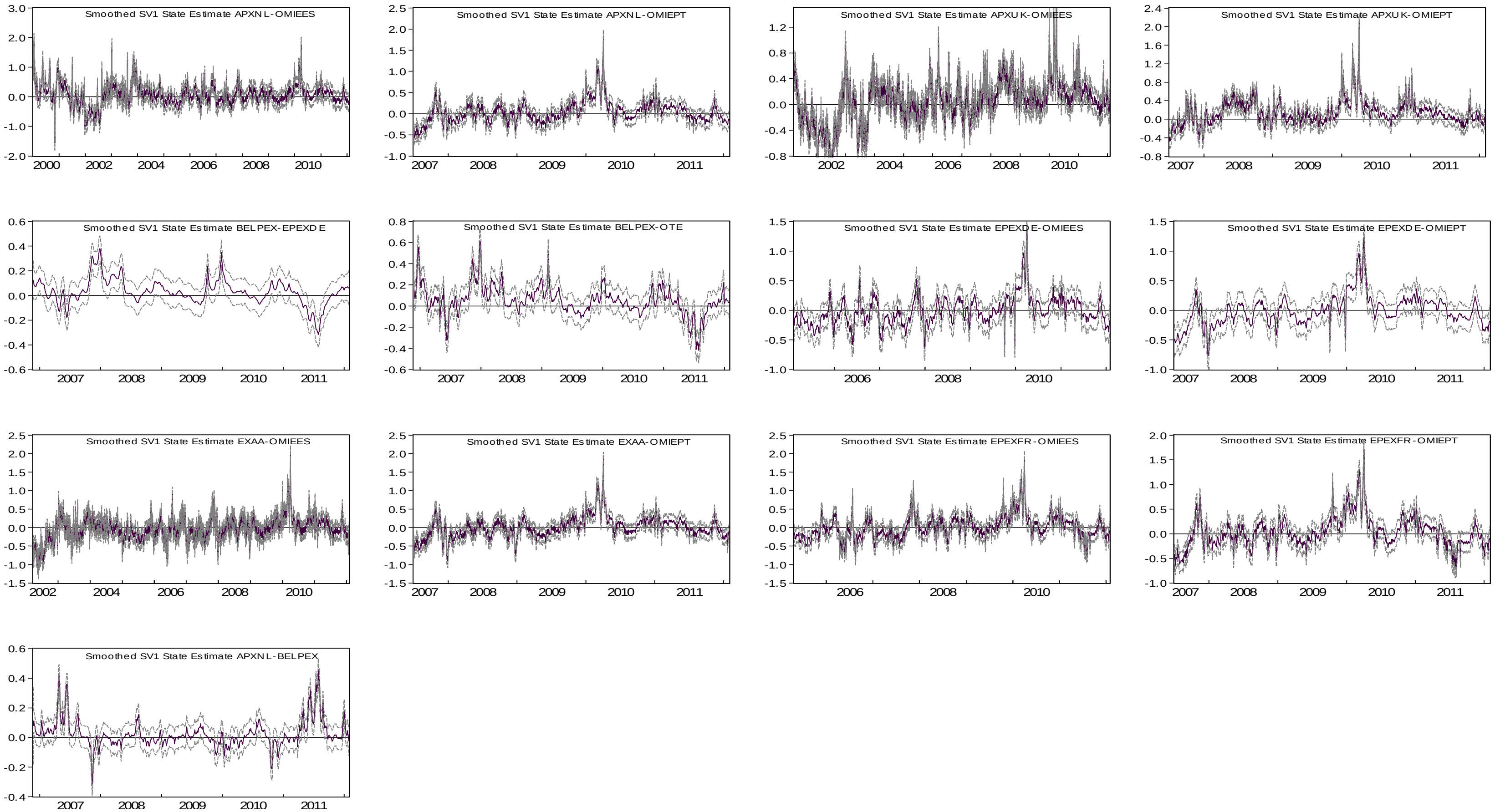

Figure 7.9: Smoothed convergence indicators for European electricity markets pairs displaying mixed evidence of convergence. Black line smoothed indicator, grey lines ± 2 RMSE.

