Market Integration and Regulation in European Wholesale Electricity Markets: Five Essays on Energy Economics

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Preface

The thesis has strongly been influenced by and benefited from discussions with professors and colleagues, as well as presentations at various national and international conferences, seminars, and workshops. Thus, I am very grateful to my colleagues and all who supported my work during these years as a PhD student.

I would like to thank my supervisors Justus Haucap, who encouraged and supported me since my years as an undergraduate student, for his excellent advice and patience when writing this thesis. I also want to thank my second supervisor Ulrich Heimeshoff whose experience and help I benefited a lot from. These two have had a very large influence on my work and I want to express real gratitude towards their help.

Many thanks to my co-authors and colleagues Jürgen Rösch and Dragan Jovanovic who have given me lots of food for thought while working together.

I thank my girlfriend Pina Wagner as well as my dearest friends Christoph Heine, Michael Kaluzny, Andre Kuntjoro and Robert Schumacher.

This thesis is dedicated to my parents without whom none of this would have happened. Thank you for everything.

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Chapter 1

Introduction

This thesis analyzes the impact of specific structural breaks, e.g., product innovation, and regulatory interventions in European wholesale electricity markets. Unlike other markets such as those for convenience goods, network-bound industries, including railways, telecommunications, gas and electricity, have been restructured, liberalized and (partially) privatized only a bit more than a decade ago. In the European electricity sector, this process towards a market-based system was initiated in the 1990s (Sioshansi and Pfaffenberger, 2006). Following Jamasb and Pollitt (2005) the steps of an electricity market reform can be summarized as:

- Vertical unbundling of generation, transmission and retail activities as well as horizontal splitting to decrease market concentration,
- Privatization of formerly publicly owned businesses,
- Securing access on the transmission level and elimination of barriers to entry on the wholesale and retail level.

The focus of this thesis is on the wholesale level. While many countries have chosen different paths when setting up the wholesale market system (see Wilson, 2002; Correlje and de Vries, 2008) and country-specific factors, e.g., climatic conditions, primary energy availability, and economic structure, make international comparisons difficult, there are some features which most of the restructured and liberalized markets inherit. Many of these features reflect the fact that electricity as a product is grid-bound and can be differentiated over time. This has lead to the introduction of

- short-run markets (intra-day and daily),
- long-run markets (forward and futures),
- reserve markets (short-run for electricity and long-run for generation capacity),
- and transmission capacity allocation mechanisms.

While these markets are distinguished along a time dimension, they inter-depend on each other, i.e. long-run markets depend on expectations of future day-ahead market developments. In practise, the short-run day-ahead market has become one of the most important and analyzed markets and is also subject of this thesis.

These cornerstones of liberalization and market design at the wholesale level have since been reviewed. Newbery (2002) notes that in the wake of liberalization, European markets did not adequately address issues of market power abuse adequately, i.e., few large formerly state-owned utilities dominated the market. One remedy has been to foster competition through the expansion of transmission capacities which in addition necessitates efficient management of these. This is a core objective identified by the European Union, resulting in the proclaimed establishment of a single European market for energy, i.e., electricity, gas and other energy sources. This single market is also known as Internal Energy Market (IEM) and its final stage for the electricity market is supposed to be completed in 2014.

The first part of the thesis centers around the aspect of the IEM and empirically analyzes the status of market integration. In detail, Chapter 2 entitled **"Benefits of a Single European Electricity Market"** (co-authored by Justus Haucap and Ulrich Heimeshoff) gives an introduction to European wholesale power markets and analyzes the benefits of further market integration of European wholesale electricity markets. We find that major gains from trade are still left unrealized due to (1) incomplete market coupling of national wholesale markets, (2) isolated national regulation of capacity and reserve mechanisms (CRM) and (3) a lack of harmonization of national support schemes for renewable energies.

The third Chapter entitled **“The Extent of the European Power Markets”** (co-authored by Ulrich Heimeshoff) analyzes the degree of market integration in nine Western and Northern European countries from 2004 to the beginning of 2011. As an empirical identification strategy national holidays are used as sources of exogenous demand shocks to measure integration of European energy markets. Our main findings indicate that integration of European wholesale energy markets has increased with regard to Germany and Austria as well as Belgium, and the Netherlands.

Chapter 4 entitled **“Tracing Cross-Demand Shocks in Southern-European Wholesale Electricity Markets: An Empirical Analysis of the Relevant Antitrust Market”** (single authored) expands this approach and uses more sources of exogenous variation (such as data on temperature and renewable electricity generation) to analyze the extent of the relevant antitrust market for the South-Western European countries, i.e., Spain, Portugal and France, from 2006 to 2012. I find strong empirical evidence that Spain and Portugal constitute the relevant market.

The second part of the thesis moves away from the issue of an IEM and analyzes the impact of two specific market interventions on competition in the wholesale electricity market. As Jamasb and Pollitt (2005) have pointed out, a concentration on the integration of energy markets is insufficient because an efficient management of the European system also touches issues such as market design in general and its alignment with transmission utilization and security of supply in detail. Two market interventions which may have an impact on market design are discussed in chapter 5 and 6.

Chapter 5 entitled **"Discriminatory Bidding Constraints in the German Wholesale Electricity Market"** (co-authored by Justus Haucap and Dragan Jovanovic) analyzes the effects of an implicit price cap on dominant firms in the German wholesale electricity market. In its sector inquiry into the German wholesale market for electricity from 2011, the Federal Cartel Office concluded that any dominant power generation company must not bid above their marginal costs of production or proof the necessity of these excessive bids to cover average total costs of the whole plant fleet. This paper analyzes the effects of these bidding constraints on competition. A key finding is that such an intervention is disproportionate, discriminatory, and can have adverse economic effects on investment decisions of dominant firms as well as potential competitors due to foreclosure. It is an untenable conclusion that price mark-ups can only be allowed to a dominant firm if these are necessary to cover total average costs of its respective power plant portfolio. If put into effect, the bidding constraint may induce cross-subsidization of power plants in deficit which may harm competition by deterring market entry. We also analyze the current geographical market definition that is the basis of structural market power indices, which in turn determine the degree of market dominance allocated to firms. This is especially important in the context of market coupling and the integration of European power markets.

Chapter 6 entitled **"The Green Game Changer: An Empirical Assessment of the Effects of Wind and Solar Power on the Merit Order"** (co-authored by Jürgen Rösch and Leonie Giessing) estimates the price and quantity effect of renewable power generation on the Spanish merit order from 2008 to 2012. We use the given structure of the merit-order to estimate a VAR model. The coefficients of the technologies right in the merit-order of the respective technology are constraint to zero. We argue that wind and solar production are exogenous to the system for the time observed. As expected, the effect is negative for the wholesale price and the produced quantities of most generation technologies. The estimated impact, however, is biggest for mid-merit plants. This finding sheds light on the theoretical discussion which power plants are affected most by renewable energy sources.

The effect is also mainly driven by wind power. Solar power increases wholesale prices while it has a negative impact on the quantities produced by baseload and mid-merit power plants.

Chapter 7 concludes the thesis and discusses potential extensions of the analysis performed in this thesis.

Part I

Market Integration and the Relevant Antitrust Market

Chapter 2

Benefits of a Single European Electricity Market*

2.1 Introduction

Markets with effective competition are generally characterized by consumer choice, low prices and quality levels desired by consumers. Effective competition thereby directly benefits (1) consumers by increasing consumer surplus through lower prices and also (2) firms by protecting competitors against the abuse of market power by dominant firms (e.g., incumbents). This major economic insight is also the underlying principle for the liberalization of European energy markets. Fostering competition in energy markets is even more important than in many other sectors of the economy due to the outstanding importance of energy prices and availability for production processes, economic growth and consumer welfare in modern industrialized economies. While there are, in fact, many energy markets for different products such as gas or oil, this paper focuses on competition in wholesale electricity markets.

*This paper is based on an earlier version that is co-authored by Justus Haucap and Ulrich Heimeshoff and was commissioned by the European Parliament.

A means to foster competition and to increase the utilization of electricity networks and generation capacities is the integration of European wholesale markets through physical and commercial coupling of the national electricity systems. It is the declared main objective of the European Commission to create a single European wholesale market for electricity, which is also clearly stated in the Directive 2009/72/EC by European Parliament and Council.

> *"A secure supply of electricity is of vital importance for the development of European society, the implementation of a sustainable climate change policy, and the fostering of competitiveness within the internal market. To that end, cross-border interconnections should be further developed in order to secure the supply of all energy sources at the most competitive prices to consumers and industry within the Community. A well-functioning internal market in electricity should provide producers with the appropriate incentives for investing in new power generation, including in electricity from renewable energy sources, paying special attention to the most isolated countries and regions in the Community's energy market. A well-functioning market should also provide consumers with adequate measures to promote the more efficient use of energy for which a secure supply of energy is a precondition."*

Our paper proceeds from this position and consists of three parts, following this introduction: In the next chapter we discuss the relationship between economic market definition and the integration of European power markets, before we describe the state of competition in European wholesale electricity markets in chapter 3. In chapter 4 then present empirical evidence for the extent of the Internal Energy Market (IEM) and analyze the costs that result from the lack of further European integration, i.e. the costs of national energy markets still being isolated.

An assessment of the benefits of market integration from a competition perspective requires a description of the close relationship between market definition and market integration. Market definition is the basis for any analysis of the degree of competition in a given market. Therefore, analyzing power markets requires an understanding how wide the relevant market is to be defined geographically. As we will show in chapter 2 this is by no means a trivial task in terms of practical delineation and may have consequences for regulation and competition policy.

Chapter 3 starts with a recap of the results of the European Commission's sector inquiry which were published in 2007 (section 3.1), before we present an update of the status quo for 2011 (section 3.2). The chapter, thereby, provides an overview of the European history of competition in wholesale electricity markets and serves as a benchmark for recent market developments. We also provide an overview of the degree of fragmentation of national support schemes for renewable energies as well as capacity mechanisms.

In chapter 4, we provide an empirical assessment on two matters of market integration, the contemporary extent of markets and the welfare effects of coupling markets. We start with demand fluctuations and resulting free generation capacities, which are the basis for energy flows across borders. We give special emphasis to renewable energies, as the stochastic nature of electricity generation by renewable energy sources (RES) significantly affects the free capacity levels and the need for cross-border flows. In addition, we present results on price effects of cross-country energy transmission based on own calculations and compare the potential evolution of market concentration under different scenarios of market integration.

Against this background we then provide an overview of empirical studies on the benefits of further market integration (section 4.2), which includes the cost of isolated national energy markets in Europe. The main reason for isolated markets in general and also isolated energy markets are barriers to entry, which basically materialize in insufficient cross-border interconnections. We discuss institutional differences between countries, which are related to differences in laws, regulation and market design. We present examples for different barriers to entry and discuss costs related to these barriers. Furthermore, our paper analyzes who is harmed by barriers to entry.

We conclude the research paper with a brief summary of our results and policy recommendations for future energy policy and regulation in the European Union in chapter 5.

2.2 Competition and Market Integration

To understand the concept of market coupling and its importance from a competition economics and policy perspective, let us first explain how markets can be defined and why this is relevant for any competition analysis. We then show that market integration and delineation are related and then describe the basic concepts of market integration. At the end of this section we will discuss potential factors which can distort the otherwise efficiency enhancing integration of wholesale electricity markets.

A thorough competition analysis usually necessitates delineation of the relevant market. Broadly speaking, the market definition exercise identifies all firms which are actively or potentially competing with each other, thereby limiting each other's scope for the exercise (and abuse) of market power.

Typically markets are defined along two or three dimensions: (i) product characteristics, (ii) space (geography), and (iii) time. The latter becomes especially important if the production or consumption of a good is time critical, e.g., non-storable goods such as electricity. Generally, the key principle for market definition is the same with respect to all three dimensions, as the main question is: Is there a critical number of consumers which regard a certain product (location or time of purchase) to be a (potential) substitute for another product (location or time of purchase). Technically the question is whether there is a critical elasticity of demand so that sufficiently many consumers would switch to a different product, location, or time of purchase to render a price increase (or any other potential use of market power) unprofitable, implying that competitive forces are sufficiently strong to discipline the firm(s) under consideration.

For instance, while apples and oranges are different products, they can be still regarded as potential substitutes. Hence, if the price for apples reaches a critical point, at least some consumers will substitute them against oranges.

The geographic dimension concerns the inclusion of products from other regions into the relevant market. For example, products such as raw sugar or crude oil are traded in wholesale markets which are considered to be world-wide markets whereas transportation or, more generally, transaction costs for other goods are so high with respect to inter-regional trade that these markets have to be delineated more narrowly, e.g., for retail grocery products. This aspect becomes very important for the following delineation of the relevant wholesale market(s) for electricity.

In the case of electricity markets the product dimension is rather straight forward. The direct benefit of electricity is mostly irrelevant to consumers because its consumption is more a precondition to consume or use other goods such as television shows, cell phones, light, refrigerator, computer and so on. This indirect utility is crucial as there is typically no direct substitute for electricity. Moreover, since (a) the electricity itself cannot be distinguished by type or production while (b) certificates of origin (e.g., for green electricity versus electricity from fossil fuels) are typically traded separately from the electricity itself, electricity can be regarded as a homogenous product, at least at the wholesale level. Its specific product characteristics also require market delineation with regard to the time dimension. Note that electricity is a network bound product and that power consumption (demand) and production (supply) have to be balanced at all times. Therefore, electricity generation largely depends on expectations about demand. These expectations only vary to a certain extent. Hence, electricity can be sold based on consumption predictions, leading to a wide array of products differentiated by time. There are financial and physical contracts which mostly cover a period of one year, quarter, month or day ahead of the actual delivery date. The products with the shortest time difference between trade and delivery, e.g., minutes or seconds, are labeled *balancing energy* and are clearly distinguished from the others. In detail, the price system for *balancing energy* is often set up as a two-part tariff because the provision as well as the actual generation of electricity is being traded. The importance of this differentiation is derived from the fact that the day-ahead market has become the reference market for other products and is also the main focus when analyzing the extent of the relevant market in its geographic dimension.

When analyzing the geographic extent of the market, the network dependence becomes crucial. Electricity is transported via a network and if there is no physical connection between two regions, then those markets cannot belong together unless they are indirectly connected via another region. Existence of cross-border network capacities is, therefore, the cornerstone of any market covering more than one region. This is the core of the discussion about the integration of European energy markets. An analysis of market integration almost always circles around an analysis of the relevant geographic market. In theory, any two power markets are integrated when demand elasticity keeps suppliers in any of the two markets from raising prices above competitive levels. Since power is an almost perfectly homogenous product, the *law of one price* is supposed to hold, i.e., in the absence of transaction costs, wholesale prices (net of any taxes) in two areas should be equal. In this context, transaction costs include transportation costs which in turn translate into costs of network congestion. An isolated power market, therefore, goes along with insufficiency in cross-border transmission capacity. A difficulty in practice is the definition and identification of a relevant threshold that marks the switch between integrated and isolated energy markets from a competition point of view. This will be discussed in the next section.

Before we explain the concept of power market integration, and market coupling in particular, it is important to add that power is traded either bilaterally, called over the counter (OTC), or over power exchanges. The trading system of these power exchanges is basically that of a uniform-price auction, where the last successful bid sets the market price. In these auctions, bids can be sorted in increasing order of prices, called the merit order. If the market is sufficiently liquid, the day-ahead auction becomes the reference price for long-term contracts, e.g., yearly or monthly contracts.

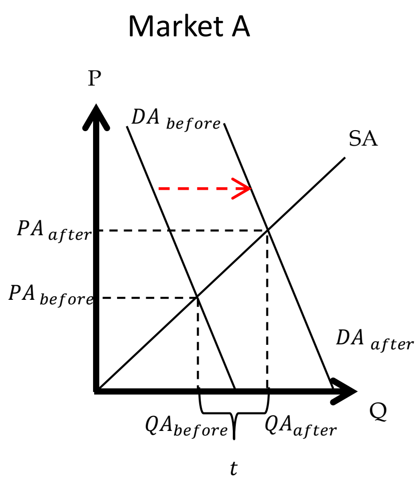
In a next step, the implementation of an efficient trading system that incorporates cross-border activities becomes important. In this paper, we focus on market coupling. For an introduction to the topic of market coupling we refer to European Market Coupling Company (2013) and Kurzidem (2010). A stylized textbook example of market integration between two regional markets, say, *A* and *B*, is used to explain the basic concept and importance to competition policy. For simplicity, power in each market is traded over a day-ahead power exchange and the equilibrium prices and quantities for each market, indexed by *A* and *B*, are labeled as *P* and *Q*, respectively. In addition we assume identical production facilities, i.e., identical production costs. There exists a direct link between both transmission networks with a total capacity of *T* units. The actually traded quantity is defined as *t*, with $t \leq T$. We define market *A* to have lower demand and higher excess capacity than market *B*. It would then be optimal, if these sellers of excess capacities from market *A* bid into market *B* that are cheaper than those of market *B*. This would result in a price decrease in market *B* from PB_{Before} down to PB_{After}.

There are two market-based options to combine cross-border trade and cross-border transmission capacities: explicit and implicit capacity auctions[1]. In the case of explicit auctions, power trading does not directly integrate the auction of cross-border capacities, but potential energy seller bid for energy and transmission capacities separately.

Two main inefficiencies are endemic to the method because of the relation of transmission auctioning to the day-ahead energy market. Cross-border transmission capacities are booked prior to the actual day-ahead market. As a consequence, the bid for transmission capacity is based on predictions of the expected day-ahead prices. Booked transmission capacity is not necessarily equal to the power units finally sold via cross-border trade. This constitutes the first inefficiency. Secondly, a further inefficiency stems from the fact that transmission capacities are booked for both directions (*A* to *B* and *B* to *A*). So capacities can be booked for the wrong direction, i.e., they are booked for one direction despite the fact that this turns out to be unnecessary in the end (on the topic of inefficiencies in cross-border trading systems see Kurzidem, 2010; Höffler and Wittmann, 2007; Pellini, 2012).

[1] Both concepts can even be combined. Let us assume that a company in market *A* decides to sell power for a full year to buyer in market *B*. The necessary transmission capacity for this long-run contract could be booked via an explicit auction. Short-run adjustments over the day-ahead market of both areas could be managed via an implicit auction design.

Figure 2.1: Principles of market coupling



DA= Demand Market A, DB= Demand Market B, SA= Supply Market A, SB= Supply Market B, PA= Price Market A, PB= Price Market B, QA= Quantity Market A, QB= Quantity Market B, Before= Before Market Coupling, After= After Market Coupling.

An implicit auction combines both energy and transmission trade to resolve the problems just mentioned. A prerequisite for this concept to work optimally is a common auction office. Information on the availability of transmission capacities is gathered from the various transmission system operators and incorporated in the algorithm that optimizes the respective power auctions in market A and B. In addition to the elimination of the aforementioned inefficiencies, the simplicity of a single auction also leads to a decrease in transaction costs. It is important to note that the new responsible auction office is in fact a monopolist. Therefore, it is crucial that the auctioneer remains independent from other market participants and does not discriminate among different generators and/or traders.

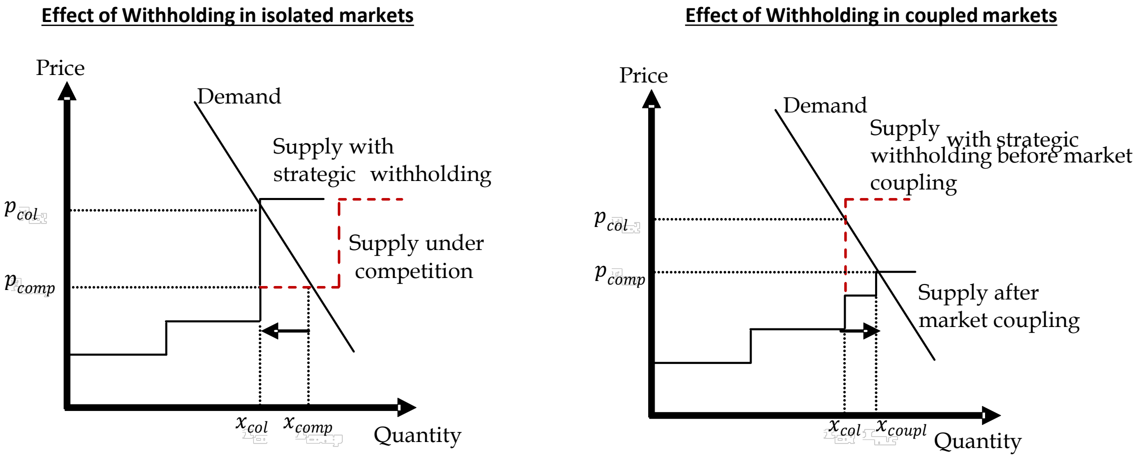
Market coupling and market splitting are two subclasses of the implicit auction concept (for a short explanation of the two concepts see ACER/CEER, 2012). The former concept defines relevant local markets, A and B in our example, that are fixed for a given period and then performs the implicit auction. So even while there is not necessarily any congestion between these two areas, some power markets are treated as separated areas which simply clear with the same wholesale price if congestion is no problem. Market splitting defines the relevant local sub-markets according to congestion. So if there was no congestion problem at a specific point in time between area A and B, then both would be treated as a single area. The difference becomes clearer if shown in a practical example. For instance, the French, Belgian, Dutch and German Power exchanges are linked together via market coupling, where every country constitutes as separate market. The Nordic countries, Sweden, Denmark, Norway and Finland, are linked via market splitting. There is not a single Swedish area but fragments which are defined by transmission capacities and potential congestion. Therefore, power prices can vary even in Sweden while the remaining markets may, for example, have equal prices.

When we state that the utilization of power is more efficiently used in a market integration framework, this means that power flows, economically, from the lower price area to the more expensive area, leading to a balancing of prices on a lower level on average than before. We have implicitly assumed that the bids from both, sellers and buyers are based on competitive behavior. It is well known in competition economics that most real markets are best described by models of oligopolistic interdependence instead of perfect competition, which in turn implies the existence and exercise of some degree of market power. The use of market power is especially lucrative in the case of collusive behavior, where companies act strategically together to increase profits. In electricity markets, the two most common strategies are excessive pricing and withholding of capacity in order to increase prices. These practices become especially interesting during times of high and very high demand (peak hours) which are usually on weekdays between 8 a.m. and 8 p.m. (see for example EPEX Spot, 2014a; 2014b; APX, 2014).[2]

The major contribution of market coupling to competition is that it increases the number of competitors, therefore constraining the exercise of market power and lessening the likelihood of anti-competitive behavior. This is where the independence of the market coupling operator becomes crucial as bids have to be arranged in an efficient way in order to reach the welfare maximizing equilibrium. An integration of markets may not guarantee competitive results, but market integration increases their likelihood, as firms which

[2]This definition is based on demand-specific factors and may vary with regard to region-specific weather conditions, economic performance in general and energy-intensive industries in particular.

Figure 2.2: Market coupling and strategic withholding



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are dominant in one market now face competitors which may themselves be dominant in their respective market area. As most national power markets are rather concentrated, in particular France (see section 3.2), this becomes an important factor for the efficiency of an integrated (European) market.

Even if most firms acted competitively there are a number of other factors, caused by the fact that many countries are involved in the process, which interfere with market coupling and may yield inefficient results. These factors are differences in the participants' wholesale market design, general energy policies and national regulatory frameworks. To avoid the resulting systematic inefficiencies, the overall economic and legal framework should be aligned. Two examples show the difficulties that can arise from different policies and frameworks that lack compatibility or harmonization.

In many European countries competition authorities, transmission system operators, power plant operators, retailers and other stakeholders debate about the introduction of so-called capacity mechanisms to safeguard the security of power supply at the wholesale level. The core question of this debate is whether the energy-only market, the basic version of wholesale electricity trading, is still capable of inducing sufficient investment into generation capacity in the context of emissions trading and the increasing share of intermittent renewable generation. Capacity mechanisms reduce investment risks via an extra payment for provision of generation capacity. A number of European countries have already introduced such a system. However, the largest countries have not yet done so and the actual capacity mechanism design is likely to vary significantly between member states (see Sioshansi, 2008). This is important because different capacity mechanisms clearly have different advantages and disadvantages as well as diverging degrees of permanent regulatory intervention. If two markets with different market designs are to be coupled, then these differences affect the functioning of market coupling significantly. Eurelectric has indicated in their working paper that investment decisions can be distorted for the case of a market with strategic reserves, paid for availability and only activated in extreme cases (see Eurelectric, 2011), and a full-blown capacity market, where each supplier receives a premium. The market coupling process as such is not distorted, i.e. bids are still efficiently ordered under competition. However, cross-payments are likely to occur which may jeopardize the integration of markets in the long run. If, in our example, the regulator in market A would only pay premiums to (strategic) reserve capacities that are solely activated in the case of insufficient generation, while a capacity market would be set up in market B, market A would benefit from spare capacities of market B without paying the capacity premium. As a consequence, the own strategic reserves would be activated less frequently if at all, and buyers in market B would pay the premium for capacities which help to secure supply for market A. This may, in general, not create inefficiency but is a matter of rent distribution. In addition, investment decisions of potential plant owners are based on the most lucrative market (A vs. B). If the allocation of new generation becomes sufficiently asymmetric, a new congestion situation may result, necessitating new investment into transmission capacities.

The second example concerns regulatory interventions such as price caps. For instance, the German cartel office has concluded in its 2011 sector inquiry that according to §§ 19 and 29 GWB (German law against restraints of competition) and article 102 TFEU that dominant electricity generators are subject to marginal-cost pricing, i.e., they are not allowed to place bids which exceed their marginal costs (German Cartel Office, 2011). An exception could only be made if the generator could prove that higher bids are necessary to cover the fixed cost of its generation portfolio (i.e., not even the power plant under consideration). We address this subject in detail in chapter five and only want to give a very short explanation as to why such an implicit price cap, if it was actually imposed by the Federal Cartel Office, could pose a problem to market integration. In addition to the general problems of such a price cap, the German government ordered especially dominant companies to keep unprofitable power plants online for security of supply reasons. However, this interferes with the concept of market coupling. First, a well-functioning coupling of market areas also leads to a reconsideration of the relevant market. However, the basis for the regulatory intervention is the assignment of dominance, which in practice is often the result of a quantitative assessment of market shares. In our example, a (theoretically) perfect market coupling with sufficient cross-border transmission capacities would mean that these two markets are in fact one and only stochastic shortages in either transmission or generation capacities would create temporary congestion and price differences. Market shares have to be recalculated. So the difficulty of such a regulatory intervention, regardless of its economic benefits and disadvantages, is based on both a divergence between the economic and legal market and the quantitative estimation of market shares inside a coupled sub-market. Let us assume that in market A a price cap is introduced that forces companies to place bids no higher than their marginal costs. Now a market participant from market B has unsuccessfully placed a bid which is estimated to be above her marginal costs. This bid, however, could satisfy demand from market A if shifted by the market coupling operator. It is questionable whether this bid is compliant with the actual marginal-price cap. Put simply, does a price cap based on market shares which are calculated on the basis of a joint market still hold for only that sub-market? The economic consequences can be as large as in the example described before.

We, therefore, conclude this section with the finding that market coupling theoretically increases market efficiency, but issues such as market design or other regulatory interventions have a significant impact on the performance of market coupling. Therefore, it is important to align the different existing national regulatory frameworks across Europe or to set up a new common framework altogether.

2.3 Status Quo of European Electricity Markets

The liberalization process of European wholesale electricity markets started in the 1990s. However, the process did not progress simultaneously across the EU member states, but national market designs and national energy policies still differ heavily. Accordingly, the lack of harmonization and integration has been a long standing concern for the European Commission.

In 2005, the European Commission then launched a sector inquiry into European wholesale markets for electricity and gas (European Commission, 2007). An increase in wholesale electricity prices, their divergence across countries as well as complaints of market participants about the (lack of) competitiveness of the market had raised severe competition concerns. As a result, many structural deficiencies have been analyzed in the inquiry.

In the following, we first describe the key findings of the 2005 report before we present more recent information about the persistence of these problems. Assessing the competitive structure of European wholesale markets and possible barriers to entry can help to understand the recent development of market integration.

2.3.1 Competitive Deficiencies in the Early Stages

As mentioned in the previous section, market integration can only unfold its full potential if there are no major distortions to competition such as collusive behavior. Electricity markets bear some characteristics that facilitate collusion. The main concerns are listed below:

- No storability of the good to an economically relevant extent,
- homogeneity of the final product (i.e., not the fuel-type used to generate electricity),
- low elasticity of demand, in particular for private households,
- high barriers to entry due to high investment lead time, capital-intensity and network dependency,
- high vertical information asymmetry to the detriment of consumers and competition authorities,
- high horizontal information symmetry among generators or even transmission system operators,
- and high levels of concentration and cross-shareholding.

In its sector inquiry, the European Commission has concluded that some of these factors can be attributed to the European wholesale markets (European Commission, 2007) and that the overall state of competition is not satisfactory. The key findings can be summarized as follows:

- Quantitative concentration tests based on hourly data were conducted to reveal whether specific generators were capable of significantly influencing the market through capacity withholding in a given number of hours per year. High levels of concentration were found and there exists a large potential of exercising market power during peak hours regardless of the overall concentration level. Even during off-peak hours, where competition should be most effective, countries with high concentration ratios exhibit large potentials for capacity withholding.
- Inter-regional competition was ineffective as the then current interconnection capacity was insufficient. In addition, long-term pre-liberalization capacity reserva-

tions may have blocked an efficient capacity utilization and vertically integrated companies controlling the network have little incentives to invest into new cross-border transmission capacity.

- Vertical foreclosure hinders effectively new market entry, e.g., by means of denying of hampering access to the network.

- Lack of information transparency on all levels, i.e., wholesale, network and retail which leads to a distrust in market results and the price mechanism.

Table 2.1: Concentration ratios of available capacity and effective generation in selected European countries in 2004

Country	**CR1**	**CR3**
Austria	43.2% (AC)/46 % (EG)	83.3%/ 85,2%
Belgium	83% /82.3%	100%/ 100% (CR1+ Fringe)
Denmark East	85%/76.3%	100% /100% (CR1+Fringe)
Denmark West	54%/60.6%	100% /100% (CR1+Fringe)
France	86.7%/75.4%	97.4%/ 90.7%
Finland	37.4%/33.7%	84.1%/81.8%
Germany	24.4%/28.4%	68.5%/67.9%
Italy	51.4%/43.9%	74.4%/76.7%
Poland	25.7%/33.8%	67%/70.7%
Spain	35.6%/48.3%	83%/86.7%
Sweden	42.8%/47.1%	83.4%/86.7%
Netherlands	28.3%/26.6%	72%/70.2%
United Kingdom	15.5%/19.7%	42.8%/48.1%

AC= Available Capacity, EG= Effective Generation, CR=Concentration Ratio. The CR1 generator in the AC category is not necessarily equal to that of EG. Source: COM (2007).

The insufficient level of market integration leads to a general delineation of the relevant geographical markets at national levels. An analysis by DG Competition for the year 2004 shows that most European markets are highly concentrated. A more detailed assessment of the concentration ratios for the years 2003 to 2005 can be found in the report by London Economics (2007) which in essence comes to the same conclusion as the Commission's sector inquiry.

2.3.2 Assessment of Competition in 2011

Over the course of the years after the sector inquiry some major changes to the wholesale electricity market and generation in general have taken place. The member states have mostly implemented (or at least started to implement) the regulations contained in the third package of the European Parliament and Council, in particular Directive 2009/72/EC. In the context of this paper, the most important change affects the rules for the internal energy market and Regulation (EC) No 714/2009, which concerns network access for cross-border exchange. Predominantly, electricity generation from renewable energy sources (RES) has increased and lead to a change in the composition of European generation parks, in particular in Germany and Spain, which is analyzed in detail in chapter six. The impact of RES will be discussed in the next subsection, along with the discussion of possible adjustments to the market design of various European markets.

National regulation and competition authorities report yearly on the competitive development of the wholesale, transmission and retail level. We focus on the wholesale level and summarize the essential findings for a number of member states, which are also part of the quantitative analysis in the next section. The following presents a summary of a selection of national regulation reports for the year 2011.[3]

Austria and Germany

- Austria and Germany constitute a fully integrated market (German Federal Cartel Office, 2011). Due to the significant difference in installed generation capacities, Austrian power generators are no dominant competitors on the wholesale market. The four largest generators in Germany hold approx. 73% of the competitive generation capacity (Platts, 2011). Including Austria lowers the share by one tenth, i.e., approximately 66.7% remain (Platts, 2011).

- One-sided competition between RES generation (beneficiary) and conventional gen-

[3] The national reports can be found on the homepage of the Council of European Energy Regulators (CEER).

eration affects wholesale prices and creates large generation overcapacities.

- De-commissioning of nuclear power plants in Germany reduces market shares of the four largest generation companies in Germany.

- Germany acts as the pivotal hub for electricity exchange despite a decrease in available cross-border capacity of 7.12% on average, in particular to France, Sweden and Denmark.

Belgium

- The four largest generators in terms of total generation capacity are Electrabel (70%) SPE/EdF (14%), E.ON (9%) and T-Power (3%) (Platts, 2011).

- A decoupling of the market on 28 March 2011 lead to a significant upward effect on wholesale prices in Belgium, with an average price of 206.1 €/MWh for base load and 2999 €/MWh in the 8th hour of the day. An analysis of the dispatching process and offering behavior came to the conclusion that capacity proposed was sufficient to prevent the peak. It is not made clear in the national report which consequences this result has on a potential antitrust case.

Czech Republic

- The Power Exchange Central Europe now enables electricity trades for the Czech Republic, Slovakia and Hungary.

Denmark

- Dong Energy and Vattenfall are the two largest players in Denmark with market shares of 47.21% and 15.71% of installed capacity (Platts, 2011). In relation to the Nordic region these shares change to 6.2% (Dong Energy) and 18.7% (Vattenfall), respectively.

- With the exception of the border between Germany and Western Denmark, all cross-border capacities are controlled via day-ahead market coupling.

- Large share of actual generation can be attributed to wind power (30%)
- Two Danish price areas exist inside the coupled Nordic markets which, for most of the time, are different from other price regions, in particular Norway and Sweden. East Denmark exhibits both the highest and lowest prices in the whole Nordic region.

Norway

- Statkraft, E-CO Energi and Norsk Hydro are the three largest players in Norway with market shares of 38.63%, 9.16% and 5.93% of installed capacity (Platts, 2011). In relation to the Nordic region these shares change to 11.3% (Statkraft), 2.8% (E-CO Energi) and 1.9% (Norsk Hydro).
- Low precipitation lead to price increases because Norwegian power generation is mainly based on hydro (95% of installed capacity) and nuclear.

Sweden

- In 2011 the formerly single Swedish price region was divided into four sub-markets.
- According to the Swedish Energy Market Inspectorate (2012: p.36), the three largest generation companies are Vattenfall (41%), Fortum (20%) and E.ON Sweden (18%). The market shares of these three generators in the Nordic region are 18.7% (Vattenfall), 6.7% (E.ON Sweden) and 11.2% (Fortum). The Herfindahl-Hirschman-Index (HHI) in the four Swedish sub-markets reflects a very high concentration in SE1 (6375) and moderate concentration in the other regions SE2 (1866), SE3 (1956), SE4 (2325). However, the four areas were not isolated for the entire time span. Therefore, the actual HHI, depending on the state of congestion, was quite moderate for most of the time, i.e., significantly below an HHI of 2000.
- Co-ownership of power plants, especially nuclear plants, is still regarded as a limiting factor for competition.
- Low precipitation lead to price increases.

France

- EdF and GdF are the two largest players in France with market shares of 83.16% and 5.36% of installed capacity (Platts, 2011).
- Virtual power plant capacity is offered as a remedy for the dominance of EdF.
- Like Norway and Sweden, France is highly dependent on nuclear and hydro power plants. Therefore, precipitation and temperature play a very important role in security of supply.
- The French regulator conducted an investigation into the price mark-ups of EdF, i.e. the difference between marginal costs of production and spot prices. An average mark-up of 3.2% was found for 2010, which was not considered an abuse of a dominant position. Few offers exceeded 100 €/MWh, and they were found to reflect system marginal costs in the EPEX Spot auction.
- Transparency and availability of production and consumption data was increased significantly since 2010 and 2011.

Spain

- Iberdrola, Endesa and Gas Natural Fenosa are the three largest players in Spain with market shares of 23.5%, 22.7% and 15% of electricity generation (Platts, 2011).
- The degree of congestion between Spain and Portugal decreased from 80% of the time in 2007 to 9% in 2011.
- Apart from the progress in its market integration with France, Spain and Portugal also pursue the integration with the whole North-West European region.

The Netherlands

- GDF Suez, RWE AG and Vattenfall AB are the three largest players in the Netherlands with market shares of 22.07%, 17.16% and 16.22% of installed generation capacity (Platts, 2011).

- As a part of the CWE region, the Netherlands successfully integrated with Germany at the end of 2010. The next step of integration of the entire North-Western region is expected to happen in 2012.

United Kingdom

- EDF, SSE and RWE Npower are the three largest players in the UK with market shares of 22%, 16% and 10% of electricity generation (Platts, 2011).
- The Department for Energy and Climate Change started a consultation on a draft which intends to prohibit output manipulation. This is supposed to prevent anti-competitive behavior such as withholding of generation capacity.

A comparison of concentration ratios between 2004 and 2011 may lead to the assessment that the situation has improved in many countries. However, most markets are still highly concentrated. Especially the French market cannot be expected to exhibit significant reductions in concentration any time soon. Despite the high national concentration ratios, the increasing degree of integration between the markets is a positive development, which will be discussed in more detail in the next chapter. In addition, Germany and Austria are now considered to constitute a common market area (see also Chapter 5). While Austria may be too small to cause drastic changes in the competition assessment, it is a positive aspect nonetheless.

The largest impact on competition, however, can be attributed to the increasing share of subsidized generation from renewable resources. The various support schemes will be addressed in the next subsection, but what is important from a competition point of view is that these foster a one-sided competition relationship to the detriment of conventional generation. Since the latter is the source of high concentration, market shares for the largest generators decrease. This development comes at the cost of a well functioning market-based energy system. So it is unclear whether this development should be described as positive.

Deconcentration may have an impact on market power and the incentives for its abuse through capacity withholding, but it is not expected to be large enough to completely rule out its possibility. Capacity withholding still remains difficult to prove and it can be still very profitable for firms to engage in this sort of behavior even if concentration ratios are very low.

Progress has been made in other crucial points listed in the 2004 competition assessment of the European Commission (2007): Information transparency, data availability in particular, and vertical ownership unbundling between network and generation, which has decreased the likelihood of vertical foreclosure.

It is important to stress the discrepancy between physically and economically integrated markets. As described before in this chapter, market definition has a very large impact on the assessment of competition. For instance, relying on a very narrow definition will have (too) negative effects on mergers, while the opposite holds true for a very broad definition. Remedies like price caps or structural divestiture remedies are often based on the assessment of market power, which is (partly) based on concentration ratios.

The market definition problem arises because the two examples where the assessment is the easiest are also the most extreme. If there was no physical connection between two areas, and no third country was involved, then these two areas cannot belong to the same market. If cross-border capacities were as high as maximum demand, then these two should belong together, as prices would be equal all the time. Any status in between is less clear. The European Commission should define under what conditions it regards two areas as belonging to a common market. It could be argued that a clear definition is not a relevant matter because all that is important is sufficient competitive pressure from outside. This is, however, a rather incomplete assessment because all that matters inside a relevant market is sufficient pressure from competitors. Therefore, an assessment of sufficient pressure means that markets belong together. In power markets, and coupled markets in particular, this translates into price equality. So the question is, how often sufficient pressure can be observed.

2.3.3 Support Schemes for Renewable Energies and Market Design

As the European Commission has recently pointed out in a number of documents (European Commission, 2012a; 2013a; 2013b), support mechanisms for electricity production from renewable energies vary heavily between member states. In principle, three types of support mechanisms can be used:

- Government administered feed-in tariffs (FIT),
- Government guaranteed feed-in premia on top of market prices (FIP), and
- Government set renewable quota systems (RQS).

While we can distinguish between these three pure systems there are also hybrid systems where different support schemes are combined. For example, solar energy may be supported through the use of feed-in tariffs while wind power may be supported through feed-in premia or renewable quotas. These systems are partially complemented by tax incentives, public procurement auctions and investment grants. As of today, all EU member states have adopted somewhat different support systems even though some of them may be more similar to each other than others. Table 2.2 provides a rough overview over different support systems established in Europe.

The extent to which electricity generated from renewable energies is used in the member states also varies heavily between member countries, as is illustrated in Figure 2.3. The different support schemes have induced major inefficiencies especially if viewed from a European perspective. Most importantly, since all support schemes only support renewable energies *within their own national territory* massive gains from trade and from market integration are foregone. These gains from trade could easily result, as climate and weather conditions vary heavily across and even within member states. For example, conditions for wind power are typically superior in Northern Europe while the conditions to produce solar-based electricity are much better in Southern Europe. Hence, enormous gains from trade could be realized by focusing on solar power in Southern Europe and on

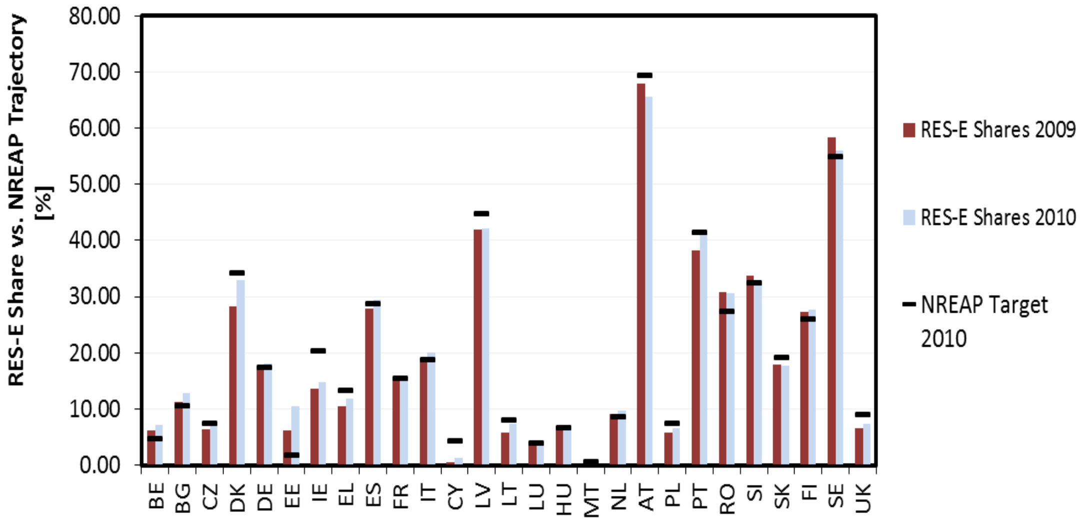
Table 2.2: Overview of RES-E support instruments in the EU-27

Country	**Instruments**					
	FIT	**P**	**Q**	**I**	**T**	**F**
AT	x					
BE	x		x	x	x	
BG	x					x
CY	x			x		
CZ	x	x		x		
DE	x	x				x
DK		x				
EE	x	x				x
ES	x	x			x	
FI				x	x	
FR	x					
GR	x			x	x	
HU	x			x		
IE	x					
IT	x	x	x			
LT	x		x	x		
LU	x			x		
LV	x		x	x	x	
MT	x			x		x
NL		x			x	x
PL			x		x	x
PT	x					
RO			x			
SE			x		x	
SI	x	x				x
SK	x				x	
UK	x	x	x		x	

FIT=Fixed Feed-in Tariff; P=Premium; Q=Quota; I=Investment Grants; T= Tax Exemptions; F=Fiscal Incentives. Source: European Commission (2012a).

wind energy in Northern Europe. However, since almost all RES support schemes (with the particular exception of Sweden and Norway) are based on national frontiers so that only domestic production is supported, these benefits are foregone, resulting in according inefficiencies (for more details see section 4.3 below).

