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MASTER'S THESIS

DETERMINANTS OF PRICE VOLATILITY OF GERMAN INTRADAY POWER MARKET

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ANA MALIĆ

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

INTRODUCTION

Electric power markets in many countries around the world have witnessed a rapid deregulation of power generation. What regulators had previously controlled by fixing prices as a function of supply costs now represents a competitive interaction of complex supply and demand forces, resulting in dynamic and uncertain electricity prices (Goto & Karolyi, 2004, p. 1). European electricity markets are no different. In Europe, the development of electricity markets is significantly influenced by the energy and climate policy of the European Union (hereinafter: EU). The main aim has been to open electricity markets for competition and create a common European electricity market (Viljainen, Makkonen, Annala, & Kuleshov, 2011, p. 6). One of the goals of the EU is the creation of a sustainable energy system and the achievement of the EU set climate and energy targets known as "20-20-20 targets by 2020" or the "3 x 20" policy. This includes pledges to reduce emissions by 20% from 1990 levels, raise the share of EU final energy consumption produced from renewable resources to 20% and improve energy efficiency by 20% (Deloitte Conseil, 2015a, p. 2). Based on Deloitte report (Deloitte Conseil, 2015a, p. 2), electricity markets have been most affected by these policies.

Deregulated electricity prices are characterized by volatility that varies over time and occasionally reaches extremely high levels, commonly known as "price spikes" (Keppler, Bourbonnais, & Girod, 2007, p. 53; Ramos & Veiga, 2014, p. 219; Goto & Karolyi, 2004, p. 1). Even small changes in the amount of electricity generated or change in demand can catapult into large changes in electricity prices in just a matter of few hours in competitive power markets (Girish & Vijayalakshmi, 2013, p. 70).

Previous research shows that high shares of intermittent energy production also increase price volatility. Understanding the volatility process is critically important to distributors, generators and market regulators as it influences the pricing of derivative contracts traded on power prices that allow them to better manage their financial risks (Goto & Karolyi, 2004, p. 1).

In EU, climate and energy policies have had a vast impact on power generation mix. Between 1990 and 2012, total electricity generation from renewables increased by 177% (Eurostat, n.d.-a). The relative importance of renewable energy sources in relation to EU-28 net electricity generation grew between 2003 and 2013 from 12.6% to 23.2%, while there was a relatively small decrease in the relative importance of combustible fuels from 56.4% to 49.8% and a larger reduction in the amount of electricity generated from nuclear power plants from 30.9% to 26.8%. Among the renewable energy sources, the proportion of net electricity generated from solar and wind power plants increased greatly: from 0.01% in 2003 to 2.7% in 2013 for solar power and from 1.4% in 2003 to 7.5% in 2013 for wind turbines (Eurostat, n.d.-b). The share of unpredictable renewable generation capacity is still increasing year by year. Between 2010 and 2012, Deloitte Conseil (2015a, p. 19) observed the following changes; nuclear generating capacity decreased by 6.5%, hydropower capacity remained stable, fossil-powered capacity increased by 2.7% and wind and photovoltaic solar increased very significantly (by 24% and by 134% respectively). In 2013, renewable electricity generation accounted for 26% of total gross electricity generation (Eurostat, n.d-a).

Increased level of power generation uncertainty from renewable sources resulted in the need of power producers to optimize their generation portfolios shortly before physical delivery, which means higher volumes need to be traded on intraday. Therefore, EPEX SPOT[1] intraday markets are experiencing significant growth in traded volumes. According to EPEX SPOT Press release (EPEX SPOT, 2016a), volumes traded on intraday in 2015 reached 59,000,290 MWh which is a 25.4% increase from 2014 when volumes reached 47,058,790 MWh. For comparison, volumes traded on intraday in Germany only reached 5,662,044 MWh in 2009.

In Germany, the intraday market is the last trading market before physical delivery where market participants may self-balance their portfolios in order to avoid the involuntary purchase of costly balancing services from the transmission system operators (Hagemann, 2013, p. 1). Intraday markets provide an option to rebalance generation portfolios on hourly and quarter-hourly basis, up to 30 minutes prior delivery. Hagemann (2013, p. 2) notes that the literature so far has neglected the analysis of intraday market prices, even though the intraday market is becoming increasingly more important in the presence of high shares of electricity production from intermittent renewable energy sources (Hagemann, 2013, p. 1; Karanfil & Li, 2015, p. 5).

The main research purpose of this master's thesis is to identify the volatility of continuous intraday trading, to exhibit the price variance realized when there is no uniform price auction with only one clearing price. The price variance is compared to the auction data, and the differences between variances are explored via scenario analysis of price spikes occurred during continuous trading. Furthermore, the aim is to define the main factors of price volatility on German intraday market, their outlining and assessment of their effect on price movements. The objective is also to outline each price determinant's effect on price volatility and see if the price determinant has a different effect on price when approaching delivery.

The thesis consists of two parts, divided into four chapters. The first part is dedicated to a general economic analysis of power markets, while the second part focuses on power price volatility.

In the first chapter, the power markets are analysed in general from the economic point of view. Main recent developments in the policies of the power market are also shortly presented, since new policies are the basis for market development and also have an effect on price volatility. The second chapter is dedicated to an analysis of German power market, as one of the most liquid power markets in Europe. In this section the market structure, policies and models, and basic fundamentals of the German power market are determined.

[1] EPEX SPOT is the exchange for the power spot markets in Europe. It covers Germany, France, United Kingdom, the Netherlands, Belgium, Austria, Switzerland and Luxembourg ("EPEX SPOT SE: About EPEX SPOT," n.d.).

1 POWER MARKET DESIGN

Delivered power is a bundle of many services. These include transmission, distribution, frequency control, and voltage support, as well as generation. The first two deliver the power while the second two maintain power quality; other services provide reliability. Each service requires a separate market, and some require several markets (Stoft, 2002, p. 17).

In liberalised power markets such as the Nordic countries, Germany, France and the Netherlands we can distinguish **five types of power markets** (EWEA, 2010, p. 9):

(1) **Bilateral electricity trade or OTC** (over the counter) trading: Trading takes place bilaterally outside the power exchange, and prices and amounts are not made public.
(2) **The day-ahead market** (hereinafter: DA) **or spot market**: A physical market in which prices and amounts are based on supply and demand. The resulting prices and the overall amounts traded are made public.
(3) **The intraday market**: There is quite a time difference between close of bidding on the day-ahead market and on the regulating power market. The intraday market was therefore introduced as an 'in between market'.
(4) **The regulating power market** (hereinafter: RPM): A real-time market covering operation within the hour. The main function of the RPM is to provide power regulation to counteract imbalances related to day-ahead planned operation. The demand side of this market is made up of transmission system operators (hereinafter: TSOs) alone, and approved participants on the supply side include both electricity producers and consumers.
(5) **The balancing market**: This market is linked to the RPM and handles participant imbalances recorded during the previous 24-hour period of operation. The TSO acts alone on the supply side to settle imbalances. Participants with imbalances on the spot market are price takers on the RPM/balance market.

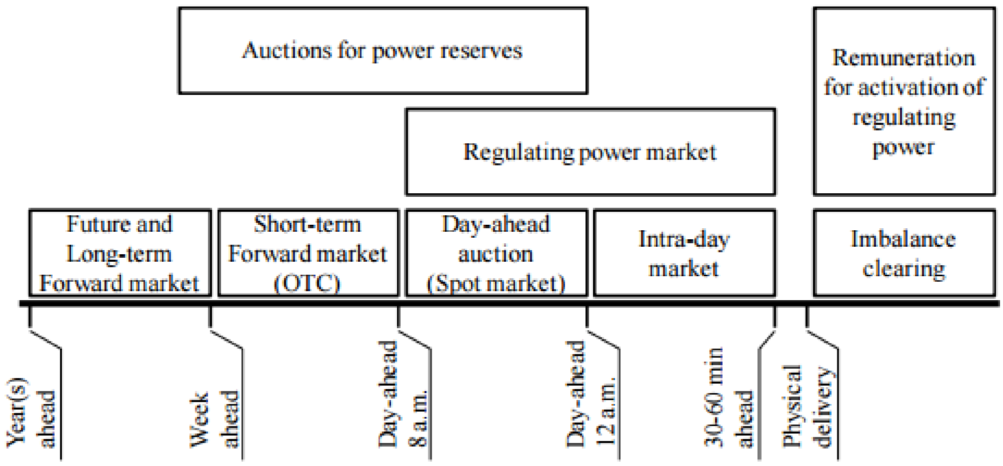
Due to non-storability power markets present severe coordination problems. They are the only markets that can suffer a catastrophic instability that develops in less than a second and involves hundreds of private parties interacting through a shared facility (Stoft, 2002, p. 203). Therefore, the most critical coordination services must be provided by the TSOs. RPM usually consists of services structured into three main tiers (Amprion, 2016):

(1) Primary control reserve needs to be activated within 30 seconds and available up to 15 minutes;
(2) Secondary control reserve needs to be activated within 5 minutes and available up to 15 minutes;
(3) Tertiary control reserve (also known as minutes reserve) needs to be activated within 15 minutes and available for a minimum of 15 minutes up to 1 hour, or several hours in the event of several disturbances.

The timeline of power trading is presented in Figure 1.

With the exception of the real-time market all the rest are financial markets in the sense that the delivery of power is optional and the seller's only real obligation is financial. If power is not delivered, the supplier must purchase replacement power or pay liquidated damages. In many forward markets, including many DA markets, traders need not own a generator to sell power. The real-time market is a physical market, as all trades correspond to actual power flows (Stoft, 2002, p. 7).

Figure 1. Sequence of power trading in bilateral markets



Source: C. Obersteiner, *The market value of wind power from a generator's perspective – An analysis of influencing parameters*, 2010, p. 21.

Besides the need to be in constant supply and demand balance, power markets are also affected by two major demand flaws which differentiate markets for electricity from other commodity markets. The first demand-side flaw is the lack of demand elasticity. The second demand-side flaw prevents physical enforcement of bilateral contracts and results in the system operator being the default supplier in real time (Stoft, 2002, p. 15).