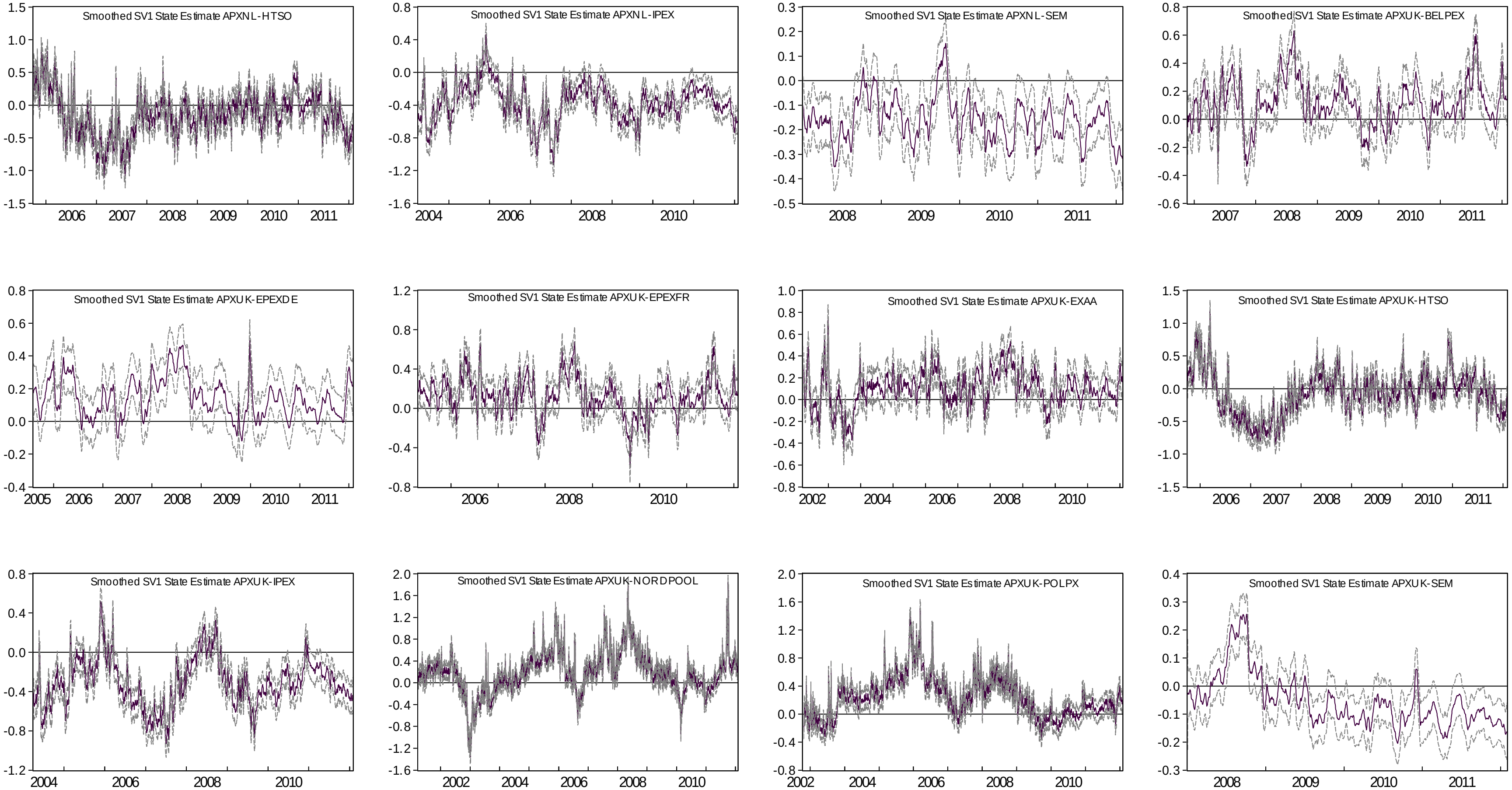

Figure 7.10: Smoothed convergence indicators for European electricity markets pairs displaying no evidence of convergence (I). Black line smoothed indicator, grey lines ± 2 RMSE.