Figure 2.3: Share of electricity from renewable energies

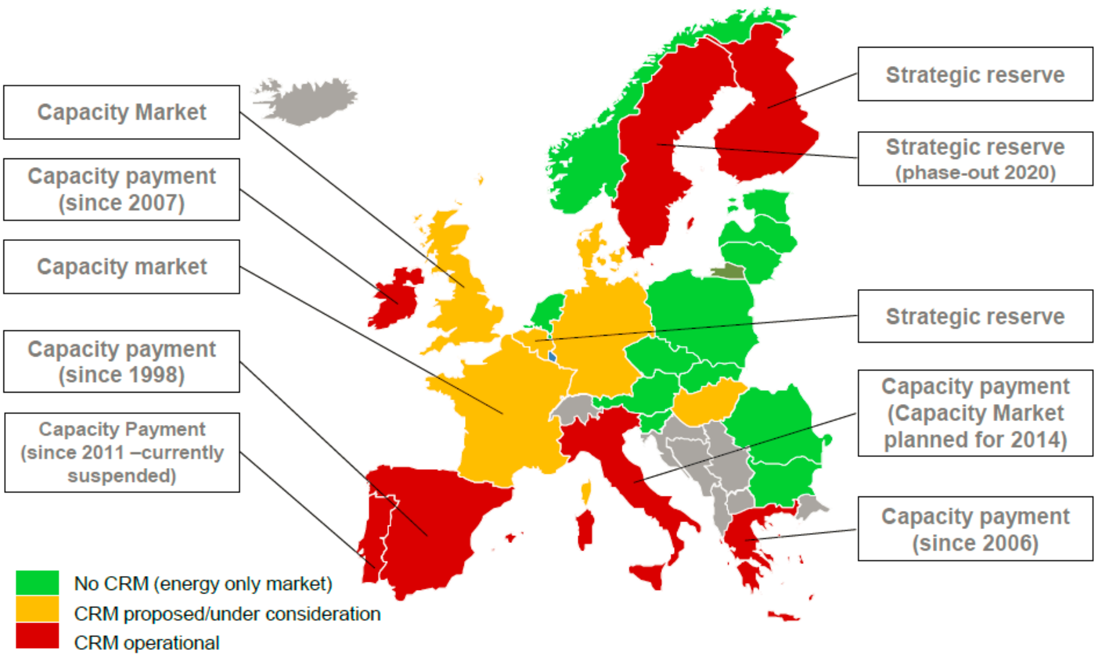


Source: European Commission (2013a).

For example, Germany had in 2011 more than 35% of the worldwide installed solar PV operating capacity, while Italy had only 18.3% and Spain 6.5% (see Renewable Energy Policy Network, 2012) even though in Spain the very same PV modules could -due to the naturally better sun conditions in Spain- produce about twice as much electricity as in Germany. From a European perspective the massive investment in solar PV capacity in Germany instead of Spain must be regarded as a misallocation of resources.

In addition, European electricity markets are threatened to be fragmented by national capacity and reserve mechanisms (CRM). There are various forms of CRM support schemes in order to secure the adequacy of generation investment. Again, as national member states tend to only make capacity payments to power plants within their own territory, significant benefits from trade and integration are foregone, as larger market areas typically require much lower capacity payments as (a) they increase competition within capacity auctions/markets and (b) less capacity is needed overall to safeguard the security of supply. Figure 2.4 illustrates the variety of mechanisms which are implemented or are planned in member states today.

Figure 2.4: Status of capacity remuneration mechanisms in Europe- 2013



Source: ACER (2013).

2.4 Quantitative Analysis of Market Integration

In the two previous sections we learned that a physical integration of two market areas may increase the efficient utilization of power plants to cover demand and foster competition on the generation level. However, there are some difficulties in assessing the practical usefulness, the actual degree and welfare effects of market integration. In the following subsection we explain that the potential for market integration also crucially hinges on the demand profile of the two interconnected areas. In addition, we give an indication as to how far wholesale markets have been integrated. The last subsection provides an overview of empirical evidence on the benefits of market coupling.

2.4.1 Potential and Degree of Market Integration

Market integration has progressed since the last sector inquiry for the European Commission. A thorough analysis on the subject of market integration has been conducted by the Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) (ACER/CEER, 2012). The following markets have been technically and commercially coupled:

- Denmark Finland, Norway and Sweden (Nordic countries) have stepwise adopted a market splitting model directly after market liberalization in the 1990s.
- France, Belgium and the Netherlands coupled their markets (Central Western Europe-CWE) before Germany and Great Britain joined in 2010 and 2011, respectively. The transmission allocation method is expected to switch from open market coupling to flow-based market coupling at November 2013 earliest (CWE, 2013).
- The Nordic and CWE region have recently started the process of integration.
- Spain and Portugal coupled their markets in 2007.
- The Czech Republic and Slovakia integrated in 2010. A new project has begun in 2011 to explore the integration of Hungary (ACER/CEER, 2012).
- Italy and Slovenia coupled their markets in 2011.

The analysis of common high-peak hours provides a first indicator of how large the impact of cross-border trade can actually be and how strongly this can affect prices and help securing supply. In this calculation, high peak is defined as the highest 10% of load hours per country. During these hours, supply is expected to be tight[4] causing prices to rise. The higher the share of hours, in which two connected market areas have simultaneous high-peak phases, the less market coupling can help reducing wholesale prices by reshuffling bids of spare capacities, as the two generation parks are simultaneously fully used. On the other extreme, if two market areas exhibit no correlation in high-peak hours, the national generation capacity level that is needed in each market to fully cover demand at all times is much lower than in the case of perfect correlation of peak hours. In other words, the same demand can be covered with less installed generation capacities if high peak demand of two areas are uncorrelated.

Table 2.3: Descriptive statistics of load hours per country

Variable	Country	Obs.	Mean	Std. Dev.	Min.	Max.
load_at	Austria	62640	6675.404	1273.071	3622	10040
load_be	Belgium	61224	10009.37	1495.701	5973	14191
load_ba	Bosnia-Herzegovina	63384	1366.085	254.5111	796	2150
load_bg	Bulgaria	63384	4282.015	869.4377	2459	26948
load_cr	Croatia	62640	2397.018	1020.493	1016	5945
load_cz	Czech Republic	63384	7254.845	1229.556	4096	16589
load_dk	Denmark	52536	3194.301	1058.795	1266	6347
load_fr	France	62640	56008.04	12230.22	29896	102000
load_fi	Finland	27048	9816.381	1757.215	5219	14965
load_de	Germany	61224	55162.17	9937.933	28984	79884
load_hu	Hungary	62640	4702.163	707.7632	1173	6602
load_it	Italia	53185	37257.72	7839.498	18819	56822
load_lu	Luxembourg	61968	749.9997	127.8918	148	1188
load_no	Norway	27048	14662.44	3489.561	180	25229
load_pl	Poland	62640	16209.31	2757.065	8815	23728
load_pt	Portugal	63384	5727.244	1097.442	3171	9397
load_es	Spain	53880	29170.52	5252.556	1067	44880
load_se	Sweden	61992	16030.13	3553.045	8016.77	26713
load_ch	Switzerland	62602	5593.407	1097.824	736	10829
load_nl	Netherlands	62640	12538.25	2325.712	5767	18465
load_sl	Slovenia	62640	1437.358	263.1574	341	2100
load_sk	Slovakia	61968	3234.878	432.9248	2039	4423

Source: ENTSO-E (2013).

[4] Another reason is simply a large share of (technically) unavailable generation capacity.

Our analysis covers the years from 2006 to 2012 and is based on load data from the European Network of System Operators (ENTSOE), covering 21 European countries, which are part of six regional transmission groups, defined as South-Western European (SWE), Central-Western European (CWE), Central-Southern European (CSE), Central-Eastern European (CEE), Southern-European (SE) and Northern European (NE). The analysis of common high-peak hours is conducted pairwise for each member of each regional transmission group.[5] So duplicates can occur, e.g. Germany-France. The data set is unbalanced as ENTSOE only covers the last three years (2010-2012) for the Nordic countries. In the case of Sweden and Denmark, data was retrieved directly from the TSOs.[6]

In addition, we calculated the total load for each transmission group as the sum of all of its member states and also compared each member state of each region with the respective total regional load. As a consequence larger countries gain higher weight in the total regional load, but this is appropriate because it is also these large countries which influence cross-border trade most. For example, average German load over all years is roughly 55 GW, whereas average Belgium load is roughly 10 GW and that of Luxembourg as low as 0.7 GW.

The overall result is that shared and independent high-peak hours are relatively balanced, but there are a few exceptions that stand out. So the raw potential for market coupling is given and could have a large impact on the technological composition of the European power plant landscape.

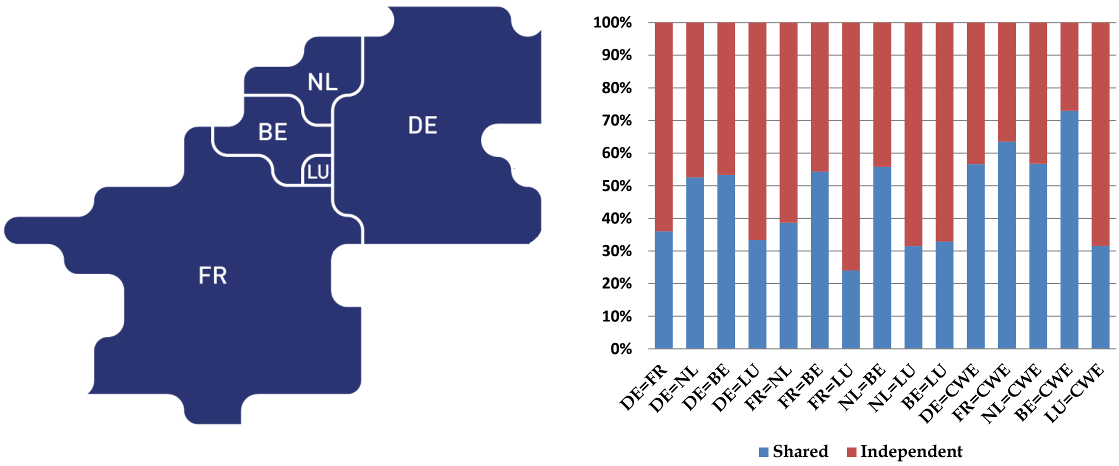
In the CWE region, where France and Germany are located as well as the Benelux states, the share of independent high peak phases is roughly around 50% for most pairwise comparisons. Especially France and Germany do not seem to share the majority of high-peak hours. This indicates that the potential for market coupling is quite large which can have

[5]If up to three consecutive load values of a single day are missing or zero, they are replaced by nonzero positive values of the previous hour. Any longer period of missing or zero values is set to missing. This majorly happened in the case of Switzerland. There are other implausible values for Switzerland which were set to missing, e.g. on 12 July 2007 with indicated load values well below 1 GW during a period which had load values of around 4 GW on previous and later days of the same month.

[6]The data for Denmark consists of Denmark West from 2006-2010.

enormous consequences for smaller countries, in particular caused by RES generation. In Germany, the yearly share of renewable resources in power generation has already reached roughly 25%. If applied to the average load, that gives approximately 14 GW of power pushing into the German wholesale power exchange at bidding price of near-zero. This so-called merit-order effect causes a crowding out of conventional power plants which in turn can still be successful in neighboring markets. So the final crowding-out happens to the more expensive power plants in the smaller countries.

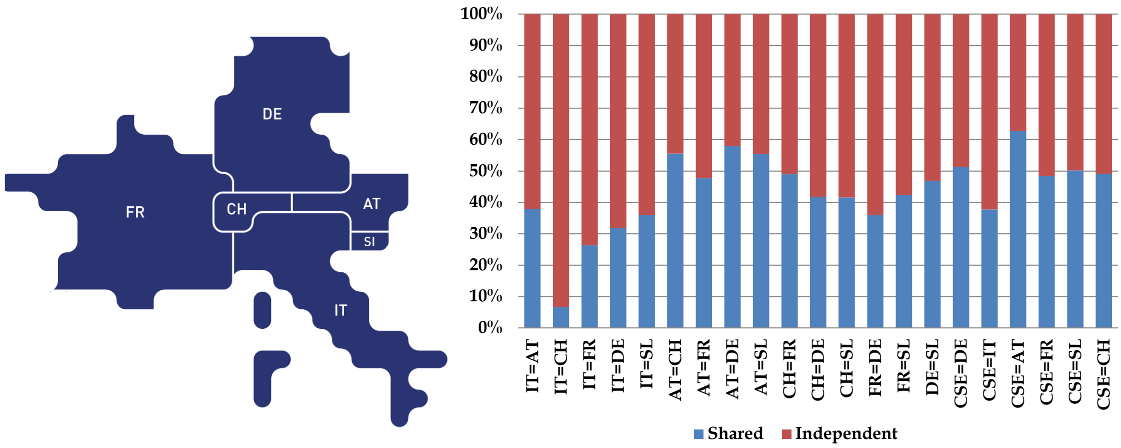
Figure 2.5: Potential for cross-border trade during largest 10% high-peak hours, CWE-Area



Source: Figure based on map by ENTSO-E.

A similar picture can be drawn in the Central-Southern-European region, where common high-peak hours vary mostly between 40-60%. Here, Italy stands out as its common share is well below 40% for all its neighboring countries and even below 10% with Switzerland. The latter relationship is interesting because Italian load is on average around 37 GW while that of Switzerland is 5.6 GW. If the transmission capacity between Switzerland and Italy was sufficient, Italy could help securing Switzerland's supply. In the Central-Eastern region, the share of common hours does not fall below 40% and is basically quite balanced over all members of that region. However, the share of independent hours is still large enough for potential benefits of market coupling. The share of common high-peak hours between each member and total CEE is apparently larger than the country-pairwise comparisons. In the South-Western region the share of common high-peak hours

Figure 2.6: Potential for cross-border trade during largest 10% high-peak hours, CSE-Area

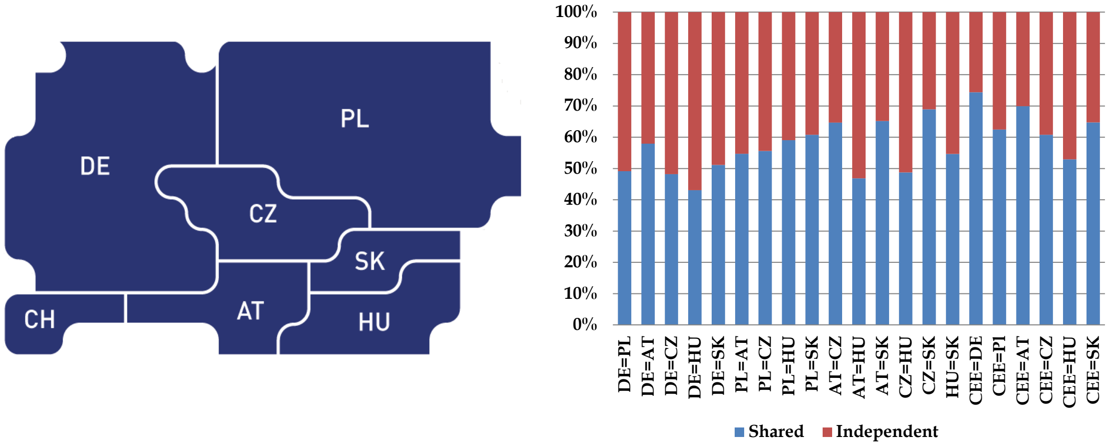


Source: Figure based on map by ENTSO-E.

is 40%, creating a large potential for market coupling to increase efficiency. A comparison with the total-regional load shows that France shares 70% of high-peak hours. Spain and Portugal are already coupled and the potential for securing each other's supply is relatively large with 60% of individual high-peak hours. Sweden and Norway share 70% of their high-peak hours, but the other pairwise comparisons with the Nordic countries do not exhibit such large shares. This is an interesting finding because the Nordic countries, along with connected Baltic countries, have already established a market splitting system since liberalization of the Nordic markets. Germany shares less than 50% of the common hours with the Nordic countries except for Denmark.

After the analysis of the potential for market coupling to efficiently distribute bids and asks on the wholesale level, we give a first indicator of the degree of market integration by analyzing whether prices series of the coupled markets behave as economic theory predicts. If there are two perfectly homogenous products and transactions costs are zero, then the *law of one price* predicts price equality. If transaction costs are positive, then these should be reflected in the price differences.

Figure 2.7: Potential for cross-border trade during largest 10% high-peak hours, CEE-Area



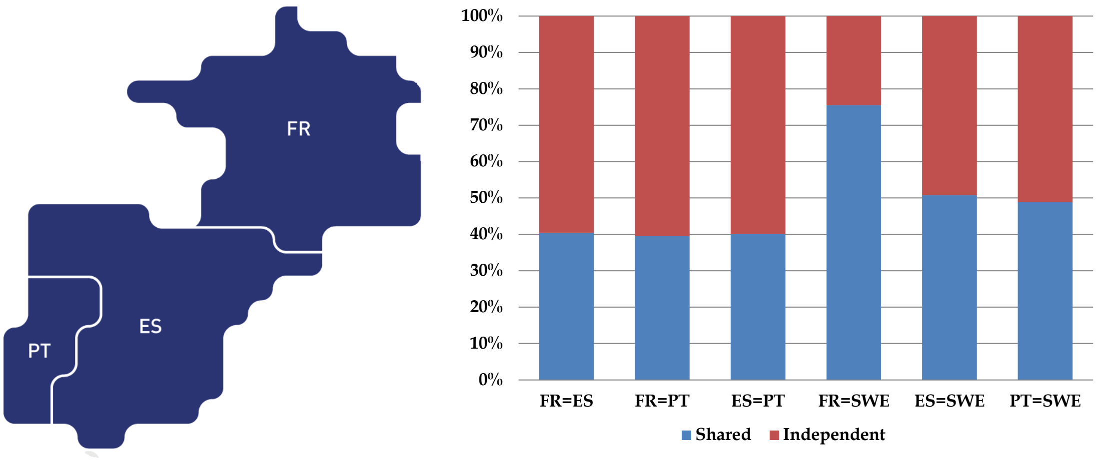
Source: Figure based on map by ENTSO-E.

We analyze hours of price equality between direct neighbors from 2006 to 2012.[7] For some countries we also have data going back as far as 2001, but price convergence was insignificant (<1%). Results indicate that market coupling has a large impact on price convergence and thus on the integration of markets physically and economically. The strongest impact can be seen in the CWE and SWE region because unlike the Nordic countries, market coupling has been introduced only recently. Especially the coupling of Spain and Portugal in combination with further upgrade of cross border capacities appears to have strengthened the link between both markets (see also chapter 4).

The initial effect of market coupling on the price difference between Germany and the other members of the CWE region was quite large, but has decreased to around 60% in 2012. A possible explanation for this could be an increase in congestion of cross-border transmission capacity, caused by diverging economic situations, e.g. an economic crisis or large amount of intermittent renewable generation in one region, e.g., Germany. Overall, the CWE region appears to have increased the degree of integration. For the years 2011 and 2012, the CWE region had equal prices for 28.21% and 27.54% of the time.

[7]Price data was collected from the respective power exchange or from Platts (2011). Corrections were made for daylight savings.

Figure 2.8: Potential for cross-border trade during largest 10% high-peak hours, SWE-Area



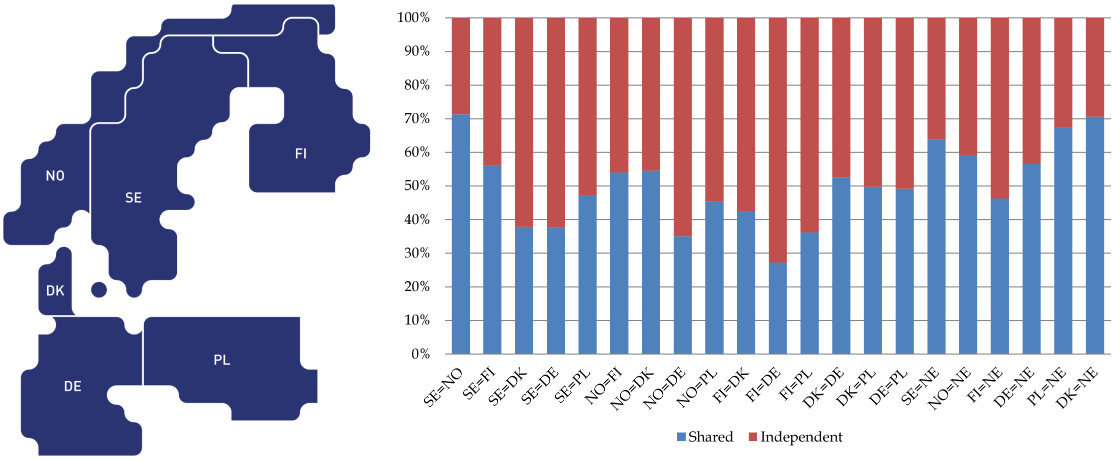
Source: Figure based on map by ENTSO-E.

This stands in contrast to the development in the CSE and CEE region, where only the coupled markets of France and Germany as well as Italy and Slovenia show a significant change. In the CEE region, there was no year in which any price convergence was higher than 2%.

For the Northern European region, we subdivide the analysis in three parts because some Nordic countries are subdivided into intra-regional price zones. First, the price effect of the integration process with Poland, the Netherlands and Germany is presented. The connection of the Danish (DK1 and DK2) and German market shows the strongest progress. The Netherlands also exhibit a large jump in equal price hours with Denmark (DK1) from about 2.23% in 2010 to 20.84% and 16.2% in 2011 and 2012, respectively.

Between the Nordic countries, price convergence was relatively high in comparison to other regions. Price equality between Norwegian price areas (not depicted in the figure) varied a lot over the years. On the one hand, price equality between NO2 and NO3 dropped from 96.23% in 2006 to 33.46% in 2010 and increased to 54.14% again in 2012. On the other hand the connection between NO1 and NO2 saw an increase of 66.43% in 2005 to 85.11% in 2012. Before Sweden was subdivided into four price areas, its price convergence with Norway was already on a relatively high level, as can be seen below.

Figure 2.9: Potential for cross-border trade during largest 10% high-peak hours, NE-Area



Source: Figure based on map by ENTSO-E.

Table 2.4: Price convergence since market splitting in Sweden 2011-2012

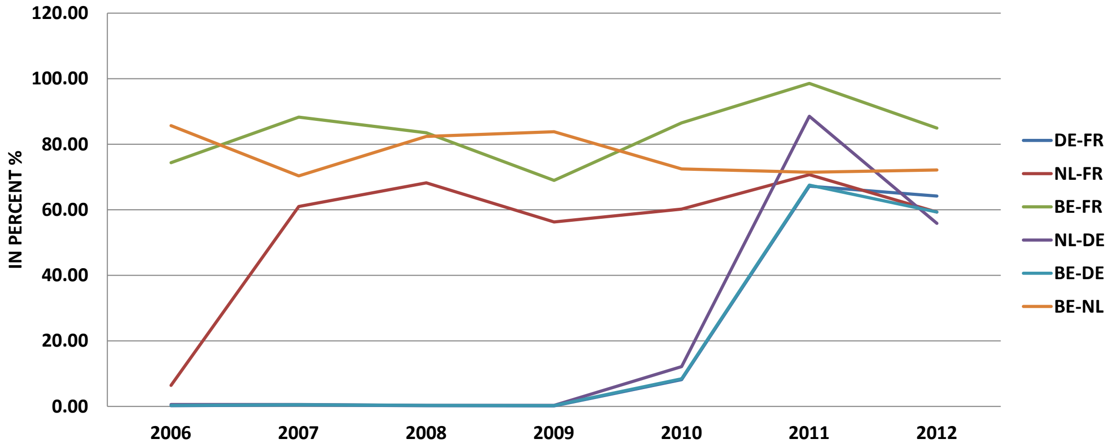
Areas	**2011**	**2012**	**Areas**	**2011**	**2012**
SE2-SE1	100%	97.73%	SE3-NO1	70.49%	68.18%
SE3-SE1	91.19%	93.69%	SE1-NO3	83.2%	92.27%
SE4-SE1	68.92%	83.34%	SE2-NO3	83.2%	90.01%
SE4-SE2	68.92%	85.26%	SE1-NO4	66.26%	86.42%
SE3-SE2	91.19%	95.96%	SE2-NO4	66.26%	84.15%
SE4-SE3	72.68%	88.51%	SE3-DK1	83.27%	55.08%
SE3-DK2	69.6%	59.81%	SE1-FI	95.9%	61.2%
SE4-DK2	96.11%	68.02%	SE3-FI	92.49%	64.45%

Source: ACER/CEER (2012).

Since the splitting of the single Swedish price area into four different areas, price convergence has increased between Norway and Sweden. However, it can also be seen that there is enough congestion inside the Swedish system to cause price divergence. With regard to the Nordpool System price, there is a decline in price convergence down to 15% in 2012. This shows that despite the early coupling of the markets, prices are unequal for most of the time.

Böckers and Heimeshoff (2014) have analyzed the degree of market integration between Germany and eight neighboring countries (see chapter 3 of the thesis). Many price-based

Figure 2.10: Price convergence and market coupling in the CWE-Area 2006-2012



methods such as price correlation or cointegration analysis have been subject to criticism in the market delineation literature.[8] Therefore, Böckers and Heimeshoff use nation-specific holidays as an exogenous shock to identify the degree of integration. They find empirical evidence that Germany and Austria show strong price reactions before market coupling of the CWE region in October 2010 and also before the German cartel office concluded in its sector inquiry in 2011 that both belong to the same relevant market. In addition, Belgium and the Netherlands also show signs of market integration with Germany, which is discussed in detail in chapter 3.

In its report of 2012, ACER/CEER calculated hours of price equality for selected European countries. The Nordic countries had equal price hours even in 2003, which is due to the early adoption of market coupling after liberalization.

Results show that market coupling seemingly leads to a higher percentage of equal price hours between its members. While the pairwise comparison of German and Dutch prices does not necessarily yield the highest percentage, it clearly shows a large jump from $< 1\%$ in 2009 to 12% in 2010 and finally 87% in 2011. The nonzero percentage in 2010 can be almost solely attributed to the integration of Germany into the CWE market coupling

[8] See Böckers and Heimeshoff (2014) for a discussion on the matter.

Figure 2.11: Price convergence and market coupling in the SWE-Area 2006-2012

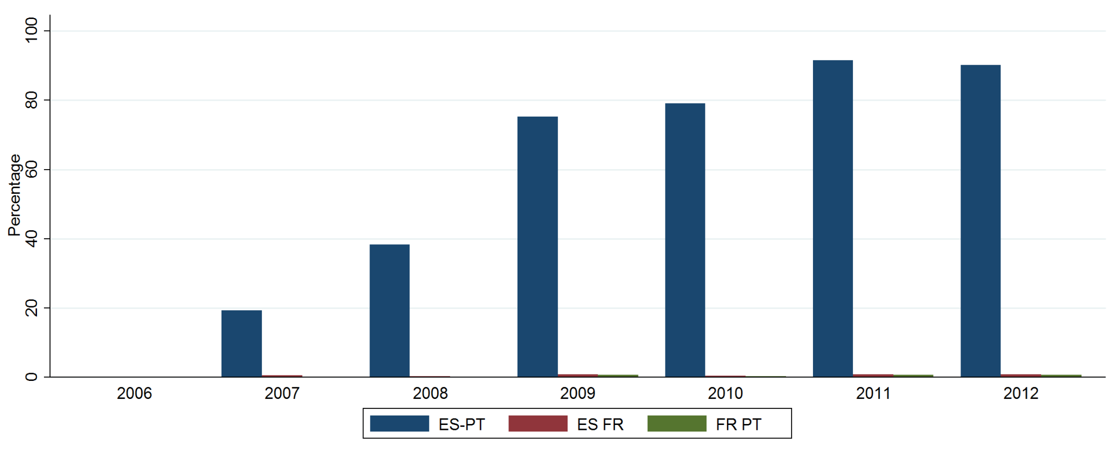


Table 2.5: Percentage of hours for equal hourly day-ahead prices

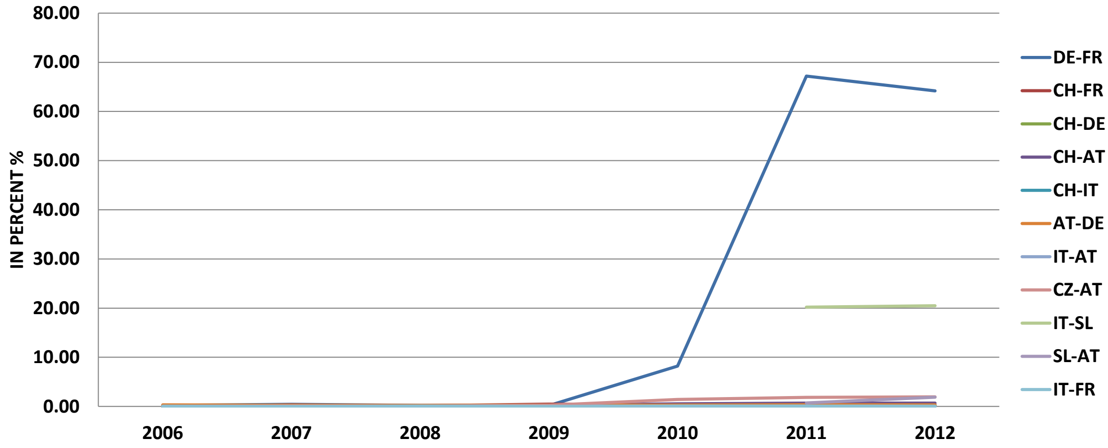
Pair	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
DE=FR	0%	0%	0%	0%	8%	68%
DE=FR=NL	0%	0%	0%	0%	8%	63%
FR=NL	4%	60%	66%	54%	58%	67%
NL=DE	0%	0%	0%	0%	12%	87%
SE=NO=FI=DK	33%	28%	9%	25%	19%	26%
ES=PT	n.a.	19%	38%	75%	79%	92%

Source: ACER/CEER (2012).

in October 2010, because the share of equal hours was less than 1% in peak and off-peak hours and rose up to 86.5% in off-peak and 78.7% in peak hours directly after the integration. The pairs Spain-Portugal, Belgium-France and, in particular, Slovakia-Czech Republic stand out most with regard to price convergence. Concerning the whole CWE region, in 63% of all hours prices were equal.

It can be concluded that market coupling leads to price convergence, but its welfare effects are not clear. In addition, it is unclear whether new barriers to entry have emerged. ACER/CEER reports the case of Sweden where the subdivision into smaller sub-markets, depending on congestion, has raised concerns by the European Commission that the Swedish network operator (Svenska Kraftnät, SvK) may have abused its dominant po-

Figure 2.12: Price convergence and market coupling in the CSE-Area 2006-2012



sition, when it curtailed export capacity for congestion reasons (ACER/CEER, 2012) .

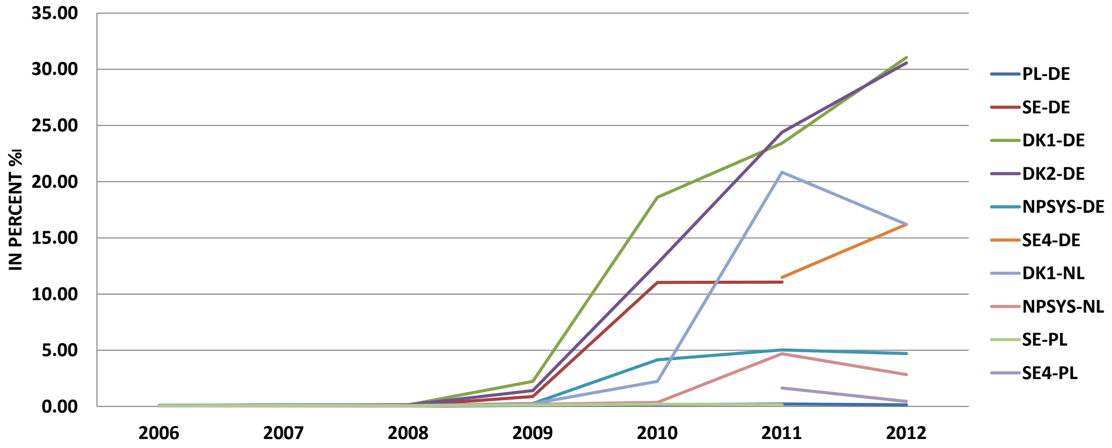
Another issue raised by ACER/CEER (2012) concerns the large differences in liquidity of the power exchanges. In the CWE region, France and Belgium have only 13% of trade volume as a percentage of national demand, while Germany and the Netherlands have 40% and 32% respectively. If the trading volumes are very low, the efficiency of market coupling can be negatively affected.

A practical anecdote for the difficulty of assessing the degree of market integration and its impact on competition policy can be found in the national report for Bulgaria (State Energy and water Regulatory Commission Bulgaria, 2012) for the year 2011:

> *"The electricity market in Bulgaria can be characterized as national and at the same time, well-integrated with the neighboring countries."*

From this statement it is clear that the Bulgarian regulatory office regards the Bulgarian market to be geographically defined along its national border. Stating in the same sentence that the country is well-integrated raises the question as to what extent markets have to be integrated to also constitute the relevant antitrust market. This issue will be addressed in more detail in chapters 3 and 4.

Figure 2.13: Price convergence and market coupling in the NE-Area 2006-2012, A



2.4.2 Empirical Studies on Welfare Effects of Market Integration

To analyze welfare cost of an absence of market integration (*the cost of non-Europe*) is basically the flipside of calculating the benefits of market integration of two formerly disconnected areas. While a separation of two previously connected areas also entails adjustment costs, (which have not been modelled yet to the best of our knowledge), these costs should be similar to the gains expected from a switch from disconnection to sufficient cross-border connection. These adjustment costs include, for example, the build-up costs of additional local generation capacity to satisfy an expected level of security of supply. In case of market coupling, this also includes efficiency losses from the transition of implicit to explicit cross-border trade, which includes the *false booking of cross-border capacity* if cross-border trade is feasible after disconnection at all.

The quantification of welfare benefits of market integration requires either regression analysis or simulation. Any regression analysis is difficult in this context, as there are many endogeneity problems which, if unresolved, cause a severe estimation bias. This concerns, for example, generation investment decisions, expected performance of the market coupling operator and the simultaneous causality between demand and supply.

Figure 2.14: Price convergence and market coupling in the NE-Area 2006-2012, B

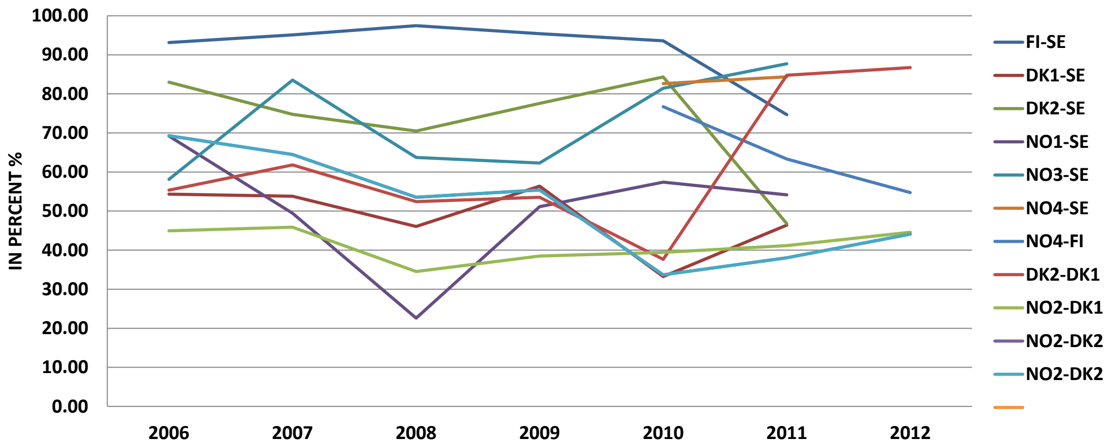
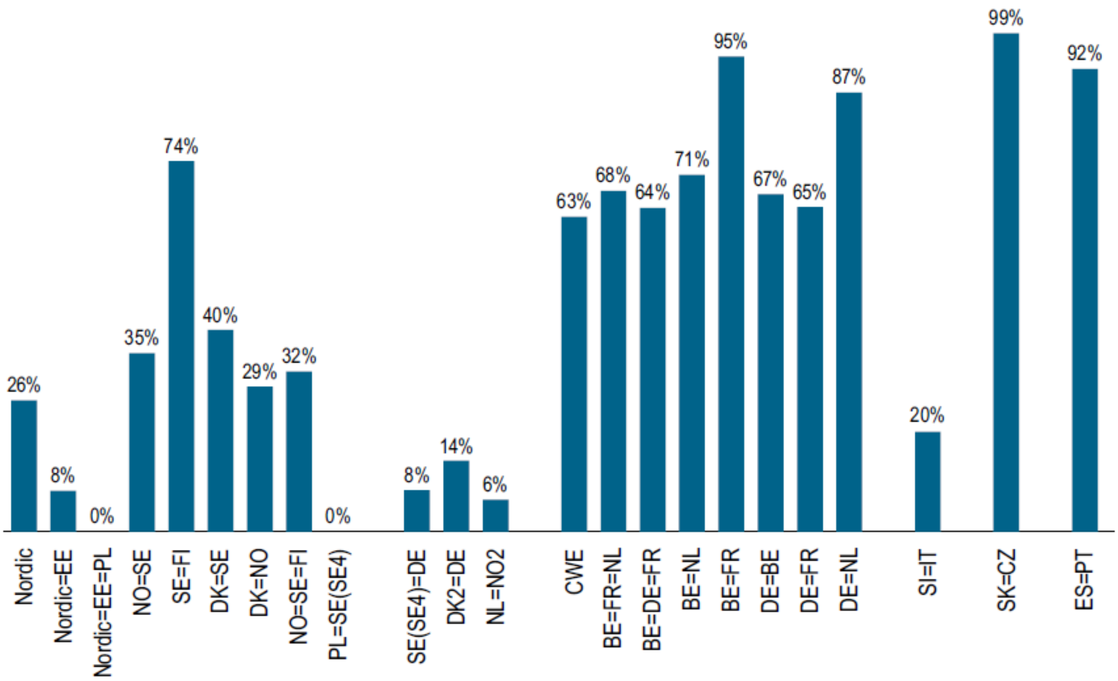


Figure 2.15: Percentage of hours with equal prices in 2011

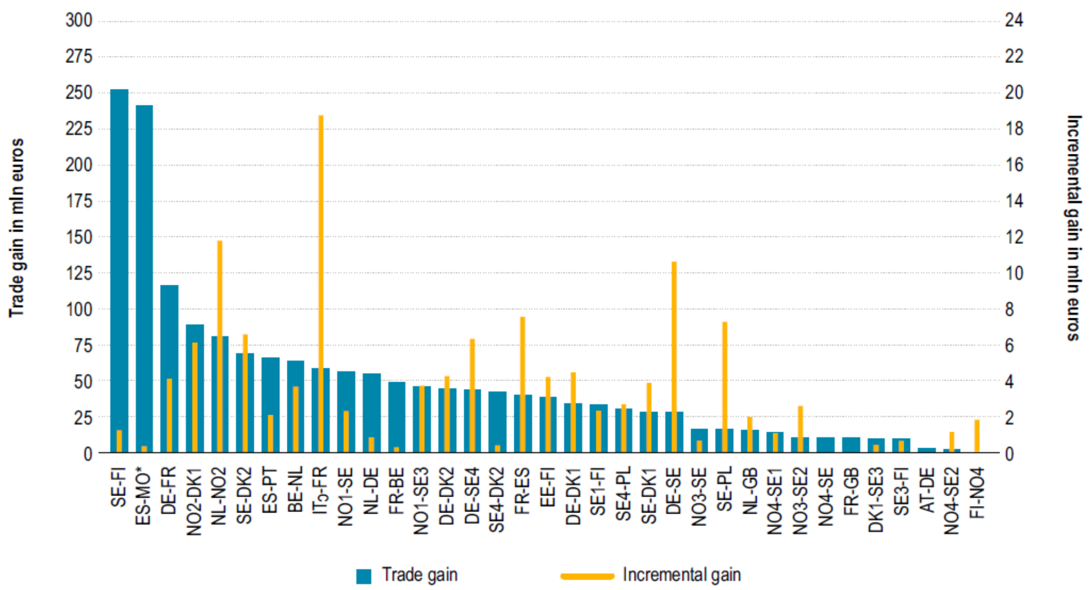


Please note that SE4, No2 or DK2 are sub-markets of Sweden, Norway and Denmark respectively. Source: ACER/CEER (2012).

Market simulation studies are often linear or mixed-integer optimization models, where many parameters, e.g., demand elasticity and its level as well as type and level of installed capacity, are exogenously given and a key parameter is varied artificially to generate different scenarios, here in principal the cross-border trade. Examples for a simulation of power markets can be found in Hobbs and Helman (2004), Hobbs and Rijkers (2004) as well as Kurzidem (2010).

Several European Power exchanges were requested by ACER/CEER to perform simulations to give an indication about the scale of welfare benefits. Three scenarios, which only differ in the availability of cross-border capacities, were used and applied to real data from 2011. Despite the limitations of the analysis, results suggest that the welfare gains from market integration are highly positive. Based on these simulations, the CWE region alone achieved gains from trade worth more than 250 million Euros in comparison to isolated national markets.

Figure 2.16: Welfare gains from market integration based on 2011 data



The base scenario relying on historical data is compared to the isolation scenario (Trade gain) and the scenario with increased transmission capacity (Incremental Gain). Source: ACER/CEER (2012).

Figure 2.16 illustrates the estimated trade gains (in million Euros) of various forms of bilateral market integration (blue bars, left-hand scale) as well as incremental gains (yellow lines, right-hand scale). As can be seen, major trade gains are still left unrealized between Italy and France (about 19 million Euros per year), Germany and Sweden (about 10.5 million Euros per year) and the Netherlands and Norway (about 12 million Euros per year). Significant gains can also be expected from increasing transmission capacities between Spain and France as well as between Sweden and Poland.

As was stated in the theory section above (section 2), perfect competition is not to be expected in practice. Hence, an analysis which takes oligopolistic market structures into account could give a more realistic impression of the welfare enhancing impact of market integration. Hobbs and Rijkers (2005) have simulated oligopolistic power markets based on Cournot competition. Subject of analysis is the market coupling of the CWE region, and the demand conditions of 2000 are used to simulate three scenarios. The main findings, depicted in Table 2.6, are similar to those of ACER/CEER (2012).

Table 2.6: Welfare effects of the introduction of market coupling

	Base Case	**Scenario 1**		**Scenario 2**	
		PT	**MC**	**PT**	**MC**
Mean Prices in €/MWh					
Belgium	28.36	45.01	36.69	30.72	29.27
France	14.40	14.15	14.25	14.32	14.32
Germany	18.86	22.41	22.06	22.39	22.40
Netherlands	27.34	32.87	37.08	31.54	28.94
Welfare Measures in M€/a					
Generation Cost	12993	12072	12206	12072	12206
Consumer Surplus	26139	22974	23371	23965	24315
Producer Surplus	6820	8914	8721	8609	8363
TSO congestion revenue	470	796	787	574	523
Social Surplus	33430	32684	32879	33147	33201
LSSC	0	-746	-550	-282	-229

PT=Present Transmission Scenario; Scenario 1: Cournot Game Assumption; Scenario 2: Electrabel is Price-Taking in Belgium; MC=Market Coupling;LSSC= Loss of Social Surplus compared to Base Scenario; Source: Hobbs and Rijkers (2005).