Presently, demand is almost completely unresponsive to price in most power markets because wholesale price fluctuations are not usually passed on to retail customers (Stoft, 2002, p. 43). Secondly, bilateral contracts cannot be enforced in real-time, which basically means suppliers cannot physically cut off consumers who take too much power from the system.

1.1 Electricity supply chain

The participants of the electricity market are the producers, traders and suppliers that supply electricity to consumers. Transmission network transmits electricity from power stations to distribution networks. When the electricity reaches the distribution networks, it passes through substations which use transformers to lower the voltage of the electricity ready to deliver for every use (Energy Agency, 2016). Production, trading and supply are usually organised as market activities, while transmission and distribution are non-market activities. This is due to the fact that transmission and distribution are natural monopolies, because a single high-capacity line minimizes both capital costs and losses to electrical resistance per unit of power carried (Michaels, 1993, p. 1).

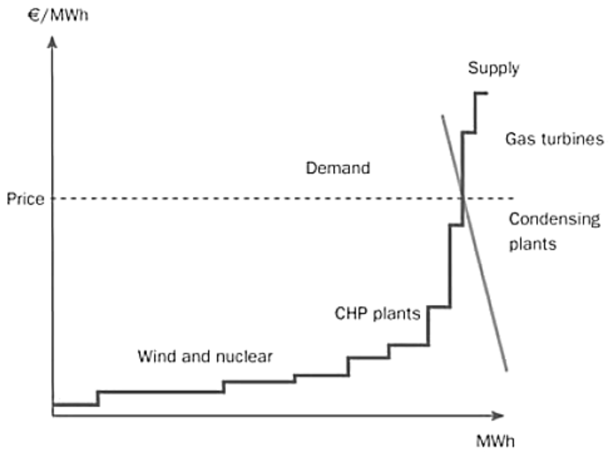
1.1.1 Power generation

The power generation mix in different countries varies markedly, and the biggest factors influencing the mix are (Harris, 2011, pp. 21 - 22):

(1) historic legacy of energy imports from long-term trade partners;
(2) natural endowment of fossil fuel or renewable energy;
(3) politics and social/cultural opinion in relation to coal mining subsidies, nuclear power, emissions, renewable energy and related matters;
(4) effectiveness of the electricity supply industry in coordinating, managing commercial relationships, and efficiently and reliably delivering energy and capacity;
(5) general transportation infrastructure to, from and in the country in question;
(6) climate which affects heating demand in winter and air conditioning in summer;
(7) legacy of district heating.

Typically, the power portfolio is made up of a range of power technologies: wind, nuclear, combined heat and power plants, condensing plants[2] and gas turbines. The ordering of the power supply of each of these players depends on the amount of power they can supply and the cost of this power. In a power market, the supply curve is called the '**merit order curve**' (EWEA, 2010, p. 10).

Figure 2. Annual supply and demand curves in the power market



Source: EWEA, Wind Energy and Electricity Prices: Exploring the'merit Order Effect'; a Literature Review by Pöyry for the European Wind Energy Association, 2010, p. 10.

As seen in Figure 2, such curves go from the least expensive to the most expensive units and present the costs and capacities of all generators.

[2] A condensing power plant generates electric energy using mostly coal, natural gas or oil as the fuel source (Fortum, n.d.).

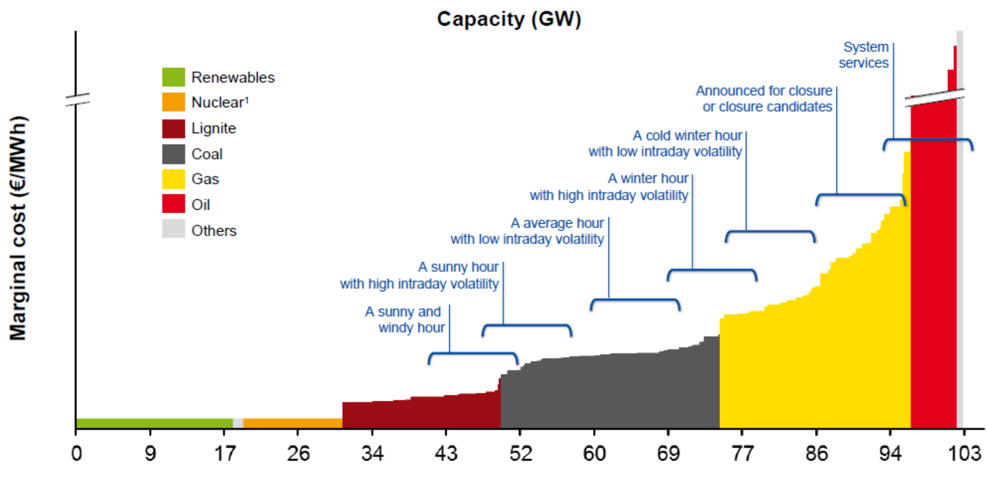
As shown, the bids from nuclear and wind power enter the supply curve at the lowest level, due to their low marginal costs, followed by combined heat and power plants, while gas turbines are those with the highest marginal costs of power production. Note that hydro power is not identified in the figure, since bids from hydro tend to be strategic and depend on precipitation and the level of water in reservoirs (EWEA, 2010, p. 10).

In ENTSO-E's 2016 Summer outlook & winter review (ENTSO-E, 2016, p. 15) the slightly different, simplified merit-order is presented:

(1) Solar
(2) Onshore Wind
(3) Offshore Wind
(4) Other Renewable Sources
(5) Nuclear
(6) Coal
(7) Gas
(8) Other non-renewable sources
(9) Hydro pumped storage
(10) Demand side management and strategic reserves.

Merit-orders differ from country to country, since every country employs a different power generation mix. In Figure 2 a general supply stack is presented, which can be applied to most countries with some adjustments. Figure 3 presents a more detailed stack of German production in 2014 with implications of the technology used on intraday market.

Figure 3. German supply stack tranches in 2014



[1] Excluding nuclear fuel tax

Source: Timera Energy, Vattenfall's German sale: mixing lignite & water, 2017.

Harris (2011, pp. 58 - 59) notes several factors which alter the fixed and marginal cost of production such as technology type, unit size (operating cost per MW decreases with unit size due to economies of scale), cost of fuel, emission permits, depreciation status of the plant, obsolescence, operating regime…

Every form of electricity generation has its strengths and weaknesses and future electricity generation will need a range of options, with keeping in mind the necessity of them being low-carbon if greenhouse gas emissions are to be reduced. For many decades, almost all the electricity consumed in the world has been generated from three different forms of power plants - fossil, hydro and nuclear (World Nuclear Association, 2016).

Due to fluctuating demand and non-storability of electricity the planning of adequate capacity can be considerably complex. In order to maintain sufficient generation to satisfy demand for prospective peak demands in the future, the peak generation capacity must be considerably greater than the average generation. Since power generators have fixed costs, then there must be a way of compensating the generators, and therefore of paying for them by consumers (Harris, 2011, p. 191).

Base load plants have relatively high investment costs and low variable costs (i.e. fuel and CO2 costs). Peak load plants, on the other hand, have low investment costs and relatively high variable costs (Nicolosi & Fürsch, 2009, p. 249). Nuclear plants are suitable to run at base load, while thermal generation is considered as intermediate generation source since it can run both at base load and peak load, even though it is more cost-effective if it runs at base load. Run-on-river hydro generation can be employed as base load generation when water levels are high and can be subsequently optimized as peak load generation when hydrology is low. Gas turbines and pumped-up hydro storage are usually used as peaking generators. Wind and solar are considered intermittent sources of generation because of their high variability and unpredictability. High degree of intermittency of power demands a high degree of supporting positive and negative reserve from conventional plant (Harris, 2011, p. 195).

Power markets face the problem of determining how much generation capacity should be built using each type of technology. This explains the unusual importance of demand shifts and consequently of load-duration curves in power markets (Stoft, 2002, p. 42).

1.1.2 Transmission, network operation and system operation

Networks can be described as high-voltage transmission or ‘grid’ networks, low-voltage distribution networks and interconnectors between grids. The exit voltage at which distribution picks up electricity from the transmission grids is commonly around 110 kV (Harris, 2011, p. 62).

TSOs are responsible for connecting energy production and demand centres and transporting the energy from source to sink. Electricity TSOs operate, maintain and expand the extra-high-voltage power systems (typically at voltage levels 220 kV and above). Some of the core tasks of TSOs include system management (balancing, real-time dispatch), asset operations (operational planning, maintenance) and network development (Bausch & Schwenker, 2009, p. 458).

Energy networks are natural monopolies since it is inefficient to duplicate the physical network, and the balancing requirements for energy management mean that many short-term decisions must be unilateral (Harris, 2011, p. 72). The system operator must keep the system in balance, keep the voltage at the right level, and restart the system when it suffers a complete collapse. The system operator carries out these basic functions by purchasing what are called “ancillary services.” These include various types of reserves, voltage support, and black-start services (Stoft, 2002, p. 19).

Balancing refers to the situation after markets have closed (gate closure) in which a TSO acts to ensure that demand is equal to supply, in and near real time. An important aspect of balancing is the approach to procuring ancillary services (ENTSO-E, n.d.). Since 2001, the German TSOs have procured their primary control, secondary control and minutes reserve in an open, transparent and non-discriminatory control power market in accordance with the provisions of the Federal Cartel Office. The total control power demand of all German TSOs amounts to approximately 7,400 MW. Primary control and secondary control power are procured in a monthly cycle; minutes reserve is daily called for tender (Amprion, 2016).

Because transmission is a natural monopoly it usually remains regulated (Guan, Ho, & Pepyne, 2001, p. 402). In EU the Third Energy Package requires unbundling - separation of energy supply and generation from the operation of transmission networks. If a single company operates a transmission network and generates or sells energy at the same time, it may have an incentive to obstruct competitors' access to infrastructure. This prevents fair competition in the market and can lead to higher prices for consumers (European Union, 2016).