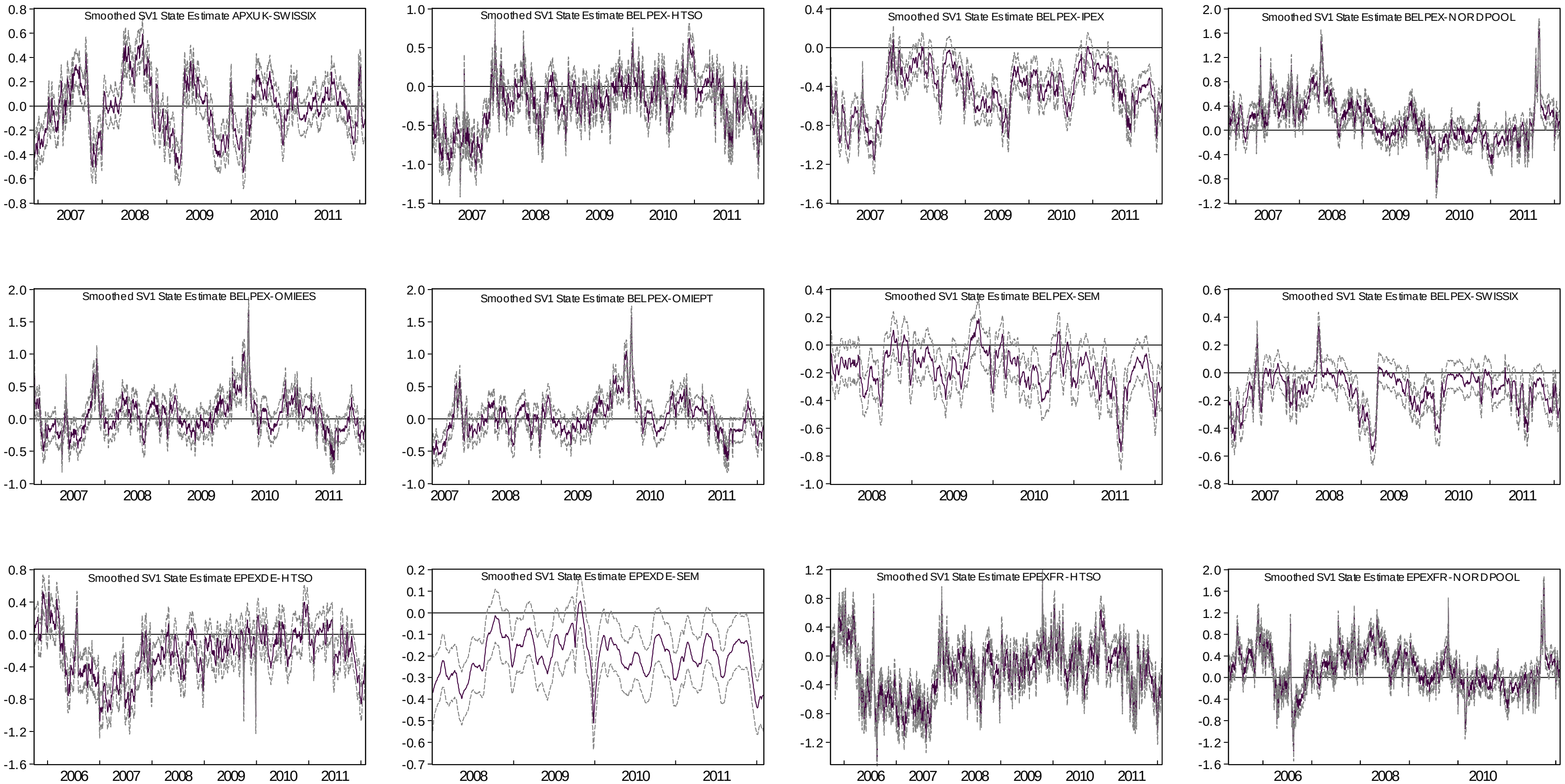

Figure 7.11: Smoothed convergence indicators for European electricity markets pairs displaying no evidence of convergence (II). Black line smoothed indicator, grey lines ± 2 RMSE.

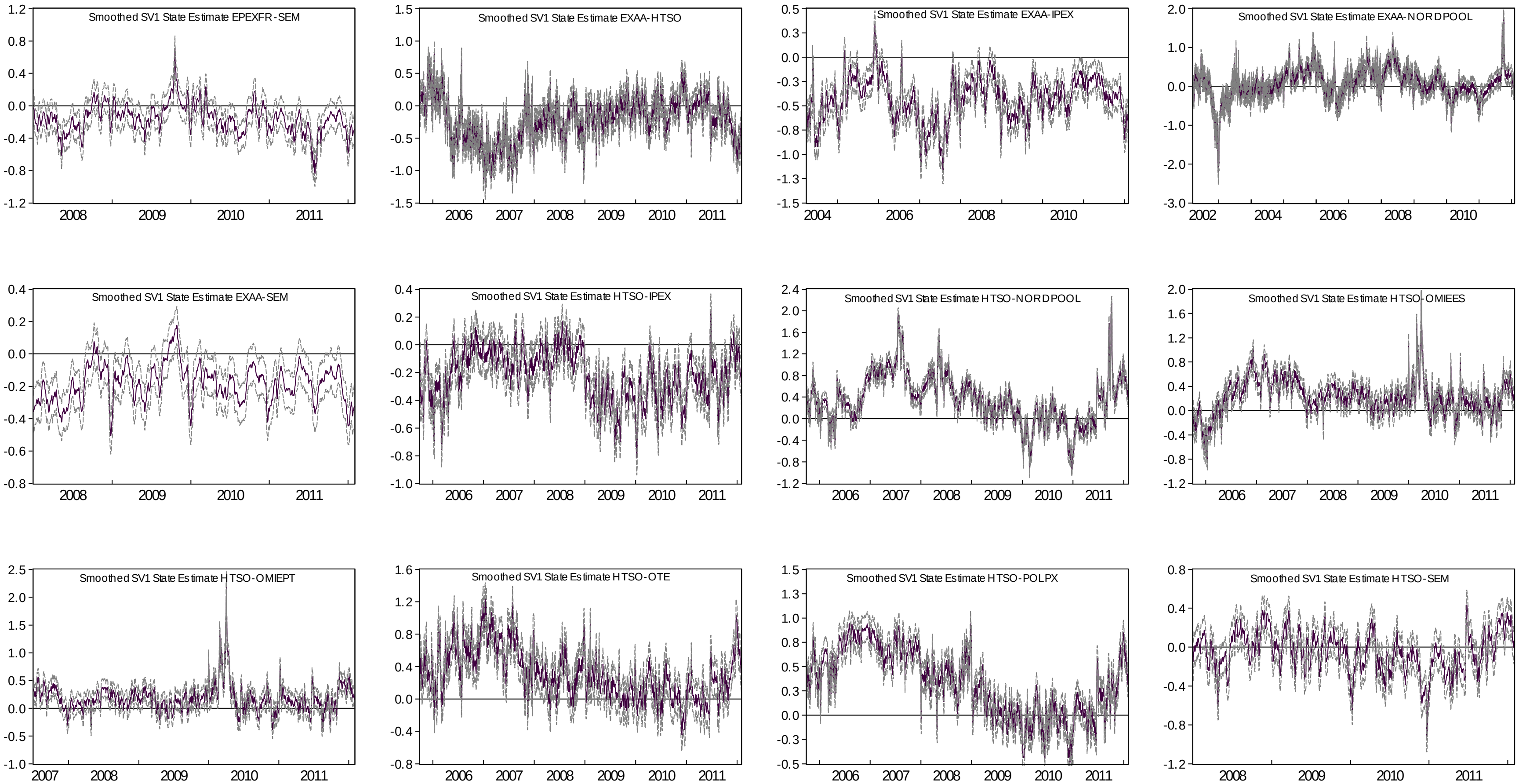

Figure 7.12: Smoothed convergence indicators for European electricity markets pairs displaying no evidence of convergence (III). Black line smoothed indicator, grey lines ± 2 RMSE.