Prices drop in Germany and Belgium while France and, in particular, the Netherlands experience a price increase. Overall market coupling still increases welfare, especially with regard to the oligopolistic scenario. A comparison of the base scenario (perfect competition) with the two models of oligopolistic behavior shows that the welfare loss resulting from imperfect competition are significantly lower with market coupling than without (-550 M€/year vs. -746 M€/year and -229 M€/year vs. -282 M€/year). Hence, depending on the degree of competition, market coupling (integration) leads to significant welfare gains.

A study presented by a group of transmission system operators of the CWE region compares social welfare gains using actual and artificial congestion data, which also includes a scenario of unconstrained transmission capacity. While welfare is expected to increase by 14.7 M€, the sole beneficiary are producers (EPEX SPOT, 2013). However, no information on the calculation method is available.

Kurzidem (2010) shows that a so-called flow-based market coupling reduces trading costs in comparison to regular market coupling and that it depicts actual congestion and thus prices differences between markets more accurately. Flow-based market coupling takes the actual physical flow into account which may differ from commercial flow. If a generator in market A sells power to a buyer in market B, then it is not necessarily, or even likely, given that electricity flows the same direction to the full extent, but rather splits along any transmission paths. These may cause so-called loop flows which are not considered in the basic market coupling concept despite their potential to jeopardize network security (Kurzidem, 2010).

To sum up, market coupling uses generation capacity more efficiently and thus reduces the necessity of large idle generation capacity. The potential for savings is indicated through the share of diverging high-peak periods between member states. The larger the share of divergence, the more generation capacities could gain in utilization. This holds in particular for an integration of European capacity and reserve mechanisms (CRM). Given that CRM are subsidies paid to safeguard security of supply better exchange and further market integration could reduce the required subsidy levels by (a) inducing more competition and (b) reducing the absolute levels of additional capacity needed.

2.4.3 Benefits from Harmonizing Support Schemes for Renewable Energies

As mentioned in the previous section, in 2011, Germany had more than five times as much solar PV operating capacity than Spain, even though PV is twice as effective in Spain as in Germany due to different climate conditions. This inefficiency could be avoided if a European market for renewable energies were to be created.

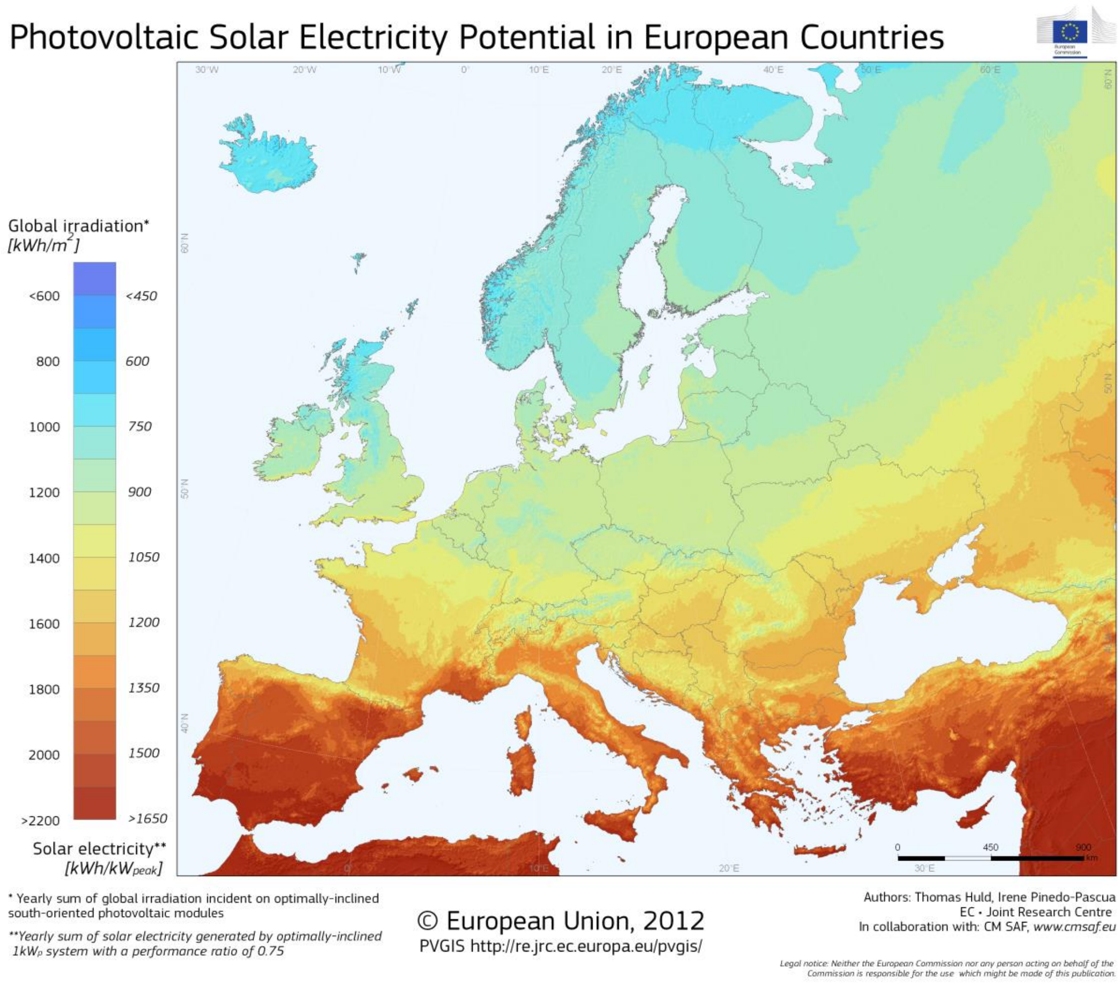
A European market could easily be implemented if national feed-in tariffs would be substituted by a European tradeable quota system. Under a renewable quota system, electricity retailers and energy-intensive businesses would be obliged to procure an annually increasing share of power from renewable energies as would be those electricity users who either generate their own power, who import electricity or who directly purchase electricity from an energy exchange (see Haucap and Kühling, 2012).

This green power does not have to be procured physically but evidence of such has to be furnished by means of corresponding green power certificates. These certificates are allocated to the producers of electricity from renewable energy sources to the extent to which they produce such anywhere in the EU. The green power certificates should be tradable.

The advantages of a quota system include the possibility to accurately adjust the speed of network expansion and to facilitate better planning of network expansion requirements. Moreover, competition within the segment of electricity generated from renewable energy sources also means that efficient technologies, locations and plant sizes will tend to be selected. Sweden is already (along with Norway) pursuing a very similar model (see Haucap and Kühling, 2012).

This is also in line with most recent efforts by the European Commission to counteract the tendency for a fragmentation of the single market on account of incompatible systems promoting renewable energies. As wind power generation is more efficiently located in the north of Europe, while solar PV is efficiently located in the South, a quota system would generate significant efficiencies (also see Wissen, 2011). Figure 2.17 illustrates the different solar PV electricity potential across Europe.

Figure 2.17: Photovoltaic solar electricity potential in European countries



Source: European Commission (2012b).

As can be easily seen solar PV can be more cheaply produced in the south compared to the north. Still the vast majority of Europe's solar PV capacity is located in the north. Market integration could remove these inefficiencies. As Energy Commissioner Günther Oettinger recently stated: "We should continue to develop renewable energy and promote innovative solutions. We have to do it in a cost-efficient way. This means: producing wind and solar power where it makes economic sense and trading it within Europe, as we do for other products and services." (IP/12/571).

As a cautious calculation one could use the following approximation: If the solar capacity currently installed in Germany which produced about 18.500 GWh in 2011 (and much more in 2012, due to additional capacities) would have been located in Spain, the very same capacity could have easily produced about 37.000 GWh. Working with a rather conservatively low electricity price of 40 €/MWh, the efficient allocation of solar PV between Germany and Spain alone would have resulted in additional electricity worth about 740 Million Euro within a single year. Additional savings could easily be generated by reducing the necessary support schemes in Germany (currently about eight billion Euro per year for solar PV) and from considering (a) more countries than just these two and (b) considering other technologies such as wind.

2.5 Conclusion and Recommendations

The integration of European electricity markets can bring about major efficiency gains in welfare terms to European consumers and industries. Through a process of market coupling, electricity markets can be further integrated.

Efficiency gains result, as market coupling uses generation capacity more efficiently and, thus, reduces the necessity of large idle generation capacity. The potential for savings is indicated through the share of diverging high-peak periods between member states. The larger the share of divergence, the more generation capacities could gain in utilization. This holds in particular for an integration of European capacity and reserve mechanisms (CRM). Given that CRM are subsidies paid to safeguard security of supply better exchange and further market integration could reduce the required subsidy levels by (a) inducing more competition and (b) reducing the absolute levels of additional capacity needed.

Hence, while market coupling theoretically increases market efficiency, issues such as market design or other regulatory interventions have a significant impact on the performance of market coupling. Therefore, it is important to align the different existing national regulatory frameworks across Europe or to set up a new common framework altogether.

While levels of wholesale market concentration have generally decreased across Europe, a major benefit of further market integration would be the increased level of competition in European electricity markets. Based on simulations published by ACER/CEER (2012), the CWE region alone has achieved gains from trade worth more than 250 M €in comparison to isolated national markets now. Major trade gains are still left unrealized, however, between Italy and France (about 19 M€per year), Germany and Sweden (about 10.5 M€per year) and the Netherlands and Norway (about 12 M€per year). Significant gains can also be expected from increasing transmission capacities between Spain and France as well as between Sweden and Poland.

The different support schemes for renewable energies have induced major inefficiencies if viewed from an European perspective. Most importantly, since all support schemes only support renewable energies within their own national territory massive gains from trade and from market integration are foregone. These gains from trade could easily result, as climate and weather conditions vary heavily across and even within member states. For example, conditions for wind power are typically superior in Northern Europe while the conditions to produce solar-based electricity are much better in Southern Europe. Hence, enormous gains from trade could be realized by focusing on solar power in Southern Europe and on wind energy in Northern Europe. However, since almost all RES support schemes (with the particular exception of Sweden and Norway) are based on national frontiers so that only domestic production is supported, these benefits are foregone, resulting in according inefficiencies. A cautious calculation reveals that the efficient allocation of solar energy plants between Germany and Spain alone would have resulted in additional electricity worth about 740 M€within a single year. Additional savings could easily be generated by considering (a) more countries than just these two and (b) considering other technologies such as wind.

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Declaration of Contribution

I, Veit Böckers, hereby declare that I contributed to the paper *"Benefits of a Single European Electricity Market"* as listed below:

- I gathered the relevant literature and data for the sections 2.1, 2.2, 2.3, 2.4.1, and 2.4.2.
- I conducted the quantitative analysis provided in section 2.4.1.
- I wrote sections 2.2, 2.3, 2.4.1 and 2.4.2 and contributed to section 2.1 and 2.5.

Signature, Coauthor 1: ________________

Signature, Coauthor 2: ________________

Chapter 3

The Extent of European Power Markets*

3.1 Introduction

The creation of a common market in general and a common energy market specifically are important goals of the European Union (EU). To reach this goal, transmission capacities between countries have been increased and a tendency towards more market integration in European wholesale energy markets can be observed. Additionally, the degree of market integration is also fostered by so-called market coupling between several countries. However, market integration in the sense of a common European wholesale energy market and antitrust markets are not necessarily the same. We discuss this issue in later sections in more depth. The extent of European power markets has been debated extensively over the last years. Are national energy markets still separated or do we observe convergence towards a common European wholesale energy market?

Many empirical studies conduct tests based on prices to test the degree of market convergence in energy markets (see e.g. De Vany and Walls, 1999; Nitsche et al., 2010;

*This paper is based on an earlier version that is co-authored by Ulrich Heimeshoff.

Robinson, 2007; Zachmann, 2008; Mjelde and Bessler, 2009; Kalantzis, 2010). Power markets and particularly power prices are driven by many factors and often these factors are common for several regional markets. Due to this reason, the search for exogenous shocks is an important task for market delineation and analysis of market integration. Our paper proposes a new method to test for market integration for wholesale electricity markets based on national holidays as a source of exogenous demand shocks. Most European countries have their own national holidays, which differ from national holidays in neighboring countries. On holidays demand for power decreases significantly, creating free generation capacities which could be bid into power exchanges in other countries. As a result, in other countries there is ceteris paribus a given demand facing a much higher supply, which should have significant effects on prices. Using national holidays as shocks has the advantage that these shocks are clearly exogenous to wholesale power prices in neighboring countries.[1]

The remainder of the paper is as follows: In the next section we give a short overview about European wholesale power markets as background information for our empirical analysis. Section three describes price-based tests for market delineation and their strengths and weaknesses. The following chapters discuss our empirical strategy and the data. In the subsequent sections the results are presented and section seven concludes.

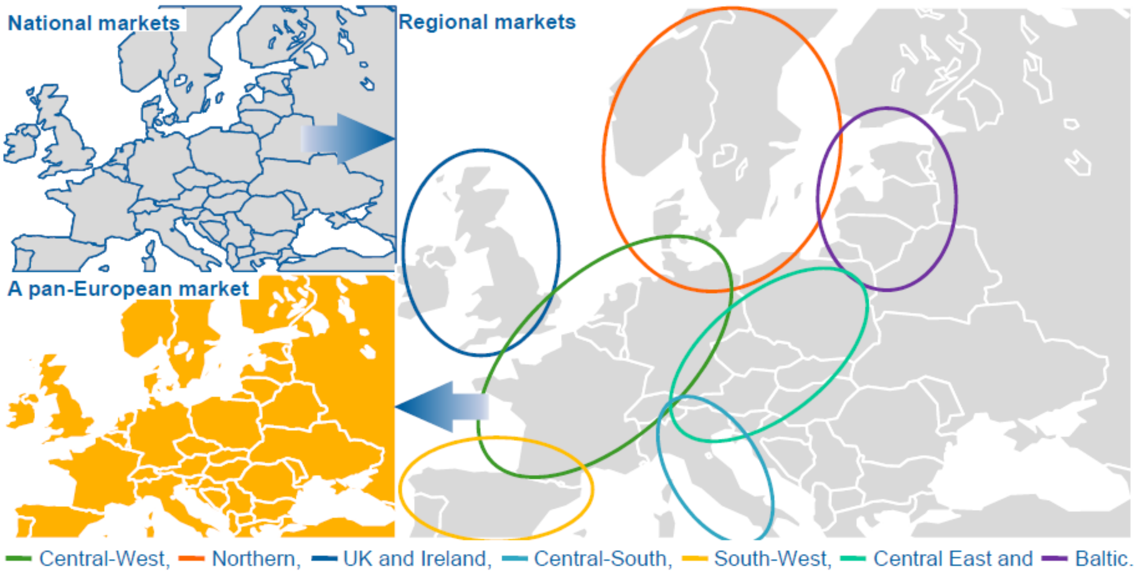
3.2 Integration of European Power Markets

The liberalization phase of European electricity wholesale markets was initiated between 1990 and 2000, with different kinds of market designs and degrees of privatization as part of an effort to create the single European Internal Energy Market (IEM) by 2014 (European Commission, 2012), which incorporates electricity and other primary energy sources, e.g. gas.[2] The principles of the IEM see a process of increasing competition

[1] See Platts (2014) for an example of price drops in Germany due to a holiday in France.
[2] See Sioshansi (2008) and Sioshansi and Pfaffenberger (2006) for a thorough introduction to the subject.

and market integration, so the common market should increase cross-border energy trade, foster security of supply as well as decrease costs of electricity (Padgett, 1992). This necessitates a common set of rules which firms have to follow. Directive 96/92/EC introduced these common rules for an internal electricity market in Europe. Since then, further additions and changes such as legal and functional unbundling have been implemented. The geographical extent of the future IEM is indicated by Figure 1.

Figure 3.1: Evolution of European market coupling



Evolution from national markets over various networks of coupled markets to a single market. Right-hand side depicts initiative to create regional markets launched in 2006 by European regulators. Source: European Market Coupling Company (2013).

The IEM expands over the entire Western, Southern, and Northern European countries as well as EU member states of Central-Eastern Europe. Despite efforts to increase competition after the first stage of liberalization, e.g., unbundling of vertically integrated companies, the majority of wholesale electricity markets is still dominated by few major generation companies[3] and competition authorities as well as regulatory agencies still delineate markets on a national basis.[4] If structural conditions on a national level do not facilitate competition, remedies could be increasing competitive pressure by facilitating

[3]However, the dominance is changing in some countries due to the introduction of renewable energies which nowadays often have significant shares of power generation capacities.

[4]See COM (2007) or ACER/CERRE (2012) for reports on this topic.

access to the market for foreign suppliers. A precondition for competition is the reduction of geographical and commercial barriers to entry such as insufficient physical transportation facilities, discriminatory rules for the allocation process of cross-border electricity exchange or barriers to cross-border activities in national legal frameworks, as different trading hours or product definitions (Cornwall, 2003).

The lack of cross-border transmission capacities is obviously an important reason for a potentially low level of cross-border competition, because in grid-bound markets transportation of electricity between different areas would be impossible. The second element refers to the economically efficient utilization of additional generation capacity via allocation rules and matching of commercial rules of respective power markets. Today, market coupling is often introduced as an efficient way to utilize the cross-border trade potential between two areas (ACER/CERRE, 2012). Market coupling takes cross-border transmission capacities and the bids and asks of two or more power exchanges into consideration and allocates them efficiently.[5] As a result, two market areas that share enough transmission capacities also share the same price. Many markets have been coupled on a regional level already and this can be seen as a step-wise process towards the IEM:

- Nordic Region: Sweden and Norway (1996), followed by Denmark (1998) and Finland (2000) and, recently, Estonia and Poland.
- Central Western European (CWE): France, Belgium, and the Netherlands (2006), Germany (2010) and UK (2011).
- Both regions are also linked since 2010 between the Netherlands and Norway as well as Germany and Denmark and Germany and Sweden.
- Other coupled areas such as Italy and Slovenia, Spain and Portugal, or the Czech Republic and Slovakia are not considered in this paper.

[5]The necessary condition is absence of discriminatory practices or other abuses of market power of the operator.

3.3 Empirical Market Delineation and Power Markets

In this section, we discuss two topics which are important to our analysis. First, we explain why the concept of market integration and the relevant antitrust market do not necessarily mean the same. In the second part of this section, we then describe the most popular empirical methods of market delineation in the context of energy markets.

In antitrust economics, the definition of the relevant market touches two different dimensions: product characteristics and geographical size. Inside this framework, firms are constraint in their behavior through competitive pressure, which means that transaction and switching costs are low enough to facilitate demand- or supply-side substitution. In the case of electricity, this means that the product characteristics of the good are close to perfect homogeneity, differentiated only through time, e.g., balancing power vs. long-run commitment. The geographical size depends on whether suppliers of different regions can physically and economically challenge one another.

Market integration here refers to the implementation of joint commercial trading rules and sufficient physical connections to enable an efficient balance of power consumption and production between market areas. Perfect integration thus means that production happens at minimum costs and that both price areas exhibit equal prices. Still, both terms market integration and the relevant antitrust market are not necessarily congruent, i.e. a relevant antitrust market, and hence sufficient competition, does not necessitate perfect market integration (see also Padgett, 1992).[6] Sufficient pricing constraints in a relevant energy market translates into sufficient supply from outside the national borders. Inside the peak-load pricing framework, these constraints can already be strong enough if there are only a few suppliers that facilitate competition in the most important hours, i.e., during hours of tight supply-demand ratios[7]. So while prices between two candidate markets may not be

[6]An example from another liberalized market is the substitution between fixed and mobile telecommunications with regard to access as well as usage or traffic. On a regulatory level, both markets are still regarded as distinct despite a growing literature which shows that there are competitive constraints between them (see Barth and Heimeshoff, 2014a; 2014b).

[7]A tight supply-demand ratio means that supply barely exceeds demand due to very high demand, supply

equal all the time, they do not diverge systematically , e.g. due to persistent use of market power.

The elimination of economic and physical barriers through market coupling and expansion of physical transmission capacities is an important task in European energy policy. However, the current process of market integration does not necessarily result in an interregional antitrust market which is exemplified by a statement of the Bulgarian State Energy and Water Regulatory Commission (SWERC, 2012):

> *"The electricity market in Bulgaria can be characterized as national and at the same time, well-integrated with the neighboring countries."*

Apparently, there may still be a discrepancy between what is regarded as a well-integrated market and a single antitrust market. It is the subject of our paper to contribute to the literature on market integration using exogenous shocks for identification. This leads us to the second important part of this section, i.e., the discussion of the set of empirical market delineation methods. An empirical delineation often includes a discussion of the trade-off between identification accuracy on the one side and data requirements as well as model assumptions on the other[8].

Methods with a high accuracy often involve the estimation of price elasticity of demand (Davis and Garces, 2010). The basic idea is that cross-price elasticities, representing demand-side substitution of one product with another, reveal whether it is profitable for a firm to raise prices above a certain threshold (typically 5% or 10%). If this is the case, the market can be narrowly delineated. If it is not profitable, the set of potential substitutes belongs to the same relevant market. The most prominent test of this form is known as SSNIP-test (Small-But-Significant-Nontransitory-Increase-in-Price) or hypothetical monopolist test. However, there are two major concerns with this approach. First, if the product under consideration is provided by a monopolist, the test may find that it is not profitable to increase prices, because these are already equilibrium prices under

shortages or a combination of both.

[8]Davis and Garces (2010) provide a good overview over the most popular set of methods.

a monopoly. This is known as the Cellophane Fallacy (Mueller and Stocking, 1955). In addition, demand estimation necessitates the existence of instrumental variables due to simultaneity problems. This is usually achieved by using supply-relevant information, e.g., cost shifters, as exogenous shocks to instrument prices. Cost shifters (and other instrumental variables) may be difficult to obtain and in electricity markets these are often fuel prices (indices) which are either traded worldwide or at least hold for Europe. Therefore, they are not individual but common shocks which complicates identification.

This is why price-based tests are very popular for testing geographical market integration in wholesale power markets, because they do not require large data sets and the theoretical framework is not very restrictive[9]. These tests are typically based on Jevon's Law (see Stigler and Sherwin, 1985), which states that prices for perfectly homogenous goods, absent transportation costs, should be identical.[10] Prices might deviate to some extent in the short run, but in the long run there should be no major price differences. An important feature of wholesale electricity markets is the homogeneity of products, which allows us to abstract from product differentiation. Price based tests can be grouped into four categories:

(i) Correlation analysis,

(ii) stationarity of prices,

(iii) speed of adjustment, and

(iv) cointegration analysis.

The idea of correlation analysis is that almost equal prices should be correlated very highly, which implies values of the correlation coefficient of almost one. Correlation analysis has very low data requirements and is also easy to implement, but there are several problems related to this method. The correlation between two price series could be driven

[9]See Davis and GarcÃ©s (2010) for a selection of cases where these tests were even used for market definition purposes.

[10]However, transportation costs are relevant to a certain degree on energy markets, but we do not analyze them explicitly in the paper because there is insufficient data on a daily or even hourly basis.

by common shocks caused by seasonalities or common input factors (see Werden and Froeb, 1993). Due to these characteristics, the choice of the sample period can have significant influence on the results. Furthermore, there are no generally accepted thresholds for correlation indicating when given values of correlation distinguish integrated from separated markets (see Sherwin and Stigler, 1985). Another approach is the analysis of the time series properties of price differences. If products belong to the same geographical market, price differences should be quite small and their series should be stationary (see Forni, 2004).[11] The idea behind this approach is the fact that prices of homogenous products in a common geographical market should develop in the same direction and price differences should not increase or decrease significantly. The data requirements for this test are rather low and using modern econometrics software, the implementation is easy. However, there are some serious problems related to this approach. First, unit root tests often have low power in small samples, which might lead to biased test results (Hassler and Wolters, 2006). This problem is relevant to competition analysis, because one often has to deal with small samples to conduct the analysis. It is also difficult to apply to differentiated products, where price differences occur regularly and price trends do not always tend toward the same direction.[12] Furthermore, if price series are integrated of a higher order than one, tests often fail to detect integration (see Hosken and Taylor, 2004).[13]

Horowitz (1981) suggests the speed of adjustment between price series as an indicator of market integration. This approach sets the crucial assumption that two price regions only belong to one market if both coefficients in the regressions are statistically not different from zero. So even if differences are very small but significantly different from zero, the economic consequence is to assume two separated markets. Furthermore, the choice of time period is crucial for the results.[14] Additionally, the test rejects a single market

[11] See also Shrives (1978) for an early application.

[12] For differentiated products there are often economic reasons as higher quality of a given product compared to a competitor which might justify price differences.

[13] Econometric methods to analyze orders of integration higher than one are far less developed than standard methods for I(1)-processes (see Haldrup, 1998).

[14] Horowitz (1981) regresses the price difference of period t noted as $(p_1 - p_2)_t$ on a constant and the lagged price difference $(p_1 - p_2)_{t-1}$. The regression to implement his test is $(p_1 - p_2)_t = \gamma + \lambda (p_1 - p_2)_{t-1} + \varepsilon_t$.

even when price differences are economically justified, as for example in the case of different prices for milk per liter in different packing sizes (see Werden and Froeb, 1993). Furthermore, it is not clear from an economic point of view what a significant constant and insignificant (lagged) price differences should suggest for the test decision. With regard to energy markets this problem does not occur, but other problems as biases due to common shocks might still occur as in the other methods discussed above. A natural extension of the previous approaches to market delineation is cointegration analysis (see Hamilton, 1994, for a detailed exposition of the methodology). The basic idea is that in most markets temporary price differences between very similar goods almost always exist. Cointegration allows for short run deviations from a long run equilibrium, or in other words, in the long run prices are equal, but we allow for short run price differences. However, this concept by construction only works for non-stationary time series. A main critique of the approach is a possible bias due to common drivers of prices, which are often not incorporated into the model (see Werden and Froeb, 1993). This means that price tests lack one important aspect which is a key feature of the price-elasticity test: a credible source of exogenous variation to identify pricing constraints. This critique can be addressed within the cointegration concept because the tests are usually based on Vector Autoregressions (VAR) or Vector Error Correction Models (VECM) and it is easy to include additional variables incorporating common drivers into the models. Results of cointegration analysis also depend on the frequency of the data. The long run character of the cointegration vector might underestimate effects (price differences) which only last for several months. Even more, the less restrictive theoretical framework means that other reasons than pricing constraints may explain the cointegration relationship. Therefore, the accuracy of identification may suffer in terms of the question whether two (or more) candidate markets constitute the relevant antitrust market.

There exists a number of empirical studies which analyze the degree of integration between markets based on price tests (see De Vany and Walls, 1999; Nitsche et al., 2010; Robinson, 2007; Zachmann, 2008; Mjelde and Bessler, 2009; Kalantzis, 2010).[15] They

[15]For more discussion on cointegration analysis as a method to delineate market and the fuel-power

focus on price convergence of power exchange prices on a pairwise basis and generally find increasing integration between European wholesale energy markets. However, this does not mean that integrated markets are also single markets from an antitrust point of view, as mentioned earlier.

3.4 Empirical Strategy

We analyze market integration based on exogenous shocks. The results of our analysis may be in line with antitrust market delineation but do not have to necessarily. Markets which are integrated due to our results could still be separate markets with regard to antitrust market delineation. This is due to the fact that regular price-elasticity tests identify whether or not it is profitable to increase prices while our approach looks at price reactions from negative and positive cross-country demand shocks. The aim of our paper is adding to the literature on market integration by including sources of exogenous variation in demand into our empirical study.

We suggest national holidays implemented within a regression framework including input prices as a source of exogenous variation. These holidays are negative exogenous demand shocks which should have significant impact within integrated markets.

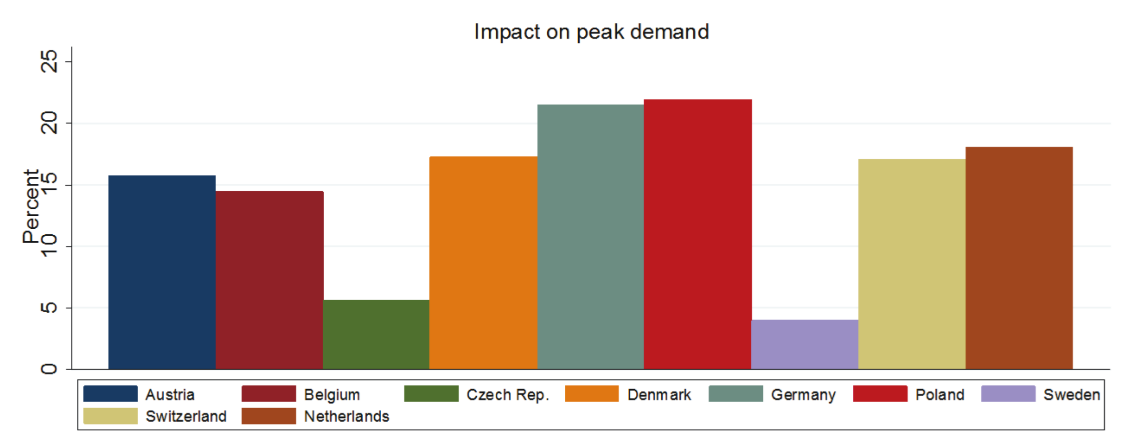
3.4.1 Identification through Demand Shocks

The potential set of exogenous demand shifters depends on the resolution level of the data, i.e., whether there exists information on an individual or market level. We have market level data and, therefore, can only rely on demand shocks on a higher level. As a consequence, we identify working schedules, temperature and holidays as potential nation-specific demand shocks. As mentioned before, temperature is not observed in our data set

relationship see Mohammadi (2009), Neumann, Siliverstovs and von Hirschhausen (2006) and Ravallion (1986).

and is hence replaced by deterministic seasonal dummy variables. A direct consequence of this is that seasonal effects cannot serve as exogenous shocks because they always indicate the same period of time for each market area. The same holds for economic intra-day cycles, defined as peak in our model, because they are assumed to be sufficiently similar, i.e., the main working hours are defined to be between 8 a.m and 8 p.m. We thus rely on national holidays as nation-specific demand-shocks because they are easily and frequently observable and differ between countries despite the fact that a number of Christian holidays are common. Figure 2 depicts the impact of holidays compared to the average of peak consumption on regular days.

Figure 3.2: Reduction of electricity consumption on holidays



This analysis covers the years from 2006 to 2011. Calculation based on ENTSO-E (2013a).

With the exception of the Czech Republic and Sweden, the negative impact of a holiday on power demand varies between 15% and 20% percent of average peak load. For example, during peak times between the years of 2006 and 2011, a holiday in Germany could create additional excess supply of roughly 14 GW on average. These 14 GW could cover 114% of average peak load in the Netherlands and 78% of the absolute maximum in the observed period. By the same calculation, there could be a potential of 3.7% of average German load served by additional Dutch supply on Dutch-specific holidays. This may lead to a one-sided form of competitive pressure within a potentially integrated market. For example, if only monopolies exist in both countries prior to any physical connection, the Dutch monopolist would become a small competitor in a common market area after (perfect) integration of both markets. The descriptive analysis shows that holidays indeed lead to a reduction in (peak) demand in every country.

Our hypothesis is that decreases in demand and subsequent supply increases in neighboring countries cause lower prices. As a result, national holidays are exogenous sources of variation which help testing for market integration.

3.4.2 Empirical Model

The baseline scenario assumes that markets are geographically delineated by national borders. Let $i = 1, 2...N$ define the respective national markets and j be a neighboring country which is an element of the subset C of potential candidate markets, with $C \in N$. The subset of potential candidates is restricted to directly neighboring countries. Our empirical approach is to estimate a regression model to analyze whether exogenous demand shocks of market j have significant impact on the initial market i. The model is defined as

$$\begin{aligned} p_{i,t} = \alpha_t + \beta\, holiday_{i,t} + \sum_{j \in C} \gamma_j\, holiday_{j,t} + \sum_{y=1}^{7} \phi_{y,t}\, year_y + \sum_{d=1}^{6} \phi_d\, day_{d,t} \\ + \sum_{m=1}^{11} \kappa_m\, month_{m,t} + \vartheta\, ln(coalprice_t) + \varsigma\, ln(oilprice_t) \\ + \psi\, ln(emission_t) + d\, mc + \epsilon_t. \end{aligned} \tag{3.1}$$

The γ_j coefficient indicates whether demand shocks from other markets have an impact and is an indicator for market integration. By calculating the marginal effect on supply, we examine to which extent a demand reduction of market j reduces or increases prices of market i. The variable mc is a shift dummy that marks the introduction of market coupling. If market coupling is already in place before the observed period, e.g., between

Denmark and Sweden, the dummy variable is left out due to reasons of multicollinearity. Due to the nature of our data set, the residuals may be subject to autocorrelation. Therefore we apply the Newey-West method to calculate heteroscedasticity and autocorrelation robust standard errors. The lag length is set to six and thus covers a week.

3.5 Data

For the years from 2004 to the end of 2011, we have data on power prices and load (from 2006 onwards) for nine different countries including Germany, the Netherlands, Belgium (from 2006 onwards), Austria, Switzerland (from 2006 onwards), Poland, Czech Republic, Sweden, and Denmark. We also have price data on the system price for the entire Nordic region, $price\_npsys$ as well as input prices for coal, gas (from 2006 onwards), oil, and uranium. Holidays are gathered from the homepages of the respective national embassies or official tourism information websites. Cyclical control variables are included with regard to $year$, $month$, and day of the week (day) as well as a control dummy for market coupling (mc).

We aggregate data to daily means of peak (defined as 8 a.m. to 8 p.m.) and off-peak periods (otherwise). The data set is split-up into two subsamples, i.e., from 2004 to 2007 and from 2008 to 2011, to analyze whether dynamic effects can be found. Table 3.1 displays the hourly descriptive statistics before the split-up in order to give an indication what average prices are before differentiation. Then the data has to be adjusted before calculation. Load and power price data were corrected for daylight savings, i.e., duplicate hours deleted and missing hours replaced by mean values of the last and follow-up hours. Power price data in currencies other than EURO were transformed into EURO using the daily exchange rate published by OANDA. The load data from ENTSO-E does not always cover 100% of national load but sometimes only, say, 95%. In this case, we rescale the values up to 100%. The time resolution of input prices is either daily or weekly and thus missing values are replaced by means for short missing intervals in the daily date and

Table 3.1: Descriptive statistics of hourly values

Variable	Obs	Mean	Std. Dev.	Min	Max	Source
price_de	70060	45.48	28.83	-500.02	2436.63	EPEX
price_nl	67774	49.09	33.035	0.01	1250	APEX
price_be	43735	50.61	52.14	0.01	2500	APEX
price_at	70127	45.88	24.86	0.01	888	EEXA
price_pl	78833	38.29	14.46	0	293.06	PPX
price_se	68609	41.20	23.28	0	1400	Nordpool
price_dk1	70073	41.21	17.72	-120	943	Nordpool
price_dk2	70025	43.35	29.33	-38.1	2000	Nordpool
price_npsys	70103	39.33	14.67	0	300.03	Nordpool
price_cz	78904	41.07	23.62	-150	519.53	OTE
price_ch	44299	55.13	25.45	0	553.88	Swissix
load_at	52440	6633.37	1249.34	3622	9815	ENTSO-E (a)
load_be	52440	10072.84	1491.18	5973	14081	ENTSO-E (a)
load_cz	52440	7241.48	1215.71	4096	16589	ENTSO-E (a)
load_dk	43752	3061.08	1041.69	1266	6347	ENTSO-E (a)
load_de	52440	60931.32	10808.43	31850.55	87784.62	ENTSO-E (a)
load_pl	52440	16094.52	2722.73	8815	23447	ENTSO-E (a)
load_se	52464	15958.7	3551.13	8016.77	26713	ENTSO-E (a)
load_ch	51658	5596.48	1100.78	736	10829	ENTSO-E (a)
load_nl	52440	12584.6	2314.45	5767	18465	ENTSO-E (a)
import_at	576	314.18	482.52	0	1939	ENTSO-E (b)
import_be	288	399.65	329.32	0	1545	ENTSO-E (b)
import_ch	384	671.14	507.14	0	1950	ENTSO-E (b)
import_cz	384	202.29	314.40	0	1253	ENTSO-E (b)
import_de	1008	402.33	433.35	0	2408	ENTSO-E (b)
import_dk	288	227.14	193.33	2	836	ENTSO-E (b)
import_nl	252	683.90	636.02	0	2759	ENTSO-E (b)
import_pl	576	90.90	152.92	0	833	ENTSO-E (b)
import_se	408	140.49	190.34	0	1286	ENTSO-E (b)
oil	70128	72.46	25.39	29.02	143.95	EIA
gas	52584	18.72	5.90	4	53	ENDEX
emission	56256	10.44	7.89	0.01	29.83	EEX
coal	70128	89.37	32.93	50.5	224.75	Platts, Argus McCloskey

The following units of measure are chosen: Load and imports are in MWh, prices in €/MWh, oil in USD/barrell, gas in €/MWh, emission certificates in EURO/tonne and coal in USD/tonne.

by previous values for weekly data. Coal data comprises two time series obtained from Platts until October 2011 and Argus McCloskey from then on. Gas is not fully available for the first period (2004-2007), so oil is used as a proxy (correlation of 0.60066 for the period of 2007-2011). Measure of units for input prices are USD/barrell for oil, €/MWh for gas, EURO/t for emission certificates and USD/t for coal. Holidays are redefined so that they are unique in a pairwise comparison. Therefore the effect of foreign holidays on the German power price only reflects those holidays which are not shared with Germany.

Typically inter-regional trade is restricted by transmission capacities. However, we do not have such data on a daily or even hourly basis. Thus monthly data of actual electricity cross-border flows is used to analyze descriptively whether major changes may have occurred which could have an impact on the analysis. The data for Denmark is grouped, because ENTSO-E stopped its subdivided flow reports for both Denmark West and East in 2010. We thus summarize the total flows of both regions to construct the joint Danish flows before its general introduction by ENTSO-E.

3.6 Results

In our empirical analysis[16], four major results emerge with regard to the price-constraining effects of holidays: First, we cannot reject the null hypothesis that there exists no integrated market on a fully European level. Instead we find many smaller integrated markets on an inter-regional level, e.g., Austria and Germany. Second, we find that market integration has increased over time. In the first observation period (2004-2007), we detect much lower reactivity in comparison to the later period (2008-2011) and hence cannot reject the null hypothesis of national market delineation for the first period. The second time period (2008-2011) yields significant results and thus leads to a rejection of the null hypothesis in some cases, which we will discuss in detail below.

[16]Since the empirical analysis yields a total of 40 regression output tables, we did not include them. These can naturally be provided if necessary.

As a third result, own holidays have a strong negative impact on peak prices, except for Belgium. And finally, competition constraints can be one-sided if there is a large scale difference in quantity between two countries (e.g., Germany and Switzerland). From these results, we infer that there is strong empirical evidence that market integration has increased for a number of markets over the observed data periods. An overview on the potential candidates for integrated markets shows that there appear to be fractional regional markets which may have common members:

- Austria and Germany
- Germany and the Netherlands
- Belgium and the Netherlands
- Denmark and Sweden
- Sweden and Poland
- Czech Republic and Poland

As illustrated in Tables 3.2 to 3.5, the pricing constraint between Germany and Austria may be one-sided in the beginning, i.e., German holidays towards Austria, but it is significant in the more important peak periods. Contrary to these findings, the German and Austrian markets have only recently been regarded to constitute a single relevant market, see the German Federal Cartel Office (2012). One of the reasons was near-zero price differences,[17] sufficient transmission capacity and the fact that the price at the German power exchange has already served as reference price for Austria. The Austrian power exchange price thus only experiences smaller trading volumes. However, these characteristics of the relationship were already observable for a longer period. For the case of Germany and the Netherlands, there is no significant effect in the first period and a low effect in the second period.

Our estimation results show that the demand shock on own holidays is negative, especially

[17] These are argued to be mainly due to different trading hours at the two exchanges, see EEXA (2012).

in peak periods. For instance, the Danish power prices of both local areas are reduced between -10.67 €/MWh (Denmark 1, peak 2007-2011) and -15.47 €/MWh (Denmark 2, peak 2008-2011). German peak prices experience the largest drop in absolute terms with -30.80 €/MWh in the years 2004-2007. Not all effects of own-holidays are this large in scale. For instance, the Belgian holiday is only significant for the peak and off-peak data set of 2008-2011. For the Netherlands, the effect is also insignificant in the peak period of the first data subset. Otherwise, the effect of own-holidays is significantly negative in peak periods. Off-peak prices are not as much affected by holiday-specific demand shocks. This, however, is a reasonable result because there is low demand in off-peak periods regardless of holidays. Holidays may add to the potential generation overcapacities, but the effect is on a smaller scale during off-peak periods. As a result, we can conclude that holidays significantly reduce electricity prices and thus may serve as a tractable demand shock in general.

Table 3.2: Results of Holiday effects for peak period 2004-2007

	price									
	de	nl	be	ch	at	cz	pl	se	dk1	dk2
holiday_de	-30.80†	-17.50**	-10.35	-23.02**	-28.41†	-9.28	0.27	-3.15*	-9.88†	-7.74**
	(-6.79)	(-2.38)	(-1.25)	(-2.13)	(-7.20)	(-1.10)	(-0.66)	(-1.66)	(-3.27)	(-2.35)
holiday_nl	-0.32	-14.00	-13.70**							
	(-0.04)	(-0.93)	(-1.98)							
holiday_be	7.09	-5.94	-3.03							
	(0.50)	(-0.64)	(-0.12)							
holiday_ch	-8.41**			-22.08†	-7.30					
	(-2.00)			(-4.75)	(-1.19)					
holiday_at	-9.24*			-4.40	-22.76†	-0.93				
	(-1.86)			(-0.41)	(-5.48)	(-0.11)				
holiday_cz	3.19				(omitted)	-8.84**	0.31			
	(0.24)					(-1.98)	(0.75)			
holiday_pl	-23.44*					-17.38†	-4.24†	-3.30**		
	(-1.79)					(-3.44)	(-5.82)	(-2.37)		
holiday_se	-10.69						-2.07**	-4.88†	-4.036	-6.572**
	(-1.49)						(-2.77)	(-3.09)	(-1.52)	(-2.44)
holiday_dk	-9.52							-1.82	-13.42†	-12.25†
	(-0.85)							(-0.79)	(-4.31)	(-4.17)

Coefficients are rounded to the second digit and significant on a 1% †, 5%** or 10%* level; t-values in parenthesis. Omissions due to multicollinearity.

For market integration purposes the analysis now focuses on cross-demand effects of holidays. For the period of 2004 to 2007 German holidays significantly decrease peak prices in Denmark (both areas), Austria and Switzerland. Interestingly this does not hold for off-peak periods where significantly positive cross-demand effects by German holidays are found for Austria and the Netherlands. Thus, only the Austrian prices are significantly affected in both peak and off-peak periods, translating into reductions of -7.43 €/MWh (off-peak) and -28.41 €/MWh (peak). Swedish holidays reduce peak prices in DK2 by -6.57 €/MWh, which is reasonable as this is the price area with a direct transmission cable from Denmark to Sweden. In addition, Swedish holidays have a low but significant effect on Polish off-peak prices (-0.65 €/MWh) and a moderate impact on German peak prices (-5.81 €/MWh).