Under the third package, unbundling must take place in one of three ways, depending on the preferences of individual EU countries (European Union, 2016):

(1) Ownership unbundling; where all integrated energy companies sell off their gas and electricity networks. In this case, no supply or production company is allowed to hold a majority share or interfere with the work of a transmission system operator
(2) Independent System Operator (hereinafter: ISO); where energy supply companies may still formally own gas or electricity transmission networks but must leave the entire operation, maintenance, and investment in the grid to an independent company
(3) Independent Transmission System Operator (hereinafter: ITO); where energy supply companies may still own and operate gas or electricity networks but must do so through a subsidiary. All important decisions must be taken independently from the parent company.

Germany’s four TSOs have unbundled according to different models. Two of the TSOs, TenneT and 50Hertz, are ownership-unbundled. That is, ownership and control of the transmission system is separated from that of distribution, production and supply. The two remaining TSOs, Amprion and Transnet BW, have unbundled pursuant to the ITO model, under which the TSO remains within the integrated company and the transmission assets remain on its balance sheet. Additional regulatory conditions are imposed to guarantee the independence of the ITO from the vertically integrated undertaking (Agora Energiewende, 2015, p. 8).

1.1.3 Distribution

Distribution companies deliver energy from suppliers to end users and maintain the distribution networks. The distribution sector picks up energy from a high-voltage transmission grid and delivers it to final customers through low/medium voltage power lines. Distribution networks are local monopolies and therefore have their revenues controlled by regulation. The charges are closely connected to the regulated asset value, operating costs, and capital expenditure plans (Harris, 2011, p. 83).

1.1.4 Supply

The supply sector, also called ‘the retail sector’ in competitive markets, does not produce or deliver energy but purchases it from generators, pays the networks for transportation (transmission and distribution), pays various other charges (such as metering and levies) and charges the consumers. The presence of the supply sector means that the generation, transmission and distribution sectors can concentrate on core business (Harris, 2011, p. 87). Most retailing consists of financial transactions, all of which can be provided from an office building (Stoft, 2002, p. 19).

Supply sectors vary in nature. For example, they can be driven by brand and outsource the billing and energy management, or driven by need to find a route to market for generated power. Three key activities for suppliers are (Harris, 2011, p. 87):

(1) Customer relationship – brand, inbound call centre management, outbound call centre management, cross selling, energy services;
(2) Risk management – wholesale energy, network costs, environmental costs, credit management;
(3) Physical and data process – Metering, information management, connections, and service delivery.

1.2 Power market development - from non-competitive to competitive markets

The worldwide discussion on energy markets reform started in the early 1980s and then several emerging and developed countries have commenced reform initiates including liberalization, privatization, and restructuring of the energy supply and distribution industry (Karan & Kazdağli, 2011, p. 11). Currently, all European countries have moved from regulated regional monopolies to liberalised electricity markets (Ockenfels, 2008, p. 12).

Competition provides much stronger cost-minimizing incentives than typical “cost-of-service” regulation and results in suppliers making many kinds of cost-saving innovations more quickly. These include labour saving techniques, more efficient repairs, cheaper construction costs on new plants, and wiser investment choices (Stoft, 2002, p. 12).

Improvements in transmission, rather than changes in generation technology, have removed the natural monopoly character of the wholesale power market in most locations. This makes the replacement of regulated generation monopolies with deregulated wholesale power markets possible. In the short run, power-market problems tend to be more dramatic than the benefits. The problems are primarily the result of two demand-side flaws - it is possible to design a workable market around them, but it does require design as well as extensive and clever regulation (Stoft, 2002, p. 8).

1.2.1 Market design

There are two basic models countries employ in their development of competitive markets, namely the exchange model (European countries) and the pool model (USA, Canada, Australia, New Zealand, Russia).

In exchange models electricity trading usually takes place in a sequence of closely connected but separate markets and other allocation mechanisms for generation, transmission and balancing electricity. Power producers dispatch their power plants independently and co-ordinate with the transmission system operator. In almost all countries a central auction in which the trading participants can largely trade hourly contracts for electricity for the following day is held one day before physical delivery. Participation in the exchange is not mandatory, so that trading which “bypasses” the exchange is also possible (Ockenfels, 2008, p. 12).

Advantage of the exchange model is that market platforms can compete with each other. This quickly leads to adjustment pressure in case of a defective, inefficient or costly market design of the power exchange. On the other hand, the decentralised organisation can lead to problems in co-ordination and to inefficiencies in cases where the different markets are only synchronised to an insufficient degree and where the participants in the markets have wrong expectations regarding prices and shortages in linked markets (Ockenfels, 2008, pp. 12 - 13).

Pool models have a centralised organisation. The entire electricity trading has to be transacted via the pool and long-term contracts are usually traded as purely financial products. In most cases, only the supply side bids actively into the pool while the demand is estimated and bids into the pool in an aggregated manner. After that, all operational decisions regarding generation, transmission and balancing energy are optimised by computer algorithms, both comprehensively and simultaneously.

Mandatory trading under the pool model facilitates the co-ordination of generation and transmission. The use of the power plants and the grid, in particular, are optimised at the same time by the so-called “locational marginal pricing” or “nodal pricing”. In this process, electricity prices are established for every feed-in and withdrawal point in such a way that these prices reflect the existing transmission bottlenecks and generation cost structures in the overall system in an economically accurate manner. Pool models are based on the pre-condition of close monitoring of the market, its institutions and of the market participants. This not only implies high costs (of monitoring and market supervision) but also that the regulator (with poorer information) has to take decisions which the market takes in a system with a decentralised organisation (Ockenfels, 2008, p. 14).

In this thesis, the focus will primarily be on the exchange base model, since it is the market model used in Germany. The German electricity market structure will be explained in greater detail in the next chapter.

1.2.2 Energy policies

The motivation for the energy market reforms is driven mostly by economic reasons to make the energy sector cost-efficient through the introduction of competition among the players. There are also other drivers for reform, namely; political ideology on the faith of market forces, distaste for strong unions, the desire to attach foreign investment and environment concerns (Karan & Kazdağli, 2011, p. 11)

In Europe, the development of electricity markets is significantly influenced by the energy and climate policy of the European Union. The main aim has been to open electricity markets for competition and create a common European electricity market (Viljainen et al., 2011, p. 6). The European Union had embarked on two major reforms in energy and climate policy: first, the progressive liberalisation of the internal electricity and gas markets through the third internal energy market package, the so called “Third Package”; and second, ambitious climate and energy targets and policy measures as part of the so-called “2020 Climate and Energy Package” (International Energy Agency, 2014, p. 11).

Energy policy in the European Union aims to address the three objectives of economic competitiveness, security of supply, and environmental sustainability. IEA notes that at the time of their last report in 2008 sustainability – notably mitigating climate change – was the key driver for EU energy policies. However, the context for EU energy policy has changed dramatically when the following report was concluded in 2014. In 2014, concerns of energy security and industrial competitiveness have become more pressing (International Energy Agency, 2014, p. 11).

The EU has also set energy and climate targets for 2020, 2030 and 2050. Targets for the year 2020 aim at decreasing greenhouse gases by 20%, increasing energy efficiency for 20%[3] and increasing the use of renewable energy by 20%. Targets for 2030 aim at 40% reduction in greenhouse gas emissions, generation of at least 27% EU energy from renewable, increase of energy efficiency by 27%[4]. By 2050, EU aims to cut greenhouse gases by 80-95% compared to 1990 levels (Comission of the European Communities, 2009, p. 2; EWEA, 2010; European Commission, 2017)

EU energy policy has significantly shifted power markets in the past years and the process of creating a common European electricity market is still on-going.

On 25th February 2015, the Commission adopted "A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy". The publication of this strategy created a new momentum to bring about the transition to a low-carbon, secure and competitive economy (European Commission, 2015). On 19th March, 2015, the European Council met to set out the first steps of an Energy Union. The Energy Union will be the new umbrella that brings together all the elements of energy policy into a coherent, integrated approach (European Council for an Energy Efficient Economy, n.d.). Creating an ‘Energy Union with a forward looking climate policy’ has been agreed by EU leaders as a strategic priority for Europe from 2015 to 2020. The Energy Union concept is a recognition that risks of energy security, climate security and economic resilience cannot be contained within national borders or managed in isolation from each other. The transboundary nature of the challenge calls for a collective and coherent response, reflecting the energy security and economic resilience gains from demand management, low-carbon infrastructure and new technology (E3G, 2017).

On 30th November 2016, the European Commission published its long anticipated “Clean Energy for All Europeans” package, more commonly referred to as the “Winter Package”, consisting of numerous legislative Proposals together with accompanying documents, aimed at further completing the internal market for electricity and implementing the Energy Union (Losch & van Lothar, 2016, p. 1).

The newly published Winter Package has the following key aims (Losch & van Lothar, 2016, p. 2):

(1) to establish a common power market design across the Union and to ensure the adequacy of the Union’s power systems;

[3] Energy efficiency target can rise to 30% if the conditions are right. The European Council specified: "provided that other developed countries commit themselves to comparable emission reductions and economically more advanced developing countries to contributing adequately according to their responsibilities and respective capabilities" (European Commission, 2010, p. 2).

[4] European Council for an Energy Efficient Economy states that the Commission would prefer a 30% target and that this target will be reviewed by 2020 (E3G, 2017).

(2) to promote the better integration of electricity produced from renewable sources into the market and assess the sustainability of bioenergy;
(3) to advance energy efficiency, energy cleanliness and energy performance, including for buildings, in the industry (eco-design), in innovation and in transport, all of which, together with the support of renewables, are needed to achieve the Union’s climate goals; and
(4) to implement rules on the governance of the Energy Union.

2 GERMAN POWER MARKET

The German electricity market is the biggest in continental Europe by number of players and generation capacity. It is also the fastest to open up, with immediate 100% full customer choice without any restructuring of the industry (Karan & Kazdağli, 2011, p. 6). The German power market is liberalized but dominated by four main players who account for 73% of electricity generation. The grid is operated by four TSOs that were historically owned by the four big energy generators. More than 900 distribution system operators (hereinafter: DSOs) currently operate in in the country (Deloitte Conseil, 2015b).