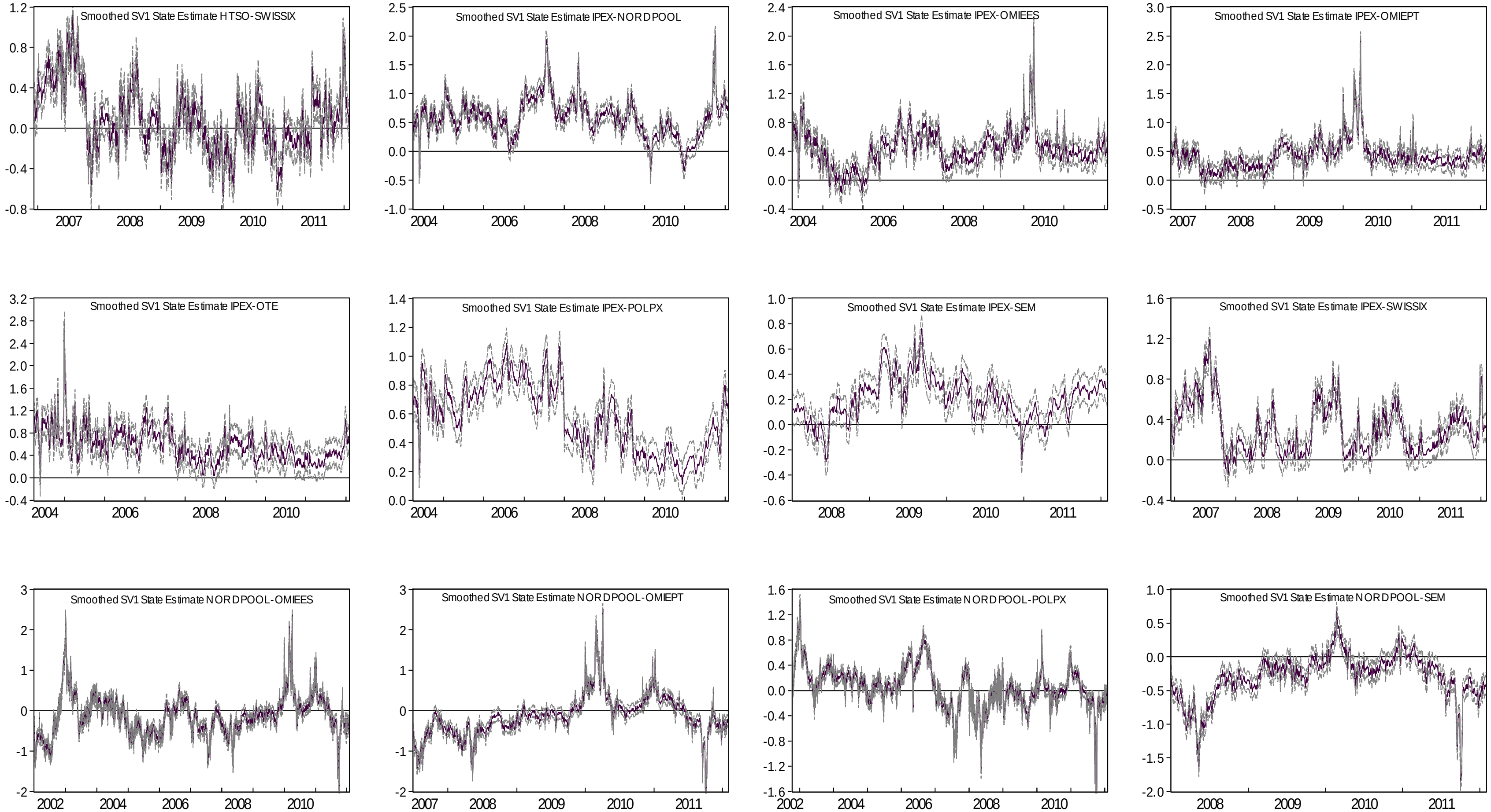

Figure 7.13: Smoothed convergence indicators for European electricity markets pairs displaying no evidence of convergence (IV). Black line smoothed indicator, grey lines ± 2 RMSE.