In the period of 2008-2011, the number and strengths of cross-demand-effects changes. From an European perspective a selection of smaller potential candidate markets can be identified. The first potential geographical group consists of the Netherlands, Belgium, Germany and Austria. Here, Germany serves as the geographical link between the Netherlands and Belgium on the one side and Austria on the other. For the case of Belgium, cross-demand effects of Dutch holidays lead to a price reduction of -10.99 €/MWh (peak) and -5.69 €/MWh (off-peak). In turn, the marginal effect of Belgian holidays on Dutch peak prices is -4.02 €/MWh.

German peak prices decrease on a Dutch holiday by -4.64 €/MWh, while they remain unaffected during off-peak. Austrian and Dutch power prices are being reduced by a German holiday by -22.18 and -6.41 €/MWh, respectively. This could still indicate the existence of market integration despite a one-sided competitive relationship.[18] A possible explanation for the one-way direction of competition could be the relative size of Germany in comparison to its two neighbors because the additional overcapacity that could be bid into the German market may not be large enough to reduce prices in Germany significantly.

Most of the other relationships found are one-sided and occur during peak periods. This comprises the pair of the Nordic countries, i.e., Sweden and the second Danish price area, Sweden and Germany, Germany and the second Danish price area (DK2) as well as the Czech Republic and Poland. For example, the marginal effect of $holiday_{se}$ on $price_{dk2}$ is -5.63 €/MWh. The marginal effect of Swedish holidays on Germany is

[18] As indicated by the German Federal Cartel Office for the case of Germany/Austria.

-8.28 €/MWh. While significant cross-demand effects have been found in both directions between Poland and Sweden for the first data subset at least during peak periods, this relationship has changed for the second data set. For each, peak as well as off-peak periods, Swedish holidays have a significant effect, but not vice versa. The switch from significance to insignificance of Polish holidays during peak demand is interesting. In the first data subset, Swedish demand was lower on Polish holidays than on average in comparison to the second data subset. This may have led to additional Swedish spare generation capacities which we could not control for. Therefore, the significance of the cross-demand effect of a Polish holiday may have been overestimated in the first subset of 2004-2007. We cannot control for other potential reasons, but explicitly do not want to rule them out.

Table 3.3: Results of Holiday effects for peak period 2008-2011

	price									
	de	nl	be	ch	at	cz	pl	se	dk1	dk2
holiday_de	-18.01†	-6.41†	114.2	-6.71*	-22.18†	-9.85**	-0.76	-5.15	-3.04*	-5.18**
	(-7.66)	(-3.77)	(0.98)	(-1.92)	(-3.24)	(-2.60)	(-0.45)	(-1.27)	(-1.94)	(-2.14)
holiday_nl	-4.64**	-12.63†	-10.99†							
	(-2.24)	(-3.79)	(-3.72)							
holiday_be	-1.57	-4.02**	-15.20†							
	(-0.89)	(-2.27)	(-5.10)							
holiday_ch	-0.84			-18.10†	-1.39					
	(-0.34)			(-5.56)	(-0.55)					
holiday_at	-5.78*			-4.02	-14.15†	-6.31*				
	(-1.96)			(-1.54)	(-8.08)	(-1.93)				
holiday_cz	8.33				(omitted)	-12.28†	2.04			
	(1.53)					(-4.63)	(1.21)			
holiday_pl	-4.38*					-5.70**	-11.57†	-1.87		
	(-1.75)					(-2.33)	(-5.88)	(-0.67)		
holiday_se	-8.28†						-5.13**	-8.89†	-2.20 *	-5.63**
	(-3.65)						(-2.47)	(-3.68)	(-1.65)	(-2.04)
holiday_dk	-5.57							-5.95*	-10.67†	-15.47†
	(-1.22)							(-1.87)	(-5.16)	(-5.01)

Coefficients are rounded to the second digit and significant on a 1% †, 5%** or 10%* level; t-values in parenthesis. Omissions due to multicollinearity.

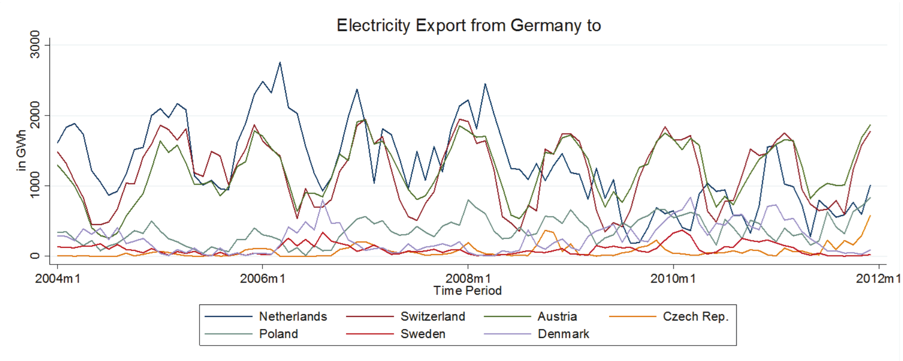
The definition of the size of the integrated market thus becomes difficult in a way as there may be geographical paths of pricing constraints. For example, suppliers in the German market may be constrained by Dutch and Austrian suppliers, which means that these three could be candidates for an integrated market. However, Dutch suppliers may be not directly price constrained by Austrian suppliers, but indirectly through competitive pressure of Austrian on German suppliers. Therefore, from the perspective of a Dutch competition authority this could lead to a closer integrated market consisting of the Netherlands and

Germany. Thus, each national competition authority may delineate the market differently or expand its geographical dimension only to direct neighbor countries. Despite this difficulty, our empirical evidence suggests that the potential competitive constraints imposed by direct neighbors is at least sufficiently large and mutual for Germany and Austria as well as the Netherlands and Belgium. If one-sided competitive constraints are regarded as sufficient, then geographical delineation yields many small inter-regional markets as illustrated in the beginning of this section.

Transmission constraints play an important role when assessing the degree of market integration.[19] The more constrained transmission capacities are, the more likely it is to witness price differences. Constraints basically occur during periods of high demand, i.e., peak periods, but transmission line outages may induce a tight ratio of demand and supply, too. These cannot be addressed in our data set. While there is no daily or even hourly data available to take transmission constraints into account, we can provide a descriptive of monthly available data on actual electricity flows. The analysis of transmission flows is thus separated from the regression analysis. However, if major developments in transmission flows can be identified, then these could serve as an explanation for the increase in market integration from separate towards a joint market. As can be seen from the Figures below, around the second half of 2009, transmission flows have been increasing from the Netherlands to Germany and decreasing the other way around. Since market coupling has only been introduced at the end of 2010, this effect cannot be solely explained by the official start of market coupling, but perhaps both power exchanges may have already been (permanently) running successful test runs. Cross-border exchange between Germany and Austria has remained relatively stable over the years. This is especially interesting keeping in mind that the German Federal Cartel Office will consider both markets as a joint market after its latest sector inquiry (German Federal Cartel Office, 2011). So if both markets constitute a joint market only recently then it could be seen as an unexpected result to find no trace of such a significant structural break in cross-border electricity flows.

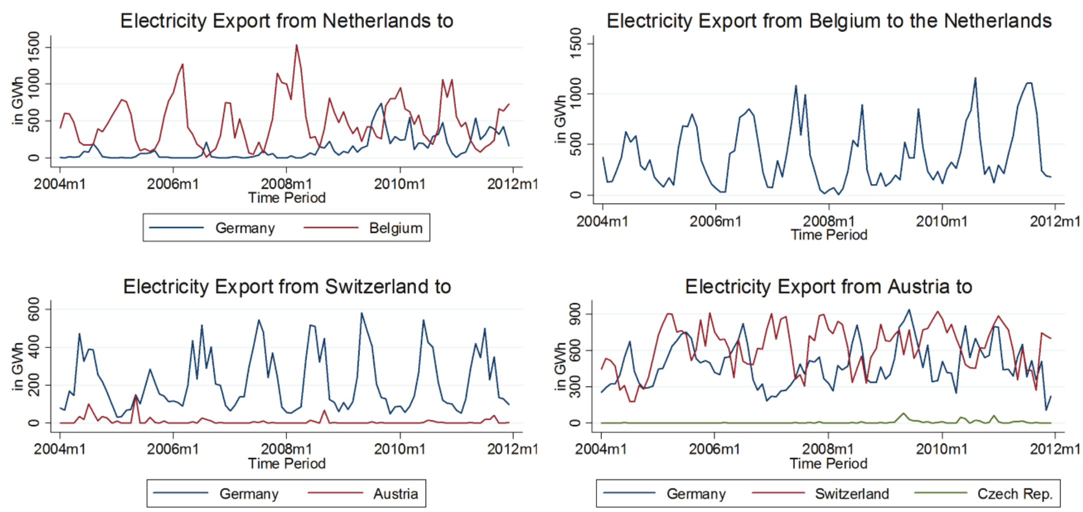
[19] We thank an anonymous referee for the suggestion to discuss the effect of transmission flows on tests of market integration.

Figure 3.3: Development of German exports from 2004 to 2011



Exports based on monthly data provided ENTSO-E (2013b).

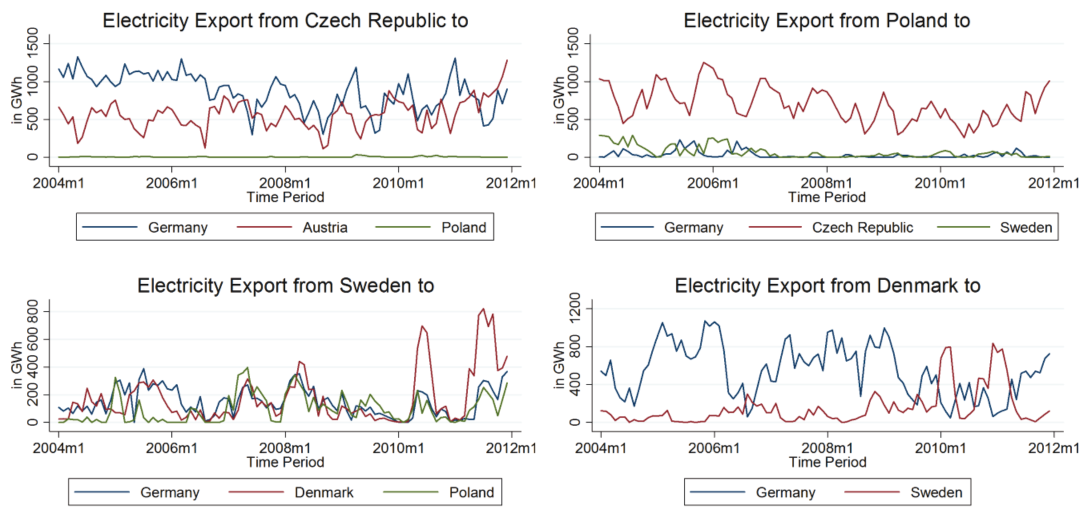
Figure 3.4: Development of other exports from 2004 to 2011, I



Exports based on monthly data provided ENTSO-E (2013b).

A sudden jump in electricity exports from Sweden to Denmark can be observed since 2010. The same can be observed for the other direction, i.e., from Denmark to Sweden. Danish exports to Germany have decreased at least for the year around 2010 and then slowly increased again. Electricity flows from the Czech Republic to Austria have increased from 2011 onwards. Further data is necessary to distinguish between a stochastic or permanent development. Other cross-border relationships have remained relatively stable.

Figure 3.5: Development of other exports from 2004 to 2011, II



Exports based on monthly data provided ENTSO-E (2013b).

3.7 Conclusion

In recent years, the extent of European wholesale power markets has been debated in the context of the European Commission's goal to create a common European energy market, also known as internal energy market (IEM). In many empirical studies price-based tests were chosen to test for market integration, which often lack exogenous variation for identification. Our paper contributes to the literature on integration of electricity wholesale markets in Europe by using holidays as exogenous demand shocks to trace pricing constraints on a geographical level. Our data set covers nine European power price exchanges for the years of 2004 to 2011. We confirm that the integrated market does not include all European markets, but there exist several regional markets. In our analysis we find empirical evidence for at least two integrated markets including Germany and Austria as well as Netherlands and Belgium. However, market integration does not necessarily mean markets also form relevant markets in the sense of antitrust market delineation (see Barth and Heimeshoff, 2014a and 2014b as well as Briglauer, Schwarz and Zulehner, 2011). Even for an integrated European wholesale energy market, antitrust authorities still have the obligation and need for delineating markets, because integrated markets and antitrust markets do not have to be the same.

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Appendix

Table 3.4: Results of Holiday effects for offpeak period 2004-2007

	price									
	de	nl	be	ch	at	cz	pl	se	dk1	dk2
holiday_de	-7.40†	-5.90†	-0.57	-2.47	-7.43†	-2.45	-0.11	-0.25	-2.30*	-2.42*
	(-4.39)	(-2.83)	(-0.17)	(-0.49)	(-4.44)	(-1.01)	(-0.29)	(-0.16)	(-1.78)	(-1.97)
holiday_nl	-2.20	3.34	-10.48**							
	(-0.71)	(0.49)	(-2.54)							
holiday_be	-1.16	-0.04	-1.68							
	(-0.59)	(-0.02)	(-0.39)							
holiday_ch	-3.39			-2.84*	-0.39					
	(-1.13)			(-1.69)	(-0.12)					
holiday_at	-3.057			-5.13	-5.64†	-1.95				
	(-0.82)			(-0.88)	(-4.06)	(-0.72)				
holiday_cz	0.704				(ommited)	-2.00	-0.35			
	(0.14)					(-0.80)	(-0.70)			
holiday_pl	-2.776					-2.045	-1.53†	-1.48		
	(-0.92)					(-1.10)	(-3.89)	(-1.06)		
holiday_se	-5.81†						-0.65**	-2.13	-1.05	-1.00
	(-3.66)						(-2.29)	(-1.31)	(-0.85)	(-0.62)
holiday_dk	1.23							-0.34	-6.69†	-4.04*
	(0.40)							(-0.19)	(-2.92)	(-1.92)

Coefficients are rounded to the second digit and significant on a 1% †, 5%** or 10%* level; t-values in parenthesis. Omissions due to multicollinearity.

Table 3.5: Results of Holiday effects for offpeak period 2008-2011

	price									
	de	nl	be	ch	at	cz	pl	se	dk1	dk2
holiday_de	-8.44†	-2.00*	81.75	-4.64*	-13.44**	-2.06	0.03	-6.13	-1.39	-1.32
	(-3.48)	(-1.69)	(1.02)	(-1.72)	(-2.09)	(-0.86)	(0.27)	(-1.38)	(-0.75)	(-0.66)
holiday_nl	-3.47*	-1.61	-5.69**							
	(-1.76)	(-0.85)	(-2.45)							
holiday_be	0.93	-0.27	-4.91**							
	(0.55)	(-0.19)	(-2.53)							
holiday_ch	-1.47			-8.57†	-4.98**					
	(-0.85)			(-3.64)	(-2.20)					
holiday_at	0.961			0.23	-7.04†	-5.31**				
	(0.46)			(0.10)	(-6.31)	(-2.55)				
holiday_cz	3.78				(ommited)	-4.47†	0.64			
	(0.94)					(-2.91)	(0.47)			
holiday_pl	0.85					-2.58	-5.10†	-0.22		
	(0.41)					(-1.62)	(-6.14)	(-0.08)		
holiday_se	-2.61**						-2.18**	-2.37	-0.10	-1.74
	(-2.16)						(-2.41)	(-1.28)	(-0.08)	(-1.10)
holiday_dk	-5.56*							-3.52	-9.16†	-8.65†
	(-1.72)							(-1.21)	(-4.03)	(-3.71)

Coefficients are rounded to the second digit and significant on a 1% †, 5%** or 10%* level; t-values in parenthesis. Omissions due to multicollinearity.

Declaration of Contribution

I, Veit Böckers, hereby declare that I contributed to the paper *"The Extent of European Power Markets"* as listed below:

- I gathered the relevant literature and data for the analysis.
- I conducted the quantitative analysis.
- I contributed to the writing of each section.

Signature, Coauthor 1: ____________

Chapter 4

Tracing Cross-Demand Shocks in Southwestern European Wholesale Electricity Markets : An Empirical Analysis of the Relevant Antitrust Market

4.1 Introduction

In many markets, changes in market structure or behavior, induced by technological progress, changes in consumer taste or (politically motivated) regulation, may lead to dynamic changes in the relevant antitrust market. For instance, in telecommunications, technological progress has led to the situation that providers of cable TV networks nowadays compete with providers of fixed-line telephone networks for customers on the market for internet services as well as television.[1] Another example not related to electricity markets nicely describes the effects of regulatory interventions on the relevant antitrust market. In Germany, sugar producers formed a long lasting cartel which agreed upon territorial market parameters (German Federal Cartel Office, 2014). Their coordination of territories and quantities was facilitated by means of regulatory quotas,[2] which critically affect cross-border trade, and price floors. In their press release, the German Federal Cartel Office claims that this case would clearly show how market regulation may contribute to the establishment of competitive restraints that are detrimental to consumers.[3]

Fundamental changes can also be found in wholesale electricity markets, e.g., (implicit) price caps, technology-specific subsidization schemes, and the expansion or upgrade of (cross-border) transmission capacities. It is the self-proclaimed objective of the European Commission to establish an internal energy market by 2014 (European Commission, 2012). The consequences of such a development are far reaching in key technical, economic, and political aspects. For example, national security of supply inside a European framework thus becomes a joint (maximation) objective. Technically, strong disturbances, e.g., massive negative supply or positive demand shocks, in one region may then affect other regions in increasing scale, but by the same token open a wider set of countermeasures by means of balancing opportunities. From a competition policy point of view this also means that the relevant market for wholesale electricity may expand to an inter-regional dimension, creating a single European market. In this paper, the relevant antitrust market is tested for the South-Western European wholesale electricity markets using a unique data set covering the years of 2007 to 2012. Special attention has to be paid to the subject of market coupling which has significant effects on cross-border trading and, hence, the relevant antitrust market.

[1] See Briglauer, Schwarz and Zulehner (2011) for an empirical study on the difficulty of delineating the relevant market in the case of fixed versus mobile telecommunication.

[2] Product-specific characteristics also played a large role such as the necessity to keep transportation ways short due to losses in product quality.

[3] The original quote is: *Der Fall zeigt damit eindrucksvoll, wie eine umfassende Marktregulierung dazu beitragen kann, dass es zu Wettbewerbsbeschränkungen zu Lasten der Kunden kommt* (German Federal Cartel Office, 2014).

In addition to the importance of market definition for antitrust or merger analysis, various competitive measures are based on quantitative indicators. These indicators, in turn, serve as an argument for the introduction of remedies by competition authorities. Wholesale electricity markets are no different in this respect. Typical competitive remedies are price caps which can even be restricted to dominant firms (see chapter 5 of the thesis). In the last decade, subsidization schemes to foster electricity from renewable resources (RES) have lead to a significant change in electricity production (prominently the merit-order effect among technologies). This also has an impact on competition in the market in that there is an asymmetric competitive relationship between subsidized RES with prioritized feed-in and conventional electricity producers (see chapter 6). A higher market share of the former on the national market can lead to large price reductions and thus higher volatility of price differences between countries. These policies as well as potential introductions of capacity mechanisms may not only have a direct impact on competition, but create a feedback with respect to the definition of the relevant market. Therefore, an evaluation of these policies often requires having a definition of the relevant power market in the first place. In the further course of the paper, the terms *power market*, *electricity market* refer to the wholesale electricity market unless specified otherwise.

Usually, empirical tests for market definition such as the SSNIP (Small-but-Significant-Nontransitory-Increase-in-Prices) are based on demand estimations. These, however, require rich data sets covering information on quantities, prices, instrument variables for the respective prices, and other exogenous shifters. In the case of wholesale electricity markets, demand estimation can become difficult because nation-specific supply-side instruments are rare and plant-level data, which would enable analysts to control for more factors, is often unavailable. Therefore, other approaches have been developed to conduct empirical market delineation that can be easily applied by competition or regulatory authorities. These methods are not exclusively devised for electricity but can be applied to various competition cases. Many of these tests solely rely on price data, e.g., correlation or cointegration analysis, which has led to a discussion about inference and causal interpretation, see Werden and Froeb (1993). As a consequence, these will not be considered and, instead, another approach is chosen to detect pricing pressure.

I follow the idea by Böckers and Heimeshoff (2014) from chapter 2, who use exogenous demand shocks to trace cross-price reactions. If two or more price areas constitute the relevant market, then area-specific demand-shocks should be traceable in connected regional markets. In this paper, the empirical framework is set by a control-function approach and information on temperature and holidays are used as nation-specific demand instruments to trace pricing pressure in the Spanish, Portuguese and French market.

The outline of the paper is set up as follows. In section 4.2, the construct of market coupling is briefly explained following an insight into the status quo of market integration as well as a short overview of the market structure of European countries. Adjustments to and descriptive statistics of the data set then build the transition to the empirical model. Finally, the results are presented, discussed and then summarized in the conclusion.

4.2 Competition on and Integration of European Electricity Markets

Market integration aims at the physical and commercial combination of two or more (initially isolated) market areas. The importance of the actual joint allocation mechanism has to be stressed at this point because the commercial merger of markets can be affected to a large extent through inefficiencies in the trading system. For example, if transmission capacities between two price areas A and B have to be booked or auctioned by generators in advance (a week or a year before) then deviations of the real demand situation from the expected scenario may lead to inefficient commercial flows (Kurzidem, 2010).[4] Market coupling is a process which considers transmission capacities between two (or

[4] Actual physical flows will be affected, too, in the sense that if there were no booking from one area to another, generation capacity would be missing. However, there will still be physical flow for that direction due to the physical characteristics of electricity.

more) areas as an endogenous constraint in its optimization algorithm to cover demand in the participating areas at minimum costs (see chapter 2). In other words, it enhances the efficient use of transmission and generation capacities through joint cost minimization algorithms (for a more thorough analysis see, e.g., Böckers et al., 2013 and especially Booz et al., 2013) and leads to (perfect) price convergence between the connected areas. Booz et al. (2013) estimate the benefits of market integration between 2.5 to 4 bn€per year. Simulations by ACER/CEER (2012) as well as Hobbs and Rijkers (2005), who also construct a scenario of oligopolistic competition, support the hypothesis of positive benefits from integration.

The link between an antitrust market and market integration is established by regarding physical and commercial inefficiencies in cross-border trade as barriers to market entry. If non-existent, transportation costs between two (or more) price areas should decrease (close) to zero. This, combined with product homogeneity, should create sufficient pricing pressure from outside the (former) national market. Consequently, this should render any price increase unprofitable inside the relevant antitrust market as proposed by the SSNIP test.[5]

Böckers and Heimeshoff (2011) argue that the relevant antitrust market does not necessitate perfect market integration. The degree of market integration has to be sufficiently large to keep firms from abusing its market power permanently, i.e, short-term deviations from the competitive price are possible. On the one hand, peak periods, which are the most profitable hours for abuse of market power, appear frequently, i.e., systematically. So if constraints on transmission capacities are nonzero, market power could be (jointly) exercised. On the other hand, the pricing mechanism of these power exchanges is basically that of a unit-price auction and the joint market operator, if assumed to be neutral, tries to minimize costs for the complete integrated region. Therefore, the operator has an incentive to shift bids from the competitive region to that which is presumably subject to market power abuse. This means, that as long as there are sufficiently many low bids to

[5] Note, that the cellophane fallacy may still occur as mentioned in chapter 3.

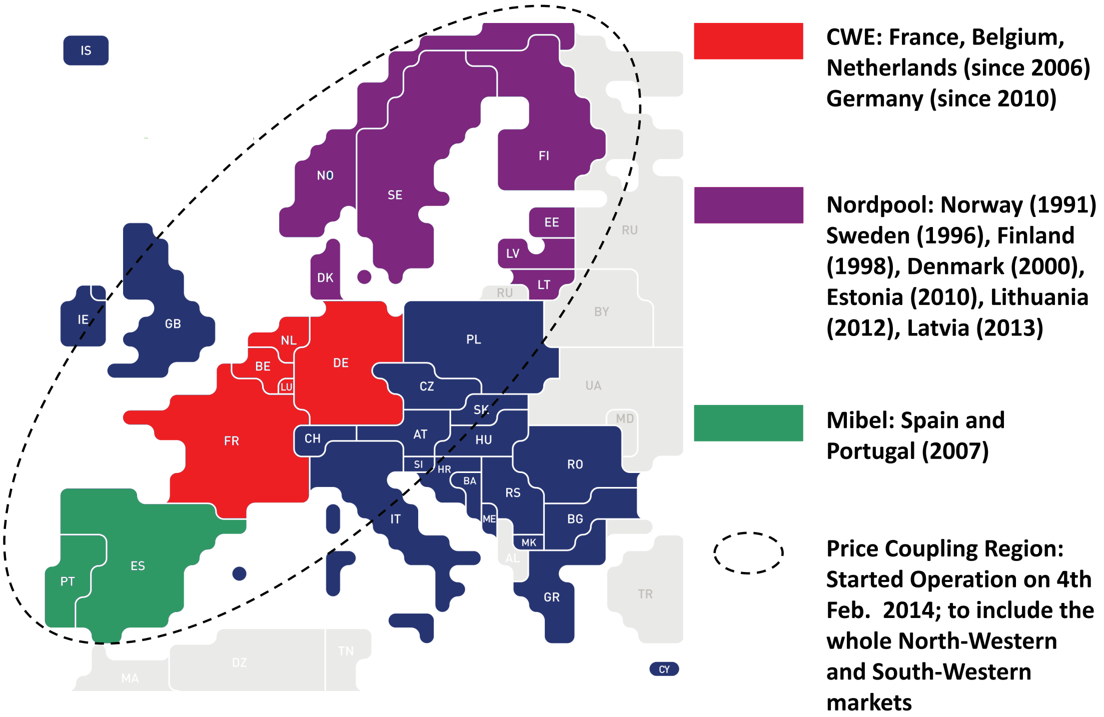
counter higher bids, firms may refrain from exercising market power. As a consequence, transmission capacities do not have to enable competitors from one price region to fully cover demand of another. Dijkgraf and Janssen (2009) note that this can still lead to a national delineation, if there are dominant firms with very large generation capacities, who can influence pricing behavior during peak times even though there is partial competitive pressure induced by competitors from other areas.

The European countries can be subdivided into several regional blocks according to the European Network of Transmission Operators for Electricity (ENTSO-E), which was already described in chapter 2 and 3. This helps to understand why there are different regional market-coupling projects because these projects started basically within these regional blocks. In a next step these coupled markets are then coupled with one another, expanding the number of integrated markets. Market integration can, thus, be considered a step-by-step process. As it is the main objective of this paper to analyze the relevant antitrust market for the Southwestern European electricity markets, we focus on France, Spain and Portugal. The following figure gives an overview about the historical development of market coupling activities in Europe in general and shows which of the three candidate countries has engaged in market coupling. Note, that there are more market coupling projects than depicted (Slovakia-Czech Republic, Italy-Slovenia, UK-Netherlands).

Figure 4.1 shows that inter-regional cooperations have been initiated in Europe directly or only few years after the phase of market liberalization. Market coupling operators (and their stakeholders) then started initiatives to cooperate with one another, creating even larger coordinated regions which are run through joint optimization. The so-called *Price Coupling Region* (PCR) outlines the intended geographical extent of the Single European market in 2014. This covers the whole North-Western to South-Western European countries. The joint operation has already begun on 4th February 2014 (OTE, 2014) and it remains to be seen to which extent this improves the process of integration of already coupled areas.

To sum up, a structural foundation has been build that, along with the expansion of cross-

Figure 4.1: Market coupling in Europe



Source: Based on ENTSO-E (2014); Nordpoolspot (2014); European Price Coupling (2014); Mibel (2014).

border transmission capacities, could allow for (complete) price convergence and sufficient competitive pressure.

While an empirical assessment necessitates observed historical data over a long time period, latest data seems to support the realization of the intended effect according to OTE (2014) which argue that there was strong price convergence on 11th February 2014, which saw only two diverging price areas emerging inside the PCR, with average prices 29.45 €/MWh for most of the North-Western region except Great Britain. Still, a report by the Agency for the Cooperation of the Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) indicates that there have been significant barriers to market integration at least until the end of the year 2012 (ACER/CEER, 2013). Inefficient commercial allocation mechanisms and physical transmission bottlenecks lead to price divergence and thus imperfectly integrated regional markets. In particular, the report found an increase in price divergence in the CWE region in 2012, which ACER/CEER attribute to two main factors other than an inefficient utilization of transmission capacities:

- An increase of electricity input from volatile renewable generation in Germany, which lead to a price reduction, and
- a drop in nuclear availability in France and Belgium, causing a premiums on power prices which could not be countered through competitive pricing constraints.

Areas such as SWE, CSE and the Baltic regions showed no significant changes (ACER/CEER, 2013). According to the analysis, the convergence between coupled regions did not increase significantly and even decreased between the CWE and Nordic regions. On the one hand, these results show that full price convergence has not been reached yet, but, on the other hand, this does not necessarily mean that each market still has to be delineated geographically along the national borders.

Similar to the descriptive analysis by ACER/CEER, time-series approaches (cointegration, stationarity of price differences) are predominantly used to analyze the extent of the relevant market. Since causal inference is difficult, as argued by Werden and Froeb (1993), only one example of these studies is presented here. A discussion on time-series studies can also be found in Böckers and Heimeshoff (2011). In essence, the studies come to the same conclusion that there is no full integration among the pairs of countries.

Dijkgraaf and Jannsen (2009) make another case in their analysis of European wholesale markets, which cover the markets for Belgium, France, Netherlands, Germany, Spain, the Nordic countries and Poland over the period of November 2006 to November 2008. They argue that while the homogeneity of electricity is the main reason to focus on the geographical dimension of the relevant market, the nonstorability of electricity leads to the creation of multiple smaller markets separated through time, i.e., electricity for the 3rd hour of a day is a different product than electricity for the 4th hour of the very same day. Electricity could thus be regarded as a bundle of products, differentiated by time.

If this subdivision of markets is taken into account when defining the relevant market, they come to the conclusion that some price areas may temporarily indeed constitute the relevant market. They conduct stationarity tests for price-difference time series and regress a simple OLS model to control whether coefficients have the right algebraic sign and scale (optimally a beta coefficient value of -1 would indicate full convergence between a pair of prices). The problem between market integration and the relevant antitrust market still remains, regardless of the actual number of markets, because it is debatable how often two regions must exhibit equal prices before they are considered to constitute a joint market (see Böckers and Heimeshoff, 2011). Even if there were 24 hourly markets, and, say, in 9 out of 24 hours price convergence was permanently observed, it is still unclear whether both regions constitute a single market as a whole or not. The same issue holds for a higher ratio, e.g., 22 out of 24 hours. As a consequence a competition authority has no clear definition on which basis it could decide upon a case of a potential merger between two firms of different regions. For most other (consumer) products, the average marginal (cross-)price elasticity is chosen in an empirical demand estimation to argue whether two or more regions belong together.

Practicing market definition accordingly means to disregard the time differentiation and rather rely on a joint (average) effect over all 24 markets. This interesting aspect will be taken into account by means of a descriptive analysis of the number of equal prices averaged over the respective hour.

Böckers and Heimeshoff (2011) also analyzed Western European power markets for the years of 2004 to 2011 and use daily averages over peak and off-peak periods to analyze pricing pressure. They find evidence that the relevant antitrust market has partially expanded for some countries and that size matters as smaller countries exercise less pricing pressure than larger countries. Potential candidates for a relevant antitrust market are Germany and Austria as well as the Netherlands and Belgium. Their approach is discussed in more detail in the later section because it lays the foundation to the empirical strategy chosen in this paper.

4.3 Data

National wholesale electricity prices are originally in hourly format and have been retrieved from the respective power exchange (Powernext, OMIE, Mibel). The data set thus covers the following countries for the years of 2006 to 2012: Portugal, Spain, France. What is labeled as *supply-specific instruments* covers input prices such as coal (API2 by Argus McCloskey and Platts), gas (TTF), oil (ICE Brent oil index) and emission certificate prices (EEX). These data are available on a weekday basis. Power consumption data, labeled $load$, is gathered from ENTSO-E (country package data, 2013) and originally covers hourly vertical load values. In general, power prices, data on electricity consumption as well as those for other energy prices (gas, oil and coal) have been corrected for daylight-savings, time zones (all now measured in CET) and missing data (interpolated by the average of the prior and succeeding data point), whereas missing data was only interpolated on an hourly basis if the gap was not larger than five hours.

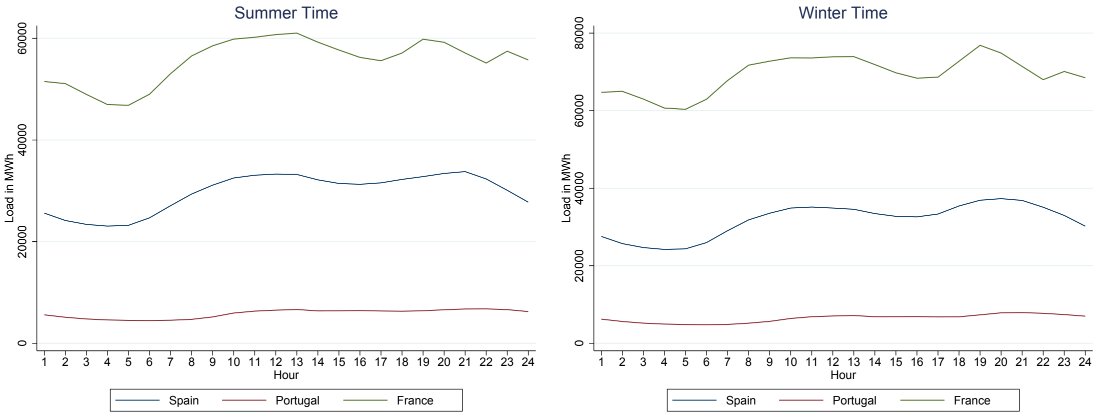
Table 4.1: Descriptive statistics

Variable	**Obs**	**Mean**	**Std. Dev.**	**Min**	**Max**
price_fr	2557	58.13341	35.47548	6.002923	1077.645
price_pt	2376	51.5945	15.71194	0	103.5308
price_es	2557	49.26885	14.75815	0	103.5308
load_fr	2551	58606.72	11516.56	36056.85	97762.08
load_pt	2551	6175.502	852.2905	3868.596	8480.889
load_es	2552	32120.12	4357.157	19743.72	42655.57
oil_price	2557	85.53559	23.90304	33.73	143.95
gas_price	2557	19.61787	5.934857	4	53
emission_price	2557	9.306469	7.005353	.01	29.825
coal_price	2557	96.32	32.15106	53.2	224.75
temp_fr	2557	15.53393	6.868005	-1.597692	30.82692
temp_es	2557	19.05696	7.185194	2.027692	34.20769
temp_pt	2528	18.2312	4.437484	7.296154	32.54692
renewables_es	2557	9302.299	3506.65	2207.754	21424.18
renewables_pt	2170	1726.402	725.7909	516.6667	4716.667

Temperature data [6] originally covers hourly air temperature data of several cities per coun-

[6] I would like to thank Meteo France for financial support and the Meteorological State Agency in Spain

Figure 4.2: Example of average load patterns



Source: based on data from ENTSO-E (2014).

try (see Appendix for an overview). The data has been averaged over the cities to create a single temperature index for each country. Due to differences in time measurement of the data between Weather Online Ltd. and the national weather institutes, this data has been re-based to CET time zone. In addition, deterministic control variables are created which cover yearly, monthly and daily effects.

The focus of the analysis is laid on the period of high demand, entailing an empirical definition of the relevant hours because peak demand periods may vary in length and scale across countries. Figure 4.2 depicts the load pattern of the three candidate markets. Common to all three curves is that peak periods at least cover the time between 8 a.m. to 8 p.m. The whole data set is split up accordingly, entailing the calculation of averages for the variables of interest.

Data on generation from renewables is retrieved from the respective market operators OMIES (Spain) and OMIP (Portugal) and only available on a daily basis, i.e. as the total sum of production. There is no information on the distribution of generation from renewables over the day. As a consequence, the impact of renewables can be overestimated. The original format of the data is in total GWh per day. To keep measurement units uni-

(AEMET) and WeatherOnline Ltd. - Meteorological Services for the provision of data.

form the data will be transformed into daily averages per MWh. Portuguese data is only available from 2007 onwards.

4.4 Empirical Strategy

Before the actual approach is presented, let us discuss the appropriateness of using power exchange prices to analyze the relevant market. Power exchanges are not the only possible way to trade electricity. Bilateral trading is just as important in many countries and, in addition, long-term contracts, e.g., yearly or quarterly futures, may well dominate short-term contracts such as intra-day and day-ahead in terms of trade volume. However, the identification of the relevant market can still be analyzed using hourly or daily power exchange prices because it acts as a reference for both futures (forwards) as well as bilateral prices. Forward contracts are signed to match the expected spot price plus, depending on who is the buyer and seller, a (risk) premium (see Longstaff and Wang, 2004; Botteruda, Kristiansen and Ilicc, 2010). Bilaterally traded prices should not diverge strongly from spot prices for the same type of product (hourly, daily etc.) due to potential arbitrage.[7] The design of these auctions is that of a unit-price auction which means that there is just one clearing price. Therefore, different power exchange prices inside a country rather stem from a deliberate geographical separation of market areas (for example due to severe transmission capacity constraints in the initial stage). These reasons may justify the use of price data from power exchanges to analyze the extent of the relevant market.

A descriptive analysis of hourly price differences is conducted to touch the interesting aspect brought up by Dijkgraaf and Jannsen (2009) that each hour constitutes its own timely differentiated market. As discussed above, competition authorities cannot permanently act or decide on the basis of hourly markets because many relevant competition decisions such as mergers are permanent across hours. Still, it may also serve as an in-

[7] This holds if competitive markets are assumed and exclusive contracts and similar influential collusive behavior are ruled out.

dicator for systematic differences which could influence the regression analysis in the later stage. Accordingly, consumers would buy bundles of electricity unless not only for just one hour. Such bundles would exist in a broad variety because individual consumer consumption may be heterogeneous in scale and duration. However, as was seen in the previous section, there appears to be an overall pattern of consumption (peak/off-peak) per country and the periods of high demand are quite similar between (neighboring) countries or price regions (see chapter 2). Therefore, during peak hours, you would expect higher price differences between any two areas that exhibit constrained cross-border transmission capacity.

First, we define a dummy variable reflecting perfect price convergence ($\delta = 1$) between two areas, i and j, for each hour z of each day k. Then we aggregate δ for each hour per year (so there are 24 values per year) to control for differences between the hourly products per year. The parameter δ can thus be regarded as a measure of convergence.

$$\begin{aligned} z &= \Big[1, 2, 3...24\Big] \\ k &= \Big[1, 2, 3, ...365\Big] \\ \delta_{i,j,z,k} &= \begin{cases} 1 & if\ p_{i,z,k} - p_{j,z,k} = 0 \\ 0 & if\ p_{i,z,k} - p_{j,z,k} \neq 0 \end{cases} \\ \Delta_{i,j,z}^{year} &= \sum_{k=1}^{365} \delta_{i,j,z,k} \end{aligned} \tag{4.1}$$

Systematic differences could be reflected for example by

- a time trend (e.g. $\Delta_{i,j,z}^{year\ x} > \Delta_{i,j,z}^{year\ x-1} > \Delta_{i,j,z}^{year\ x-2}$),
- a structural break (e.g. $\Delta_{i,j,z}^{ST} > \Delta_{i,j,z}^{NST}$),
- or a clear differentiation between peak and off-peak hours (e.g. $\Delta_{i,offpeak,z}^{year\ x} > \Delta_{i,peak,z}^{year\ x}$).

An example for the first two systematic differences could be a continuous growth in cross-border transmission capacity (trend) or the introduction of market coupling (structural break). If there was perfect price convergence, there would be no deviation, which leads to a value of 365 for each hour z of each year of $\Delta^{year}_{i,j,z}$. Then there would be no systematic deviation between any two hours a and b, i.e., $\Delta^{year}_{i,j,a} = \Delta^{year}_{i,j,b}$. Completely disconnected areas would exhibit either no same prices at all or a completely random pattern for each z between the years (i.e., $\Delta^{year\ x}_{i,j,z}$ vs. $\Delta^{year\ x+1}_{i,j,z}$) or between each z of each year (i.e., $\Delta^{year\ x}_{i,j,z}$ vs. $\Delta^{year\ x+1}_{i,j,z+1}$). Any degree of integration in between, that is any realization of $0 < \Delta^{year}_{i,j,z} < 365$ with a systematic pattern, is open to interpretation with regard to signals of strong or weak market integration for product z.

4.4.1 Empirical Model

The identification strategy is based on Böckers and Heimeshoff (2011) who use nation-specific demand shocks to trace pricing pressure. I expand their approach by including more demand-side impact factors and then use a control-function approach to estimate pricing pressure. The endogeneity bias induced by simultaneity is a standard problem in empirical industrial organization, necessitating alternative approaches such as simultaneous equation models (SEM), Two-Stage-Least-Squares instrumental-variable regression (2SLS IV) or a control-function approach (CF) to make identification of the effects feasible again (for an introduction see Wooldridge, 2010).

I first define demand and supply equations for a set of n, $n = 1, 2, 3$, markets. Let i and j define the markets, with i,$j = 1, 2, 3$ and $i \neq j$, at time point t. Quantities $d_{i,t}$ and prices $p_{i,t}$ are first stacked in vector form, D and P respectively. Let X be a vector of demand-specific variables and W the respective supply shifters, whose components will be discussed in detail in the next subsection.

$$
\begin{aligned}
D^{'} &= \begin{bmatrix} d_{1,t} & d_{2,t} & ... & d_{n,t} \end{bmatrix} \\
P^{'} &= \begin{bmatrix} p_{1,t} & p_{2,t} & ... & p_{n,t} \end{bmatrix} \\
X^{'} &= \begin{bmatrix} Holiday_{i,t} & Season_t & Temperature_{i,t} \end{bmatrix} \\
W^{'} &= \begin{bmatrix} coal_t & oil_t & gas_t & certificate_t & renewables_{i,t} \end{bmatrix}
\end{aligned} \tag{4.2}
$$

Let A,B,Γ and Λ and Ψ be vectors and matrices of coefficients and E and U describe vectors of error terms. Demand and supply equation are thus defined as:

$$
\begin{aligned}
D_{Demand} &= A + BP + \Gamma X + E \qquad (4.3) \\
P_{Supply} &= Z + \Phi D_{Demand} + \Lambda P_{i \neq j} + \Psi W + U
\end{aligned}
$$

The only available nation-specific supply shifter is generation input from renewables, which can be regarded as exogenous for two reasons: the stochastic availability of the resources (solar radiation and wind), and subsidization programs which partially (if not fully) disconnect the generation decision from market prices (see Böckers, Rösch and Giessing, 2013 in chapter 6). Input prices are included as common supply shifters ($coal$, gas, oil and $emission$) to control for variable cost shocks.