German and European energy systems are heavily intertwined, German power system is interconnected with Austria, Switzerland, the Czech Republic, Denmark, France, Luxembourg, the Netherlands, Poland, and Sweden, with a total transfer capacity of more than 20 GW. Whatever happens in Germany has effects on its neighbours and vice versa (Agora Energiewende, 2015, p. 1). There are hardly any grid congestions between Germany and Austria, consequently, the two countries can be considered as one market area (Ecofys, 2015, p. 13).

Germany is a net energy exporter. The biggest export markets are The Netherlands and Austria, while Germany draws net energy imports mainly from the Czech Republic. Trade between Germany and France requires a closer view: While Germany exports electricity according to financial transactions, physical flows are to a certain extent transit flows from France via Germany to Switzerland. There is a significant volume of unplanned physical flows (loop flows) occurring between Germany and its neighbours. Due to constraints on the German transmission system, the excess power from the north travels through the transmission systems of neighbouring countries, and particularly through Poland, the Czech Republic, or via the Netherlands, Belgium, and France (ACER/CEER, 2014, p. 149; BNetzA, 2014, p. 90; Agora Energiewende, 2015, p. 17).

German power market is marked for its high liquidity which is fundamental to competition in the electricity sector. Spot and futures markets are crucial for meeting suppliers' short- and longer-term electricity requirements (BNetzA, 2016, p. 24).

2.1 Industry structure, ownership and regulation

Germany has unbundled most generation, transmission, distribution, and retail activities in the electricity sector. European law requires unbundling - or separation, to some degree - of those activities of electricity companies (Agora Energiewende, 2015, p. 7). Four large power companies continue to dominate the German power market: E.ON[5], RWE, EnBW, and Vattenfall. These four companies are responsible for the bulk of electricity distribution, generation, and retail supply in the country. While competition has been slow to evolve, it has been increasing over the past few years. As more renewables have entered the system, the ownership profile of generation has been shifting. While the big four power companies own most conventional generation (hard coal, lignite, nuclear, and natural gas), they possess only about 5% of renewable resources. Private citizens, including farmers, own 46% of renewable generation in Germany, followed by project developers, industry, and banks (Agora Energiewende, 2015, p. 7).

German transmission system is divided into four control areas, managed by four TSOs (Amprion, Transnet BW, Tennet and 50Hertz). Each TSO is responsible for network operation in its zone, but all four TSOs need to cooperate in order to maximize economic and operational efficiency in all four zones.

Table 1. Ownership Structure of German Energy Companies

Companies	Ownership
Amprion	RWE 25.1%, Commerz Real AG 74.9%
TransnetBW	100% owned by EnBW
TenneT	100% owned by the state of The Netherland
50Hertz Transmission	60% Elia and Elia Asset; 40% IFM
E.ON	100% privately owned, 75% institutional; 25% retail investors
RWE	66% institutional, 13% private shareholders, 15% RWEB
EnBW	93.5% owned directly & indirectly by the state of Baden Württemberg
Vattenfall	100% owned by the Swedish government

Source: Agora Energiewende, *Report on the German power system. Version 1.01. Country Profile*, 2015, p.11.

The distribution system in Germany is the most complex in Europe, with around 900 distribution system operators serving 20,000 municipalities. This includes the four large companies as well as about 700 Stadtwerke (municipally owned utilities) and a number of

[5] In January 2016, E.ON separated conventional power generation (hydro, natural gas, coal) and global energy trading into a new company Uniper. E.ON plans to focus on renewables, energy networks, and customer solutions (E.ON, 2016).

regional companies. The four large DSOs—RWE, EnBW, E.ON, and Vattenfall—operate a significant portion of the distribution grid through concession contracts with municipalities (Agora Energiewende, 2015, p. 8). The ownership strucuture of these companies is presented in Table 1. For a more detailed review of the market share of German electricity companies see Table 2.

Table 2. Market Share of German Electricity Companies

Sector	Leading Companies	Market Share	Total Number of Providers
Transmission	Amprion TransnetBW (EnBW) TenneT 50Hertz Transmission	100% combined	4
Distribution	EnBW E.ON RWE Vattenfall	The 4 big distribution companies own and operate a significant portion of the distribution system though the exact level is not clear.	Approximately 890 DSOs, about 700 of which are municipally owned by Stadtwerke
Total Generation	EnBW E.ON RWE Vattenfall	56% installed capacity (June 2014) 59% of electricity generated (2012)	Over 1000 producers (not including individuals)
Retail Suppliers	EnBW E.ON RWE Vattenfall	45.5% of total electricity offtake (TWh)	over 900 suppliers

Source: Agora Energiewende, *Report on the German power system. Version 1.01. Country Profile*, 2015, p.8.

2.2 Power production and consumption

In this section, the supply (production) and demand (consumption) will be presented in greater detail.

2.2.1 Consumption in Germany

According to Agora Energiewende (2015), Germany's gross electricity consumption was 576.3 TWh and peak demand amounted to 83.1 GW in 2013.

The German government has imposed a 10% reduction target for total energy consumption by 2020. By 2050, consumption should be reduced by 25%. These targets apply to the consumption level of 2008 (Ecofys, 2015, p. 12).

Germany is a winter peaking country primarily due to the demands of lighting and water and space heating; 6.1% of space heating is fuelled electrically, including night storage systems and heat pumps (Agora Energiewende, 2015, p. 17).

In 2012, households accounted for approximately 26% of total electricity demand, while 43% originated in the industrial sector (Ecofys, 2015, p. 12). 27% of total electricity consumption in Germany results from six energy-intensive industries: chemicals, paper, steel, aluminium, copper and textiles (Ecofys, 2015, p. 1).

Electricity prices have risen for both household and industrial customers over the past years (Agora Energiewende, 2015, p. 23), despite the trend of declining wholesale power prices. The EEG surcharge (arising from the German Renewable Energy Act – Erneuerbare-Energien-Gesetz) alone increased from 8.8% of the average household customer bill in 2010 to 17% in 2013. This increase is the result of a combination of factors, including the growing share of renewable generation supported by the Feed-in Tarrifs (hereinafter: FiT), decreasing wholesale energy prices (which have the effect of increasing the level of FiT which must be paid), and exemptions for many large industrial customers which have transferred these costs on to other customers (Agora Energiewende, 2015, p. 23).

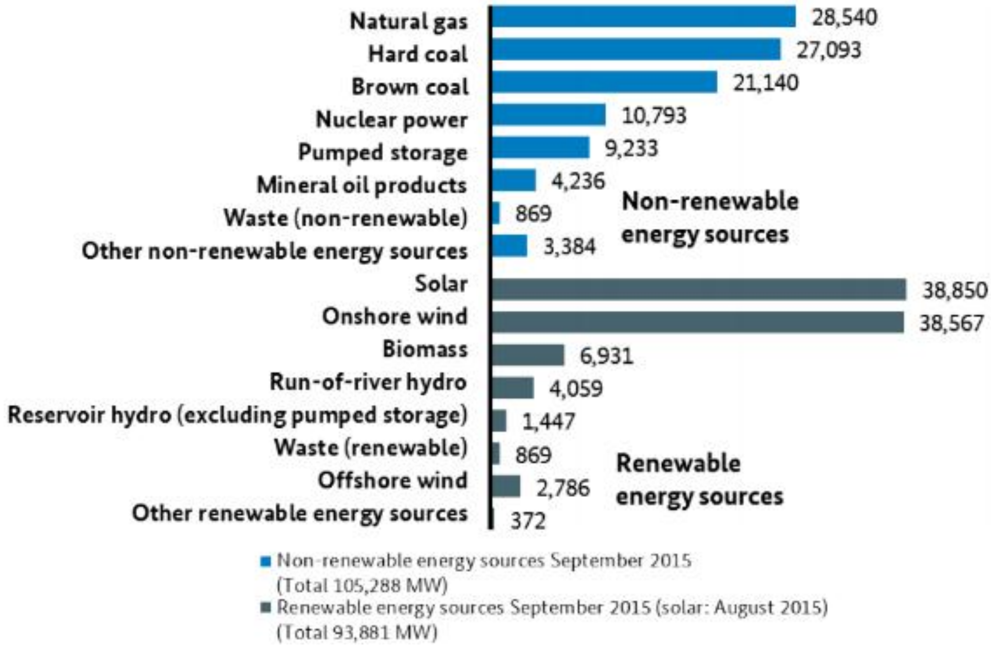
Compared to other Member States, German household electricity prices in 2014 were the second highest in the EU. The difference between industrial prices in Germany with and without available exemptions are significant. Without exemptions, industrial customers in Germany pay one of the highest retail rates in Europe. With exemptions, they pay one of the lowest (Agora Energiewende, 2015, p. 24).

2.2.2 Power production in Germany

Germany has the highest share of renewable power in Europe in terms of installed capacity, and is in fact the country with the third largest amount of installed renewables capacity (excluding hydro) in the world. In 2014, renewable energy accounted for more than one quarter of all electricity produced in the country. At the same time, hard coal and lignite contributed 44% of electricity production in 2014, while nuclear energy (which is to be phased out by 2022) accounted for about 16% of production (Agora Energiewende, 2015, p. 7).

Currently, the German power system has a surplus of capacity, though due to the stepwise phase out of nuclear capacity, some challenges might arise in near future in Southern Germany (Agora Energiewende, 2015, p. 35; ENTSO-E, 2014, p. 47). In addition to the nuclear phase out, some conventional capacity will be retired in the coming years. Although several GW of new coal and gas plants are currently under construction, experts expect potential shortages to arise in the next decade. It is currently argued if the current market design is suitable to incentivise new resources able to meet peak demand and thus to avoid power shortages in the 2020s (Agora Energiewende, 2015, p. 35).

Figure 4. Installed electrical generation capacity for Germany in September 2015 (in MW)



Source: BNetzA, *Monitoring report 2015,* 2016, p. 42.