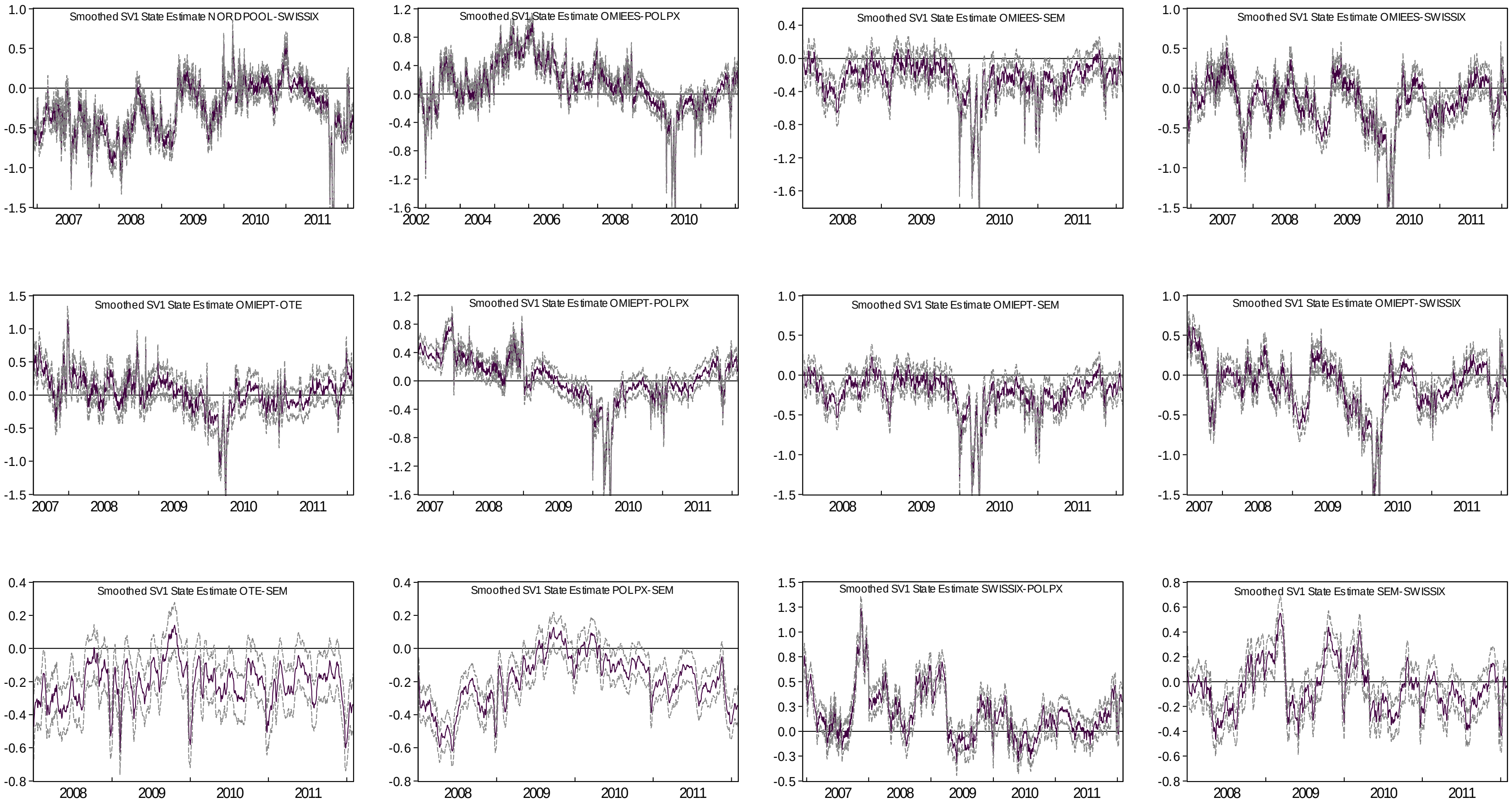

Figure 7.14: Smoothed convergence indicators for European electricity markets pairs displaying no evidence of convergence (V). Black line smoothed indicator, grey lines ± 2 RMSE.

	GARCH (1,1)						EGARCH (1,1)						
	α_0	α_1	β_1	*Akaike Info Crit.*	*Schwarz Crit.*	*Log likelihood*	α_0	λ_1	α_1	β_1	*Akaike Info Crit.*	*Schwarz Crit.*	*Log likelihood*
APXNL RETURNS	0.000	0.010	0.990	0.503	0.508	-1104.7	-0.006	0.008	-0.033	1.000	0.501	0.508	-1099.15
	(0.000)	(0.000)	(0.000)				(0.000)	(0.000)	(0.003)	(0.000)			
APXUK RETURNS	0.001	0.188	0.792	-1.025	-1.019	2035.51	-0.226	0.159	0.171	0.971	-1.051	-1.043	2086.98
	(0.000)	(0.011)	(0.010)				(0.015)	(0.012)	(0.010)	(0.003)			
BELPEX RETURNS	0.030	0.740	0.023	-0.029	-0.017	31.18	-2.020	0.739	-0.488	0.498	-0.168	-0.153	164.27
	(0.001)	(0.05)	(0.008)				(0.085)	(0.035)	(0.032)	(0.025)			
EPEXFR RETURNS	0.032	0.702	0.046	0.036	0.045	-40.29	-1.279	0.513	-0.618	0.687	-0.196	-0.185	248.15
	(0.001)	(0.036)	(0.09)				(0.037)	(0.012)	(0.019)	(0.012)			
EPEXDE RETURNS	0.039	0.870	-0.001	0.233	0.242	-292.25	-1.621	0.646	-0.614	0.591	0.003	0.015	0.64
	(0.001)	(0.023)	(0.005)				(0.06)	(0.017)	(0.015)	(0.017)			
EXAA RETURNS	0.033	0.721	0.070	0.161	0.168	-286.83	-0.918	0.416	-0.628	0.787	-0.205	-0.196	373.39
	(0.002)	(0.046)	(0.014)				(0.043)	(0.022)	(0.021)	(0.012)			
HTSO RETURNS	0.001	0.176	0.793	-0.843	-0.833	979.02	-0.318	0.131	-0.372	0.936	-0.957	-0.945	1111.78
	(0.000)	(0.014)	(0.012)				(0.025)	(0.015)	(0.018)	(0.006)			
IPEX RETURNS	0.000	0.129	0.871	-0.738	-0.730	1060.00	-0.322	0.116	-0.416	0.929	-0.892	-0.882	1281.36
	(0.000)	(0.007)	(0.008)				(0.016)	(0.013)	(0.011)	(0.005)			
NORDPOOL RETURNS	0.001	0.291	0.710	-2.130	-2.125	4900.42	-1.111	0.586	-0.299	0.856	-2.219	-2.212	5105.77
	(0.000)	(0.009)	(0.006)				(0.025)	(0.011)	(0.008)	(0.004)			
OMIEES RETURNS	0.000	0.136	0.878	-1.007	-1.002	2593.1	-0.260	0.150	-0.325	0.959	-1.140	-1.133	2935.51
	(0.000)	(0.004)	(0.003)				(0.008)	(0.005)	(0.005)	(0.002)			
OMIEPT RETURNS	0.000	0.331	0.709	-2.054	-2.041	1723.86	-0.443	0.270	-0.291	0.948	-2.122	-2.106	1781.95
	(0.000)	(0.015)	(0.011)				(0.026)	(0.014)	(0.013)	(0.004)			
OTE RETURNS	0.009	0.342	0.698	0.906	0.913	-1664.3	-0.208	0.139	-0.352	0.930	0.707	0.715	-1295.9
	(0.001)	(0.011)	(0.007)				(0.004)	(0.005)	(0.006)	(0.001)			
POLPX RETURNS	0.000	0.150	0.837	-2.346	-2.339	3986.26	-0.379	0.234	-0.285	0.958	-2.431	-2.422	4131.75
	(0.000)	(0.006)	(0.006)				(0.017)	(0.008)	(0.01)	(0.003)			
SEM RETURNS	0.001	0.061	0.887	-0.877	-0.863	658.10	-3.275	0.232	0.168	0.166	-0.879	-0.861	660.32
	(0.000)	(0.011)	(0.022)				(0.479)	(0.046)	(0.039)	(0.126)			
SWISSIX RETURNS	0.018	0.710	0.065	-0.489	-0.477	462.44	-1.836	0.466	-0.585	0.575	-0.733	-0.719	692.83
	(0.001)	(0.059)	(0.017)				(0.092)	(0.038)	(0.032)	(0.023)			