The control-function approach is very similar to the typical instrument variable approach of 2SLS. First, the original empirical supply function is set up. In order to account for potential problems of heteroscedastic or autocorrelated error terms, I use bootstrapped standard errors with 500 replications.[8]

$$p_{i,t} = \alpha + \beta_1 p_{j,t} + \beta_2 coal_t + \beta_3 gas_t + \beta_4 oil_t + \beta_5 emission_t + \beta_6 load_{i,t} + \varepsilon_t$$

Then the endogenous variables are identified, here demand ($load_{i,t}$) and the price of other

[8] On the problems of using heteroscedasticity and autocorrelation robust methods such as Cochrane-Orcutt see Mizon (1995).

regions p_j. Suitable instruments are then chosen to regress the endogenous variable on them. Note that the empirical function for prices from other regions also includes the demand-specific shifters of the respective region.

$$\begin{aligned} load_{i,t} =& \theta + \sum_{2007}^{2012} \gamma_y \; year_t^Y + \sum_{m=2}^{12} \delta_m \; month_t^m + \sum_{2}^{7} \tau_d \; day_t^d + \rho \; holiday_{i,t} + \varphi_1 \; hot_{i,t} \\ &+ \varphi_2 \; cold_{i,t} + u_{i,t} \end{aligned}$$

$$\begin{aligned} p_{j,t} =& a + b_1 coal_t + b_2 gas_t + b_3 oil_t + b_4 emission_t \\ &+ b_5 \; renewables_{es,t} + \sum_{2007}^{2012} c_y \; year_t^Y + \sum_{e=2}^{12} e_m \; month_t^m + \sum_{2}^{7} f_d \; day_t^d \\ &+ g \; holiday_{i,t} + h_1 \; hot_{i,t} + h_2 \; cold_{i,t} + \omega_{i,t} \end{aligned}$$

The residual of this first-stage regression ($u_t = end\_load_{i,t}$ for demand and $\omega_t = end\_p_{j,t}$ for supply) are then included in the final regression along with the original endogenous regressor.

$$\begin{aligned} p_{i,t} =& \alpha + \beta_1 p_{j,t} + \beta_2 end\_p_{j,t} + \beta_3 coal_t + \beta_4 gas_t + \beta_5 oil_t \\ &+ \beta_6 emission_t + \beta_7 load_{i,t} + \beta_8 end\_load_{i,t} + \varepsilon_t \end{aligned} \tag{4.4}$$

4.4.2 Demand Instruments

Important impact factors for electricity demand can be subdivided into three groups as in Taylor (1975): income, electricity price and other socio-economic factors. For lack of micro data, the socio-economic factors are condensed to the GDP on an aggregate level.

$$\text{Demand} = D_{i,t} = F(\text{Season, GDP, Temperature, Special Events}) \tag{4.5}$$

So while GDP is observable, its available frequency is only yearly, quarterly or monthly at best. This creates a very low degree of variation in a data set based on daily or even hourly measurement. Seasonal drivers are being controlled for through deterministic dummy variables such as the day of the week (*day*), month (*month*) and year (*year*). Air temperature and holidays (here labeled as *Special events*) also constitute important nation-specific demand shifters and will thus serve as exogenous identifying instrumental variables. Since both variables are important to the analysis, the next two subsections give a short analytical insight into the (expected) effect of both exogenous factors on demand and thus prices.

Temperature

The impact of temperature on electricity has been subject to many empirical studies. Among others, Engle, Mustafa and Rice (1992) as well as Pardo, Meneu and Valor (2002) have empirically shown that there is a nonlinear relationship between temperature and electricity demand. Pardo, Meneu and Valor (2002) analyze Spanish data for the years of 1983 to 1999 and construct a temperature index variable by means of the average air temperature of large populated cities. They then use seasonally detrended consumption data to plot against the temperature index and find that consumption increases at both tails of the distribution. Thus, the relationship resembles a broad u-shaped function and is, subsequently, not included in its level form, but rather re-defined as one or more variables indicating temperature shocks, i.e., significant deviations from the mean.

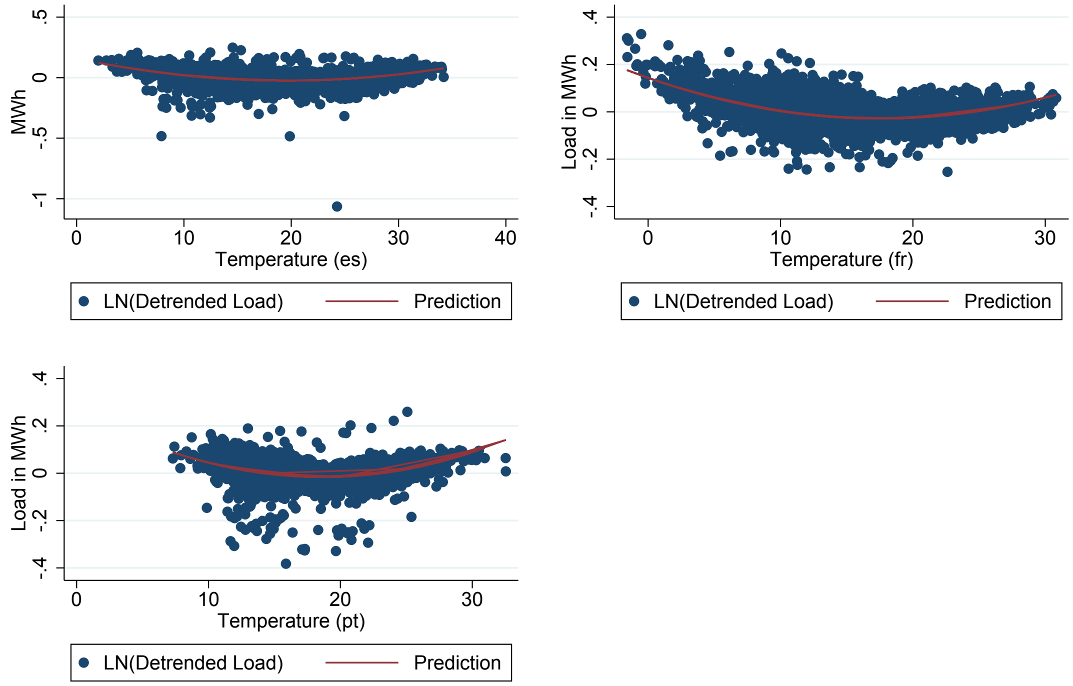
I follow the approach by Pardo, Meneu and Valor (2002) to analyze the basic relationship between temperature, $temp_i$, and consumption, d_i, of area i which is then used to adjust the data set if the relationship is nonlinear. Therefore, in a first step, the following model specification is estimated to detrend demand and control for cycles.

$$\hat{D_{i,t}} = \alpha_i + \sum_{d=1}^{6} \beta_d dayofweek_t + \sum_{m=1}^{11} \gamma_m month_t + \sum_{y=1}^{6} \delta_y year_t + \zeta holiday_{i,t} + \epsilon_{i,t} \quad (4.6)$$

Then, $\epsilon_{i,t}$, which represents detrended demand, is plotted against the temperature index $temp_{i,t}$. Figure 4.3 shows that there is indeed a nonlinear relationship for all three cases. The reference temperature is defined by the temperature at the minimum predicted value of $\hat{\epsilon_{i,t}}$ of the quadratic regression as in Pardo, Meneu and Valor (2002):

$$\begin{aligned} \hat{\epsilon_{i,t}} &= \zeta_i + \tau_i temp_{i,t} + \iota_i temp_{i,t}^2 + u_{i,t} \\ tempref_{i,t} &= y[temp_{i,t}|Min(\hat{\epsilon}_{i,t})] \end{aligned} \tag{4.7}$$

Figure 4.3: Detrended peak consumption and temperature



Source: Own calculation.

The reference temperature per peak period is relatively similar for Spain, Portugal and France. At least for the Spanish case a comparison of results with another study is feasible because Pardo et al. calculate as the reference temperature to be 18 Degrees Celsius. This is relatively close to the 19.6 Degrees Celsius in this analysis.

Table 4.2: Reference temperature for Spain, France and Portugal

Variable	Reference Value
temp_es	19.598
temp_fr	17.475
temp_pt	18.587

Temperature in Degree Celsius.

Following Pardo, Meneu and Valor (2002), the nonlinear impact of temperature will be modeled through a split-up of the original temperature variable into two variables which indicate positive and negative deviations from the reference temperature, i.e., hot and cool days respectively.

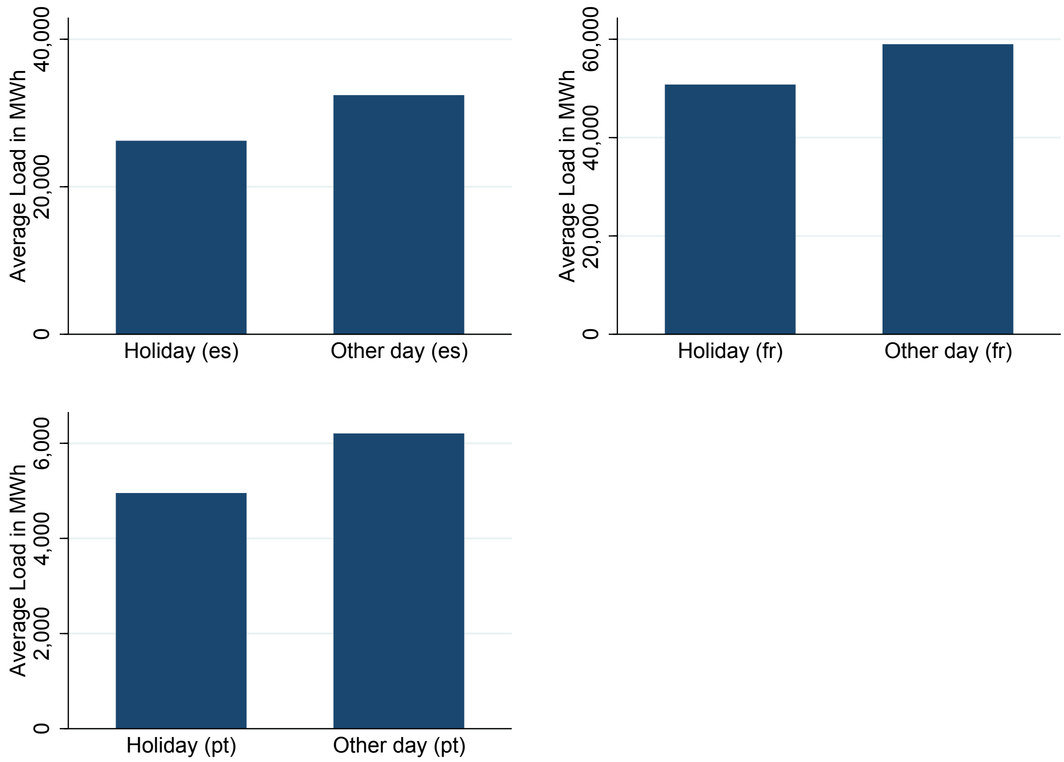
$$
\begin{aligned}
hot_{i,t} &= [temp_{i,t} - tempref_{i,t}, 0] \; if \; temp > tempref_{i,t} \\
cold_{i,t} &= [tempref_{i,t} - temp_{i,t}, 0] \; if \; temp < tempref_{i,t}
\end{aligned} \tag{4.8}
$$

Holidays

Another important exogenous shock that can be frequently observed is a (nationwide) holiday as discussed in Böckers and Heimeshoff (2014). The negative impact is also discussed by Pardo et al (2002) as well as Brubacher and Wilson (1976), who find empirical evidence that holidays serve as good predictors in time-series models. Böckers and Heimeshoff (2014) present a longer discussion about the impact of holidays on electricity demand so the focus in this paper is only laid on a short descriptive analysis of the potential effect on demand, depicted in Figure 4.4. In the final regression setup, holidays will be controlled for using a dummy variable. Note, that these holidays cannot serve as a unique identifier for regional price areas within a country unless holidays are region-specific.

Figure 4.4 shows that the demand shocks on holidays are similar in their general effect but may differ in scale. There may be many reasons for this result, so explanations at this stage

Figure 4.4: Demand shocks on holidays



Source: Own calculation.

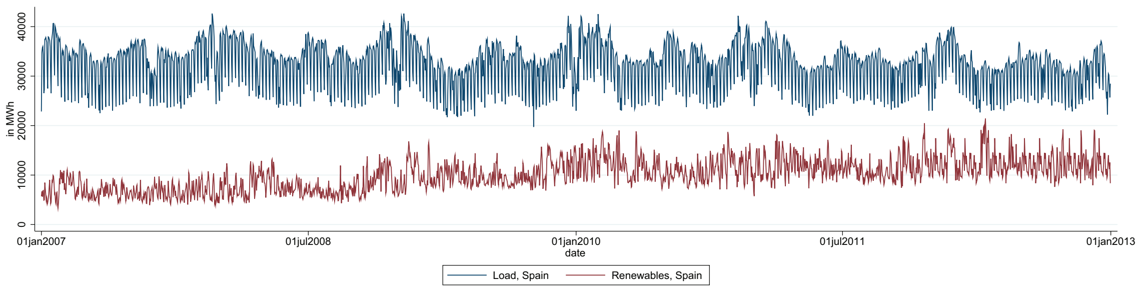
are rather speculative. One potential reason could be that a country's economic structure with regard to the distribution of industries across primary, secondary and tertiary sectors may have a significant impact. For example, if a country's sole industrial activities would be manufacturing steel- or aluminum-based products, then a nationwide holiday should result in a significantly larger reduction of consumed electricity in comparison to a country whose economic activities are based in the service industry.

A practical confirmation of the choice of temperature and holidays as well as seasonal dummy variables as a means to instrument demand is delivered by the demand forecast conducted by the French network operator RTE (*Réseau de transport d'électricité*). Each of the aforementioned instruments is used in their forecast, in addition to other variables which are not observed in our data set. To add an anecdote to further support the choice of instruments, Platts (2014) reports that German and French power prices dropped on 8th May 2014 due to the combined effect of French holidays on the one side and a large oversupply of conventional generation capacities in Germany, which is caused by a large increase in generation from renewables. German and French OTC peak load prices fell onto 31.50 €/MWh and 17 €/MWh, respectively. The second component of this combined effect, renewable generation, is part of the supply-side instruments which will be discussed next.

4.4.3 Supply Instruments

Generation from renewable resources along with input prices serve as supply-shifting instruments. However, input prices are rather European-wide if not world-wide reference prices and thus may not serve as instruments that distinguish between Spanish and Portuguese supply. These prices are rather important to cover fuel cost shocks which also drive prices. We thus rely on generation from renewable resources as identifying instruments. As mentioned before, these are exogenous with regard to their profit resources as well as physical resource availability.

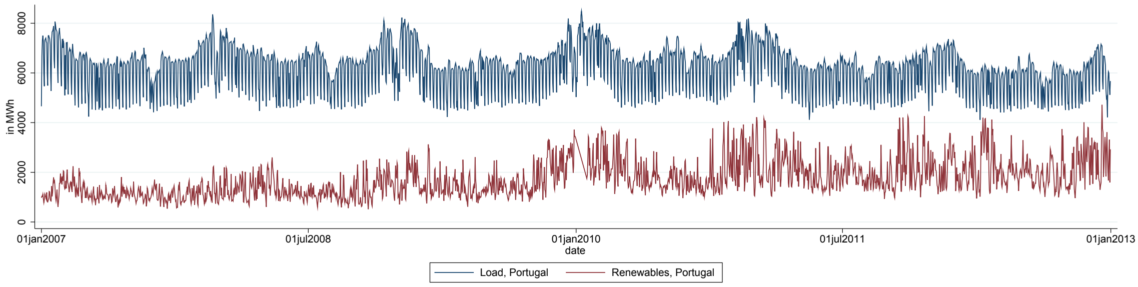
Figure 4.5: Renewable generation in Spain



Source: Own calculation.

Figures 4.5 and 4.6 depict the increasing share of consumption covered through renewable generation. Note, that total renewable production is used in this analysis, while the depicted load only covers peak hours. Again, this may well lead to an overestimation of

Figure 4.6: Renewable generation in Portugal



Source: Own calculation.

the effect of renewables, because an off-peak/peak differentiation is not feasible due to the daily format of generation data. The numbers indicate that renewables lead to very large exogenous supply shocks and thus serve as supply-side instruments.

4.5 Results

We first turn to the results of the descriptive analysis of hourly prices, which are exemplified in Figure 4.7. The results of differences in the number of converged prices across the hours is rather inconclusive for the case of France and its two neighbors in the sense that the patterns do not seem to vary systematically. While a time trend could be assumed for the years from 2008 to 2012, the first year of the data set, 2007, shows the highest level. However, the absolute number of equal prices is so low that any equality of prices could be considered purely coincidental. A correlation analysis between Spanish and French power prices also yields a very low result after controlling for common drivers such as trends, seasonal behavior and input prices.

Table 4.3: Correlation between Spain and France

	Price_fr
Price_es	0.2039***

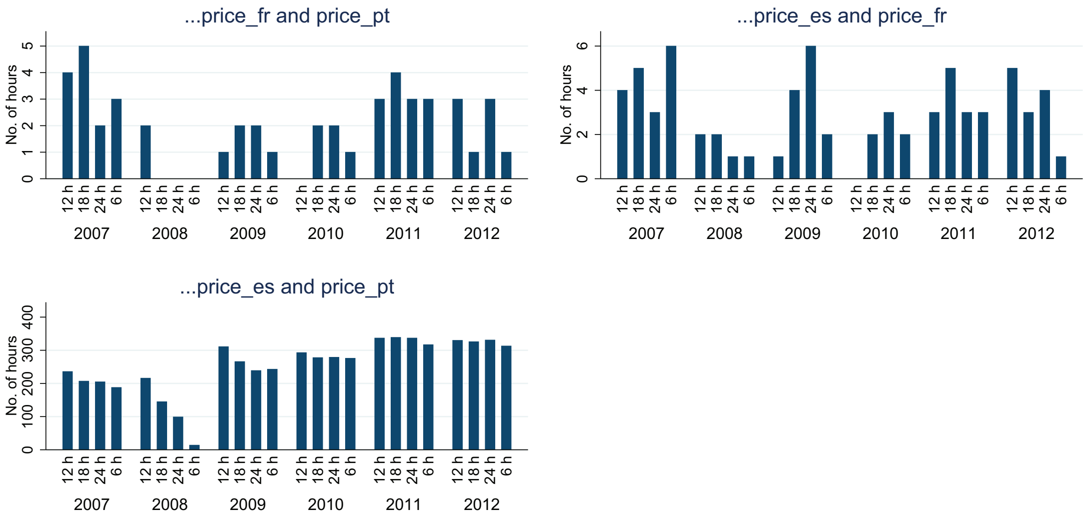
Significance on a 1%***, 5%**, and 10%* level.

While a low correlation value does not necessarily have to mean that pricing pressure is insufficient, further support comes from a descriptive analysis of the relationship of cross-border transmission capacity and the average load level of both countries for 2012. Available data on Net-Available-Transmission-Capacity-values (NTC values) for 2012 shows that average NTC values were less than 1 GW (996 MW FR-ES and 911 MW ES-FR) and maximum NTC values reached 1400 (FR-ES) and 1100 MW (ES-FR), respectively. Compared to the average of Spanish and French load values, these NTC values translate into 3.4 % (average NTC) and 4.8 % (maximum NTC) of Spanish load and 1.6 % (average NTC) and 2.0 % (maximum NTC) of French load. It can be assumed that at least the maximum NTC values have not decreased over the years. Therefore, using them to conduct the same analysis for previous years could be a good proxy because NTC values are not available in this analysis. The results do not change much for Spain (ranging from above 3 to below 5 % of average load) and France (ranging from above 1.5 to 2 % of average load).

We could thus conclude from the combination of a low degree of correlation, number of hours of identical prices and transmission capacity that France and its Southern neighbors do not constitute the relevant antitrust market. From the low number and stochastic pattern of identical prices we cannot infer that there is strong empirical evidence for 24 different product markets out of which some could actually expand its market size geographically.

The relationship between the Spanish and Portuguese market draws a different picture in this respect. Both markets first exhibit strong patterns of identical prices which were almost uniform across the hours. In 2008 this convergence decreased, especially during off-peak hours (represented in Figure 4.7 by the hours of midnight and 6.a.m.). Then a sudden positive jump in convergence can be observed resulting in more than 300 occasions of identical prices for noon (12 h in Figure 4.7). The overall level even increased over the years and is basically uniform across the hours. This is what could be expected from an integrated market that also constitutes the relevant antitrust market and also in-

Figure 4.7: Number of hours of price convergence between Spain, France, and Portugal 2007-2012



Source: Own calculation.

dicates that there are no systematic differences between the hours. We thus turn to the estimation results based on the averages over peak periods.

Estimation results provide strong empirical evidence for the price constraining effects of cross-border trade. A marginal increase in the Spanish power price results in a higher price of 0.82 €/MWh in the Portuguese region. An even stronger result can be found for Spain, where a marginal increase in Portuguese prices leads to an increase of 0.96 €/MWh. The significance of both endogenous components of the price supports the endogeneity problem. In addition, both consumption coefficients, $Consumption_es$ and $Consumption_pt$, show the expected positive effect and are significant. However, the coefficients of their endogenous components, $LoadControl\_es$ and $LoadControl\_pt$, are insignificant. So if load is considered exogenous, arguably due to the large share of consumers that are not subject to real-time pricing but rather long-term contracts, results do not change qualitatively. In the context of market coupling between Spain and Portugal, this means that the optimization algorithm appears to be capable of rearranging bids and asks of both areas quite efficiently as it leads to almost identical prices (which is reflected in the number of hours with equal prices). The findings of this analysis thus support the

Table 4.4: Estimation results I

Variable	Coefficient	Bootstrap S.E.
Portugal		
renewables_pt	-.0014451***	.0001581
Price_es	.8215824***	.0212597
Control_es	.1235284***	.022803
Coal	.0265812***	.0045949
Gas	.1112707***	0281517
Emission	-.4101027***	.0209854
Oil	-.0159721***	.0051153
Consumption_pt	.0011284***	.0001785
LoadControl_pt	-.0003012	.0004453
Spain		
Renewables	-.0001339***	.0000427
Price_pt	.9647523***	.0172751
Control_pt	-.1810138**	.0322501
Coal	-.0081743*	.0047642
Gas	.1348442***	.0261467
Emission	.3916571***	.0253981
Oil	.0203296***	.0049117
Consumption_es	.0001048***	.0000301
LoadControl_es	.0001327	.0000958

Significance on a 1%***, 5%**, and 10%* level.

hypothesis that the two price areas belong to the same relevant antitrust market.

If $renewables\_pt$ is left out of the equation to cover a larger time period (be reminded that there is no data available for 2006), three results stand out. First, if market coupling (MC) is only considered in the form of a shift dummy variable, it significantly reduces the Portuguese price by about 0.87 €/MWh. However, this does not fully reflect the true effect of market coupling, i.e. the real effect of it lies in the price constraining effect. This leads over to the second result. A stronger and significant price constraining effect is found for both estimated models. A marginal increase (decrease) in power prices of one unit in one region results in an increase (decrease) of 0.95 €/MWh (Portugal) and 0.90 €/MWh (Spain) of the other, respectively. This is very close to the expected result of the theoretical construct of the Law-of-One-Price, $p_i - \beta p_j = 0$.

Table 4.5: Estimation results II

Variable	**Coefficient**	**Bootstrap S.E.**
Portugal		
MC	-.8783079***	.2758898
Price_es	.9519737***	.0162119
Control_es	.058811***	.0191077
Coal	.0204142***	.0046574
Gas	.0736835***	.0237786
Emission	-.289874***	.0161847
Oil	-.0366787***	.0001284
Consumption	.0001855	.0003931
LoadControl_pt	-.000229	
Spain		
MC	-.0055955	.3525024
Renewables	-.0001169***	.000043
Price_pt	.9055336***	.01324
Control_pt	-.0461404**	.0234729
Coal	.0018028	.0048972
Gas	.0875602***	.0232254
Emission	.264089***	.0169551
Oil	.024633***	.0051983
Consumption	.0001508***	.000028
LoadControl_es	.000076	.0000899

Significance on a 1%***, 5%**, and 10%* level.

Portuguese consumption is (while positive in effect) insignificant for the Portuguese power prices, which shows that leaving out $renewables_pt$ is not only a misspecification mistake in the sense of decreasing explanatory value, but also that the problem of endogeneity seems to affect the coefficient of $Consumption_pt$. As in the estimated model before, inclusion of load as an exogenous factor does not change the results.

An analysis of the French market needs more information on German, Swiss, Belgian and Dutch markets. Neglect of these factors has already proven detrimental to estimation results for the case of Spain/Portugal, so it is likely that the endogeneity would be much stronger for the French case.

4.6 Conclusion

Testing for market integration is a difficult task, especially in the case of wholesale electricity markets. Often, price-based tests such as price-difference stationarity, cointegration or correlation analysis are applied to test the integration of markets. Using a control-function approach to estimate the supply function of each region, we analyze the South-Western European markets which consists of Spain, Portugal and France. Using instruments such as renewable generation, holidays and temperature, we estimate pricing-pressure between the three countries. We find that France is an isolated market inside the SWE region, but could be part of another relevant supra-regional market which were not covered in the analysis. Spain and Portugal show strong empirical signs of pricing-pressure which are very much in line with the *law of one price*.

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Appendix

Table 4.6: Selection of cities for temperature calculation

Variable	**Obs**	**Mean**	**(Std. Dev.)**	**Min.**	**Max.**
France					
Nice	61340	16.20828	6.482064	-1	37.5
Toulouse	61368	13.93715	7.676257	-11.7	39.4
Montepellier	61368	15.34577	7.443805	-8.5	35.4
Nantes	61368	12.27407	6.470629	-7.9	36.6
Lyon	61368	12.91994	8.186068	-11.6	38.8
Paris	61357	12.53881	6.964859	-7.9	38.1
Spain					
Valencia	61033	17.1386	7.440044	-4.8	42.7
Sevilla	61252	19.44756	7.962157	-2	45.9
Madrid	60944	15.04044	8.320959	-4.9	39.4
Barcelona	58521	16.28657	6.976954	-3.5	36
Portugal					
Lissabon	55637	17.1418	5.754236	-.1	40
Portalegre	18501	15.70778	7.637811	-11.1	39.3
Porto Pedras Rubras	55501	15.20525	5.313001	-2	61.2
Porto Santo	54131	18.93434	3.099195	1	34

Part II

Regulation in European Wholesale Electricity Markets

Chapter 5

Discriminatory Bidding Constraints in the German Wholesale Electricity Market*

5.1 Introduction

[1] The German wholesale market for electricity is subject to major changes. This especially stems from two macroeconomic trends: an increase in cross-border trade due to increasing integration of European wholesale markets and the so-called *Energiewende*, or energy-turn-around, in Germany, an umbrella term for the ecological transformation of the whole power industry (see chapter 1 and 6 for an international overview). Both have a critical impact on power trading, i.e., the generation process on the one hand and trade rules as well as the price mechanism on the other. The *Energiewende*, while still relying on rather regulatory interventions than market-based mechanisms, has had a large

*This paper is based on an earlier version that is co-authored by Justus Haucap and Dragan Jovanovic.

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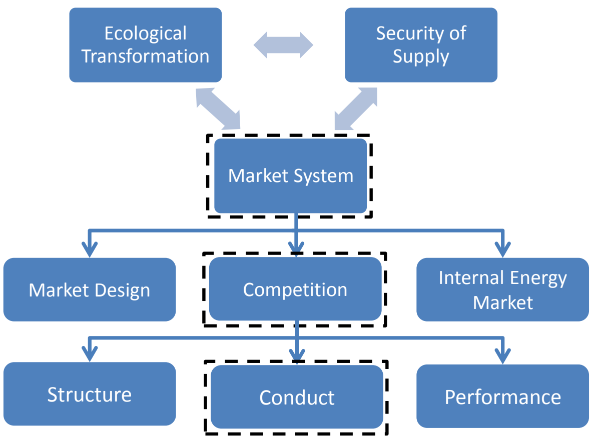
impact on the technological composition of the power plant fleet, favoring low-emission generation technologies in combination with a publicly widely demanded nuclear phase-out. The rapid increase in installed capacity of renewable generation (which we refer to as renewables from here on), first and foremost based on wind and solar energy sources, characterizes this transformation. Renewable generation has accounted for 20% of gross power production in 2011 and 21 % in 2012 (AG Energiebilanzen 2014). This has a large impact on conventional power generation technologies such as coal- or gas-fired power plants. Volatile renewables crowd these conventional technologies out of the power exchanges due to their low (near-zero) marginal costs. At the same time their stochastic nature induces a highly frequent change between low and high residual demand for conventional power plants. Various studies and reports, e.g., BDEW (2013), EWI (2012), Consentec (2012), and Böckers et al. (2011), have analyzed the consequences for security of supply and market design in Germany.

Figure 5.1: Market interventions on the power generation level



Another important corner stone of the future European power markets is the constitution of an internal energy market in Europe. After liberalization in the late 1990s, power markets were geographically defined to be national by the respective national competition authorities and mostly characterized by highly concentrated oligopolies. In accordance to the market definition applied by the Federal Cartel Office, these dominant firms possess high market shares, especially with respect to base load and mid-merit power plants. The generation portfolio and the entailing price level have been scrutinized by many national and European competition authorities. This holds also true for Germany, where discussions about the abuse of market power by the four largest (vertically integrated) power generation companies, E.ON, RWE, Vattenfall and EnBW, have led to a series of in-depth competition analyses. Among these studies, which often placed specific emphasis on price mark-ups and generation capacity withholding, two reports by the European Commission (2007; 2008) and the sector inquiry by the Federal Cartel Office (2011) are of particular importance. In the wake of its investigations the EC pressed charges against E.ON in 2008 and these proceedings were suspended on condition of certain commitments such as divestment of generation plants and vertical ownership unbundling (disposition of the transmission network).

Following up the EC reports, the Federal Cartel Office carried out a sector inquiry (German Federal Cartel Office, 2011) analyzing the years 2007 and 2008. Despite the highly detailed analysis, the Federal Cartel Office found no proof for abuse of market power in form of excessive price-mark-ups or capacity withholding. Still, the Federal Cartel Office, based on §§ 19 and 29 of the German competition law (GWB) and article 102 of the Treaty on the Functioning of the European Union (TFEU), considers any bid above marginal costs by dominant firms an abuse. Any positive mark-up has to be denoted and can only be justified to cover long-run average costs of a firms whole plant fleet (German Federal Cartel Office, 2011).[2]

> *"The ruling chamber comes to the conclusion that, on the basis of the current auction mechanism and given market structure, the addressees subject to* §§*19, 29 GWB, para. 102 AEUV (dominant firms only) are forbidden in principle, to bid above marginal costs, unless the company can prove that a specific mark-up is necessary to cover the total average costs*

[2]Original quote: Die Beschlussabteilung geht im Ergebnis davon aus, dass es bei Zugrundelegung des geltenden Auktionsmechanismus und der gegebenen Marktverhältnisse den Normadressaten der §§ 19, 29 GWB, Art. 102 AEUV (nur marktbeherrschende Unternehmen) grundsätzlich verwehrt ist, zu einem Preis oberhalb ihrer Grenzkosten anzubieten, es sei denn, das Unternehmen weist nach, dass ein entsprechender Mark-up erforderlich ist, um seine -bezogen auf das gesamte Kraftwerksportfolio- totalen Durchschnittskosten zu erwirtschaften.

of his entire plant fleet."

This reversal of the burden of proof may be legally tenable, but has to be reviewed critically in its consequences for competition. This paper analyzes whether such an implicit regulatory price cap is economically justifiable and whether the assessment of market power in the context of market convergence still holds. In this respect, it is of particular interest whether these quasi-regulatory interventions imposed by a national competition authority may lead to inefficiencies in a wider, cross-border market definition.

The introduction of a market monitoring unit for power and gas, which is supposed to constantly monitor wholesale markets for potential abuse, makes it even more important to understand (i) how to clearly identify market abuse and (ii) whether this definition is in line with the implicit price cap introduced by the Federal Cartel Office.

5.2 Market Power and Dominance

The implicit price cap solely aims at firms holding a dominant position. This makes a clear distinction of the terms *market power* and *dominant position* in its legal and economic interpretation necessary. Subsequently, we relate the terms to the relevant peak-load pricing theory.

In competition economics, a supplier has market power if she is capable of setting a price above short-run marginal costs (Motta, 2004). In this sense, there is market power in almost every existing market. This, however, is still compatible with the existence of sufficient competition as long as total costs can be covered and excess profits are only temporary. From an antitrust law perspective, market power has to be *significant* because it then impedes effective competition. It follows that market power is not equivalent to a dominant position, but a firm has to have significant market power and non-transitory profits (contemporary or at least in the past) to gain a dominant position. Furthermore, even a dominant position is not per se legally objectionable, but its abuse is. According to § 19 section 4 No. 2 GWB, a firm abuses its dominant position if it demands fees or other terms of business which deviate from those likely to be in place under effective competition. In addition, § 29 No. 2 GWB defines that a dominant load serving entity of the grid-bound power industry is forbidden to abuse its dominant position by demanding fees that exceed costs to an inadequate extent.

It is important to note that § 29 No. 2 GWB only defines that costs are not to be exceeded to an *inadequate extent*. Costs refer to the total costs of an offer or the average costs, which may be exceeded, while not inadequately. Therefore, the cartel office's strict interpretation that prices may only exceed marginal costs in exceptional cases is not imperative on the basis of § 29 GWB.

An assessment of market power and dominance require a sound market definition. Two main criteria are important for market definition: the product (not decisive in this case) and geographical dimension, which can include more than just one region:[3]

> *"Two or more firms are dominant if there is essentially no competition for a specific product or service and if they fulfill all requirements of sentence 1 [§ 19 para. 1].* ***The geographically relevant market in the spirit of this law can be wider than the scope of legal application****[emphasis added by authors]."*

The geographical extent of the market is discussed in section 5.4. Theoretically, there are many structural factors that facilitate collusion or abuse of market power which can still be attributed to wholesale power markets (see Motta, 2004; Ivaldi et al. (2003) for an overview):

- Number of competitors (see Selten, 1973; Huck, Normann and Oechssler, 2004)
- Market transparency (Stigler, 1964; Green and Porter, 1984),
- low demand elasticity,

[3]Original quote: Zwei oder mehr Unternehmen sind marktbeherrschend, soweit zwischen ihnen für eine bestimmte Art von Waren oder gewerblichen Leistungen ein wesentlicher Wettbewerb nicht besteht und soweit sie in ihrer Gesamtheit die Voraussetzungen des Satzes 1 [Authors' note: § 19 para. 1] erfüllen. Der räumlich relevante Markt im Sinne dieses Gesetzes kann weiter sein als der Geltungsbereich dieses Gesetzes.

- high barriers to market entry,
- product homogeneity (Stigler, 1964),
- cross-ownership of power plants.

According to the cartel office, the four largest power generating companies held 85% and 84% percent of total installed generation capacities in 2007 and 2008, respectively (German Federal Cartel Office, 2011). This structural dominance is the foundation for the cartel office's imposition of an implicit price cap for dominant firms based on §29 GWB. However, the determination of adequate mark-ups that are in line with competition law is complex and is a case-by-case decision. Dynamic welfare effects should be taken into consideration and strictly distinguished from distribution effects.

An assessment of market power in wholesale electricity markets has to account for peak-load pricing theory (see next subsection for a detailed introduction). This is important since the characteristics of the product in combination with constrained supply capacity can lead to prices above marginal cost despite bids placed on a marginal cost level. In general, this is not reflected in the current law. Therefore, prices above cost (of the last peak load plant) have to be scrutinized individually. From an economic perspective, this relates to the *Residual Supplier Index*[4], where market power is analyzed for individual number of hours per year (Sheffrin, 2002). In the Australian National Electricity Market (AEM) prices above a three-digit threshold initiate an in-depth monitoring process (Australian Energy Market Operator, 2012). An ex-post analysis could also be triggered through a shift of the price distribution onto a higher level, as suspected in 2008. There are three ways considered especially practical to raise prices above marginal costs:

- Price-markups of peak-load plants during peak periods,
- Price-markups of base-load or mid-merit power plants above costs of the otherwise most expensive accepted peak-load plant (financial capacity withholding),

[4]The Residual Supplier Index (RSI) is a quantitative instrument, which measures the percentage of hours in which a supplier is crucial to cover demand.

- Capacity withholding of base-load or mid-merit power plants (physical capacity withholding).

The first approach is straight forward as one (or more) supplier(s) exploit(s) scarcity situations, which are quite frequent in power markets due to frequent peak demand situations, to raise prices of peak-load power plants above marginal costs. This happens either unilaterally or on a coordinated basis. For example, if all of the peak-load power plants were owned by a single firm, then this company would be in a dominant position each time demand exceeds residual supply. In absence of collusion, a small number of hours per year already suffice to create large revenues by means of regular price-markups. Both financial and physical capacity withholding aim at the same goal: Induce an artificial supply scarcity (a leftward shift of the merit order) that causes higher prices. This strategy is especially attractive for firms with a diversified power plant fleet. In addition, a power plant distribution with large jump discontinuities amplifies this effect.

For highly diversified firms, there is another possibility to soften competition which is closely linked to a discriminatory price cap such as the one discussed by the Federal Cartel Office. If low peak-load prices have a large share of the price density function, then this should be accompanied with a decommissioning or disinvestment of power plants by suppliers. This can be difficult because a shutdown of large power plants is prohibited by §13a ENWG (German Energy Act). However, keeping these unprofitable power plants in the market could be seen as market foreclosure because these additional capacities prevent potential entrants from investing into generation capacities. This requires cross-subsidization of otherwise loss-making power plants. The connection with the price cap for dominant firms lies in the cartel office's argument that mark-ups are only allowed to cover average total costs of the **whole plant fleet**. So dominant firms are either forced to withdraw capacities or to truly abuse their market power through market foreclosure. Even if dominant firms choose to shut down plants, this would not decrease the incentive to withhold capacity. On the contrary, since new and non-dominant firms may set prices freely, i.e., above marginal costs, the incentive is even amplified if dominant firms own base-load and mid-merit power plants.

The difference between the two described abusive actions is that market foreclosure is almost inevitable if dominant firms keep unprofitable power plants alive, but capacity withholding is not in case of plant closure. In general, the actions described above usually lead to higher market prices. This result, however, has to be supported by empirical findings or other means, e.g., through legally appropriate confessions or proof, before abuse of market power via price markups can be claimed. Reversal of the burden of proof is supposed to make such a claim easier.

5.2.1 Peak-Load Pricing and Markups in Economic Theory

The inability to cheaply store electricity in a large amount, a lack of real-time pricing mechanisms for a large share of customers, and the stochastic nature of demand are the main drivers for the occurrence of the peak load problem in electricity markets. This includes the optimal mix of production technologies as well as the pricing mechanism. In a first step, the first-best solution for prices and the technology mix are derived, before describing pricing signals that induce investment.

Williamson (1966) was among the first to introduce the peak-load pricing theory in a setting where prices are determined under capacity constraints and unsteady demand, i.e., demand is not uniform and changes frequently.[5] His work lays the foundation to the problem of peak-load pricing and clearly links welfare analysis to the most efficient choice of capacity, by making welfare maximization the main objective of a (monopolistic) power producer. Williamson (1966) assumes two different states of demand which are independent and known as peak and off-peak, and shows that

- welfare maximizing prices equal marginal costs,

[5]The first introduction of peak-load pricing goes even further back to (Boiteaux, 1960) and (Steiner, 1957). The work by Williamson (1966) is based upon these and additionally offers a thorough theoretical foundation for the peak-load pricing problem.

- and that the efficient capacity equilibrium is reached if long-run profits are zero.[6]

The approach will be briefly presented and discussed in order to implement the implicit discriminatory price cap imposed on dominant firms. Let us consider two inverse demand functions, independent from one another, $P_1(Q_1)$ and $P_2(Q_2)$. The realization of the two different demand curves depends on hourly cycles on a given day. Further, let $P_1(Q_1) < P_2(Q_2)$, so that $P_1(Q_1)$ can be defined as base-load demand and $P_2(Q_2)$ as peak demand. The relative frequency of both demand scenarios is described by w_1 and w_2. So if $P_1(Q_1)$ accounts for eight hours of the daily demand cycle and $P_2(Q_2)$ for the other 16 hours, then $w_1 = 1/3$ and $w_2 = 2/3$. Production costs are defined by $C(Q_1, Q_2) = b(w_1Q_1 + w_2Q_2) + \beta Q_2$, where the first term and second term represent variable costs and fixed cost of production, respectively. In a first step, capacity is assumed to be variable and determined by Q_2 and then optimal prices can be derived.

Social welfare (W), defined as the sum of consumer and producer surplus is maximized under price differentiation, which yields

$$\begin{aligned} CR &= \sum_{i=1}^{2} w_i \left[\int_0^{Q_i} P_i(x)dx - P_iQ_i \right] \\ PR &= \sum_{i=1}^{2} P_iQ_i - C(Q_1, Q_2) \\ W &= \sum_{i=1}^{2} w_i \int_0^{Q_i} P_i(x)dx - b(w_1Q_1 + w_2Q_2) - \beta Q_2. \end{aligned} \tag{5.1}$$

First derivatives of (5.1) with respect to Q_1 and Q_2 yield optimal prices

$$P_1^* = b \text{ and } P_2^* = b + \frac{\beta}{w_2}.$$

As a result, prices equal marginal costs during base-load demand (b), whereas prices

[6]If indivisibility of capacity is assumed, the zero-profit constraint is not necessarily binding. Instead, in its capacity optimum, monopolistic producers may realize positive as well as negative profits, depending on the elasticity of demand and marginal cost levels.

during peak load additionally cover marginal capacity costs (β/w_2), i.e., peak-load prices are above marginal costs. Under this regime welfare is maximized and producers make zero profits.

Although the underlying assumptions do not sufficiently describe contemporary electricity markets (variable and divisible capacity, constant marginal costs etc.)[7], the basic intuition of this model can still be useful to draw important conclusions for the peak-load pricing problem in wholesale electricity markets: Those consumers that fully utilize installed capacities are the ones that should bear the full fixed costs (i.e. operation and investment) over the period of additional demand.

In a second step, the focus is laid on the conditions under which a producer in- or decreases her capacity from a given level $\overline{Q}$. Installed capacity $\overline{Q}$ also serves as a capacity constraint so that optimal prices have to fulfill the following conditions: $Q_1 \leq \overline{Q}$ and $Q_2 \leq \overline{Q}$. Without any detailed mathematical derivation of the optimization, it holds that demand of at least one group of consumers must be large enough, $Q_2 \geq \overline{Q}$, to realize prices that cover fixed costs. Otherwise, i.e., $Q_2 < \overline{Q}$ and $Q_1 < \overline{Q}$, capacity is reduced until the condition holds again.

Building upon Williamson's work, subsequent theoretical papers extended this rather simplistic setting by considering interdependence between base-load and peak-load demand (Pressman, 1970), positive returns on scale (Mohring, 1970), step-wise increasing marginal costs in combination with a fixed costs decrease (Crew and Kleindorfer, 1976), supply and demand uncertainty (Chao, 1976) as well as the impact of rationalization costs on prices and profits (Crew and Kleindorfer, 1976; Carlton, 1977).

Nevertheless, one important flaw which is inherent to all these approaches remains: the assumption of a benevolent monopolistic producer whose primary goal is to maximize welfare. This assumption has to be put into the historic context of regulated monopolies. However, this does not hold for contemporary wholesale markets in Europe which

[7]For a more detailed discussion see Turvey (1968).

have been liberalized and privatized decades ago.[8] Instead, the markets are characterized by imperfect competition between private and public companies. Therefore, the principle of peak-load pricing has to be put into an oligopolistic framework where companies maximize profits.