According to BnetzA's Market monitoring report for 2015, four large companies owned 61% of generation capacity and produced 67% of all volumes in the German and Austrian market areas. In their research, Janssen & Wobben (2009) state to have found the evidence of the exercise of market power in the German electricity market. Ellersdorfer (2005) claimed that »Germany's electricity market can be regarded as highly concentrated«. He also finds the potential for the dominant producers to exercise the market power. Lise, Linderhof, Kuik, Kemfert, & Östling's (2006) research shows there is a potential for strategic behaviour of market makers in Germany, but it is still considerably lower than in other European countries, such as France and Belgium.

BnetzA (2015, p. 21) stated that »market power of the largest electricity producers has decreased significantly over the last few years«, however »market for the first-time sale of electricity remains highly concentrated with the four largest electricity producers having a cumulative market share of 67%.« Still, proving market-power-induced overpricing is a challenging objective in real markets, since we do not know suppliers' actual marginal cost, particularly firm- or plant-specific marginal cost (Janssen & Wobben, 2009, p. 26). The ownership structure has a major impact on power price volatility and it will be researched further in the thesis.

Renewable energy production represents a high share of electricity production in Germany, so therefore it has to be analysed in greater detail as it significantly influences the power prices.

Renewables

Germany's energy policy or Energiewende (English: Energy Transition) aims to decarbonize energy supplied by switching to renewable sources, to reduce energy imports[6] and to phase out nuclear energy by 2022. In the past years, Germany has been heavily subsidizing the investments in renewable energy, and now in some regions of Germany the amount of energy produced from wind-powered plants already exceeds the network's capacity (Netzentwicklungsplan, 2016).

As we can see in Figure 4, in 2015, Germany had 38.85 GW of installed solar capacity and 41.35 GW of installed onshore and offshore wind capacity. The numbers are even higher for 2016. According to Fraunhofer ISE's website (Fraunhofer ISE, 2017), in 2016 Germany had 39.93 GW of installed solar capacity and 43.45 GW of onshore and 3.99 GW of offshore wind capacity. For comparison, in 2006, Germany only had 2.9 GW of solar and 20.57 GW of wind capacity. The increase was mainly driven by the high FiTs set out in the first versions of the EEG (Deloitte Conseil, 2015b, p. 15). In 2014, the Renewable Energy Act was amended with the goal of continuing progress towards Germany's renewable energy targets while controlling cost. Instead of receiving the FiT amount directly, all new installations larger than 500 kW (and larger than 100 kW after 2016) will need to sell the electricity they produce, themselves or through a third party, and will then be rewarded the difference between the FiT and the revenues earned on the wholesale electricity market ('direct marketing'). In order to comply with new EU environmental state aid guidelines, Germany will introduce auction schemes for renewable energy in 2016, to enter into effect in 2017 (Agora Energiewende, 2015, p. 31).

Even though renewable energy sources in 2014 represented 45.9% of energy sources (based on installed generating capacity) in Germany, they accounted for only 26.6% of net electricity generation (BNetzA, 2016, p. 28). The reason behind this is that wind and solar are so-called intermittent energy sources, which means their production is influenced by external factors (weather) and is not continuously available. Therefore, electricity from renewable energy resources is generated and fed in independently of the demand situation and electricity wholesale prices. Because of renewable energy schemes, renewable electricity plant operators are not exposed to competition from other ("conventional") electricity suppliers (BNetzA, 2016, p. 34).

Wind and solar generation resources increase the variability and uncertainty in the power system which requires additional flexibility. The combination of variability, uncertainty, and the near-zero variable cost of renewable energy sources may result in **generally lower but more volatile energy prices**, higher ancillary service prices, and, depending on the market design, higher forward capacity prices (Papalexopoulos et. al, 2015, p. 1). Today, Germany has some of the lowest wholesale electricity prices in Europe and some of the highest retail prices, due to its energy policies (Deloitte Conseil, 2015b, p. 15).

[6] Germany depends heavily on fossil fuels imports (Deloitte Conseil, 2015b, p. 2), while it is, as previously mentioned, a net electricity exporter.

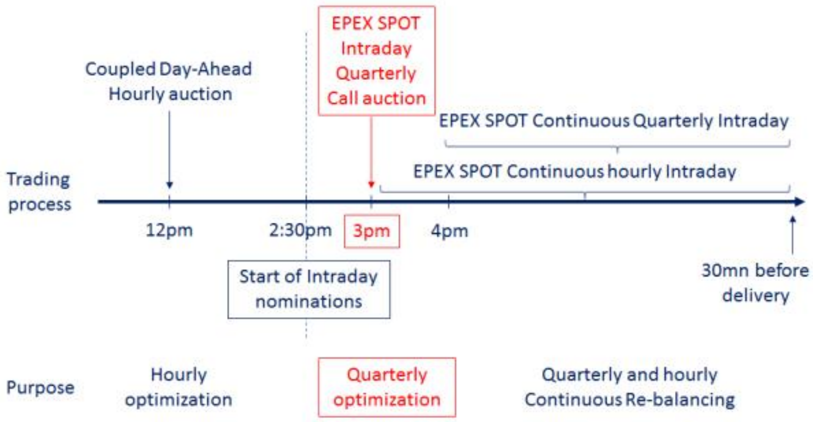
2.3 Electricity Market

Germany is the hub for electricity exchange within the central European interconnected system (BNetzA, 2016, p. 20). In addition to bilateral wholesale trading central importance lies in electricity exchanges. Such exchanges create a reliable trading place at the same time as also provide major price signals for market players in other areas of the electricity industry (BNetzA, 2016, p. 149).

The German wholesale electricity market is broadly made up of three elements: (1) a forward market; (2) a day-ahead market; and (3) an intra-day market. Electricity supply deliveries in the forward market can be negotiated up to seven years in advance, but are typically traded only up to three years because of low liquidity (Agora Energiewende, 2015, p. 21).

Electricity products for German and Austrian supply zone are traded on three exchanges - EEX (Leipzig), EPEX SPOT (Paris) and EXAA (Vienna). EEX is used for forward products, while EPEX SPOT and EXAA are spot exchanges (day-ahead auctions). EPEX SPOT also offers continuous intraday trading. The contracts can be physically fulfilled on both these exchange spot markets, on the Austrian control area (APG) and the German control areas (50Hertz, Amprion, TenneT, TransnetBW) (BNetzA, 2016, p. 151). Market liquidity has been increasing over the past few years, in part due to the obligation that TSOs sell renewable energy on the spot market (Agora Energiewende, 2015, p. 22).

Figure 5. EPEX trading process



Source: K. Neuhoff et. al, Intraday Markets for Power: Discretizing the Continuous Trading?, 2016, p. 3

The day-ahead auction on EPEX SPOT takes place at 12:00 every day (the final result is published after 12:40 p.m.). Auctions on EXAA are concentrated on five days per week, the time of the auction being earlier than on EPEX SPOT (trading closes at 10:12 a.m. and the final result is announced at 10:20 a.m.). In December 2016, EPEX SPOT introduced an auction for quarter-of-an-hour contracts (known as 15-minute intraday call auction) for the German control areas, which is held at a separate time from the auction for individual hours. This auction takes place each day at 3:00 p.m. (the result is known at 3:10 p.m.). All three auction formats are uniform price auctions (BNetzA, 2016, pp. 151 - 152). After 3:00 p.m., continuous intraday trading begins on EPEX SPOT for hourly and quarterly products as presented in Figure 5.

2.3.1 Forward markets

Both, generators and their customers will want to make long-term arrangements for the supply of power either in decentralized forward markets or in highly centralized futures markets (Stoft, 2002, p. 25). Forward markets are used to hedge the risk of fluctuating prices on the spot market. Therefore, forward markets can be regarded as **insurance markets for risk-averse hedgers** who physically produce or need electricity and aim at transferring spot price risks to insurers. Speculators, who intend to generate speculative profits by knowingly taking these price risks, act as insurers. As compensation, they demand a risk premium which equals the difference between forward and expected spot prices, taking the expectation with respect to the physical measure. Unlike the spot market, in which temporary influences directly impact on supply and demand, the forward price is determined by the risk premium and expected supply and demand during the delivery period (Janssen & Wobben, 2009, pp. 12 - 13).

Transmission rights markets

Energy prices differ by location for the simple reason that energy is cheaper to produce in some locations and transportation (transmission) is limited. When a transmission line reaches its limit, it is said to be congested, and it is this congestion that keeps energy prices different in different locations (Stoft, 2002, p. 206). Insufficient capacity can cause bottlenecks in? local market power while additional capacity can expand the size of the market and reduce market power (Stoft, 2002, p. 75). A congestion can be identified by calculating available transmission capacity (hereinafter: ATC) of all lines considering all transactions. ATC is a measure of its utilized capacity for further commercial activity (Makwana et. al, 2014, p. 2).

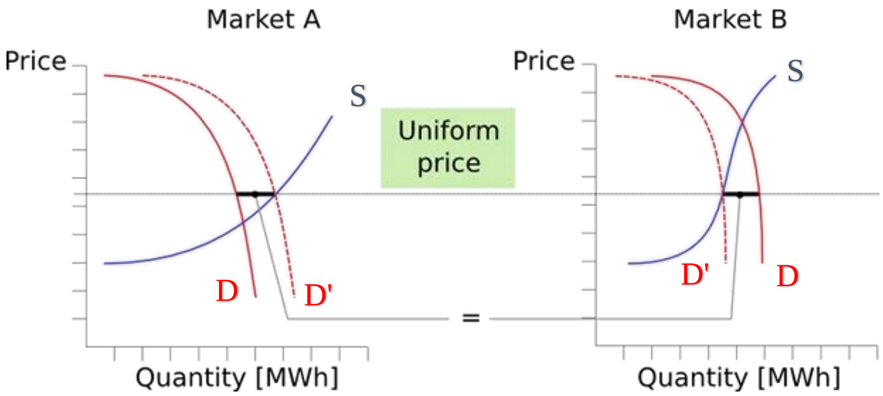
In Europe, interconnector capacity is usually acquired in special so-called “explicit auctions”[7], which are independent of the actual electricity trading. On some exchanges (for example on NordPool) bottlenecks are also taken into account “implicitly” in the framework of the so-called “market splitting” directly in the pricing mechanism at the spot market auction. “Market coupling”, in which the allocation of international transmission capacities is closely interlinked with the design of power exchanges, constitutes a third option within the power exchanges (Ockenfels, 2008, pp. 13 - 14). In implicit auctions, the capacity between bidding areas is made available to the spot price mechanism operated by the power exchanges. If there is sufficient capacity, bids in the high price market can, in effect, be matched against offers in the low price market. If there is sufficient capacity, the markets become one; if not, prices

[7] Because of the implementation of market coupling process, implicit auctions are replacing explicit auctions on day-ahead and intraday level.

converge but remain different, and the gap represents the cost of congestion (Moffat Associates, 2007, p. 6).