Table 7.7: GARCH (1,1) and EGARCH (1,1) models estimates for electricity price returns, standard errors in parenthesis. Estimations performed with Eviews 7.

7.3 Appendix C

Autometrics™ is an algorithm for performing automatic model selection, relating to the general-to-specific procedures known as "LSE" or "Hendry" methodology. *Autometrics™* is a tool included in the OxMetrics™ software (releases from 5.0 onwards).

The general unrestricted model (GUM) specified by the econometrician provides the initial set of candidate variables from which *Autometrics™* is able to select the relevant variables using a tree search. Insignificant variables are eliminated starting from the most statistically insignificant, according to a level of significance defined by the user (defined as p_a), and following group elimination strategies (i.e. pruning, bunching and chopping) that allows moving efficiently through the tree.

Upon failure of the diagnostic test, *Autometrics™* backtracks until a valid model is found. The number and type of diagnostic tests and their level of significance can be selected by the modeller. The default setting includes tests for normality, heteroskedasticity, residuals autocorrelation and structural breaks; while the diagnostic test p-value is at 1%. If multiple candidate models are found, all representing a valid reduction of the initial GUM, *Autometrics™* operates its final selection using the Schwarz Information Criterion as tiebreaker. However, alternative criteria such as the Akaike and the Hannan-Quinn can be chosen by the user.

In some cases the modeller could have an a-priori idea about the variables the specification should contain. To deal with this, it is possible to force *Autometrics™* to enter the variables thought as important in the final model.

Autometrics™ is particularly helpful when the researcher wants to specify an initial GUM where there are more variables then observations. In dealing with this, *Autometrics™* uses a block-search algorithm that works as follows. The set of all variables that enter the initial GUM,$\overline{\mathcal{B}}$, is partitioned in two: those that are selected at the iteration i (defined as $\mathcal{S}_i$) and the set of excluded variables (defined as $\overline{\mathcal{B}} \setminus \mathcal{S}_i$). The set of the variable that are excluded is partitioned in blocks (defined as $\mathcal{B}_1^0, \ldots, \mathcal{B}_{\mathcal{B}}^0$), then two actions occur in succession: an expansion step, where all the blocks from the set of the excluded variables are investigated to check for omitted variables; a reduction step, where a new candidate set $\mathcal{S}_{i+1}$ is formulated from the union of the $\mathcal{S}_i$ and the set of omitted variables. Both the expansion step and the reduction step are run considering the p_a value defined by the user. The block size together with the ordering of the variables within the block in the block partitioning phase of the expansion step can be also set by the user. In particular, *Autometrics*™ foresees that blocks are created by inserting the variables either sequentially, default setting, or randomly.

Further details on the algorithm and its performances are described in Doornik (2009a, b).