5.2.2 Peak-Load Pricing and Incentives for Investment into Peak-load Generation Capacity

Since private generation companies maximize profits rather than welfare, the level of prices and installed capacities may deviate from the social optimum; especially if the market is monopolized. An approximation of the social optimum can be achieved if the degree of competition is sufficiently high. The German wholesale electricity market is neither in the state of perfect competition nor dominated by a monopoly and hence justifies the focus of investment decisions in an oligopolistic framework. This approach is exemplified by Zöttl (2011), who, in addition, has analyzed the effects of price caps during peak-load on investment decisions.[9]

Zöttl (2011) considers a market with n firms, which compete in a Cournot framework for uncertain demand. Before firms compete in quantities they make the investment decision. The choice set consists of two types of power plants: a base-load and a peak-load plant. Both types differ in marginal costs of production and capacity costs. Marginal costs of the base-load plant are defined as c_1 and capacity costs as $k_1 X_{1i}$, with X_{1i} being the base-load capacity of firm $i = 1, ..., n$. The peak-load plant has higher marginal costs $c_2 > c_1$ and lower (fixed) costs of capacity $k_2 X_{2i}$ with $k_2 < k_1$, where X_{2i} defines the peak-load capacity of firm $i = 1, ..., n$. Total capacity of firm i is then described by X_i which is the sum of base- and peak-load plants $X_i = X_{1i} + X_{2i}$.

[8] Even under the assumption of a regulated monopoly, it is debatable whether that monopoly maximizes social welfare.

[9] Previous works on investment incentives in the context of price caps in a liberalized wholesale electricity market are discussed in Hogan (2005), Joskow (2007) as well as Joskow and Tirole (2007).

At the beginning the capacity level, which yields under imperfect competition, is compared to the optimal level assumed under perfect competition, i.e., firms are price takers. The main result is that total base-load capacity under imperfect competition is lower than the optimal level. This may also hold for peak-load plants, hence leading to an undersupply of total capacity. The model also shows that under certain conditions the optimal level can be obtained by introducing an adequate price cap. On the one hand the price cap has to be set above marginal costs of the peak-load plants. On the other hand the level has to fulfill the condition that marginal rents are higher than under the regime without a price cap. This can be described as follows: Let $P(Q)$ define the inverse demand function with $Q = \sum_{i=1}^{n} q_i$. If demand is attributed symmetrically to firms and large enough to constrain capacities, i.e., $q > X_i$, then

$$\frac{\partial P(Q)}{\partial q} q + P(Q) - c - k$$

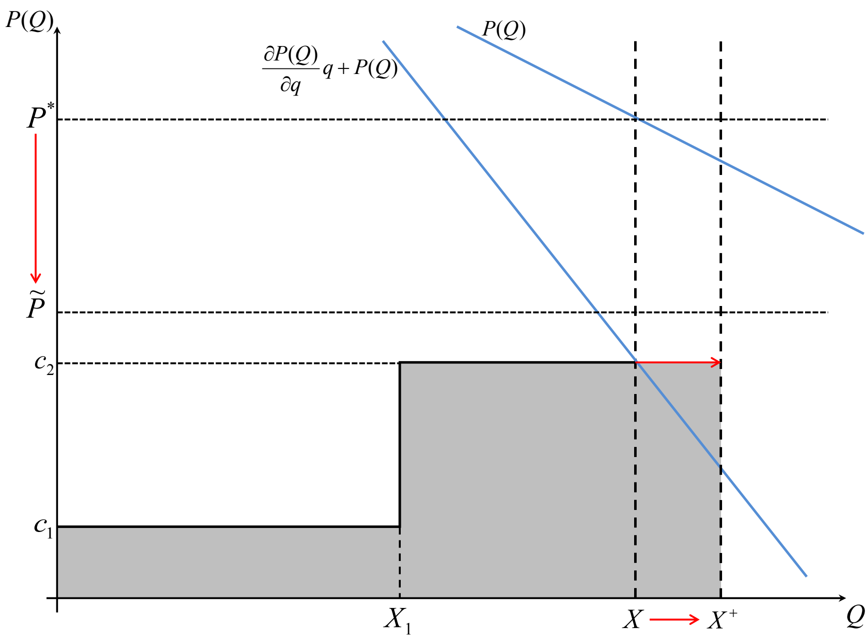
is the marginal profit without a price cap and

$$\widetilde{P} - c - k$$

the marginal profit with a price cap $\widetilde{P}$. It can be directly obtained from this that the price cap must fulfill $\widetilde{P} > \frac{\partial P(Q)}{\partial} q + P(Q)$ (the righthand side of the inequation is marginal rent without a price cap) to induce investment in peak-load capacity. The resulting market price may be lower, but investment incentives increase for peak-load plants because marginal incentives increase. Put differently, the price cap has to be set in a way that (marginal) capacity withholding becomes relatively unprofitable in comparison to (marginal) capacity expansion. This may create sufficient incentives to invest into new capacity. A conditio sine qua non is that the price cap has to be set above marginal costs.

In essence, a price cap can have a positive impact unless capacity withholding is more profitable. Note, that the increase in total capacity is solely due to the investment in peak-load capacity. This is reasonable as the advantage of base-load plants lies in its very low marginal costs ($c_2 - c_1 > 0$) which has to be weighted against the "fixed cost disadvantage" ($k_2 - k_1 < 0$) , which is independent of a price cap.

Figure 5.2: Price caps and peak-load capacity



Own Figure.

Figure 5.2 depicts the impact of a price cap $\widetilde{P}$ on peak-load capacity. Additional capacity, which is solely due to peak-load plants, is defined by X^+. Two objectives can be derived in terms of the creation of an incentive to invest in peak-load capacity.

(i) Strengthening the functioning of competition on the wholesale market (lower barriers to entry) and/or

(ii) adequate selection of a price cap.

In addition to the remedies above, there exist other opportunities to ensure a higher level of base- and peak-load capacity, involving (some sort of) capacity payments. A critical point in this model is the determination of the relevant price cap; if it is too low investment incentives may be stifled. A low price cap cuts necessary profits leading to disinvestment. This holds especially if price caps are set on the level of marginal costs of the most expensive firm, which would have a decisive impact on another very closely related matter, i.e., market design.

5.2.3 Peak-load Prices in Germany

A quantitative analysis of German wholesale electricity prices[10] for the years between 2009 and 2011 shows that a hypothetical gas turbine (existing and new) could not cover its fixed costs participating only at the power exchange (see appendix for model specification). This is in line with other literature (for example EWI, 2012). Defining the necessary price level to break even is difficult as each cost covering price level is related to the realized or expected runtime, i.e., the larger the number of profitable hours, the lower the necessary average price. We thus hold the runtime constant and then compare the average margin realized in our model with the necessary level to break even (see Table 5.1). The model shows that the runtime of gas turbines has decreased drastically over the years 2009-2011. The same holds for profit margins (PM) to the point where fixed costs could not be covered anymore. However, this is a simplified analysis of the market as it assumes perfect anticipation and neglects cross-border activities as well as participation on balancing markets.

The real price level was insufficient for new investment and old power plants. The calculation also emphasizes that the price to break even has increased strongly from ca 11 €/MWh to over 1000 €/MWh. While the real price has increased at the same time, the right tail of the price distribution has changed only slightly. One explanation for this may be the combination of large overcapacities and decreasing residual load, see, e.g., German monopolies commission (Monopolkommission, 2013). For 2011, an additional reason could be the coupling of markets, but a reliable statement is not possible without further data and analysis. It would be also interesting to see whether base-load and midmerit power plants exhibit equal patterns of unprofitability.

[10]Prices were not weighted.

Table 5.1: Return margin of a gas turbine for 2009-2011

	2009		**2010**		**2011**	
	Existing	New	E	N	E	N
Runtime in model in hours	845	3200	36	787	0	51
Average PM* ..						
in the model	10.55	8.83	3.52	4.72	-	3.19
break even**	10.91	16.44	256.17	66.83	-	1031.23
Average: Price						
realized in the model	61.79	50.39	50.39	56.17	-	64.91
break even**	62.15	57.99	322.25	118.27	-	1092.95
Comparions of prices with..						
Average (Real)	38.86		44.48		51.12	
90%-Percentile (Real)	59.97		60.98		66.99	
95%-Percentile (Real)	70.49		66.69		69.97	

Own calculation. * PM=Profit Margin. **same runtime as in the model. Prices and profit margins in €/MWh.

Absence of investment due to low price levels also has significant effects on generation adequacy. The larger the reserve margin, the lower the price level and the runtime of peakload plants. Hence a politically or socially desirable level of generation adequacy may stand in conflict with the results under the current market mechanism, which is subject to boom and bust cycles. To avoid a discrepancy between both adequacy levels, price spikes must be possible or other (regulatory) interventions become necessary, e.g., the introduction of a capacity mechanism (Böckers et al., 2011; EWI, 2012). An advantage of price spikes determined in a free market is that some customers are price sensitive and may react accordingly. These demand reactions are a natural corrective of the market mechanism which may influence the extent of necessary total capacity in the market. Price spikes should be the result of a correct reaction inside the current market mechanism, but that also depends on the state of competition. In the next section, we present a brief overview of empirical studies on price spikes and exercise of market power in the German wholesale market for electricity.

5.3 Market Power Abuse in the German Wholesale Electricity Market

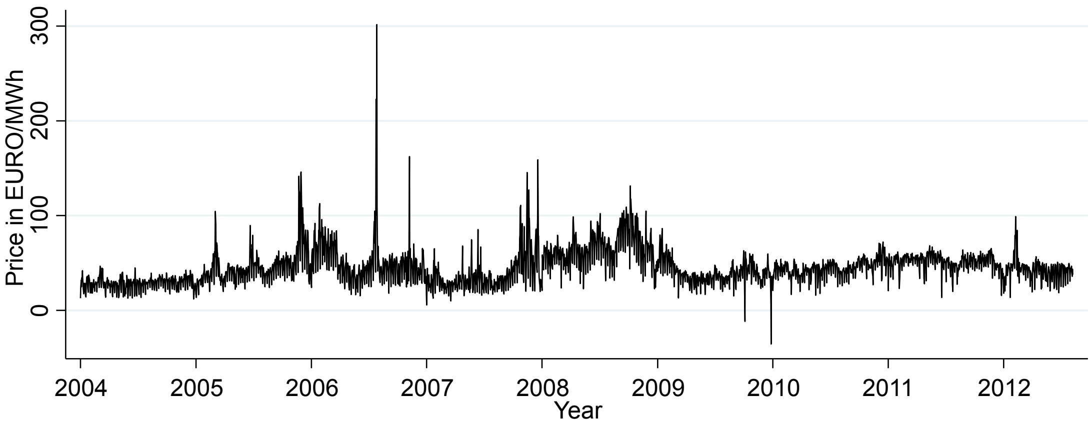
It is difficult for regulation and competition authorities to differentiate whether observed price spikes are the result of normal tight supply-demand ratios or of unilateral or coordinated actions by dominant firms. There are a number of reasons why prices may spike even in a theoretical setting of perfect competition: high costs of (1) production and (2) opportunity, (3) technical power plant outage as well as (4) very high demand. All four factors can each occur individually or in combination leading to even higher price spikes. The result is similar to that under unilateral or coordinated actions. The interpretation of relevant opportunity costs adds to the problem, which has been recognized by the Federal Cartel Office (2011). When reporting production costs to the Federal Cartel Office, there is room for hidden markups masked as marginal costs. Another severe problem is the distinction between real and strategic power plant outages. These factors emphasize the problem of identifying market power abuse. We depict the recent price development in order to give a first impression on potential price-spike periods before empirical evidence from other reports concerning market power abuse will be presented.

The development of the unweighted power prices shows that, in principle, prices remained on a similar level between 2009 and 2012, see Figure 5.3. Three years exhibit a relatively high price level according to the descriptive price percentiles. For 2006 and 2008 prices were high in relative as well as absolute terms and the whole distribution exhibited a fatter right tail. In 2011, the price level was relatively high as well, but lacked any significant price spikes.[11] In particular, the year 2008 is indicative as its median (63.3 €/MWh) and the 75% percentile (80.4 €/MWh) are significantly above the average of the respective statistical points of the other years excluding 2006 and 2008, with prices of 39.37 €/MWh (median) and 49.2 €/MWh (75% percentile).

The period from 2000 to 2008 has been subject of many empirical studies, which were

[11] See also Figures 5.6 to 5.8 in the Appendix for price duration curves between 2004 and 2011.

Figure 5.3: German wholesale electricity price, 2004-2012



Prices depicted on a daily basis. Source: EEX (2013).

mostly based on simulation models. In essence, the studies detect a number of periods where prices were above system marginal costs; especially in peak hours and the later years. None of which have been directly attributed to an abuse of market power, which is not suprising as shown in the previous section.

Müsgens (2006) has analyzed the years 2000-2003 taking cross-border flows into account. He finds markups of 50% on average and 75% during peak hours in the later years. Possible explanations for these could be exercise of market power, which may be indicated by a market concentration phase taking place during the observed period, substitution of long-run through short-run contracts as well as capacity withholding during peak periods. Müsgens notes that infra-marginal rents could also be kept on a lower level for strategic reasons, specifically to avoid regulatory inference. Carrying the argument a bit further, that would mean that the total sum of profits over the years may be even positive, but insufficient to attract new entry. This would then correspond with cross-subsidization of existing (and perhaps unprofitable) peak-load plants in a market characterized by overcapacities to prevent market entry.

Lang and Schwarz (2006) have expanded the same period to 2005 and found evidence for price markups for up to 28.8% for the year 2003. However, they argue that other factors such as costs for emission, fuel and ramping are fundamentally responsible for price increases. For the other years, price markups where no higher than 16% if simulated on an hourly basis for 2003-2005 and close to zero in a monthly analysis for the preceding years. With respect to the exercise of market power, Schwarz and Lang also point to possible strategic behavior in the form of artificially low markups as mentioned by Müsgens (2006).

Following the analysis of Schwarz and Lang (2006), von Hirschhausen and Weigt (2008) have analyzed the follow-up year 2006. During peak periods they estimate marginal-cost deviations of 11.1% (mean) and 29.8% (weekdays from 8 a.m. to 8 p.m.). Weigt and von Hirschhausen also calculate the extent of potential capacity withholding and find, especially for weekdays after July, capacity reductions of 14 GW during peak periods. A comparison between annuity fixed costs of the prevailing generation technologies and profit margins yields insufficient cost recovery for both simulated scenarios: a price curve derived from perfect competition (price equals marginal costs) and real prices. In particular, combined combustion and open gas turbines could not recover fixed costs. Weigt and von Hirschhausen thus explicitly note that it cannot be deduced from their analysis which empirical mechanism would have been adequate to cover fixed costs.

The underlying assumptions common to the mentioned simulation approaches, which can be often explained by insufficient data availability, are subject to criticism because capacity availability has not been accounted for correctly or in the case of reserve capacities or im- and export capacities not all (Weber and Vogel 2007; Swider, 2007).

Möst and Genoese (2009) single out four years either according to the degree of competition (assumed to be high in 2001 and low in 2006) or the influence of the trade system for emission certificates (introduction in 2004 and first year of trade in 2005). They use an agent-based simulation and distinguish the competitive level by addressing the potential actual exercise of market power through the Residual Supplier Index (RSI) and Lerner-Index, respectively. While Möst and Genoese find that the Lerner-Index increases for the years 2005 and 2006 by 8.81% (12.43% during peak) in comparison to the total price curve, they cannot substantiate the suspicion of market power abuse.

Table 5.2: Overview of empirical markup studies

Study	Period	Region	Method	Markup
S&L	2000-2005	G	LP&MI	Yes
M	2000-2003	EU	LP	Yes
W&H	2006	G	LP	Yes
M&G	2002/04/05/06	G	AB	Yes

Abbreviations: G=Germany, EU=Europe, LP=Linear Programming, MI=Mixed Integer Linear Programming, AB=Agent-Based Modeling. Source: S&L = Lang and Schwarz (2006); M= Müsgens (2006); W&H= von Hirschhausen and Weigt (2008); M&G=Möst and Genoese (2009).

The Federal Cartel Office also conducted a simulation based on linear optimization, but the analysis crucially hinges on the accuracy of the cost data provided by the firms. In particular, the acceptance of the definition of opportunity costs provided by the firms influences the size of the potential markup (German Federal Cartel Office, 2011). Components such as reprocurement of fuel, risk premia as well as the actual level of opportunity costs are difficult to decide upon. This gives room to exaggeration of the true marginal costs and thus underestimation of markups. As a result of its analysis, the Federal Cartel Office concludes that day-ahead prices equaled reported marginal costs, hence indicating no financial capacity withholding (German Federal Cartel Office, 2011). The suspicion of physical withholding of capacity could not be substantiated.

5.4 Market Definition

In a next step, the basis on which the implicit price cap was imposed, quantitatively determined market shares, will be analyzed by discussing the current market definition in the context of integration of European wholesale markets. In our delineation of the relevant market we focus on the definition related to Jevons (1988) as well as Stigler and Sherwin (1985). Load profiles of neighboring European countries are scrutinized for common and independent components and then linked to market definition and calculation of market shares. A description of the data used can be found in the Appendix.

Definition of the relevant market is essential from an antitrust perspective because it lays the foundation for concentration ratios. In turn, the structural assessment of dominance is the basis for the imposition of the implicit price cap by the Federal Cartel Office. Following Jevons (1988) and Stigler and Sherwin (1985), the price of a homogenous good inside the relevant market must be equal on average for all suppliers of that good, absent coordinated behavior and transportation costs. Otherwise, only transitory shocks can lead to price differences. Electricity can be considered a homogenous good if ecological preferences for the primary energy source are neglected. Hence, definition of the relevant wholesale electricity market focuses mainly on the geographical dimension.[12]

In its sector inquiry, the Federal Cartel Office states that it will consider Germany and Austria as the geographical extent of the relevant market in its future assessments (German Federal Cartel Office, 2011). Unconstrained cross-border transmission capacities, low price differences, which are mainly due to diverging trading hours, as well as the fact that both areas already face a common reference price, i.e., the German power exchange price, are the main arguments for the change in market definition. If these requirements are not fulfilled then markets would, thus, be delineated on a national level. Development of market integration, especially due to the process of market coupling, could not be accounted for in the observed time period. Market coupling was introduced in Germany in November 2010, making Germany a member of the Central-West-European region (CWE), which also comprises France, Belgium, Luxembourg and the Netherlands. There are no explicit auctions at relevant interconnectors for day-ahead trade any longer. Instead, these are implicitly integrated in the holistic optimization of all participating power exchanges, materializing in price differences between power exchanges. In the wake of market mechanism optimization, power plant utilization across the member states becomes more efficient and the market coupling operator acts as a corrective towards a common market area.

[12] The European Commission (1997) also published a report on a general discussion of market definition.

Assuming that the market operator herself does not abuse her dominant position, the exercise of market power inside a regional market becomes more difficult, because of the supranational optimization algorithm. An otherwise successful high (exaggerated) markup or withholding of capacity can be effectively restrained through optimization of import and exports, i.e., competitive bids. However, this strongly depends on the extent of cross-border transmission capacities and the symmetry of national load profiles. Perfectly (a)symmetric load profiles will (maximize) minimize the effects of market coupling on competition. Given that the real relationship will be situated between the two extremes an empirical analysis can reveal how much potential overcapacity could be utilized. As a side-effect of the optimization of the regional power plant fleet, market coupling could be a market-based alternative to the regulatory implementation of a price-cap for dominant firms without any of the adverse effects on competition and investment incentives (see also Ecofys, 2012).

Due to further developments in the optimization process of market coupling, in particular the flow-based market coupling[13] whose launch is expected to the end of 2013 (CWE, 2012), geographical market integration may proceed faster. The shift of geographical boundaries is also indicated in the following analysis. An inclusion of further countries into the relevant market is at least debatable and important to analyze, because France has become a closer candidate, too. While a common market along with the Netherlands, Belgium, and Austria would not lead to significant changes in the market-share order of dominant firms, a common market including France would have a large impact.

In chapter 3 we already presented an empirical analysis of the years 2004 to 2011 which has shown that there is evidence for a integrated market between Austria and Germany (even prior to 2011) as well as the Netherlands and Belgium. The cross-demand effects between Germany and the Netherlands are also significantly negative, however, they are rather unidirectional, i.e., German holidays excess generation capacity which in turn creates competitive pressure on Dutch wholesale prices.

[13] See Belpex (2012) for an introduction and Kurzidem (2010) for a general discussion.

Results of an analysis of hourly price-differences with regard to price equality are described in Table 5.3. As expected, market coupling has increased price equality between member states. This becomes particularly interesting during times of high demand in single countries or pairs of countries, where price markups are most likely to occur unless price caps were implemented. Price differences in times of simultaneous high demand periods should even grow if the capacity mix of both countries differs significantly. In case of asymmetric high demand periods, arbitrage should lead to near-zero price differences as long as cross-border capacities are unconstrained.

Table 5.3: Hours of price equality before and after market coupling, 2010-2012

Period	**G-F**		**G-NL**		**G-Bel**	
	Off-Peak	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**	**Peak**
2010*A	0.4%	0.3%	0.2%	0.3%	0.2%	0.2%
2010*B	49.5 %	59.9%	86.5%	78.3%	50.3%	61.2%
2011	60.3%	73.0%	88.4%	88.3%	58.0%	73.3%
2012	64.1%	64.2%	58.1%	53.4%	58.4%	59.9%

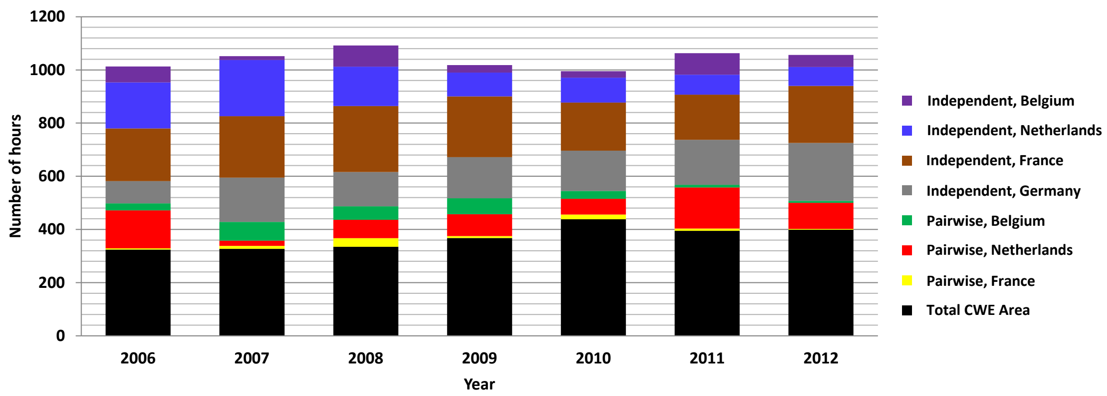
Peak hours are set from 8 am to 8 pm. Price equality is defined |price difference|<0,00999 €/MWh because some series may exhibit three digits after the decimal point. *A before market coupling; *B after market coupling.

In Table 5.3, the percentage of equal hours is distinguished for peak and off-peak hours. In 2010, the percentage of equal prices has been less than 1% prior to market coupling. This stands in contrast to almost 14,000 hours of price equality with the Netherlands and 12,000 hours with Belgium in our analysis from the launch of market coupling until the end of 2012. The comparison with France is on a similar scale. A side-effect of market coupling is that markets with relatively low power prices exhibit an increase due to market coupling.

Special attention is now paid to price differences occurring during periods of very high joint or individual demand. The potential of market coupling can unfold especially during these periods. In this analysis, very high demand is defined as load spike and comprises the highest 10% of yearly load. We define these load spikes as joint spikes if two (*Pairwise*) or all members of the CWE (defined as *CWE*) exhibit load spikes. Other very high demand situations are thus individual and defined as *Independent*.

Load spikes are usually attended by price spikes which can be restricted through foreign competition if load spikes occur individually. Apart from pairwise joint demand, it is also important to analyze to what degree spikes occur jointly inside the CWE region. An empirical analysis of historical load data of the CWE region reveals that these two types of joint load spikes account for a relatively large share of load spikes. Competitive pressure from outside is presumably lower during these hours because the current total capacity installed is adapted to cover national load and thus only marginally available to other than national customers.

Figure 5.4: Number of very high peak-load in the CWE-Area



Very high peak load is defined as the highest 10% of yearly load. Joint spikes are defined as (*Pairwise*) for a pair of countries or (*CWE*) all members of the CWE. Individual spikes are defined as *Independent*. Source: ENTSO-E (2012).

If the analysis is restricted to residual German load, i.e., after consideration of generation by renewable resources, data for the period of 1st April 2011 to 10th September 2012 shows that the number of individual load spikes has increased (see Figure 5.9 in the Appendix). However, this number is twice subject to stochastic fluctuation: that of demand and generation by renewable resources. A comparison of hours of nominal load with those of price equality indicates that price differences are still quite often close to or equal to zero. Belgium and the Netherlands have equal prices for over two-thirds of the observed period. France is the exception, where the share of equal prices drops down below 40%

during individual load spikes. Overall, this emphasizes that market integration increases more quickly and gains in importance as the CWE region is soon to merge its market coupling mechanism with that of the Scandinavian region (Nordpool). A consequence is that market definition has to be revised more frequently, especially if regulatory interventions, such as a price cap, require permanent updates about the current market situation.

So a result of the analysis is that prices differences are often zero even during periods of very high demand. Despite the fact that the share of price-differences does not equal 100%, markets may still constitute a common market according to Jevons (1988) as long as differences are due to stochastic friction, which excludes strategic behavior. The Federal Cartel Office did not require total price equality when it decided to define Germany and Austria's as the relevant market. This also holds when compared to price differences with Belgium and the Netherlands. Even France matches some of the criteria, however, on a smaller scale.

Table 5.4: Joint occurrence of load spikes and price equality after market coupling, 2010-2012

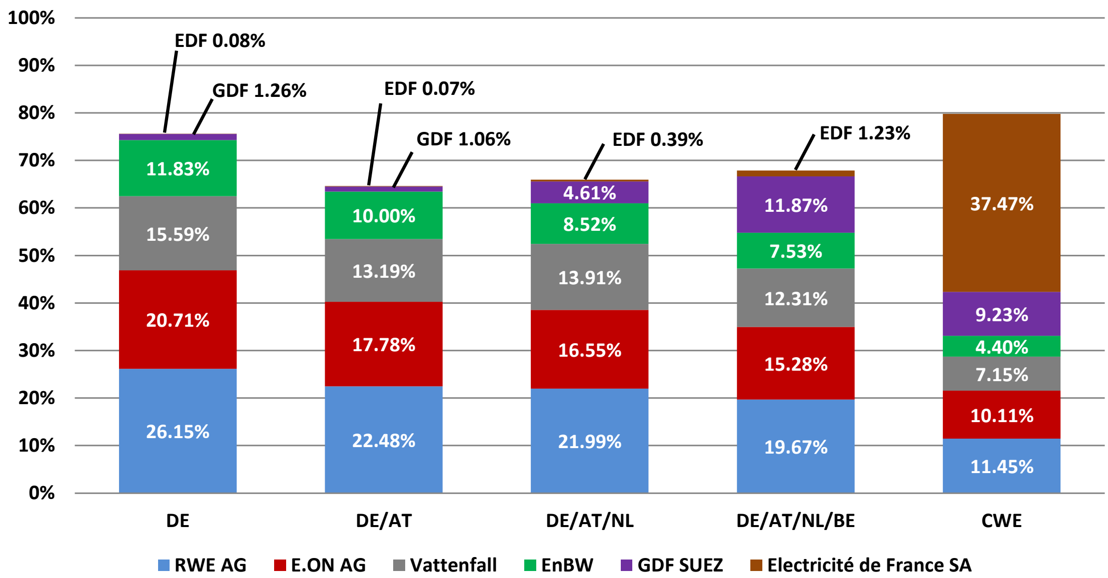
Period	**G-F**	**G-NL**	**G-BEL**
Joint load spike*	68.56%	85.96%	71.67%
Independent spike, Germany	72.63%	71.18%	69.97 %
Independent spike, others	38.66%	64.45%	66.41 %

*CWE region and pairwise. Source: own calculation. Data provided by ENTSO-E (2012) and respective power exchanges.

The results are also interesting in the context of almost constant imports and exports (see Figure 5.10 and 5.11 in the Appendix). Economically, cross-border transmission capacities only have to be upgraded to the point where competition from outside restrains pricing strategies of national suppliers. This does not necessarily imply an extension to the maximum of the neighboring country which has the lowest peak demand in comparison. While the main criteria for an internal market are met except for unconstrained bottlenecks, it hence remains unclear whether this is a necessary condition.

Figure 5.5 depicts the consequences of varying interpretations of the geographical extent on market shares. These are calculated on the basis of installed conventional generation capacities provided by Platts (2011). This approach is rather conservative because nowadays generation from renewable energies contributes considerably to total production. Yet, these technologies are not operated on a regular market basis due to fixed regulatory payments and thus create unidirectional competitive pressure on conventional capacities. Therefore, focusing on market shares of installed conventional capacities rather overstates this otherwise structural indicator of competition. As expected, the market shares of the two largest dominant firms in Germany, E.ON and RWE, shrink the larger the geographical extent of the market, in particular after the inclusion of France.

Figure 5.5: Market shares of the three largest producers (C3) of installed conventional generation I



Installed capacity explicitely excludes wind and photovoltaic as well as biomass and waste power plants. Platts only calculates net-market shares of the respective power plants and does not apply the concept of material holdings. Source: Platts (2011).

The implications for a price cap for dominant firms can be crucial, even more under a market coupling regime. Firms that are dominant in an inter-regional market that includes Germany, would not be price constrained if the Federal Cartel Office considered them not dominant in the German-Austrian market. Adding to the problem, the market coupling mechanism does not take the possibility of accepting potentially exaggerated bids into account. Therefore, it is left to the firm to estimate whether it is (a) likely to be accepted in the German-Austrian market and (b) whether its share is above the significant threshold. In extreme, a firm could be forced to permanently proof that it is not subject to the price cap or that a markup is necessary to cover fixed costs.

5.5 Competitive Assessment of the Bid Cap

Referring to §29 GWB, the Federal Cartel Office reversed the burden of proof for an abuse of a dominant position in the power sector. Without providing evidence of an abuse of a dominant position (German Federal Cartel Office, 2011), implicit bid caps are imposed on structurally dominant firms. Other (smaller) competitors are not directly affected by this and are explicitly allowed to charge mark-ups. The assumption that dominant firms abuse market power by bidding above marginal costs is subject to criticism. In economics, only in the special case of perfect competition prices are expected to match marginal costs. Under all other varying degrees of competition (except for monopolies), which appear more realistic, prices are set above marginal cost without permanently violating antitrust law.[14] In addition, the so-called More-Economic-Approach (MEA), which advocates an effects-based approach for competition authorities to assess competitive consequences in cases of abuse of dominance or mergers, explicitly lays stress on the assessment of market conduct instead of market structure (see Peeperkorn and Viertiö, 2009, for an example of the MEA in the case of mergers). Therefore, the implied reversion of the burden of proof based runs counter to the shift towards the More-Economic-Approach.

A price cap that discriminates against dominant firms may induce positive effects at first glance. The simplest effect is a decrease in the overall price level. In addition, a price cap could mimic results obtained under perfect competition if non-discriminatory. This, however, could be interpreted as treading the path towards cost-based regulation. From a legal

[14]This holds except for symmetric and homogenous Bertrand oligopolies.

perspective, a positive deviation from reported (or calculated) marginal costs facilitates the initiation of legal proceedings. In essence, the imposed price cap not only distinguishes between acceptable and unacceptable price levels but also discriminates against the source of price bids.

According to its sector inquiry, the Federal Cartel Office interprets the scope of §29 GWB to also imply an implicit price cap on dominant firms, because these are capable of cross-subsidizing their peak-load plants through profits generated by the whole plant fleet. Therefore, this assumes that dominant firms still invest in new plant projects or keep existing power plants online even in case of negative profitability in order utilize a large and diversified portfolio. This would apply in particular to E.ON and RWE if Germany is considered the relevant market. In turn for cross-subsidization, this strategic investment would serve as a barrier to entry in the class of peak-load power plants as long as fringe firms are incapable of financing new projects through granted profits generated by existing power plants. If the German government, through its regulatory subsidiary *Bundesnetzagentur*, denies the shutdown of power plants by means of the law known as *Wintergesetz*, it is rather unlikely that fringe firms would invest into new capacity as long as the law is still in force. This would lead to market foreclosure at least in the class of peak-load plants without any active exercise of strategic behavior of dominant firms.

Investment into new base-load or mid-merit power plants can only be expected if there is sufficient runtime, and thus profits, in the context of residual load. However, RWE and E.ON still hold a very large share in this class of power plants and even strengthen their position through new investment into lignite-fired power plants, thus rendering investment of third parties in this section unlikely.

Aside from these strategic options, keeping unprofitable power plants online makes no sense regardless whether the owner is a dominant firm or not. On the contrary, dominant firms could gain from a situation where fringe firms own most (if not even the entire fleet) of peak-load power plants, because the latter can charge markups. Since power exchanges operate with unit-price auctions, dominant firms can realize higher profits. In addition, the problem of capacity withholding has also not been solved by a discriminatory price cap. Capacity withholding, in particular exercised by base-load or mid-merit plants, is a major object of investigation in the sector inquiry. The probability of exercising this barely observable abusive action is even increased by a price cap because in hours in which a mark-up could have been profitable firms now simply switch to capacity withholding. In essence, the regulatory remedy is not only useless against capacity withholding, but may even facilitate it. Therefore, it is at best irrelevant for dominant firms whether they hold a large share of peak-load plants or not.

This creates in total two severe monitoring problems for the cartel office. The first one refers to the fact that financial capacity withholding may be clearly forbidden but it is almost impossible to observe, i.e., practically impossible to distinguish from real technical outages as long as there is no proof provided by inside sources or chance. The second one refers to the fact that the character of the discriminatory price cap is very similar if not identical to cost-based approaches to regulate network charges because it tries to define and monitor acceptable price components. These cost components, however, may either contain hidden costs, which, if observed, would be unacceptable, or are components which offer a large room for various interpretations, in particular opportunity costs. The main focus should be rather laid on the reduction of barriers to entry to foster competition.

Introducing a discriminatory price cap can have an even more severe side effect. Before describing the side effect in detail, we first explain the effect of the ecological transformation of the German electricity sector because the implicit discriminatory price cap is closely linked to it. The ecological change has a large impact on market design. Volatile renewable generation has a two-fold effect on the market because it does not only crowd-out conventional generation capacities (known as merit-order effect), but also changes the technological composition of the power plant fleet. This creates excess capacity in the market which entails mothballing or even retirement of power plants. Yet, some part of this excess capacity would still exhibit runtime due to production volatility of renewable generation power plants.

Under the current energy-only market mechanism excess capacity can only be a transitory system shock. Security of supply is endogenous to the system, i.e., it is the combined result of expected demand, adjusted generation portfolio and the resulting price distribution (see Böckers et al., 2011). The realized level of installed capacity is thus more constrained than it would be under a market design incorporating a capacity mechanism. It is for these reasons that the German market design is currently subject to debate about security of supply. Design options include the introduction of varieties of capacity mechanisms as well as enforcing the energy-only market. However, none of these options provides a general solution to insufficient competition on a market. To dampen incentives to abuse market power, additional remedies are introduced such as regular price caps, price-setting interdiction for existing plants as well as the discriminatory price cap discussed in this paper. In a market design based on some sort of capacity mechanism, these restrictions do not necessarily lead to a reduction in investment. This is due to the character of these mechanisms which are specifically designed to ensure security of supply in exchange for more restrictive regulations, which is supported by international experience (see German reports of Frontier, 2011; EWI, 2012; Böckers et al., 2011). In theory these markets can operate efficiently under such a regime, but risk aversion of regulators and market operators may lead to an inefficiently high level of security.

The side effect of imposing a discriminatory price cap occurs if the market design follows that of an energy-only system. This market design is theoretically capable of inducing an efficient level of security of supply even under perfect competition. A non-discriminatory price cap would therefore cause no harm under perfect competition. However, perfect competition renders any price cap redundant. If the implicit price cap on dominant firms is still implemented, it not only fails to solve the biggest competition issues, but also enhances the effect of excess capacity created by the increasing share of renewable generation. A market design featuring elements of a capacity mechanism provides excess capacity by definition and thus ensures its remuneration. In optimum the excess capacity generated through the capacity mechanism could match that generated as an effect of unidirectional competitive pressure induced by renewable generation. As we argued above, the implicit price cap on dominant firms can also induce excess capacity which adds to the aforementioned. On an energy-only market, excess supply can only be sustained through markups. Since cross-subsidization is no option, this means that peak-load plants have to be able to bid above marginal costs. This is in turn prohibited under the implicit price cap. In combination with the denial of plant shutdowns under the German $Wintergesetz$ (an Act that denies plants which are classified as vital to security of supply to shut down), this provides a permanent basis for excess capacity which creates pressure on prices. Since high prices are crucial in an energy-only market to induce investment, existing power plants make less profits or even realize losses and there will be no new investment. Therefore the side effect of an implicit price cap may pave the way towards a market design based on a capacity mechanism. As a consequence, the debate about energy-only and capacity markets is not decided by actual market failure, but through a combination of regulatory failures.

5.6 Conclusion

In its sector inquiry from 2011, the German Federal Cartel Office comes to the conclusion that dominant firms as defined in § 19 GWB may not charge any price above marginal costs unless there is proof that this is necessary to cover the total average costs of the firm's plant fleet.

From a competition point of view, such an implicit price cap is disproportional and discriminatory. While there exist reports which provide empirical evidence that the hypothesis of market power exercise through markups cannot be rejected, this still is no substantiated proof for an abuse.

The results of this paper can be summarized as follows:

- Price bids above short-run marginal costs are neither outright inefficient nor an abuse in principle.

- A discriminatory price cap equal to marginal costs has short- and long-run negative effects on investment decisions, market design and may also affect the electricity wholesale market on a European level.
- In the course of the increasing development of renewable resources, owners of conventional generation plants are faced with new challenges. On the one hand an increasing share of them is only needed as back-up capacity for volatile renewable generation and thus exhibit reduced runtimes. If these are not designed to serve under a strategic reserve, then these must cover their costs on the energy-only market. This necessitates occurrence of and thus allowance for price spikes.
- It is not economically substantiated that a price markup is only accepted if necessary to cover total average costs of the whole plant fleet. This leads to a permanent violation of competition law through market foreclosure and cross-subsidization.
- An implicit price cap in combination with a legal denial of power plant retirements, creates disincentives to invest into new capacity, induces market foreclosure and may artificially create the necessity for capacity mechanisms.
- The implicit price cap thus inherits large risks of adverse effects that are detrimental to investment incentives and competition.
- Market integration has seen significant progress and while there is still no single internal energy market, there are empirical indicators that suggest a revision of the relevant market for Germany. Potential candidates of a joint inter-regional market are Austria (already acknowledged by the cartel office), the Netherlands and Belgium. France is only a potential candidate in the long run.

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Appendix

Load data has been obtained from ENTSO-E (2012a) and corrected for daylight savings. Thus, duplicate hours have been deleted and missing hours replace with the mean of the previous and following hour. Solar and wind data has been collected from the network operators' joint website (www.eeg-kwk.net). Due to synchronization errors, data for two regions have been replaced by that published on the respective home website TENNETTSO and TransnetBW. The data is aggregated to an hourly level.

Calculation of marginal costs for a gas turbine i=(Existing, New) at time point t:

$$\begin{aligned} GK_{i,t} &= \frac{gasprice_t}{heatingvalue} * \frac{1}{efficiencyfactor_i} + \frac{emissionfactor}{efficiencyfactor_i} * certificateprice_t \\ &+ rampingcosts_i \end{aligned} \tag{5.2}$$

Table 5.5: Parameters of calculation I, 2009-2011

	Power Price	**Gas Price**	**Emission Price**
Source	EEX	APX	EEX
Frequency	hrly	daily*	daily*
No. obs.	26279	1095	1095
Mean	44.82	17.40	13.49
Std. Dev.	16.65	5.42	2.07

*Missing values have been replaced by the mean value of previous and following hour.

Table 5.6: Data source

Name	Period
EEX	01.01.2004-31.12.2012
Powernext	01.01.2010-31.12.2012
APX	01.01.2010-31.12.2012
BELPEX	01.01.2010-31.12.2012
ENTSO-E, D	02.01.2006-31.12.2012
ENTSO-E, F	02.01.2006-31.12.2012
ENTSO-E, Ö	02.01.2006-31.12.2012
ENTSO-E, Nl	02.01.2006-31.12.2012
ENTSO-E, Bel	02.01.2006-31.12.2012
Wind infeed	01.04.2011-10.09.2012
Solar infeed	01.04.2011-10.09.2012

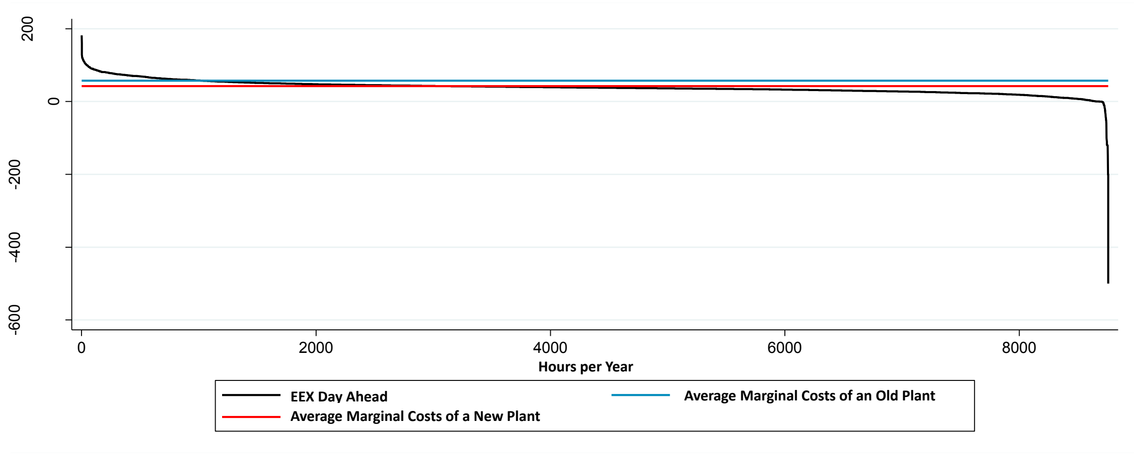
Corrected for daylight savings.

Table 5.7: Parameters of calculation II, 2009-2011

Parameter	Information
Installed Capacity	150 MW
Efficiency Degree*	90%
Transformation of..	
..Heating Value Gas*	0.902
..Emission value*	0.2002211
Ramping Costs of..	
..Existing Plant*	30 EURO/MW
..New Plant*	70 EURO/MW***
Efficiency Degree of..	
...Existing Plant*	0.284
...New Plant*	0.397
Fixed costs..	
..Existing Plant*	1,245 Mio. EURO
..New Plant**	7,1 Mio. EURO
Min. Downtime*	1 Std.
Min. Runtime	-
Max. Runtime	24 Std.