Market coupling is a congestion management method where allocation of cross-border transmission capacity is determined according to demand on the respective energy markets. It is an implicit auction approach typically used at the day-ahead stage whereby for every hour of operation either prices across the energy markets converge or all the available transmission capacity is utilised with power flowing towards the high price area. Market coupling is only slightly different from market splitting, and is in fact another form of implicit auctions pioneered by Nord Pool. Under market splitting one power exchange operates across several price zones, whereas market coupling links together separate markets in a region. The effect is, however, the same (Moffat Associates, 2007, p. 5).

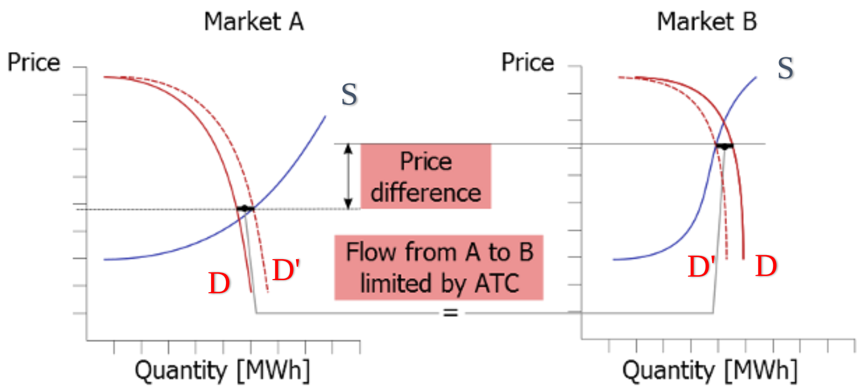
Figure 6. Market coupling without congestion



Source: N-SIDE, Market Coupling, 2017

Figures 6 and 7 present market coupling among two markets with an auction with a single clearing price. Without market coupling, Market A would clear at a lower price than Market B. The market coupling mechanism will utilise the interconnection capacity and flow energy from the cheaper Market A into a more expensive Market B, until the price on both markets is equal (N-SIDE, 2017).

Figure 7. Market coupling with congestion



Source: N-SIDE, Market Coupling, 2017

However, if the interconnection capacity is insufficient, markets clear at different prices. Cheaper Market A exports to a more expensive Market B within the transmission limits. If there is not enough transmission capacity, a congestion rent appears which means the markets are de-coupled with two separate clearing prices.

2.3.2 Day-ahead market

The day-ahead market takes the form of an auction. Generators, traders, retailers and large industrial customers submit bids specifying price/volume pairs of electricity they will sell or buy for each of the 24 hours of the following delivery day. The bids are "frozen" at a fixed deadline on the trading day and prices are determined according to the rules of the power exchange or pool. Finally, accepted bids are settled at the calculated prices (Gehrke et. al, 2007, p. 250). EPEX SPOT organizes the short-run electricity trading starting with an auction at 12:00 p.m. the day before delivery in one hour long slots for the 24 hours of the delivery day (Neuhoff et al., 2016, p. 3).

The creation of a European internal electricity market is a stated aim of the European Union. Under point 3.2 of Annex I to Regulation (EC) No 714/2009, known as the Electricity Regulation, this aim is to be implemented step-by-step in individual European regions (BNetzA, 2016, p. 143). The creation of European internal electricity market is implemented through the market coupling process. The aim of market coupling is the efficient use of day-ahead available transmission capacity between participating countries. This increases the welfare gains that can arise from cross-border exchanges in electricity. As a result, the method leads to an alignment of prices on the national day-ahead markets involved (BNetzA, 2016, p. 143). Market coupling improves the use of scarce transmission capacities by taking into account the energy prices in the coupled markets. It involves day-ahead allocation of cross-border transmission capacities and energy auctions on the power exchanges being carried out at the same time, based on the prices on the exchanges (BNetzA, 2016, p. 288).

Price Coupling of Regions (hereinafter: PCR) is the project of European Power Exchanges to develop a single-price coupling solution to be used to calculate electricity prices across Europe respecting the capacity of the relevant network elements on a day-ahead basis. The project is currently being operated by seven Power Exchanges: EPEX SPOT, GME, Nord Pool, OMIE, OPCOM, OTE and TGE; PCR is used to couple the following countries: Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden and UK ("EPEX SPOT SE: PCR: Price Coupling of Regions," n.d.). An integrated day-ahead market is now set up across the European Union through price coupling of the regions: the Nordic and Baltic markets, Central Europe, North West Europe, and South West Europe (International Energy Agency, 2014, p. 12).

Since November 2010, the power markets Germany/Austria and France have successfully been coupled in the framework of Central Western Europe, covering Germany/Austria, France and Benelux (EPEX SPOT, 2015).

Day-ahead markets are experiencing a significant growth in traded volumes; this is mainly due to the increasing share of intermittent energy sources. Volumes rose from 224,6 TWh in 2011 to 264,1 TWh in 2015 (EPEX SPOT, 2017).

2.3.3 Intraday market

Intraday market takes place after the day-ahead market is closed and represents the final option for market participants to balance their portfolio. After the day-ahead price calculation, the unused cross-border transmission capacities are given to the intraday markets where the market participants are able to continue to trade (Fingrid, 2016).

Intraday markets are mainly used for (EPEX SPOT, 2016b):

(1) adjusting purchases and sales based on the results of the day-ahead auction,
(2) running and planning power generation closer to delivery,
(3) managing forecast errors or unforeseen events,
(4) adjusting from hourly positions to 15-min,
(5) offering flexible generation as a substitution for renewables,
(6) enabling cross-border arbitrage and trading.

The goal of intraday trading is to enable market participants to improve their positions following improvements in forecasts with respect to those already taken in the day-ahead market (Karanfil & Li, 2015, p. 5).

Forecasting the production of photovoltaic and wind power systems inevitably implies inaccuracies. Therefore, sales made based on forecasts almost always require the vendor to make balancing efforts. In the absence of resources available within their own portfolios, operators can turn towards the intraday market in order to avoid an engagement in the imbalance market with the resulting surcharges and regulatory penalties (Garnier & Madlener, 2014, p. 2).

Trading volumes are much higher in the day-ahead market than in the intraday market. Hence the intraday market is of minor importance for trading and hedging but of higher importance for system security. Any trade in the intraday market may contribute to reduce the activation of control energy through the TSOs (Pape et.al., 2016, p. 5).

Intraday trading in Germany consists of 15-minute intraday call auction (gate closure is the day before delivery at 3:00 p.m., the results are published at 3:15 p.m.) and continuous intraday trading (hourly and quarter-hourly can be traded up to 30 minutes before delivery). In a uniform price auction (in this case 15-minute intraday call auction), market participants can offer all available capacity at marginal costs and the uniform clearing price ensures remuneration at the value the capacity is required by the system. In contrast, in a continuous auction, market participants have to anticipate/negotiate the market clearing price and incorporate accordingly a mark-up in their offers in order to capture the value of generation assets to the system (Neuhoff et al., 2016, p. 9). Continuous trading is shared between exchange based and bilateral trading. The volume of bilateral transactions is reported only by the national regulatory authority BNetzA with a considerable time lag. In 2013, 20 TWh were traded on intraday at the exchange and 15 TWh on bilateral contracts (Neuhoff et al., 2016, p. 4). Continuous exchange based intraday trading is primarily used for the implementation of small adjustments to production and consumption. It is being reported that in response to large adjustment needs, for example, from the failure of a power station, market participants are more inclined to negotiate bilaterally (Neuhoff et al., 2016, p. 14).

In Germany, regulators insist that the imbalance market has a mere back-up function and that its systematic use as part of a trading strategy over time will be penalized. The German regulator legally requires balancing-responsible parties to minimize their use of the imbalance market to the largest possible degree (Garnier & Madlener, 2014, p. 5). This regulation positively affects the intraday market liquidity; subsequently the market participants have the incentive to trade on the intraday market.

Under older versions of EEG, the TSOs were responsible for trading the energy from renewables on the spot market. EEG required network operators to connect renewables to their grid, accept the entire electrical output from these plants and remunerate generators at a pre-determined rate for every kWh produced (Mitchell et.al, 2006, p. 299). The support instrument mainly used was FiT which can be classified among the low-risk support schemes since the marketing and balancing responsibility is taken over by a distribution grid or transmission grid operator (Batlle et. al, 2012, p. 213; Hagemann & Weber, 2015, p. 7). Grid operators do not control conventional power plants (except during real-time balancing); hence, portfolio internal balancing is not possible. If wind, solar and load forecast errors are not offsetting each other, the TSOs are obliged to trade externally in the intraday market in order to balance their intraday deviations. Thus, in countries with low-risk support schemes, intraday trading volumes can be raised by the trading of the TSOs (Hagemann & Weber, 2015, p. 7). New politically desired transition is towards direct marketing, for instance, recently planned amendments to the EEG in Germany require operators of photovoltaic (hereinafter: PV) and wind power assets to self-market their outputs (even in the case of fairly small asset capacities). This reflects the fact that the German TSOs will increasingly shift responsibility for PV and wind power marketing to owners and intermediate operators, supported by corresponding regulatory changes (Garnier & Madlener, 2014, p. 5). In regard to the new development directive of renewable electricity sold directly, the percentage of electricity sold by the TSOs on EPEX SPOT has fallen from 38% in 2011 to 21% in 2014 (BNetzA, 2016, p. 27).