7.4 Appendix D

Dependent variable ΔAT EC				*Dependent variable ΔBE EC*				*Dependent variable ΔCH EC*			
	Coefficient	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**
$\Delta AT\ EC_{t-1}$	-0.045	0.215	0.836	$\Delta BE\ EC_{t-1}$	-0.268	0.277	0.344	$\Delta CH\ EC_{t-1}$	0.193	0.206	0.360
$\Delta AT\ GDP$	-1.665	1.172	0.171	$\Delta BE\ GDP$	-0.519	0.574	0.377	$\Delta CH\ GDP$	0.640	0.395	0.121
$\Delta AT\ GDP_{t-1}$	2.579	1.240	0.051	$\Delta BE\ GDP_{t-1}$	0.222	0.564	0.699	$\Delta CH\ GDP_{t-1}$	-0.270	0.420	0.527
$\Delta AT\ PRICE$	-0.299	0.259	0.262	$\Delta BE\ PRICE$	-0.536	0.236	0.034	$\Delta CH\ PRICE$	0.298	0.241	0.231
$\Delta AT\ PRICE_{t-1}$	-0.134	0.306	0.665	$\Delta BE\ PRICE_{t-1}$	-0.078	0.272	0.776	$\Delta CH\ PRICE_{t-1}$	-0.017	0.294	0.955
Constant	36.967	18.400	0.058	*Constant*	-6.219	9.678	0.528	*Constant*	-2.318	4.271	0.593
Trend	0.071	0.032	0.037	*Trend*	-0.016	0.014	0.248	*Trend*	-0.001	0.004	0.872
$AT\ EC_{t-1}$	-0.276	0.153	0.085	$BE\ EC_{t-1}$	0.129	0.128	0.326	$CH\ EC_{t-1}$	-0.234	0.154	0.145
$AT\ GDP_{t-1}$	-2.809	1.470	0.070	$BE\ GDP_{t-1}$	0.428	0.685	0.540	$CH\ GDP_{t-1}$	0.331	0.384	0.399
$AT\ PRICE_{t-1}$	-0.313	0.326	0.349	$BE\ PRICE_{t-1}$	-0.010	0.269	0.971	$CH\ PRICE_{t-1}$	0.066	0.125	0.605
R^2	0.380	*Adj.* R^2	0.101	R^2	0.597	*Adj.* R^2	0.415	R^2	0.344	*Adj.* R^2	0.049
AIC	-2.546	*SC*	-2.079	*AIC*	-3.743	*SC*	-3.276	*AIC*	-4.405	*SC*	-3.938
	Statistics	**p-value**			**Statistics**	**p-value**			**Statistics**	**p-value**	
AR 1-2 test: F(2,18)	0.818	0.457		*AR 1-2 test: F(2,18)*	1.703	0.210		*AR 1-2 test: F(2,18)*	0.012	0.988	
ARCH 1-1 test: F(1,28)	0.040	0.842		*ARCH 1-1 test: F(1,28)*	0.121	0.731		*ARCH 1-1 test: F(1,28)*	4.230	0.049	
Normality test: $\chi^2(2)$	11.099	0.004		*Normality test:* $\chi^2(2)$	16.926	0.000		*Normality test:* $\chi^2(2)$	0.166	0.920	
Hetero test: F(18,11)	0.942	0.561		*Hetero test: F(18,11)*	1.139	0.425		*Hetero test: F(18,11)*	0.970	0.539	
RESET23 test: F(2,18)	5.665	0.012		*RESET23 test: F(2,18)*	0.918	0.417		*RESET23 test: F(2,18)*	3.559	0.050	

Table 7.8: Estimation output and misspecification tests for unrestricted ECM models without breaks of Austria, Belgium and Switzerland's electricity demand.

Dependent variable Δ DE EC				*Dependent variable Δ ES EC*				*Dependent variable Δ FR EC*			
	Coefficient	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**		**Coefficient**	**Std.Error**	**p-value**
$\Delta DE\ EC_{t-1}$	-0.180	0.237	0.458	$\Delta ES\ EC_{t-1}$	-0.449	0.210	0.045	$\Delta FR\ EC_{t-1}$	-0.067	0.195	0.734
$\Delta DE\ GDP$	-0.655	0.392	0.110	$\Delta ES\ GDP$	1.428	0.550	0.017	$\Delta FR\ GDP$	-1.197	0.561	0.046
$\Delta DE\ GDP_{t-1}$	-0.015	0.482	0.975	$\Delta ES\ GDP_{t-1}$	-0.422	0.645	0.521	$\Delta FR\ GDP_{t-1}$	-0.049	0.734	0.947
$\Delta DE\ PRICE$	-0.155	0.149	0.311	$\Delta ES\ PRICE$	0.199	0.230	0.398	$\Delta FR\ PRICE$	-0.223	0.276	0.429
$\Delta DE\ PRICE_{t-1}$	-0.115	0.211	0.590	$\Delta ES\ PRICE_{t-1}$	-0.080	0.136	0.566	$\Delta FR\ PRICE_{t-1}$	-0.434	0.267	0.121
Constant	12.251	4.911	0.022	*Constant*	2.890	4.918	0.563	*Constant*	-2.153	6.560	0.746
Trend	0.013	0.006	0.046	*Trend*	0.014	0.014	0.316	*Trend*	0.012	0.010	0.237
$DE\ EC_{t-1}$	-0.215	0.173	0.230	$ES\ EC_{t-1}$	-0.383	0.234	0.117	$FR\ EC_{t-1}$	-0.474	0.174	0.013
$DE\ GDP_{t-1}$	-0.660	0.290	0.034	$ES\ GDP_{t-1}$	0.104	0.366	0.780	$FR\ GDP_{t-1}$	0.398	0.503	0.438
$DE\ PRICE_{t-1}$	-0.090	0.093	0.346	$ES\ PRICE_{t-1}$	-0.094	0.075	0.226	$FR\ PRICE_{t-1}$	0.383	0.226	0.106
R^2	0.439	*Adj.* R^2	0.187	R^2	0.607	*Adj.* R^2	0.430	R^2	0.571	*Adj.* R^2	0.378
AIC	-4.110	*SC*	-3.643	*AIC*	-3.780	*SC*	-3.313	*AIC*	-4.000	*SC*	-3.533
	Statistics	**p-value**			**Statistics**	**p-value**			**Statistics**	**p-value**	
AR 1-2 test: F(2,18)	0.675	0.522		*AR 1-2 test: F(2,18)*	1.303	0.296		*AR 1-2 test: F(2,18)*	0.936	0.411	
ARCH 1-1 test: F(1,28)	0.099	0.756		*ARCH 1-1 test: F(1,28)*	0.165	0.688		*ARCH 1-1 test: F(1,28)*	0.006	0.938	
Normality test: $\chi^2(2)$	6.992	0.030		*Normality test:* $\chi^2(2)$	14.005	0.0009**		*Normality test:* $\chi^2(2)$	0.172	0.917	
Hetero test: F(18,11)	2.205	0.091		*Hetero test: F(18,11)*	0.378	0.967		*Hetero test: F(18,11)*	0.862	0.623	
RESET23 test: F(2,18)	9.242	0.002		*RESET23 test: F(2,18)*	0.063	0.9387		*RESET23 test: F(2,18)*	2.288	0.130	