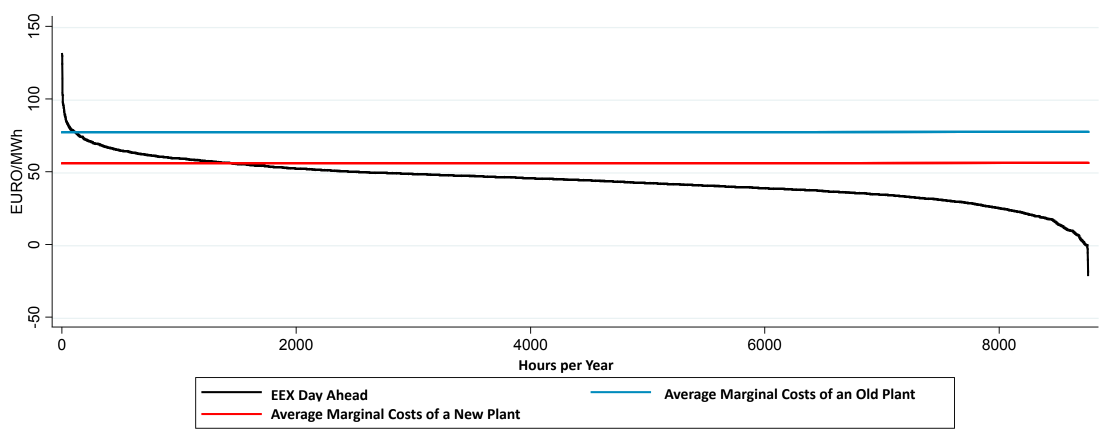
Source: *RWE (direct source), **Panos (2009), ***High ramping costs are due to Long-Term-Service-Agreements for O&M, which are assumed for new power plants.

Figure 5.6: Price spikes and marginal costs in period 2009



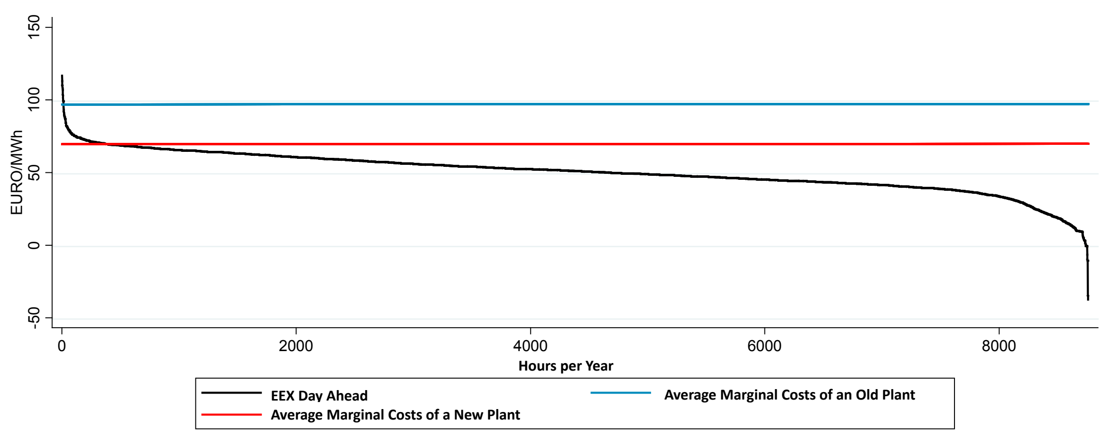
Source: own calculation.

Figure 5.7: Price spikes and marginal costs in period 2010



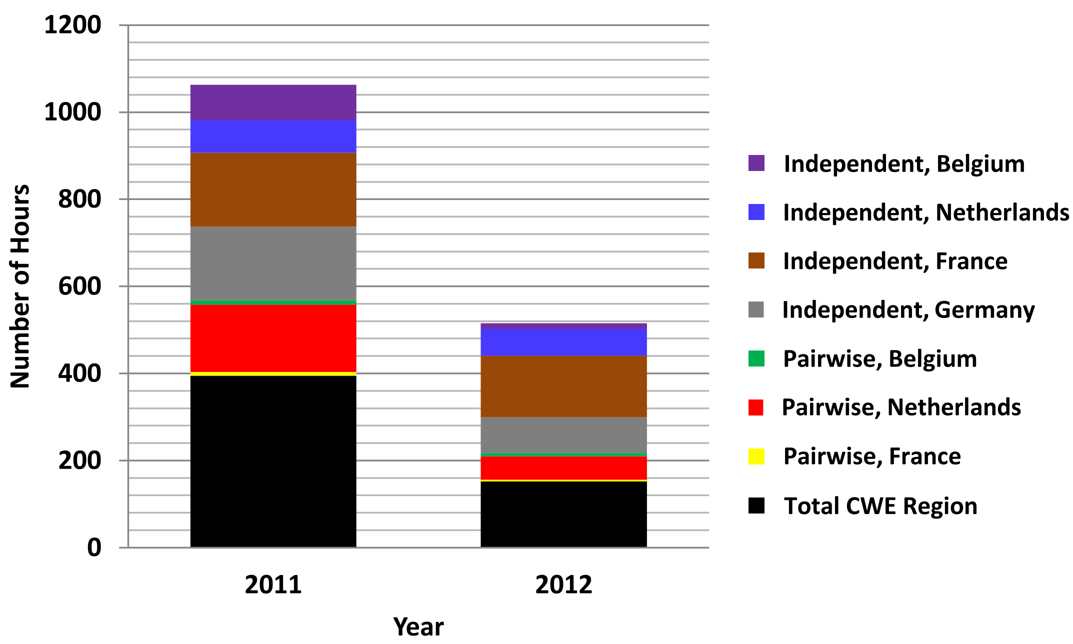
Source: own calculation.

Figure 5.8: Price spikes and marginal costs in period 2011



Source: own calculation.

Figure 5.9: Number of high peak-load hours in the CWE-Area compared to German residual load, 2011-2012



High peak-load is defined as the highest 10% of load hours in a year. Independent high-peakload is the sum of all individual high-peakload hours.

Table 5.8: Price-percentiles in Germany, 2004-2012

Year	1%	25%	50%	75%	90%	95%	99%	∅	St. Dev.
2004	6.3	21.9	28.2	35.8	41.0	44.7	56.2	28.5	10.8
2005	12.2	31.4	40.1	53.3	69.1	86.3	154.0	46.0	27.2
2006	6.1	32.6	45.0	63.3	81.2	91.8	135.8	50.8	49.4
2007	4.1	23.1	30.1	44.8	65.0	85.0	142.9	38.0	30.4
2008	3.0	47.4	63.3	80.4	100.0	117.6	149.9	65.8	28.7
2009	0.1	29.8	38.1	46.4	60.0	70.5	90.1	38.9	19.4
2010	6.9	37.0	45.1	52.1	61.0	66.7	79.5	44.5	14.0
2011	10.3	43.9	51.9	60.6	67.0	70.0	77.1	51.1	13.6
2012	4.9	34.1	42.1	52.9	60.7	65.1	87.9	42.6	18.7

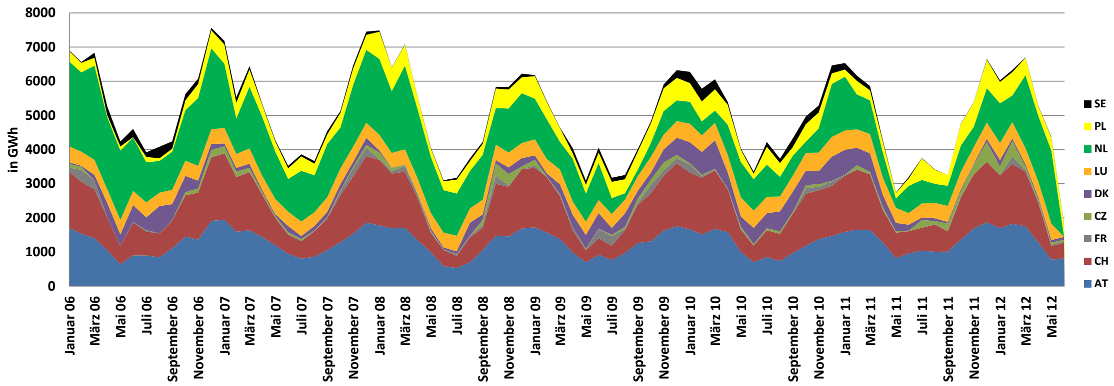
Rounded to the first digit point. Source: Own calculation.

Table 5.9: Price-difference percentile, 2010-2012

Year	1%	25%	50%	75%	90%	95%	99%	∅	St. Dev.
2010[A]									
G-F	-36.6	-4.7	-0.9	1.8	4.9	7.4	16.6	-2.6	9.5
G-NL	-15.6	-2.9	-0.4	2.0	4.4	6.1	10.6	-0.7	4.8
G-B	-28.4	-3.5	-0.5	2.1	5.2	8.0	17.4	-1.3	7.8
2010[B]									
G-F	-44.3	-7.7	<-0.01	<0.01	<0.01	<0.01	1.7	-5.2	10.7
G-NL	-33.3	0	0	0	0	0	0	-2.1	6.5
G-B	-44.4	-7.4	0	0	0	0	1.7	-5.1	10.7
2011									
G-F	-20.5	>-0.01	<0.01	<0.01	12.7	24.2	34.4	2.2	8.9
G-N	-23.5	0	0	0	0	0	3.4	-0.9	5.1
G-B	-22.7	0	0	0	12.6	24.3	34.6	1.8	32.7
2012									
G-F	-43.2	-2.8	>-0.01	<0.01	<0.01	1.4	11.8	-4.3	33.3
G-N	0	0	0	8.0	17.0	23.2	38.1	5.4	12.4
G-B	-9.0	0	0	5.7	15.8	21.9	40.1	4.4	12.0

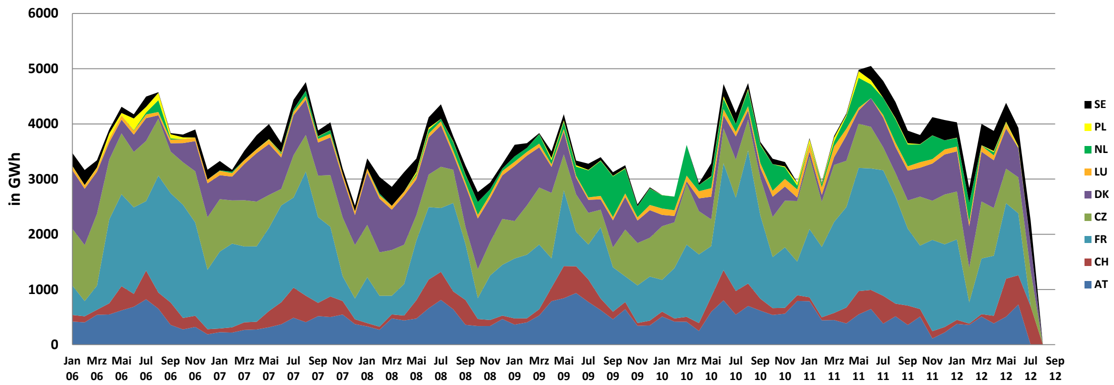
A: Before market coupling, B: After market coupling, 1: data available until 08.08.2012. Differences are rounded to the first digit point. Source: Own calculation.

Figure 5.10: Flow of exports to other countries, 2006-2012



Export in GWh based on ENTSO-E (2012b).

Figure 5.11: Flow of imports from other countries, 2006-2012



Import in GWh based on ENTSO-E (2012b).

Declaration of Contribution

I, Veit Böckers, hereby declare that I contributed to the paper *"Discriminatory Bidding Constraints in the German Wholesale Electricity Market"* as listed below:

- I gathered the relevant literature for sections 5.1, 5.2.3 and 5.4., and data for the sections 5.2.3 and 5.4.
- I conducted the quantitative analysis provided in section 5.2.3 and 5.4.
- I wrote sections 5.3, 5.4, 2.4.1 and 2.4.2 and contributed to section 5.1 and 5.2. and 5.5.

Signature, Coauthor 1: ____________

Signature, Coauthor 2: ____________

Chapter 6

The Green Game Changer: An Empirical Assessment of the Effects of Wind and Solar Power on the Merit Order*

6.1 Introduction

European power markets are in transition towards a system based on low carbon generation. Before the introduction of renewable energy sources (RES), the generation mix of most countries consisted mainly of conventional power plants which use coal, gas, oil, hydro and nuclear as the primary sources of energy, all of which are able to deliver power at a stable and reliable rate. Over the last decade, policy makers have addressed several ecological issues, particularly the reduction of CO_2 emissions, which has had a significant impact on the power production mix, i.e., less carbon intensive and more sustainable. Regulations have been introduced to influence the choice of the primary energy resource

*This paper is based on an earlier version that is co-authored by Jürgen Rösch and Leonie Giessing.

(Haas et al. 2004; 2008). So the need to take ecological issues into account is placed exogenously on power markets.

Two types of policies set the stage for this more eco-friendly approach in the European electricity sector. The first is the introduction of a tradeable emission certificate system to internalize the cost of pollution, the EU Emissions Trading System (EU-ETS). The second is the creation of public support-schemes for RES, to incentivize the investment in more ecological power production technologies. The European Union support framework set a goal that at least 20% of the final energy consumption has to be covered by renewable energy resources by 2020 (European Commission, 2008).

This analysis focuses on effects of renewable resources production promoted by out-of-market support schemes on market-based power generation in Spain.

Wind and sun are the most prominent renewable energy sources. Along with the regulated financial support, power production based on those RES usually also benefits from prioritized feed-in, guaranteeing them a permanent and secure revenue stream when they produce.[1] This is, operators of wind and solar power plants produce and sell power to the market whenever the wind blows or the sun shines. Even if prioritization were abandoned, near-zero marginal costs would still leave RES generation to be first feed-in, as all other technologies have at least their fuel costs to bear. This combination of significant subsidies and stochastic resource availability leads to the exogeneity assumption for RES generation with regard to demand and competing technologies.

This leads to a one-sided competitive relationship between conventional and RES power plants. RES production does not depend on the production decision of conventional power plants, but conventional power plants need to take RES production into account. Since RES generation can be considered as an exogenous supply shock to the physical and commercial power system we can more easily incorporate it into our empirical estimation framework.

[1] Network operators can deny feed-in only for system reliability concerns.

The effect of intermittent RES generation on conventional production and on the wholesale price of electricity is called the *merit-order effect*. A merit order of production ranks the available power plants in ascending order according to their marginal cost. Those power plants with the lowest marginal costs deliver power most of the time and are dispatched first. The higher the demand rises, the more expensive plants are utilized. Power price corresponds to the marginal cost of the last power plant that is still needed to cover demand. Power from renewable energy sources with prioritized feed-in and zero marginal cost will always be first to cover demand, leaving the conventional power plants competing for the remaining demand. Since RES production (like wind and solar) is intermittent, it cannot deliver a stable and reliable output because it is highly dependent on weather conditions; hence, it can have different effects on the merit order.

In theory, there is no clear answer as to which type of technology will be affected most. On the one hand, demand for power produced by conventional technologies is reduced, thereby also reducing the need to utilize power plants. The low marginal costs of RES production (or renewables) could therefore replace the most expensive peak plants. This would translate into lower power prices. On the other hand, demand for conventional plants is only reduced if the wind is blowing and the sun is actually shining, otherwise, the existing conventional plants will still be needed. The mechanics of the merit order still applies but it changes more frequently according to the availability of the stochastic input factors wind and solar. Thus, the second effect of RES generation on the merit order is caused by its inherent unreliability. In other words, residual demand which has to be covered by the conventional power plants is exposed to higher volatility. This reduces runtime of conventional power plants in general and requires utilization of more flexible power plants in particular. The most flexible plants, however, are also the most expensive plants in the merit order, which renders the lower marginal costs and less flexible plants to absorb the effect of renewables. If the output of RES generation is not high enough, mid-merit plants would be the most affected; base load plants would still be needed to cover the steady demand; and flexible peak-load plants would be utilized to balance the fluctuating production of wind and solar power. Consequently, prices drop when RES produces and rise, even perhaps over the average level of the pre-RES time period, when the more flexible plants are needed.

We contribute to the current debate about the effects of support schemes for RES by analyzing the Spanish power market, to estimate the merit-order effect. Our empirical approach allows for differentiation of the effect on quantities the wholesale market by the conventional production technologies during instances when renewable produce. We also show how this influences the wholesale price.

Hence, we take the merit order as the given structure and incorporate it into a Vector Autoregressive Model, i.e., we consider production of conventional power plants and price as endogenous and also take the time structure of the data into account. Wind and solar energy production are regarded as exogenous to the system, which reflects the market situation with prioritized feed-in and support schemes.

We quantify the effect of wind and solar power generation on the wholesale price and on quantities produced by each conventional power plant type, separately. This helps to understand how the current and future production mix is affected by the RES support schemes.

The Spanish power market combines several characteristics which makes it very suitable for testing the merit-order effect. Renewable technologies need not compete in the power market as they are promoted through out-of-market support schemes. The energy production mix consists of a large amount of RES production technologies, particularly wind and solar because the climate on the Iberian peninsula is very favorable for both. Ample availability of data enables a technology-specific differentiation in our analysis.

The rest of the chapter is structured as follows: Section 2 provides an introduction to the theory of power markets and the merit-order effect. Section 3 illustrates the Spanish power market. We then present the data used in section 4 prior to laying out the empirical strategy in section 5. The results are presented in section 6. The analysis concludes in section 7.

6.2 Theoretical Background

To analyze the effects of intermittent production on the composition of the power plant fleet and the market design, we first provide a concise insight of the theoretical background of power markets to explain the merit-order effect. This is fundamental in understanding how non-market based RES production affects the mechanisms in the market, and in determining which conventional generation technologies will be affected most.

6.2.1 Peak-Load Pricing and the Merit Order of Production

Electricity has special characteristics which distinguishes it from other goods. It is a grid-bound good which is neither storable nor substitutable; its provision has physical limitations and its production has to equal consumption at all times. Furthermore, demand for electricity is periodic, varying substantially during the day and over the seasons of the year. Typically, demand reaches peak during the working hours of a weekday, but is relatively low during nighttime and on weekends. Depending on the geography and climate conditions, consumption patterns differ from summer to winter.

These features make power markets subject to peak-load pricing.[2] Crew et al. (1995) present a summary of the basic principle of peak-load pricing: Different production technologies are needed to satisfy the fluctuating demand. These technologies differ in marginal and fixed costs. The technology with the lowest marginal costs has the highest fixed costs, while the one with the highest marginal cost has the lowest fixed cost. Hence, technologies can be put in order according to their marginal costs. The cheapest technology serves demand up to its maximum available capacity. As a consequence, the other technologies always have idle production capacities whenever demand can be at

[2]See Boiteaux (1960) and Williamson (1966) for some of the earliest works in this field.

least partly covered by cheaper technologies. Hence, the price during peak-demand periods has to be such that it enables the most expensive production technologies to recover their variable and fix costs.

Ranking power plants according to their marginal costs is called merit order. In practice, the merit order consists of base-, mid-merit and peak-load plants. Base-load plants usually consist of hydro, nuclear and lignite power plants, whereas mid-merit plants consist of coal-fired and combined-cycle-combustion gas turbines (CCGT). Peak-load plants usually consist of open-cycle gas turbines or plants fired with oil or gas. A cost overview and a confirmation of the chosen classification can be found in OECD (2010). The report covers the fixed and variable costs of a large set of production technologies and countries.

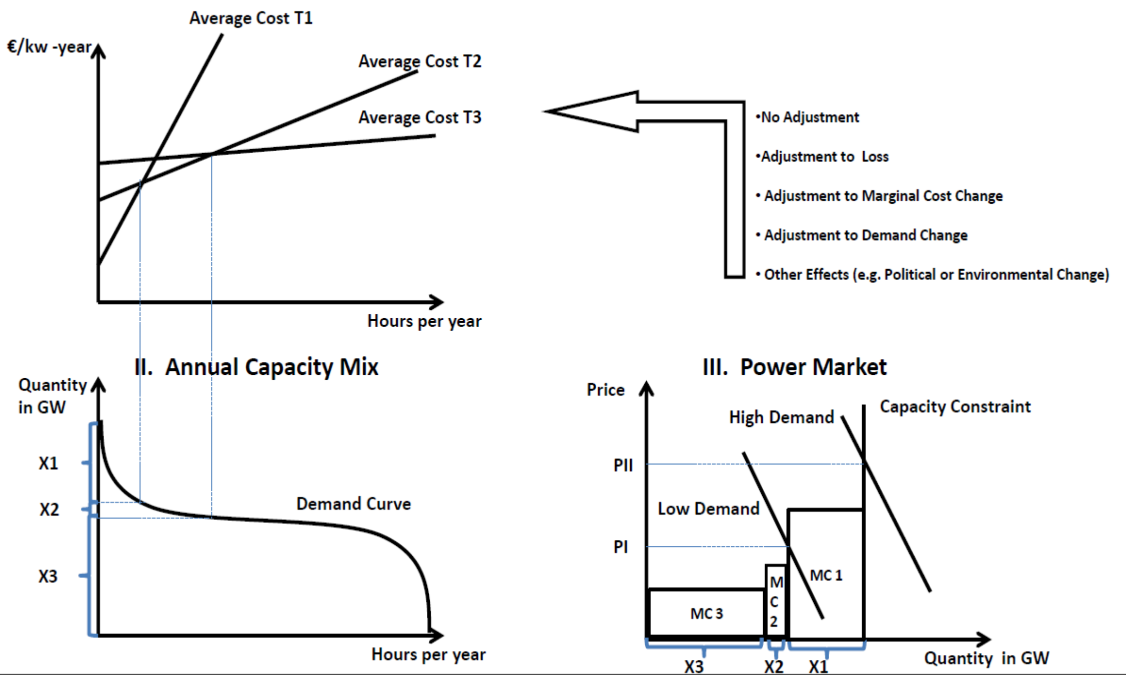
The merit order is not static, and adjustments in the power plant fleet take place constantly. Aside from the effect of renewable energy resources, various factors also affect the merit order. These adjustments are explained in a stylized example in the following figure.

An optimal capacity choice is made in a setting of perfect competition, merit order dispatch and a single-price auction. Three production technologies (T1, T2 and T3) are available to market participants. Based on the relationship between average costs and annual expected runtime of each production technology, an optimal plant mix for the provision of power exists. If the relative mixture of technologies is chosen optimally, its adoption to the expected yearly demand distribution yields a specific realization of the actual installed capacities (panel I and II).

Given this capacity choice, market participants bid their available capacities into the market. The optimal bid is the respective marginal cost of the plant, if the level of competition is sufficiently high. Each time overall demand exceeds the individual capacity of a dispatched technology type, profits are generated for this plant type. During these times, plants will recover their annualized investment and fixed costs. This creates a specific utilization of the existing production mix and price distribution (panel III).

Depending on this mechanism and factors such as policy changes, adjustments to the cur-

Figure 6.1: Static optimal capacity choice and peak-load pricing



Production Technologies T1, T2 and T3, Installed Capacities of T1 is X1, of T2 is X2 and of T3 is X3. Marginal Costs of Production for Technologies T1, T2 and T3 are MC1, MC2 and MC3. PI and PII indicate the equilibrium prices during low and high demand.

rent power plant portfolio may become necessary (panel IV). This could lead to temporary or permanent shifts in the technology mix or even the crowding out of plants using certain primary fuels. For instance, a planned or unplanned plant outage is temporary and usually does not lead to a permanent change in the merit order. Changes in the variable costs can lead to either persistent or temporary alterations - so-called fuel switches - depending on the size and frequency of the fluctuations. In the energy market, variable costs mainly consist of fuel costs (input price plus transportation costs), ramping costs and, depending on the technology, costs of emission certificates. Possible fuel switches mostly occur between coal-fired and gas-fired power plants (Sunderkötter and Weber (2011) for a theoretical model and simulation). Persistent changes in the merit order can be caused by advances, such as process innovation or the development of a new production technology. Other reasons can include the depletion of a resource or the general prohibition of its usage (i.e., the nuclear phase-out in Germany).

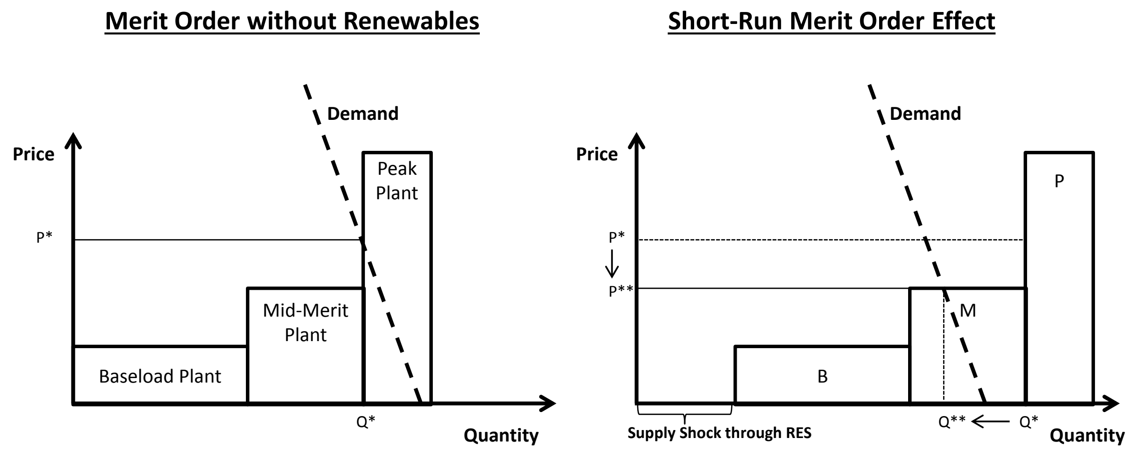
6.2.2 Merit-Order Effect

The *merit-order effect* describes the effect of weather-dependent (intermittent) renewables on the wholesale power market, particularly on the composition of the plant fleet. The production of the most prominent renewable technologies, wind and solar, is dependent on the availability of wind and sun. As no other input factor is needed for production, the marginal costs are zero or near-zero. Hence, they are located at the leftmost part of the merit order (see Figure 6.2).

The production decision of renewables is not market based. Investment and feed-in are regulated and are independent from the market mechanism. To incentivize investment in RES technologies, different support schemes for renewable energies have been developed since the 1990's, varying widely in their character (Haas et al., 2008 and Haas et al., 2004 for an overview). These subsidies can be based on actual generation (per kWh) or on installed capacity. Sometimes, lower interest rates or tax credits are used to stimulate investment (Menanteau et al., 2003 and Haas et al., 2004). Support schemes can also be divided into price or quantity driven instruments. The former pays a fixed amount independent of the actual production, while the latter seeks to reach a desired level of generation. Most of these support schemes also allow technologies a prioritized feed-in of their generation. Consequently, the compensation of RES technologies is not market-based and the decision to produce or to invest does not depend on the conventional power plants' production decision. Hence, generation by renewables is independent from competition in the power market or from any other economic factors that should be taken into consideration by the conventional power plants. For conventional power plant owners, generation by renewables is an exogenous supply shock. Every time they produce, the demand which has to be covered by conventional plants is effectively reduced.

The right side of Figure 6.2 shows the short-run merit-order effect as described, e.g., by de Miera et al. (2008). Wind and solar power have zero marginal costs and are fed-in first; they shift the merit order to the right. Technologies with the highest marginal cost

Figure 6.2: The effect of renewables on the merit order



Base, Mid-Merit and Peak refer to the marginal costs of the respective production technology.

are crowded out, as they are no longer needed to satisfy demand. Price is also reduced as total demand becomes covered by cheaper technologies. Some empirical studies (such as Green and Vasilakos, 2010; APPA, 2009; de Miera et al., 2008; Sensfuss et al., 2008; Gelabert et al., 2011) find evidence of RES production's price decreasing impact.

The inherent weather dependence and unreliability of wind and solar power can, however, also affect mid-merit plants. The short-run merit-order effect only occurs when the sun shines and the wind blows, but this, as well, depends on the intensity of wind and solar radiation. The intermittent technologies reduce the demand for conventional power plants whenever the conditions are favorable, but conventional power plants have to cover the full demand, whenever wind and solar energy sources cannot produce. Put differently, the residual demand for conventional power plants fluctuates, depending on weather conditions and installed RES capacity.

The production of fluctuating renewables can therefore be interpreted as an increase in the uncertainty of demand for conventional power plants. Vives (1989) shows, in a general oligopoly setting, that firms tend to invest in more flexible technologies if there is an increase in basic uncertainty. This implies a shift towards more flexible and more expensive plants. The merit-order shifts to the right whenever wind and solar power produce ample supply of energy and shifts back whenever they produce less or nothing. Depending on the magnitude of the RES feed-in base-load, plants can just be minimally affected as they still cover the steady demand. Mid-merit plants, which are more flexible, but still need sufficient runtime, can suffer the most, as peak plants can quickly adapt to different demand situations. In the long run, mid-merit plants may exit the market and the merit order may collapse to base-load and peak plants - which would, again, lead to higher power prices in periods without RES production.

Furthermore, the reduced number of price peaks affects all power plants. As the last power plant accepted in the auction to satisfy demand sets the price, all the other power plants to its left in the merit-order earn money on top of their marginal costs. Base-load and mid-merit plants with relatively high fixed costs need a certain amount of high prices during the year and consecutive hours of runtime to cover the fixed costs. If peak load plants leave the market and the price level decreases, the profitability of all power plants in the merit-order would also decrease. Also, the profitability of future investments in the power plant fleet will depend on the price level and will be influenced by this development.

Gelabert et al. (2011) conduct a study of the Spanish power market data for the years of 2005 to 2009. They analyze the effect of the Spanish *Special Regime* - which includes wind, solar, and other renewables, as well as smaller fossil fueled plants - on the wholesale price. They take into account the production of all other power plant types and find a negative price effect of renewables. The magnitude of the price effect, however, decreases over time. The quantity effect on the different production technologies is not considered.

Weigt (2009) could not confirm the crowding out of any specific conventional production technologies. Simulation studies by Bushnell (2011), Delarue et al. (2011) as well as Green and Vasilakos (2010), however, find the suggested switch to more flexible generation types as indicated by Vives (1989).

6.2.3 Market Design and RES

The merit-order effect also influences security of supply. Sufficient capacity needs to be ready to cover demand at any time. Power markets must provide investment incentives to attract the deployment of new capacities and to allow upgrade of existing plants. As the out-of-market support schemes influence the wholesale price and consequently the price signal to investors, it becomes questionable whether the energy-only market is capable of guaranteeing security of future supply.

Even without renewable energy sources it is unclear whether an energy-only market can attract sufficient investment. Cramton and Stoft (2005, 2006 and 2008) and Joskow and Tirole (2007) argue that the necessary number of high price spikes may not be realized. This so-called missing-money problem can lead to a permanent underprovision of installed capacity. To overcome this problem, it may be necessary to not only reimburse actual power production, but also the provision of capacity.

The increase of renewable power production is likely to intensify the missing-money problem. If either price peaks are cut or the runtime of power plants are reduced, the profitability of conventional power plants decreases. As conventional power plants are still needed to satisfy demand when there is little or no production by wind and solar, a market exit would jeopardize security of supply. Capacity payments can help keep essential plants in the market and attract sufficient further investment. The design of those capacity payments, however, can create other inefficiencies and disincentives (Böckers et al. 2011).

Another basic task of the market design is the production of cost-efficient energy. Out-of-market support schemes may also lead to inefficiencies in the technology mix. Firstly, not letting the market decide which RES technology to support can lead to an excessive expansion of a certain technology type which is desired by policy makers; this, however, is not the most efficient outcome in terms of achieving climate goals. Secondly, they lead to an adjustment in the remaining power plant fleet, but while the adjustment might be efficient under the prevailing conditions with renewable technologies, the resulting plant portfolio may nevertheless induce further costs.

Renewables have an impact on many aspects of the electricity wholesale market. We analyze which generation technology is affected by RES, and to what extent. Quantifying this effect helps evaluate the market performance, renewable support schemes and the evolution of the security of supply.

6.3 Spanish Power Market

The Spanish wholesale electricity market consists of a day-ahead market, which is organized as a pool, and a number of intra-day and balancing markets. The pool is ran as a uniform-price auction with the bid of the most expensive power plant needed to satisfy the demand setting the price.[3] Although bilateral trading is possible, the majority of the electricity is bidden into the pool. In the period from 2008 to 2012, 61% to 69% of total power was traded in the day-ahead market (OMIE, 2013 and REE, 2013a).

To meet the renewable energy targets set by the Spanish government and the EU, a support framework was established. The Spanish targets comply with the EU's goal of having at least 20% of the final energy consumption covered by renewable energy sources, by 2020 (Moreno and Garcia-Alvarez 2011). The legal promotion of renewable energy sources in Spain was initiated in 1980. The 'Law of the Electricity Sector' implementing the requirements of the European Directive 96/92/EC on the electricity market liberalization also established the *Special Regime*.

The *Special Regime* consists of renewable energy sources, conventional plants with a generation capacity of less than 50 MW and imports. It guarantees green power producers access to the grid as well as monetary support (Law 54/97). Royal Decree 2818 (RD

[3] On 1st July 2007 the Spanish and the Portuguese electricity markets were coupled to create the common Iberian electricity market, MIBEL (Mercado Iberico de Electricidad). Only the Spanish system is considered here.

2818/1998) regulates the treatment of plants in the Special Regime and lays the foundation of the two support systems currently in place.

The generators in the *Special Regime* can choose from one of two payment schemes which becomes binding for the following year. They can either opt for a time-dependent feed-in tariff (FIT), where generators receive a fixed total price per MWh fed into the grid, or bidding into the pool and receiving a feed-in premium depending on the market price. If the market price is too low, this so-called cap-and-floor system guarantees producers remuneration at floor level. If the market price exceeds the cap level, the producer receives the market price itself. Between the cap and floor levels, the producer receives a premium on top of the market price. Additionally, the support levels in both payment schemes vary according to peak (8 a.m. until 12 p.m.) and off-peak (12 p.m. until 8 a.m.) times.[4]

Conventional power plants including hydro power plants with generation capacities of at least 50 MW are part of the so-called *Ordinary Regime*, and they either bid their power into the pool or trade bilaterally. To stimulate the construction of new production facilities and discourage the retirement of already existing plants, a system of administrative capacity payments was introduced. The so called *pagos for capacidad* was introduced in 2007 and it reformed the system in place since market liberalization. The underlying idea is to support the market mechanism to achieve the desired level of supply security. Depending on the current reserve margin, power plants receive a certain amount per installed MW for the first ten years of operation. The incentive decreases with an increasing reserve margin. If the maximum reserve margin of 30% is reached, the capacity payment will gradually decline to zero (Federico and Vives, 2008).

The generation mix in Spain has changed continuously since the liberalization in 1998 (see Figure 6.3). While the installed capacities of nuclear, coal and hydro power plants remained constant, those of fuel/gas plants declined over time; however, CCGTs and *Special Regime* installed capacities increased. The latter almost increased sevenfold -

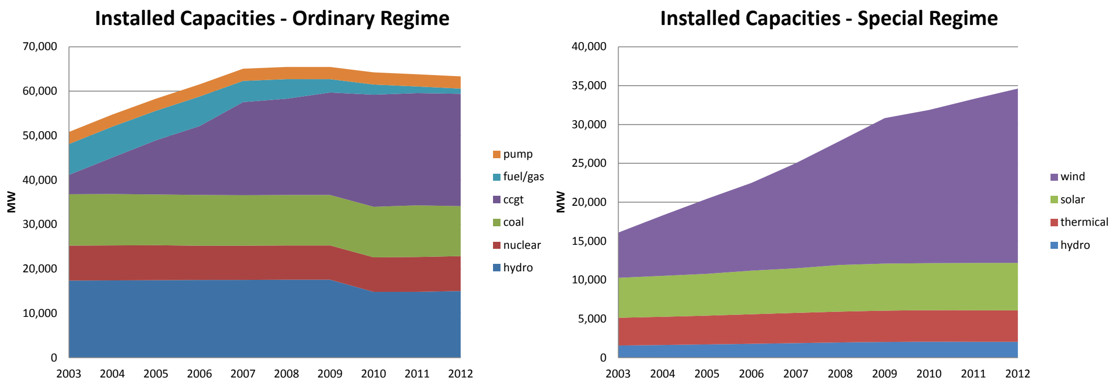
[4]For further information see RD 436/2004, RD661/2007, RD 1578/2008, RD 1565/2010 and RDL 14/2010. Detailed summaries and assessments of the Royal Degrees can be found in del Rio and Gual, 2007; del Rio Gonzalez, 2008 as well as del Rio and Mir-Artigues, 2012.

from 5,713 MW in 1998 to 38,953 MW in 2011 (Platts, 2011), which is about 38% of the total installed capacities (REE 2009, 2013a).

Within the *Special Regime*, wind energy holds the largest share with 54%, but because of a reform in 2004 (RD 436/2004) solar energy production experienced significant growth from 2006 to 2009. In a span of only two years (del Rio and Mir-Artigues, 2012) its installed capacity increased from 300 MW to 3,500 MW. The subsidies for solar generators almost tripled from 2.2 bn€to 6 bn€annually. Solar power producers received 40% of the total payments in the renewable support scheme, but it only accounted for 8% of its generation (Federico, 2010).

Figure 6.3 shows the development of both the *Ordinary Regime* and the *Special Regime*, in Spain. Hydro appears in both categories because small hydro plants with an installed capacity of less than 50MW are classified as *Special Regime*. CCGT power plants and wind power plants experienced the biggest growth. Note that the two graphs are scaled differently. *Special Regime* has now surpassed half of the installed capacity of the Ordinary Regime.

Figure 6.3: Installed capacity for ordinary and special regime



Source: Platts (2011), REE (2009; 2013).

6.4 Data

We analyze the Spanish power wholesale market during the period from 2008 to 2012. Data on Spanish demand, produced quantities[5] for each conventional fuel-type, i.e., nuclear, hydro, coal, and gas, as well as generation from the *Special Regime* is publicly available. The latter is comprised of the production of solar and wind power, as well as the generation of other renewable and non-renewable resources. We are, however, able to separate the *Special-Regime* generation in wind and solar and its other components. Furthermore, we use hourly electricity wholesale prices (OMIE, 2013 and REE, 2013a).

The installed capacities for each generation technology and the respective input prices are included as control variables i.e. prices for oil, gas, coal and uranium and European emission certificates (REE, 2009 and 2013; APX, 2013; Platts, 2011; Argus/McCloskey, 2013; UX Consulting, 2013; IEA, 2013; EEX, 2013). The input prices are available either on a weekly or weekday basis. Installed capacities are available on a yearly basis stated in MW (REE, 2009 and 2013).

Pooling all technologies in the Special Regime includes certain conventional and reliable plants (i.e. power plants with installed capacities of less than 50MW or RES technology such as biomass, which can deliver reliably). From this, we divide the *Special Regime* into its components: wind generation, solar generation and others. For wind data, we use the hourly wind forecast (REE, 2013a) and for solar data, we use the mean daily (actual) solar production[6] (REE, 2013) as there is no publicly available data on hourly solar production. To match the daily production of solar with the hourly data, we aggregate the data set to the daily average.

Spanish generation data supports the argument that wind and solar power have very low capacity credit. Their production depends on current weather conditions, so they cannot guarantee delivery at a reliable and stable rate. Very high production is followed by near

[5] Gas is subdivided into *cc*, which is a more efficient production type called combined cycle gas turbines, and *fuel/gas*, which includes the most expensive power plants running on either coal or gas.

[6] Calculated as the sum of photovoltaic and thermal solar production.

zero feed-in. In 2012, the highest wind forecast in a single hour on record was 16,100 MWh while the lowest was only 174 MWh, which is less than 1% of the mean installed wind capacities, calculated on the basis of our data set.

Table 6.1: Daily wind forecast and solar production

Windforecast					
Variable	**Mean**	**Std. Dev.**	**Min.**	**Max.**	**Inst. Cap. (MW)**
2008	3,555.07	1,890.28	551.18	8,663.24	15,977
2009	4,086.87	2,159.91	597.94	10,471.94	18,712
2010	4,861.05	2,521.63	877.29	13,088.47	19,710
2011	4,736.95	2,572.58	941.53	12,013.12	21,091
2012	5,453.75	2,775.65	1,096.54	13,693.33	22,430
2008-2012	4,538.59	2,490.38	551.18	13,693.33	19,583 (Mean)
Solar production					
Year	**Mean**	**Std. Dev.**	**Min.**	**Max.**	**Inst. Cap. (MW).**
2008	275.05	135.39	83.33	541.67	3,628
2009	677.51	219.98	166.67	1,041.67	3,481
2010	778.88	309.95	208.33	1,416.67	4,189
2011	1,021.58	375.63	250.00	1,625.00	5,069
2012	1,297.36	465.38	333.33	2,125.00	6,218
2008-2012	810.05	470.64	83.33	2,125.00	4,450 (mean)

Table 6.1 shows the average, minimum and maximum wind forecast and solar production over the years. Production is measured in MWh and installed capacity in MW. For both technologies, the difference between minimum and maximum production, as well as the mean production substantially fluctuates over time. This emphasizes the intermittent and unreliable character of those technologies.

Rainfall (measured in mm per m^2) and temperature are used as weather control variables (WeatherOnline, 2013). Solar and temperature are naturally higher correlated ($\rho = 0.49$) than solar and rain (*precipitation*), which are only weakly correlated ($\rho = -0.08$). The inclusion of temperature captures the effect of weather: higher temperatures are highly correlated with sunshine, but they may also affect conventional power plants. Run-of-the-River Hydro plants, e.g., depend on the water level in the river; also other conventional plants use rivers for cooling. Not controlling for temperature would make the effect of solar generation biased, e.g., overestimating the effect of *solar* on *hydro*. The industry production index (OECD 2013) serves as Spain's economic performance indicator.

Table 6.2 gives an overview on the descriptive statistics of each variable used in our analysis.

Table 6.2: Descriptive statistics of data

Time Series	Variable	Obs	Mean	Std. Dev.	Min.	Max.	Source
Prices							
Power	Price	1827	47.12134	12.91916	2.466667	82.13042	OMIE(2013)
Oil	brent	1827	92.19025	24.57975	33.73	143.95	IEA(2013)
Gas	ttf_price	1827	20.42837	5.802648	7.2	40.1565	APX(2013)
Uranium	uxc_price	1827	52.51631	9.651544	40	90	UXC(2013)
Emission	eua_wprice	1827	9.446716	5.623614	0.015	16.865	EEX(2013)
Coal	coal_index	1827	104.4412	32.44161	56	224.75	PLATTS(2011),Argus(2013)
Quantity Sold at Power Exchange							
Hydro	q_hydro	1827	1588.825	901.0896	270.7	6472.296	OMIE(2013)
Pump	q_pump	1827	441.9877	287.1578	0	1407.283	OMIE(2013)
Nuclear	q_nuclear	1827	1593.403	653.9276	304.0917	5820.079	OMIE(2013)
Coal	q_coal	1827	1414.727	1079.746	0	5642.158	OMIE(2013)
CCGT	q_cc	1827	4778.429	2935.616	115.125	13200.96	OMIE(2013)
Fuel/Gas	q_fuel_gas	1827	528.4486	117.6727	205.5125	759.4125	OMIE(2013)
Demand							
Demand Power Exchange	q_demand	1827	22237.38	3337.577	13326.87	33503.61	OMIE(2013)
Special Regime Quantities							
Total Special Regime	specreg_actual	1827	9909.278	2818.552	4458.333	20166.67	REE(2013)
Power Exchange Special Regime	q_re_mercado	1827	10000.77	2656.686	4312.063	19861.38	OMIE(2013)
Wind Forecast	windforecast	1827	4538.593	2490.38	551.1765	13693.33	REE(2013)
Solar PV Total	solarpv_actual	1827	671.5015	316.9182	83.33334	1291.667	REE(2013)
Solar Thermal Total	solarthermal_actual	1827	138.5468	188.4821	0	833.3333	REE(2013)
Installed Capacities							
Hydro	hidro_inst	1827	14852.63	81.25765	14808	15014.72	REE(2009, 2013)
Pump	bombeo_inst	1827	2746.928	.1442007	2746.64	2747	REE(2009, 2013)
Nuclear	nuclear_inst	1827	7767.809	50.63277	7716	7852.98	REE(2009, 2013)
Coal	carbon_inst	1827	11408.85	152.5875	11247.61	11700	REE(2009, 2013)
Fuel/Gas	fuelgas_inst	1827	2272.678	1420.547	178.16	4401	REE(2009, 2013)
CCGT	cc_inst	1827	24106.2	1485.152	21677	25290.58	REE(2009, 2013)
Special Regime	especial_tot_inst	1827	33938.77	3541.956	28618	38884.52	REE(2009, 2013)
SR Wind	wind_spec_inst	1827	19582.89	2200.578	15977	22430.64	REE(2009, 2013)
SR Solar PV	solar_pv_spec_inst	1827	3685.364	422.1233	3207	4267.526	REE(2009, 2013)
SR Solar Thermal	solar_term_spec_inst	1827	764.902	681.7313	61	1949.97	REE(2009, 2013)
Other							
Precipitation	precipitation	1827	0.6109329	1.216827	0	15.875	Weatheronline(2013)
Temperature	temp	1827	18.70234	5.997503	5.334043	31.45833	Weatheronline(2013)
Industry Production	ind_prod	1827	84.97141	7.67428	75.28896	107.1877	NISS(2013)

6.5 Empirical Strategy

To estimate the effect of renewable generation on the wholesale price and the quantities produced by conventional power plants, the merit-order is used as the underlying structure. We endogenize each technology's produced quantity according to their rank in the merit order and the day-ahead price, in a VAR model. The quantity produced by each technology depends on the price and all the quantities produced by technologies to its left in the merit order. Production from renewable energies is treated as exogenous to the system. This reflects the current situation in Spain, with an out-of-market support scheme for renewables. We also include demand, installed capacities, input costs for the different technologies, temperature and rainfall to control other exogenous influences not attributable to the effect of renewables. To capture seasonality and cyclic components, we include dummies for the days of the week (six), months (eleven) and years (four).