2.3.4 Balancing market

Shortly before physical delivery, the transmission system operators take over the responsibility for all remaining system imbalances and ensure system security through the activation of control energy (Hagemann & Weber, 2015, p. 2). Balancing markets are used by the system operator to resolve remaining imbalances (Borggrefe & Neuhoff, 2011, p. 5). After solving physical imbalances, imbalance price calculations are made which are based on TSO's payments or proceeds for the activated control energy (secondary and minute reserve). Imbalance prices are calculated for each balancing interval (equivalent to the scheduling interval of ¼ hour). Since 1st June 2010, a uniform balancing energy price (reBAP) has been applied to the whole of Germany (Regelleistung, 2016). Market participants will generally try to avoid the use of control energy for two reasons. The first reason is that, in Germany, using balancing services is always more expensive than self-balancing on the intraday market. The second reason is that the TSOs may impose sanctions on market participants that cause many imbalances by abrogating their balancing contract (Pape et.al., 2016, p. 5).

Balancing costs results from production forecast errors. All deviations not balanced, either within portfolios or in the intraday market, are then compensated for in the imbalance market, often at substantial cost premiums. Due to subsidies and exemptions from balancing obligations, PV and wind power operators in many markets have been insensitive to the two aforementioned threats to market value. However, with regulatory shifts towards market exposure and reduced subsidies, operators must mitigate these threats in order to achieve profitability and ultimately competitiveness. Balancing costs can be minimized by using flexibility to compensate or shift unexpectedly short or long positions arising from forecast errors. The scientific and economic debate around flexibility usually involves two alternative kinds of resources: demand-side flexibility and storage (Garnier & Madlener, 2014, pp. 2 - 3).

Historically, balancing markets have been the only markets to provide reserve and response operations. System operators contract this reserve and response capacity in day-ahead and longer- term markets with generators to provide flexibility that can be called upon on short notice to balance the system when forced power plant outages or load prediction errors occur. Balancing was only necessary for events of small probabilities (power station failures) or for small volumes (as in the case of load prediction errors); the amount of reserve capacity contracted was thus large compared to the small share of actual electricity requested. Balancing services were provided nationally, or in the case of Germany, within the region of the TSO. Mutual support between regions was restricted to emergency situations, such as unexpected power plant failures, and not remunerated - only energy that was provided had to be returned (Borggrefe & Neuhoff, 2011, p. 5).

3 PRICE VOLATILITY OF GERMAN INTRADAY POWER MARKET

In the broadest sense, price volatility is a measure of the randomness of price changes: the higher the degree of randomness, the greater the volatility (Eydeland & Wolyniec, 2003, p. 80). Understanding the volatility process is important for market participants in order to better manage their financial risks. Power price volatility is also important when making decisions about investing in generation technology – frequent spikes can mean that power plants with high marginal costs can cover their costs and be profitable.

Garnier & Madlener (2014a, p. 20) argue that volatility increases the relevance of bidding strategies. The more volatile prices and production forecast errors are the more inefficient static or one-dimensional trading approaches become. Therefore, understanding the volatility of power prices is of crucial importance for the whole power industry.

In the following chapter the price volatility of German continuous intraday market is thoroughly analysed. After shortly summarising the main findings from previous research, the comparative analysis of continuous and auction data is concluded to determine if intraday prices are indeed more volatile. Transaction data on hourly level is examined to determine price volatility of continuous trading in order to examine the effect of continuous matching process on price volatility.

Further, fundamental price determinants and their effect on price volatility will be explored based on literature research. The focus here is to establish if the determinants exhibit different behaviour on intraday and have therefore a different impact on price volatility compared to day-ahead.

3.1 Literature review on power price volatility

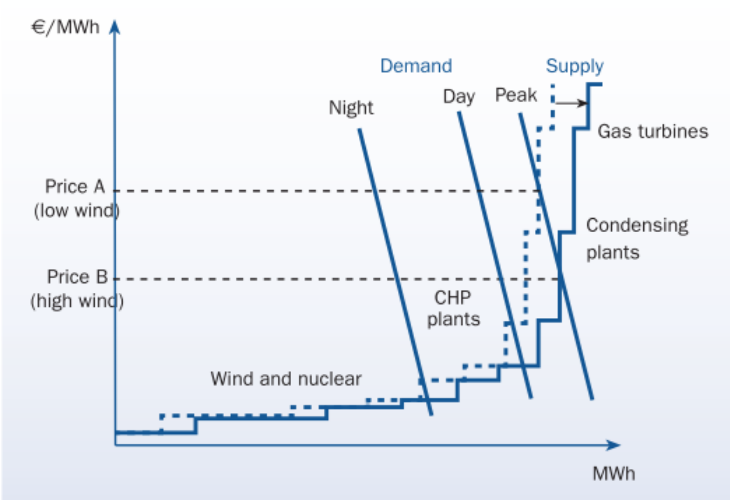
Several analyses have highlighted that among all traded commodities, electricity exhibits the highest volatilities (Weber, 2005, p. 15; Girish & Vijayalakshmi, 2013, p. 71; Weron, 2000, p. 1; Eydeland & Wolyniec, 2003, p. 85). Enormous price fluctuations can be observed in all electricity markets (Burger et. al, 2004, p. 2). Factors that influence demand include weather, season; while aggregate supply is influenced by the location of generators, their market concentration, the transmission structure and the bidding and auction process of the market. As a result, deregulated prices are characterized by volatility that varies over time and occasionally reaches extremely high levels, commonly known as “price spikes” (Goto & Karolyi, 2004, p. 1). As previously mentioned, short-term prices depend more on weather, demand and production availability, while long-term volatility is mostly driven by fuel and carbon costs.

Stoft (2002, p. 78) identifies that the biggest structural problem of power markets is the almost complete lack of demand response to fluctuations in the wholesale price. The same problem is identified by Borenstein (2001, p. 1) who states that because of this short-term prices for electricity are going to be extremely volatile. Borenstein (2001, p. 2) identifies three major causes of price volatility in power markets: the need for constant supply and demand balance because of non-storability, lack of demand side flexibility and capital intensity of electricity generation[8].

[8] Excess capacity in a competitive market will cause prices to fall to a level below the average cost of producing electricity, and generators will lose money. This implies a high cost of idle capacity which is the reason that it is very costly to maintain the ability to increase electricity production on very short notice (Borenstein, 2001, p. 2).

Price volatility in power markets is furthermore increased by growing shares of intermittent energy production. For example, in the UK, Green and Vasilakos (2010, p. 1) have evaluated the impact of intermittent wind generation on hourly equilibrium prices and output. Matching the wind profiles for each month to the actual hourly demand scaled to possible 2020 values, they found that the volatility of prices will increase. A similar research was done on a 15-minute historic data in Texas by Woo et al. (2011, p. 1), which showed that while rising wind generation does indeed tend to reduce the level of spot prices, it is also likely to enlarge the spot-price variance. Nicolosi & Fürsch (2009, p. 1) demonstrated that in German market in the long run a higher peak load plant share is required to cope with the increasing volatility of the residual demand. They state that if the volatile wind power in-feed leads to an increasingly fluctuating inelastic residual demand curve, the power price becomes increasingly volatile. Weigt (2009, p. 8) notes that electricity markets typically face a relatively flat supply curve in the beginning and a rapid slope increase in peak-load levels. Given that wind has no fuel cost it is added at the left side of the merit order curve, shifting the whole curve to the right. During off-peak times, this shift has little price impact due to the flat gradient. However, during peak times, even a small shift can cause significant price differences (Morthost, 2010, p. 22; Weigt, 2009, p. 8). If there is plenty of wind power at midday, during the peak power demand, most of the available generation will be used. This implies that we are at the steep part of the supply curve and, consequently, wind power will have a strong impact, reducing the spot power price significantly (from Price A to Price B in Figure 8). But if there is plenty of wind-produced electricity during the night, when power demand is low and most power is produced on base load plants, we are at the flat part of the supply curve and consequently the impact of wind power on the spot price is low (EWEA, 2010, p. 11 – 12).

Figure 8. Effect of wind power at different times of the day



Source: EWEA, Wind Energy and Electricity Prices: Exploring the'merit Order Effect'; a Literature Review by Pöyry for the European Wind Energy Association, 2010, p. 11.

Hagemann (2013, p. 17) analysed intraday prices in 2011 and indicated high price volatility (standard deviation of 16.25) and the repeated occurrence of extreme intraday prices. Nevertheless, he noted that the average deviation between the volume weighted hourly intraday price and the hourly day-ahead price is quite small. Neuhoff et al. (2016, p. 12) analysed the effects of the introduction of 15-min intraday auction on intraday prices and concluded that the new auction sets a strong price signal and reduces the variance of the price.

3.2 Price volatility of German continuous power market compared to spot auctions

Research of power price volatility indicates that prices are more volatile on intraday than on day ahead markets. For example, Garnier & Madlener (2014, p. 10) have analysed EPEX market data for Germany in 2013 and have found that absolute prices of hourly deliveries averaged higher in intraday, and that intraday price variance was much higher than the day ahead (+20%). Further, the spread between the highest and the lowest price intraday exceeds the day-ahead spread by more than 9%. All of these measures support the notion that for intraday price volatility is higher, and that absolute price movements are larger as well. The power market has undergone many changes since the analysis was conducted (e.g. more renewable capacity installed, transitions from feed-in tariffs to direct marketing, introduction of 15-minute call auction, rise in volumes traded,…), so there is a need to re-evaluate the volatility of intraday power market compared to day-ahead spot auctions.

In this section price volatility of EPEX continuous intraday trading is analysed using SPSS. To easier define the level of volatility of intraday prices, comparative analysis is run first with day-ahead spot price (hereinafter: EPEX_DA), 15-minute call auction prices (hereinafter: 15-min) aggregated to an hourly level and weighted average prices of continuous hourly intraday trading (hereinafter: Cont_WA).