Table 7.9: Estimation output and misspecification tests for unrestricted ECM models without breaks of Germany, Spain and France's electricity demand.

Dependent variable Δ IT EC				Dependent variable Δ NL EC				Dependent variable Δ UK EC			
	Coefficient	Std.Error	p-value		Coefficient	Std.Error	p-value		Coefficient	Std.Error	p-value
$\Delta IT\ EC_{t-1}$	-0.188	0.183	0.315	$\Delta NL\ EC_{t-1}$	0.085	0.256	0.744	$\Delta UK\ EC_{t-1}$	0.059	0.184	0.752
$\Delta IT\ GDP$	0.106	0.180	0.562	$\Delta NL\ GDP$	0.534	0.396	0.192	$\Delta UK\ GDP$	-0.363	0.384	0.356
$\Delta IT\ GDP_{t-1}$	-0.406	0.235	0.099	$\Delta NL\ GDP_{t-1}$	-0.298	0.429	0.495	$\Delta UK\ GDP_{t-1}$	0.495	0.484	0.318
$\Delta IT\ PRICE$	-0.020	0.059	0.734	$\Delta NL\ PRICE$	0.002	0.069	0.980	$\Delta UK\ PRICE$	0.118	0.116	0.322
$\Delta IT\ PRICE_{t-1}$	-0.103	0.048	0.045	$\Delta NL\ PRICE_{t-1}$	-0.010	0.079	0.903	$\Delta UK\ PRICE_{t-1}$	0.007	0.173	0.969
Constant	-3.404	1.881	0.085	*Constant*	-1.162	3.664	0.755	*Constant*	13.566	4.490	0.007
Trend	-0.003	0.002	0.121	*Trend*	-0.002	0.008	0.760	*Trend*	0.019	0.007	0.016
$IT\ EC_{t-1}$	-0.438	0.127	0.003	$NL\ EC_{t-1}$	-0.381	0.231	0.114	$UK\ EC_{t-1}$	-0.771	0.181	0.000
$IT\ GDP_{t-1}$	0.579	0.208	0.012	$NL\ GDP_{t-1}$	0.382	0.307	0.227	$UK\ GDP_{t-1}$	-0.324	0.286	0.271
$IT\ PRICE_{t-1}$	0.035	0.050	0.490	$NL\ PRICE_{t-1}$	0.013	0.045	0.779	$UK\ PRICE_{t-1}$	-0.122	0.084	0.159
R^2	0.652	*Adj.* R^2	0.496	R^2	0.260	*Adj.* R^2	-0.074	R^2	0.614	*Adj.* R^2	0.441
AIC	-5.852	*SC*	-5.385	*AIC*	-4.331	*SC*	-3.864	*AIC*	-4.661	*SC*	-4.194
	Statistics	p-value			Statistics	p-value			Statistics	p-value	
AR 1-2 test: F(2,18)	0.808	0.461		*AR 1-2 test: F(2,18)*	0.556	0.583		*AR 1-2 test: F(2,18)*	0.662	0.528	
ARCH 1-1 test: F(1,28)	0.502	0.485		*ARCH 1-1 test: F(1,28)*	0.049	0.826		*ARCH 1-1 test: F(1,28)*	2.205	0.149	
Normality test: $\chi_2(2)$	3.178	0.204		*Normality test:* $\chi_2(2)$	14.919	0.001		*Normality test:* $\chi_2(2)$	0.234	0.890	
Hetero test: F(18,11)	0.585	0.849		*Hetero test: F(18,11)*	1.976	0.125		*Hetero test: F(18,11)*	1.922	0.135	
RESET23 test: F(2,18)	6.791	0.006		*RESET23 test: F(2,18)*	1.776	0.1978		*RESET23 test: F(2,18)*	0.576	0.572	

Table 7.10: Estimation output and misspecification tests for unrestricted ECM models without breaks of Italy, Netherlands and UK's electricity demand.

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