The six production technologies, in ascending order, based on their marginal costs, are: *hydro*, *nuclear*, *coal*, *CCGT*, *fuel/gas* and *pump* storage. *Hydro* and *nuclear* are base-load plants; *coal* and *CCGT* constitute the mid-merit order; and *fuel/gas* and *pump* storage are the peak plants. The ranking is based on information regarding the costs of power plants for the merit order from OECD (2010). The order is clear for most of the power plants. Fuel-switches mostly occur for coal and gas-fired plants as shown by Sunderkötter and Weber (2011), so we incorporate the change between the two technologies as a robustness check and change the order of *coal* and *CCGT* in an additional estimation.

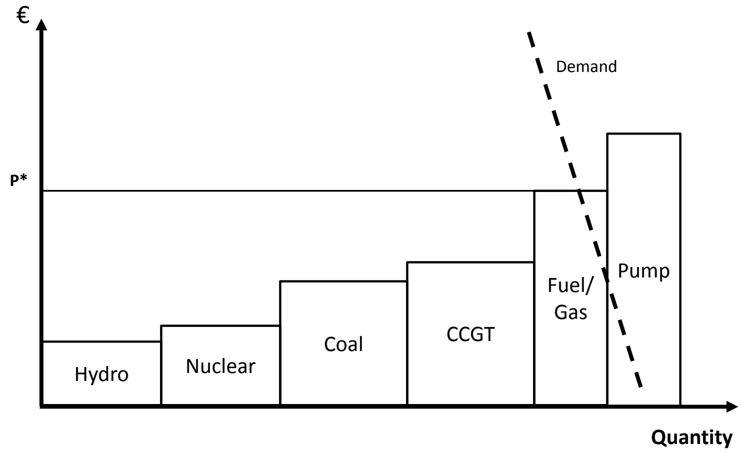
Vector Y comprises the endogenous variables. X is the vector of demand-specific shocks as well as fuel-type specific input factors. The vector RES describes the quantity produced under the *Special Regime*:

Y= $(price, q_{hydro}, q_{nuclear}, q_{coal}, q_{ccgt}, q_{fuelgas}, q_{pump})$

X = $(Demand, Season, Installed\,Capacities, InputPrices)$

RES = $(SpecialRegime)$

Figure 6.4: Merit order



The unrestricted VAR model therefore can be formalized as:

$$Y = A + BL(Y) + \Gamma RES + \Phi X + \epsilon \tag{6.1}$$

Figure 6.4 shows the underlying structure of the VAR model. The power plant with the highest marginal costs, which is still needed to cover demand, sets the price. All power plants to its left produce and earn money according to their marginal costs.

This structure (Figure 6.4) translates into equations 6.2 to 6.8. Estimating the price equation, all technologies are relevant. The equation for each technology, however, only considers technologies on its left in the merit order. The coefficients of power plants, to its right in the merit order, are constrained to zero. For instance, the production decision of a nuclear plant is not directly affected by that of a coal-fired plant as it has higher variable production costs. The opposite is true for the coal plant. If the cheaper technologies are already covering the whole demand, then the coal plant will not be dispatched. To control for temporary shifts within the merit order, we include the input prices for all power plant types and the price for emission certificates.

The inclusion of the production of the aggregated *Special Regime* does not uniquely identify the effect of intermittent technologies. It also comprises small conventional power

$$
\begin{aligned}
LnP_t &= cons_{pr} + \textstyle\sum_{i=1}^{k} \beta_{pr,1,i} LnP_{t-i} + \sum_{i=1}^{k} \beta_{pr,2,i} Hydro_{t-i} \\
&+ \textstyle\sum_{i=1}^{k} \beta_{pr,3,i} Nuclear_{t-i} + \sum_{i=1}^{k} \beta_{pr,4,i} Coal_{t-i} \\
&+ \textstyle\sum_{i=1}^{k} \beta_{pr,5,i} CCGT_{t-i} + \sum_{i=1}^{k} \beta_{pr,6,i} Fuel/Gas_{t-i} \\
&+ \textstyle\sum_{i=1}^{k} \beta_{pr,7,i} Pump_{t-i} + \Gamma_{pr} RES_t + \Phi_{pr} X_t + \epsilon_{pr,t}
\end{aligned} \tag{6.2}
$$

$$
Hydro_t = cons_h + \textstyle\sum_{i=1}^{k} \beta_{h,1,i} LnP_{t-i} + \Gamma_h RES_t + \Phi_h X_t + \epsilon_{h,t} \tag{6.3}
$$

$$
\begin{aligned}
Nuclear_t &= cons_n + \textstyle\sum_{i=1}^{k} \beta_{n,1,i} LnP_{t-i} + \sum_{i=1}^{k} \beta_{n,2,i} Hydro_{t-i} \\
&+ \Gamma_n RES_t + \Phi_n X_t + \epsilon_{n,t}
\end{aligned} \tag{6.4}
$$

$$
\begin{aligned}
Coal_t &= cons_c + \textstyle\sum_{i=1}^{k} \beta_{c,1,i} LnP_{t-i} + \sum_{i=1}^{k} \beta_{c,2,i} Hydro_{t-i} \\
&+ \textstyle\sum_{i=1}^{k} \beta_{c,3,i} Nuclear_{t-i} + \Gamma_c RES_t + \Phi_c X_t + \epsilon_{c,t}
\end{aligned} \tag{6.5}
$$

$$
\begin{aligned}
CCGT_t &= cons_{cc} + \textstyle\sum_{i=1}^{k} \beta_{cc,1,i} LnP_{t-i} + \sum_{i=1}^{k} \beta_{cc,2,i} Hydro_{t-i} \\
&+ \textstyle\sum_{i=1}^{k} \beta_{cc,3,i} Nuclear_{t-i} + \sum_{i=1}^{k} \beta_{cc,4,i} Coal_{t-i} \\
&+ \Gamma_{cc} RES_t + \Phi_{cc} X_t + \epsilon_{cc,t}
\end{aligned} \tag{6.6}
$$

$$
\begin{aligned}
Fuel/Gas_t &= cons_f + \textstyle\sum_{i=1}^{k} \beta_{cc,1,i} LnP_{t-i} + \sum_{i=1}^{k} \beta_{f,2,i} Hydro_{t-i} \\
&+ \textstyle\sum_{i=1}^{k} \beta_{f,3,i} Nuclear_{t-i} + \sum_{i=1}^{k} \beta_{f,4,i} Coal_{t-i} \\
&+ \textstyle\sum_{i=1}^{k} \beta_{f,5,i} CCGT_{t-i} + \Gamma_f RES_t + \Phi_f X_t + \epsilon_{f,t}
\end{aligned} \tag{6.7}
$$

$$
\begin{aligned}
Pump_t &= cons_p + \textstyle\sum_{i=1}^{k} \beta_{pu,1,i} LnP_{t-i} + \sum_{i=1}^{k} \beta_{pu,2,i} Hydro_{t-i} \\
&+ \textstyle\sum_{i=1}^{k} \beta_{pu,3,i} Nuclear_{t-i} + \sum_{i=1}^{k} \beta_{pu,4,i} Coal_{t-i} \\
&+ \textstyle\sum_{i=1}^{k} \beta_{pu,5,i} CCGT_{t-i} + \sum_{i=1}^{k} \beta_{pu,6,i} Fuel/Gas_{t-i} \\
&+ \Gamma_{pu} RES_t + \Phi_{pu} X_t + \epsilon_{pu,t}
\end{aligned} \tag{6.8}
$$

plants and renewables which can produce comparatively reliable, like waste or biomass. To split the *Special Regime* into its components, we use the wind forecast instead of the actual production as for the bidding behavior of the conventional plants only the forecast, and not the actual production, is relevant (Jonsson et al., 2010). The same is true for *solar*, but since forecasts are not publicly available, we use the daily averaged actual solar production provided by the market operator.

$$
q_{special\_regime} = q_{solar} + q_{wind} + q_{other_{SR}} \tag{6.9}
$$

The short-run merit order effect is based on the guaranteed feed-in of renewables and their lower marginal costs. The higher volatility of the residual demand, which has to be covered by the conventional power plant fleet, is, in contrast, due to the dependence of wind and solar power on weather. To show the effect of the intermittent renewables, we use both the entirety of the *Special Regime* (Model I) and its components (Model II).

Power generation by conventional power plants is constrained by the installed capacity of the different technologies. Installed capacity is only available on a yearly basis and enters as an exogenous variable. Since power plant construction is tedious and installed capacities do not fluctuate heavily, this might not be very restrictive.

Demand is assumed to be exogenous to the VAR system. This is common practice in power markets (e.g., Gelabert et al., 2011). Demand may not be entirely price inelastic, but not all customers are exposed to real time wholesale prices; and even those who are, can be quite inflexible. Households have habitual patterns of consumption and are not subject to real-time pricing[7] since they have fixed contracts with their energy suppliers. The tourism industry, an important sector in Spain, is also quite inflexible in terms of electricity consumption. Energy intensive producers, like a steel mill (wherein the cost of production is highly dependent on electricity price) may be able to react more flexibly to price changes. An interruption of production during peak-price times, however, may be more costly than continuous production. Stopping production will only be profitable for very high price changes. In our data set, the average price change, compared to the preceding hour, is 3.20 €/MWh with a standard deviation of 3.93, 50% of the price changes are smaller 1.98 €/MWh and 99% of the price changes are smaller than 18.21 €/MWh. The reaction to those price changes can therefore be assumed as rather small.

We also test for exogeneity of demand in the price equation using the Davidson and MacKinnon (1989) test.[8] The null hypothesis of exogeneity is not rejected.

[7]Weighted by industry branches, the energy industry contributes 13.04% to the Spanish industry production; intermediate and capital goods impact the index by 37.7% and 20.64%, respectively. The rest constitutes non-durable and other consumer goods, 24.21% and 4.41% (NISS, 2013).

[8]The test is repeated for different specifications, the test results remain qualitatively unchanged in all settings.

Table 6.3: Exogeneity test for demand

Davidson&MacKinnon	**Coef.**	**Std. Err.**	**t**
Demand	.0000257	.0001469	0.17

Solar data is only available on a daily basis. Aggregating the production data to the daily level underestimates the effect of solar, as solar production depends on sunshine, which only occurs between sunrise and sunset. In a second estimation, we therefore only take into consideration the hours between dawn and dusk.[9]

Before estimating the model, all the included time series are tested for the existence of unit roots. We use the augmented Dickey-Fuller (Dickey and Fuller, 1979) and Phillips-Perron (Phillips and Perron, 1988) test (see Appendix Table 6.6) and find that the price time series, the input prices (except for the price for uran) and the industry-production index are I(1) variables, thus we take the first differences of those variables, which are all found to be I(0). We do not transform all variables into their first-difference form because this reduces the loss of observations. For the price time series we take the logarithm *LnPrice* which is also found to be I(0). For all other time series, the null hypothesis that the variable follows a unit-root process can be rejected. We used the results of Schwarz's Bayesian information (SBIC) and Hannan and Quinn Information Criterion (HQIC) for the lag order selection.[10]

We also used the Hannan-Quinn and the Schwarz-Bayes information criteria for the lag length selection of the whole VAR model. Eight and three lags, respectively, are found for the simultaneous lag length selection by the information criteria. From an economic point of view, a short lag length is preferable. As the dynamics over the year and during the week are captured by the seasonality dummy and we also aggregated the data to the daily level, only the previous days should have an immediate impact. Thus, for the reported

[9]Sunrise and sunset time is for Madrid (TheWeatherChannel.com, 2013).

[10]We also tested for cointegration of the endogenous variables. As only the price series is integrated of order one and all other time series (except the input prices) are I(0) the economic interpretation of the cointegration test is misleading. The fact that there exists one or several linear combination of the variables that is I(0) does not necessarily mean that they follow a common equilibrium path, when several of the time series are already I(0). Furthermore, we also take the logarithm of price which is found to be I(0).

results, the SBIC lag length is chosen; the result remains qualitatively unchanged for the higher lag order and is available upon request.

After estimating the restricted VAR model, we used the Lagrange-multiplier test (Johansen, 1995) to test for autocorrelation. We found persistent autocorrelation in the residuals Newey and West (1987) standard errors are used to allow for autocorrelation up to a certain lag length. As proposed in Newey and West, (1987) the lag length for the correction is chosen as the integer of $4(T/100)^{\frac{1}{4}}$ whereas T is the number of observations in the data set. Results are robust to higher number of lags.

6.6 Results

We are interested in the effect the exogenous variables *Special Regime* and *wind*, *solar* and *other RES* on the endogenous merit order. Table 6.4 reports the results for those variables in each of the seven equations. The first two columns show the estimated equation and the dependent variable in this equation. The other columns show the price or quantity impact of a 1-MWh increase of either *Special Regime*, *wind*, *solar* or *other RES* for the respective equation. In model I the results for the whole *Special Regime* are reported. Model II shows the influence of the components of *wind*, *solar* and *other RES*.

Overall, the *Special Regime* decreases the price. A one MWh increase in *Special Regime* generation decreases the price by 0.003% - that's a decrease of 3% for an increase of one GWh. This effect is induced by *wind*. On the contrary, an increase in the production of *solar* and *other RES* increases the price.

The effect on the merit order is negative for all technologies but insignificant for *nuclear*. Again, *wind* is the driving force behind this result. An increase in *wind* energy production reduces the generated quantities of all technologies significantly - except for *nuclear* (model II). The results for *solar* and *other RES* are ambiguous.

An increase of 1-GWh in *solar* production increases the price by 5.45%, whereas only

Table 6.4: Impact of special regime and its components

	Model I	Model II		
Eq./ Dep. Var.	**Special Regime**	**Wind**	**Solar**	**Other RES**
(2) LnPrice	-0.0000306***	-0.0000318***	0.0000545***	0.0000160*
(3) Hydro	-0.0223019***	-0.0291984***	-0.0094671	0.0898763***
(4) Nuclear	-0.0004307	0.0000257	-0.047776	-0.0018914
(5) Coal	-0.0933551***	-0.0974866***	0.1093186	-0.0696695*
(6) CCGT	-0.1982958***	-0.3461214***	-0.2825958**	-0.1358050**
(7) Fuel/Gas	-0.0013968**	-0.0016611**	-0.0015485	0.0044956*
(8) Pump	-0.0183483***	-0.0196749***	0.0013187	0.0201682**
N	1824	1824	1824	1824

Level of Significance: * $p < 0.1$; ** $p < 0.05$; *** $p < 0.01$

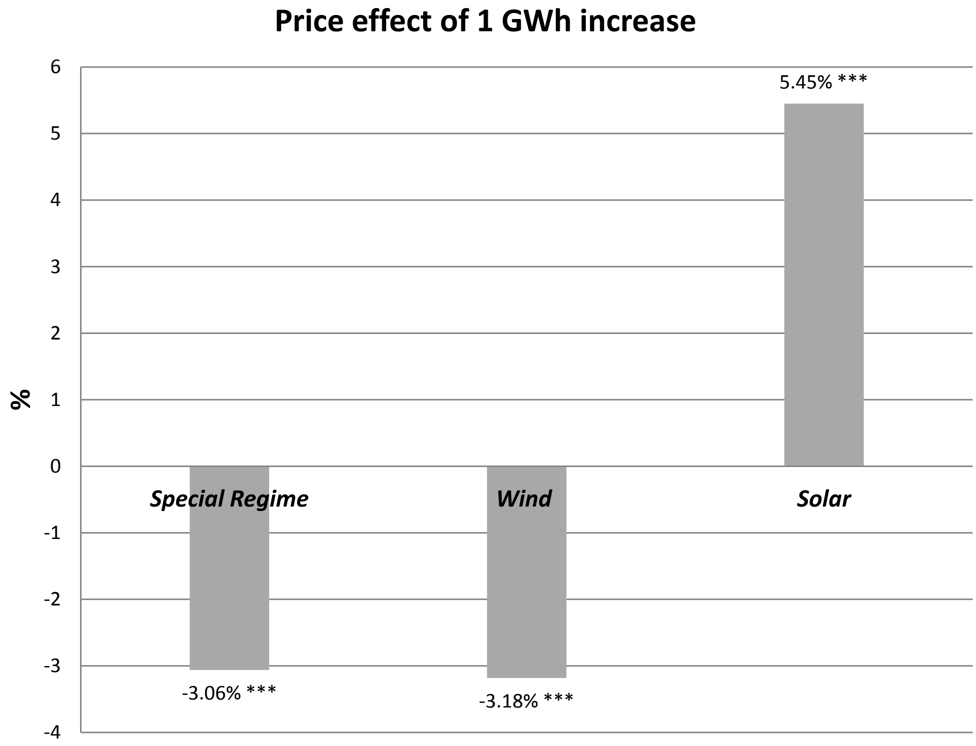
ccgt plants are significantly negatively affected in the merit order. A one GWh increase decreases CCGT plants' production by 282.60 MWh. The same is true for *other RES*: the price increases with an increased production. Production by mid-merit plants, such as *coal* and *ccgt*, decreases; but *hydro* and peak-load plants (*fuel/gas* and particularly *pump*,) benefit from more power fed-in by *other RES*.

Note that the model controls for the influence of temperature and rain. Aside from the effect of renewables, weather conditions can also cause fluctuations in the generation of conventional plants. A long drought could, for example, lead to lower water levels in rivers. This forces power plants to reduce their production as cooling water becomes scarce.

The effect of *solar* is contrary to expectations. Renewable generation reduces the demand which has to be covered by conventional power plants. Additionally, *solar* can only produce when the sun shines - which is mainly during peak hours, thereby cutting off price peaks. Figure 6.5 shows the price effect of one GWh increase of single RES generation technologies.

The effect of *solar* is largest in magnitude and offsets the negative price effect of *wind*. An increase of 1 GWh, however, is relatively much larger and is more unlikely to happen for *solar* than for *wind*. The average production of *solar* over all years was 0.81 GWh, only

Figure 6.5: Price effect of renewables

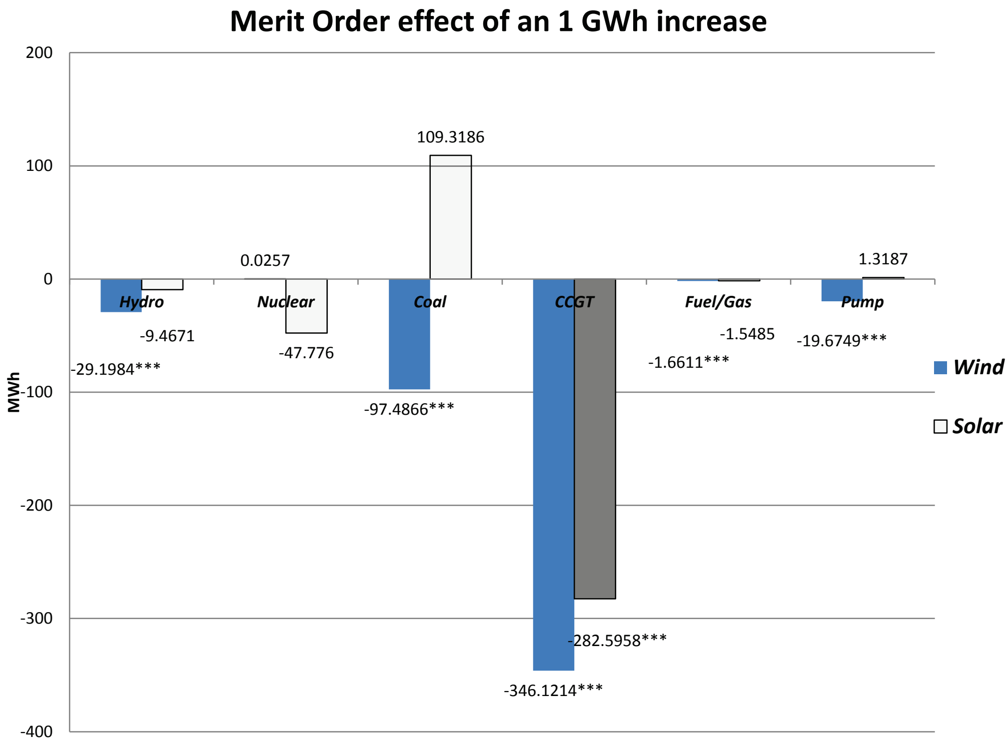


in 2011 and 2012 did it reach an average production of over 1 GWh over the whole year (see Table 6.1). Thus, an increase of one GWh is equal to twice the current production. In the case of *wind*, an increase of 1 GWh constitutes only 22% of its average production in the specified five years, which is still a substantial but also a more likely increase.

Not all technologies are affected to the same extent. Figure 6.6 shows that in contrast to the prediction of the short-run merit order effect (e.g. de Miera et al. 2008), it is not the peak plants which are the most affected, but the mid-merit plants. The prioritized feed-in of renewables effectively reduces the demand to be covered by conventional power plants. But base-load plants seem to be minimally affected if not totally unaffected; moreover, the flexible peak plants seem to reduce their quantities only to a small extent, which leaves mid-merit plants the ones absorbing the influence of renewable on the power market.

The positive price effect of *solar* cannot be explained by the effect on the merit order in Table 6.4. The production of *solar*, however, is only available on a daily basis. As we also

Figure 6.6: Merit-order effect of renewables



aggregate the hourly production data and the price to the daily average, we underestimate the effect of solar power. *Solar* can only produce during daytime but the aggregated data on quantities produced and the price, also contains night hours when it is impossible to produce solar energy. Table 6.5 therefore shows the effect of *solar* during daylight hours.[11]

The effects for the whole *Special Regime* become more distinct during daytime, except for *fuel/gas* which is no longer significant; but *nuclear* now produces significantly less. The same is true for *wind*: the effect becomes stronger for most technologies as well as for the *price*, but the influence on *fuel/gas* diminishes during daytime. The aggregation to daytime is not very meaningful for wind power, but roughly coincides with the peak hours in Spain.

[11] We took the hours between sunrise and sunset for Madrid for each day to determine the hours of possible production by *solar*. Before we aggregated the data to the daily level using all 24 hours, now we only use the daylight hours to aggregate data to the daily level. Note that we have data on quantities produced within the merit order and wind forecast on a hourly base.

Table 6.5: Impact of special regime between sunrise and sunset

	Model I	**Model II**		
Eq. Dep. Var.	**Special Regime**	**Wind**	**Solar**	**Other RES**
(2) LnPrice	-0.0000398***	-0.0000454***	0.0000749**	0.0000467***
(3) Hydro	-0.0852349***	-0.1027663***	-0.1064387	0.2087144***
(4) Nuclear	-0.0145175***	-0.0030491	-0.3305512***	-0.1640257***
(5) Coal	-0.1607183***	-0.1502956***	-0.1011762	-0.3522494***
(6) CCGT	-0.2419864***	-0.4194985***	-0.4965494***	-0.2241564***
(7) Fuel/Gas	0.001901	0.0005658	0.0116572	0.0224018***
(8) Pump	-0.0304683***	-0.0385795***	0.1444175***	0.0654165***
N	1824	1824	1824	1824

Level of Significance: * $p < 0.1$; ** $p < 0.05$; *** $p < 0.01$

Interestingly, *solar* now affects *nuclear* and *ccgt* negatively and statistically significant, and the production of *pump* increases, when the feed-in by *solar* increases. This means that the mid-merit order, and to a smaller degree base-load, reduce their production because of daytime solar power production, making more expensive and more flexible peak plants benefit from the effect of unsteady generation.

The same is true for *other RES*, where the peak plants produce more, and the other plants in the merit order, except for *hydro*, reduce their production when generation increases. *Other RES* has been quite stable and predictable in production.

The results remain qualitatively unchanged for fuel switches between coal and gas-fired power plants (Sunderkötter and Weber, 2011) and for higher order of lags.[12]

6.7 Conclusion

This chapter analyzes the impact of power generation, based on renewable resources, on wholesale power prices and conventional power generation in Spain. The data set contains information on daily averages of actual production and quantities sold at the Spanish power exchange from 2008 to 2012.

[12]Results are available upon request.

We estimate a structural vector autoregressive model, using the merit order as the underlying structure. The empirical evidence suggests that the merit order effect is not as clear cut as theory predicts. The main driver of renewable resources is wind power, which exhibits the expected negative impact on prices and on the quantities produced by conventional plants. On the contrary, solar power has a positive effect on wholesale prices.

Given the merit order of production, mid-merit plants are affected more than peak-load or base-load plants. As the share of renewable energy resources is not yet large enough, base-load plants may not be affected as of now. The residual demand is still sufficiently large for those plants to run for most of the hours during the year. Peak-load plants, on the other hand, may easily adapt to the higher volatility of the residual demand, leaving mid-merit plants to suffer the most from increasing RES production. If these findings still hold for higher shares of RES in power generation, then mid-merit power plants could be potential candidates for a market exit.

The Spanish market design already includes capacity payments for the availability of generation capacity. These could become insufficient, if CCGT and coal-fired power plants' runtimes continue to decline. If CCGTs will be crowded out in the long run, adjustments to the market design may be necessary, but this would depend on ecological goals, preferences regarding the power price and security of supply.

To guarantee security of supply, conventional power plants have to cover demand whenever unusual or unexpected weather conditions reduce wind and solar production to a minimum level. Depending on the weather condition, certain power plants may have to operate on standby for long periods during the year or even longer. Inability to cover full demand in times when production by renewables unexpectedly drops can lead to blackouts in situations of scarcity. As much as power production by renewable resources is ecologically desirable, security of supply is as essential for the industry and society.

In general, sophisticated capacity mechanisms might be necessary to complement energy-only markets to guarantee security of supply or to prevent certain technologies from leaving the market. This, however, leads to high costs of introduction and requires a European-wide change of the market design. Furthermore, this will also have substantial influence on competition (Böckers et al. 2011). While some markets like PJM in the United States have decided to implement a full-blown capacity market, the UK has abandoned such a mechanism. This unclear development of the different market designs will increase uncertainty, but since investments in power plants are, by nature, long term, investors will need a stable environment with little changes in market design.

The current support schemes often promote investments in certain technologies, independent of any inefficiency caused in the generation mix. The ultimate ecological goal is to reduce carbon emission and make power production more sustainable, not the promotion of certain production technologies. If conventional power plants are priced out of the market, problems inherent to the energy-only market (such as the missing-money problem) may be emphasized. Changes in the market design - aimed to stimulate investment in conventional resources or to prevent those technologies from leaving the market - may be necessary. These market designs are typically more restrictive and they induce higher costs to consumers.

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Appendix

Using demand and supply can cause simultaneous causality problem if demand cannot be considered exogenous to the supply system. As actual demand is mostly unobservable, equilibrium prices and quantities are considered for estimation. In equilibrium supply and demand are equal and a regression of quantities on prices will not help to identify whether the supply or demand function has been estimated. To solve the identification problem demand or supply specific factors are included. Since we are interested in estimating the price supply function, we estimate the demanded quantity. Important factors for demand are the economic performance of a country, e.g. energy-intensive industry, seasonal and temperature effects (REE 2013b) as well as exogenous demand shifters like holidays. Therefore, we assume demand to be a function of the price, past demand, economic factors, etc.:

$$D = F(price,\ past\ demand,\ economic\ factors,\ weather,\ season,\ holiday). \quad (6.10)$$

We use industrial production as an economic performance indicator, and average daily temperature, rainfall, and dummy variables for seasons and public holidays. The simultaneity bias also depends on the elasticity of demand. If demand was entirely price inelastic, the problem would be negligible. We estimate demand using:

$$\begin{aligned} D &= cons + \sum \alpha_d D_{t-i} + \alpha_y Year_y + \alpha_m Month_m + \alpha_j Day_j + \alpha_5 Ind\_Prod \\ &+ \alpha_6 temp + \alpha_7 Precipitation + \alpha_8 Holiday + residual \end{aligned} \quad (6.11)$$

Table 6.6: Results for unit-root tests, daily

Variable	Dickey-Fuller (SBIC) constant	Dickey-Fuller (SBIC) trend	Dickey-Fuller (HQIC) constant	Dickey-Fuller (HQIC) trend	Phillips-Perron (SBIC) constant	Phillips-Perron (SBIC) trend	Phillips-Perron (HQIC) constant	Phillips-Perron (HQIC) trend
price	-3.359**	-3.413**	-2.892**	-2.939	-6.923***	-7.182***	-7.240***	-7.530***
lnprice	-5.814***	-5.870***	-4.674***	-4.719***	-9.886***	-10.006***	-10.224***	-10.359***
q_demand	-4.903***	-6.604***	-4.098***	-5.429***	-12.992***	-17.496***	-14.878***	-19.832***
solar	-2.871**	-3.706**	-2.384	-2.810	-4.901***	-7.931***	-4.936***	-8.352***
windforecast	-15.721***	-16.578***	-13.861***	-14.688***	-19.373***	-20.186***	-19.039***	-19.849***
q_other_REE	-3.963***	-4.962***	-3.963***	-4.962***	-23.915***	-27.865***	-23.915***	-27.865***
sr_total	-14.076***	-14.235***	-14.076***	-14.235***	-18.478***	-18.620***	-18.478***	-18.620***
q_hydro	-4.456***	-4.746***	-3.564***	-3.876**	-6.191***	-6.543***	-6.996***	-7.411***
q_pump	-5.152***	-7.884***	-5.152***	-7.884***	-19.401***	-25.858***	-19.401***	-25.858***
q_nuclear	-5.940***	-6.420***	-4.805***	-5.233***	-12.369***	-13.484***	-13.659***	-14.955***
q_coal	-5.232***	-5.240***	-5.097***	-5.116***	-13.892***	-14.244***	-15.912***	-16.325***
q_cc	-3.209**	-6.204***	-2.816*	-5.259***	-12.829***	-21.014 ***	-14.579***	-22.798***
q_fuelgas	-7.811***	-7.811***	-7.811***	-7.811***	-9.572***	-9.570***	-9.572***	-9.570***
brent	-1.299	-1.739	-1.299	-1.739	-1.283	-1.679	-1.283	-1.679
ttf_price	-2.683*	-2.895	-2.420	-2.664	-2.716*	-2.927	-2.571*	-2.784
uxc_price	-3.950***	-3.717**	-3.950***	-3.717**	-3.937***	-3.538**	-3.937***	-3.538**
eua_wprice	-1.840	-1.428	-1.840	-1.428	-1.819	-1.393	-1.819	-1.393
coal_index	-1.629	-1.624	-1.558	-1.550	-1.380	-1.390	-1.401	-1.412
d.brent	-42.031***	-42.027***	-42.031***	-42.027***	-42.031***	-42.027***	-42.031***	-42.027***
d.uxc_price	-10.626***	-10.711***	-10.626***	-10.711***	-42.803***	-42.867***	-42.803***	-42.867***
d.ttf_price	-26.921***	-26.922***	-26.921***	-26.922***	-43.701***	-43.694***	-43.701***	-43.694***
d.eua_wprice	-40.884***	-40.918***	-40.884***	-40.918***	-40.884***	-40.918***	-40.884***	-40.918***
precipitation	-18.188***	-19.004***	-4.120***	-4.449***	-21.449***	-22.324***	-29.968***	-30.019***
temperature	-4.023***	-3.991***	-4.023***	-3.991***	-4.649***	-4.623***	-4.649***	-4.623***
ind_prod	-1.128	-1.109	-1.128	-1.109	-1.126	-1.112	-1.126	-1.112
d.ind_prod	-30.222***	-30.224***	-30.222***	-30.224***	-42.714***	-42.713***	-42.714***	-42.713***

Null hypothesis: variable contains a unit root - level of significance: * $p < 0.1$; ** $p < 0.05$; *** $p < 0.01$

Table 6.7: Results for unit-root tests, daylight

	Dickey-Fuller (SBIC)		Dickey-Fuller (HQIC)		Phillips-Perron (SBIC)		Phillips-Perron (HQIC)	
Variable	constant	trend	constant	trend	constant	trend	constant	trend
price	-14.001***	-13.998***	-11.753***	-11.749***	-45.543***	-45.538***	-45.851***	-45.859***
lnprice	-43.038***	-43.063***	-13.588***	-13.607***	-43.038***	-43.063***	-43.038***	-43.062***
q_demand	-7.995***	-9.299***	-8.098***	-9.470***	-37.050***	-37.879***	-37.073***	-37.959***
solar	-16.329***	-16.324***	-12.265***	-12.323***	-40.487***	-40.481***	-37.195***	-37.187***
windforecast	-39.444***	-39.494***	-39.444***	-39.494***	-39.444***	-39.494***	-39.444***	-39.494***
q_other_REE	-35.705***	-35.715***	-11.859***	-11.897***	-35.705***	-35.715***	-38.455***	-38.439***
sr_total	-40.358***	-40.426***	-28.646***	-28.726***	-40.358***	-40.426***	-40.354***	-40.423***
q_hydro	-13.444***	-13.729***	-10.192***	-10.798***	-33.998***	-33.986***	-35.489***	-35.643***
q_pump	-34.157***	-34.172***	-34.157***	-34.172***	-39.752***	-39.752***	-39.752***	-39.752***
q_nuclear	-9.912***	-10.215***	-8.541***	-9.231***	-45.748***	-46.371***	-47.044***	-48.737***
q_coal	-13.519***	-13.531***	-7.692***	-7.742***	-39.002***	-39.008***	-38.855***	-38.859***
q_cc	-12.132***	-12.215***	-9.526***	-9.851***	-38.139***	-38.169***	-40.213***	-40.556***
q_fuelgas	-11.397***	-11.497***	-9.819***	-11.355***	-35.389***	-35.410***	-34.753***	-35.730***
brent	-1.299	-1.739	-1.299	-1.739	-1.283	-1.679	-1.283	-1.679
ttf_price	-2.683*	-2.895	-2.420	-2.664	-2.716*	-2.927	-2.571*	-2.784
uxc_price	-3.950***	-3.717**	-3.950***	-3.717**	-3.937***	-3.538**	-3.937***	-3.538**
eua_wprice	-1.840	-1.428	-1.840	-1.428	-1.819	-1.393	-1.819	-1.393
coal_index	-1.629	-1.624	-1.558	-1.550	-1.380	-1.390	-1.401	-1.412
d.brent	-42.031***	-42.027***	-42.031***	-42.027***	-42.031***	-42.027***	-42.031***	-42.027***
d.uxc_price	-10.626***	-10.711***	-10.626***	-10.711***	-42.803***	-42.867***	-42.803***	-42.867***
d.ttf_price	-26.921***	-26.922***	-26.921***	-26.922***	-43.701***	-43.694***	-43.701***	-43.694***
d.eua_wprice	-40.884***	-40.918***	-40.884***	-40.918***	-40.884***	-40.918***	-40.884***	-40.918***
precipitation	-18.188***	-19.004***	-4.120***	-4.449***	-21.449***	-22.324***	-29.968***	-30.019***
temperature	-4.023***	-3.991***	-4.023***	-3.991***	-4.649***	-4.623***	-4.649***	-4.623***
ind_prod	-1.128	-1.109	-1.128	-1.109	-1.126	-1.112	-1.126	-1.112
d.ind_prod	-30.222***	-30.224***	-30.222***	-30.224***	-42.714***	-42.713***	-42.714***	-42.713***

Null hypothesis: variable contains a unit root - level of significance: * $p < 0.1$; ** $p < 0.05$; *** $p < 0.01$

Declaration of Contribution

I, Veit Böckers, hereby declare that I contributed to the paper *"The Green Game Changer: An Empirical Assessment of the Effects of Wind and Solar Power on the Merit Order"* as listed below:

- I contributed to the acquisition and adjustment of the data for the empirical analysis, i.e., input prices and installed capacities.
- I contributed to the setup of the empirical model, i.e. choice of the methodological approach and adjustment to the model in section 6.5.
- I contributed to writing of each section.

Signature, Coauthor 1: ________________

Signature, Coauthor 2: ________________

Chapter 7

Conclusion

Let us discuss the main findings and further research directions.

While electricity markets are both important and interrelated, the focus of this thesis is drawn to the short-run day-ahead markets. Three basic interventions are analyzed that cover the desired establishment of a single European market for electricity (Part 1) and the impact of implicit price caps as well as subsidization schemes for specific electricity generation technologies on competition (Part 2).

Chapter 2 entitled **"Benefits of a Single European Electricity Market"** (co-authored by Justus Haucap and Ulrich Heimeshoff) gave an introduction into the subject of the integration of European wholesale electricity markets. The analysis has shown that the degree of competition has changed between the years of 2004 and 2011 and that major efficiency gains can be realized from the integration of markets, especially through the coupling of markets, by inducing a higher degree of inter-regional competition. Market design issues may negatively affect these efficiency gains so it becomes vital to align the different existing national regulatory frameworks. Different support schemes for renewable energies have induced major inefficiencies if viewed from a European perspective. Most importantly, since all support schemes only support renewable energies within their own national territory massive gains from trade and from market integration are foregone.

A cautious calculation has revealed that the efficient allocation of solar energy plants between Germany and Spain alone would have resulted in additional electricity worth about 740 Million Euro within a single year. Additional savings could easily be generated by considering (a) more countries than just these two and (b) considering other technologies such as wind.

In chapter 3 entitled **"The Extent of European Power Markets"** (co-authored by Ulrich Heimeshoff) an empirical market delineation analysis has been conducted to study the geographical dimension of market integration in nine European wholesale power markets between 2004 and 2011. The paper contributes to the literature on the integration of electricity wholesale markets by using holidays as demand shocks to trace pricing constraints. Evidence was found that the integrated market does not include all European markets, but that there exist several regional markets. At least two candidates for inter-regional integrated markets have been identified with Germany and Austria on the one hand and Netherlands and Belgium on the other. The former pair has only recently been officially acknowledged by the German Federal Cartel office in their sector inquiry from 2011.

Chapter 4 entitled **"Tracing Cross-Demand Shocks in Southern-European Wholesale Electricity Markets: An Empirical Analysis of the Relevant Antitrust Market"** (single authored) presents a follow-up study on the analysis conducted in chapter 3. A control-function approach has been applied to delineate the relevant antitrust market in South-Western-European power markets (SWE), i.e., Spain, Portugal and France. Instruments such as produced quantities of renewable generation, holidays and temperature have been used to estimate pricing-pressure between the three countries. I found that France is not part of an integrated market inside the SWE region, but could be part of another relevant supra-regional market which is not covered in the analysis. Spain and Portugal showed strong empirical signs of pricing-pressure which are very much in line with the *law of one price*.

Recent developments show that the realization of the European IEM has again come a step closer in terms of trade system alignment and efficient utilization of the European power plant fleet, but there are still important issues which deserve further attention and research. Recently, generation capacity payment systems are being discussed in European countries as a consequence of the perceived failure of the energy-only market system. Regardless of whether the failure of this market system can be either attributed to an endemic trading-system flaw or to the massive subsidization of renewable power generation, capacity mechanisms are supposed to only complement the revenues generated over the regular trade of actual power. However, a non-harmonized introduction of different mechanisms into the current European power market system could potentially lead to misallocation of power plants due to capacity payment arbitrage. This could create new transmission congestion areas, leading to fragmented, smaller markets, so a revision of the relevant antitrust market may become mandatory. A market delineation that is subject to constant change in its defining core elements can become critical for competition authorities when assessing mergers or antitrust cases. Therefore further research could touch upon the problem of harmonizing subsidization schemes and a re-definition of trading systems and their impact on competition.

In the second part of the thesis, two market interventions have been discussed and analyzed. Chapter 5 entitled **"Discriminatory Bidding Constraints in the German Wholesale Electricity Market"** (co-authored by Justus Haucap and Dragan Jovanovic) dealt with the competitive effects of an introduction of an implicit price cap for dominant firms in the German wholesale electricity market. We find that such an intervention is disproportional and discriminatory. Despite empirical studies which do not reject the hypothesis of market power exercise through markups, an empirical or otherwise valid proof of abuse cannot be found. In principle, price bids above marginal costs are neither inefficient nor an abuse in principle. In addition, the price cap has short- and long-run negative effects on investment decisions and may also affect the efficiency of the joint European trading system. The effects on competition may even be adverse because the combined effect of a price cap and a law that impedes market exit of loss-making power plants may even lead to market foreclosure.

Chapter 6 entitled **"The Green Game Changer: An Empirical Assessment of the Effects of Wind and Solar Power on the Merit Order"** (co-authored by Jürgen Rösch and Leonie Giessing) has analyzed the impact of power generation, based on renewable resources, on wholesale power prices and conventional power generation in Spain from 2008 to 2012. We estimate a structural vector autoregressive model, using the merit order as the underlying structure. Empirical evidence suggests that the merit order effect is not as clear cut as theory predicts. We found that the main driver of renewable resources is wind power, which exhibits the expected negative impact on prices and on the quantities produced by conventional plants.

The main findings of the thesis show that European wholesale power markets have been largely affected to major market interventions. In the case of enforcement of market integration and alignment of national trading systems and regulatory frameworks, efficiency gains can be realized. Regulatory interventions such as the subsidization schemes for renewable generation or the introduction of price caps may lead to market distortions and thus, inefficiencies. Finally, the issues treated in this thesis are but a few out of the large set of interventions since liberalization. It would be an interesting field of research to conduct a meta-study on the combined effect of these interventions both on a national and a European level.

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Eidesstattliche Erklärung

Ich versichere an Eides statt, dass die vorliegende Dissertation von mir selbstständig und ohne unzulässige fremde Hilfe unter Beachtung der *Grundsätze zur Sicherung guter wissenschaftlicher Praxis an der Heinrich-Heine-Universität Düsseldorf* erstellt worden ist.

Diese Dissertation hat in gleicher oder ähnlicher Form noch keiner anderen Fakultät oder Prüfungsbehörde vorgelegen.

Düsseldorf, den 21.08.2014