Table 3. Descriptive statistics of day-ahead auction (EPEX_DA), 15-min auction (15-min) and weighted average prices of intraday continuous trading (Cont_WA) for 2015 and 2016

	N	Minimum	Maximum	Mean	Variance
EPEX_DA	17544	-130.09	104.96	30.30	159.81
15-min	17544	-88.99	99.00	30.39	147.78
Cont_WA	17544	-155.52	121.66	30.48	189.69

Note. 15-min auction data is aggregated to an hourly level
Source: own calculations based on EPEX data

Both auctions are concluded the day before the delivery (final results are known at 12:45 for day-ahead auction and at 15:15 for 15-minute auction), the difference between them is that on day-ahead auction hourly contracts are traded, and as the name suggests quarter-hourly contracts are traded on the 15-minute call auction. While there is one clearing price for each contract in the auction trading, continuous trading employs a continuous matching process and there are several clearing prices. For simpler comparison, analysis is therefore conducted with weighted average prices from EPEX SPOT continuous intraday trading as published by EPEX SPOT. Cont_WA prices can serve as a more comparable variable since all the transactions are represented by a single price. Also, for easier comparison of the data, results from 15-minute (15-min) auction will be aggregated to an hourly level.

Descriptive statistics presented in Table 3 show that Cont_WA exhibits the biggest price variance and the conclusion is that intraday prices are indeed more volatile. However, the difference between variances is lower as in research of Garnier & Madlener (2014, p. 10) and amounts to 15.75% in comparison to EPEX_DA, but it amounts to 22.1% compared to 15-min, which exhibits the lowest price variance. However, it needs to be taken into account that 15-min data is aggregated to an hourly level, which can influence the variance.

15-min auction exhibits the lowest price variance with the value of 147.78, which complies with previous research findings that additional auction increases liquidity, leads to a higher market depth (the revelation of market participant's capacity/flexibility) and to a reduced price volatility (Neuhoff et al., 2016, p. 18).

3.3 Price volatility of German continuous power market based on full transaction data

During the trading period, the market equilibrium may change quite rapidly, depending on the arrival of information about intraday deviations from the day-ahead planning. This stretching of liquidity over the whole trading period can make the intraday market price volatile and non-transparent (Hagemann & Weber, 2015, p. 3). As previously mentioned, there is no single clearing price for continuous trading, meaning there can be significant price differences for a single contract. Therefore, analysis based on full transaction data for continuous intraday trading is concluded in order to determine more accurate price behaviour of continuous trading. Descriptive statistics of EPEX continuous transaction data for 2015 and 2016 are presented in Table *4*. Full transaction data is comprised of all of the transactions executed on EPEX SPOT continuous intraday trading platform for all contracts traded in 2015 and 2016.

Table 4. Descriptive statistics of EPEX continuous transaction data for 2015 and 2016

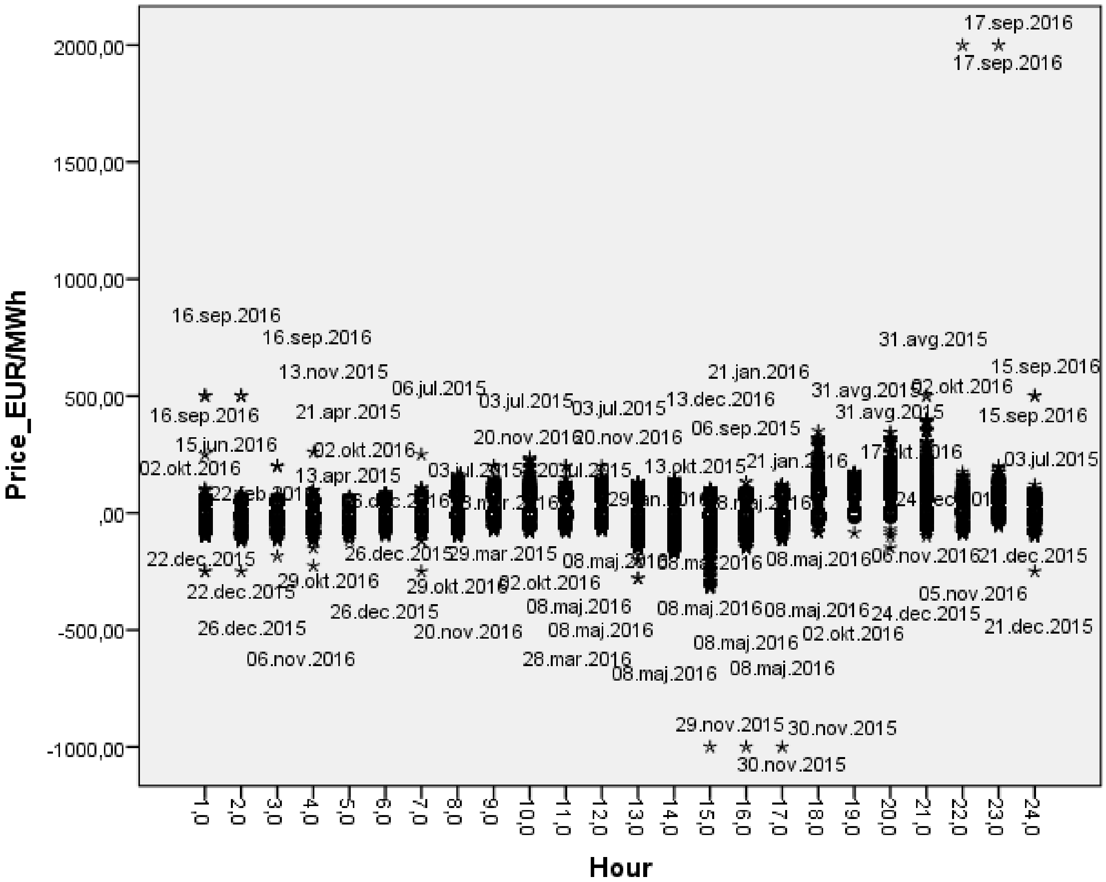
	N	**Minimum**	**Maximum**	**Mean**	**Variance**	**Skewness**		**Kurtosis**	
	Statistic	Statistic	Statistic	Statistic	Statistic	Statistic	Std. Error	Statistic	Std. Error
Price_EUR/MWh	5497347	-1000.00	2000.00	31.850	230.877	.332	.001	128.601	.002

Source: own calculations based on EPEX data

Full transaction data for the year 2015 exhibits significantly higher price variance, which is expected for continuous matching process. From the minimum and maximum price, we can conclude that absolute movements are indeed larger as already noted by Garnier & Madlener (2014, p. 10). Frömmel, Han, & Kratochvil (2014, p. 1) show that intraday range is an effective volatility indicator in the power market as the benefit of including intraday range is substantial as compared to realized variance.

However, continuous matching process may result in trades not being representative of the true market price (e.g. mistrades or mistakes during the trading process). This creates the problem of outliers, which are apparent in Figure 8. Before the data can be further examined filtering the data with some reasonable procedure for outlier detection is necessary (Janczura et. al., 2013, p. 1). Outliers can be easily mistaken for price spikes and have a significant influence on price variance, therefore they must be treated carefully. If the value which is labelled as an outlier by SPSS denotes a high quantity and a repeated trade, this can be a signal of an extremely tight market or trades that had to be executed right before the gate closure. Outliers will therefore be treated by examining the quantity of transactions. If the volume of the outlier is considered as insignificant (below 25 MW), it is taken out of the analysis. Hours are regarded as separately traded contracts and each contract corresponds to different price behaviour based on the daily load curve shape and some hourly blocks exhibit greater volatility.

Figure 9. Boxplot diagram of full continuous transaction data for 2015 and 2016



Source: own calculations based on EPEX data

In Figure 9, we can see that there are some outliers which need to be excluded from the analysis in order to produce meaningful results. Based on the data examination the condition for removing outliers is implemented – all the transactions lower than -151 EUR/MWh and higher than 401 EUR/MWh are removed, since the quantity of these transactions is below

25MW. Analysis is repeated using this condition. Table *5* represents the descriptive statistics of EPEX continuous transaction data for 2015 and 2016 with outliers removed.

Table 5. Descriptive statistics of EPEX continuous transaction data for 2015 and 2016 without outliers

	N	Minimum	Maximum	Mean	Variance	Skewness		Kurtosis	
	Statistic	Statistic	Statistic	Statistic	Statistic	Statistic	Std. Error	Statistic	Std. Error
Price_EUR/MWh	5497133	-150.90	320.00	31.8549	226.181	-.266	.001	10.015	.002

Source: own calculations based on EPEX data

Literature about power prices suggests that power prices exhibit skew and high kurtosis (Tichy, 2006, p. 1; Goto & Karolyi, 2004, p. 15; Eydeland & Wolyniec, 2003, p. 73) which is also confirmed by our results. Kurtosis describes the degree of “flatness” of a distribution, or width of its tails. High kurtosis indicates a higher probability of extreme movements (Jorion, 2003, p. 35) and is one of the most distinct features of energy prices (Eydeland & Wolyniec, 2003, p. 162, Ketterer, 2014, p. 8; Goto & Karolyi, 2004, p. 15; Panagiotelis & Smith, 2008, p. 720). In the case of energy prices it is the distribution kurtosis (or tail fatness, or spikiness) that is the main cause of non-normality (Eydeland & Wolyniec, 2003, p. 72).

As previously mentioned, hourly blocks are different contracts, therefore analysis on hourly level is also necessary since price variance significantly differs from hour to hour (see Appendix A for detailed results). Based on the results, three groups which correspond to standardised products are analysed – delivery hours 1 – 7 as Offpeak1, hours 8 – 20 as Peak and hours 21 – 24 as Offpeak2.

Table 6. Variance and Kurtosis of transaction data for 2015 and 2016

	Variance	Kurtosis
Offpeak1	143.83	19.73
Peak	231.39	8.53
Offpeak2	123.11	16.68

Note. *For detailed information see Appendix A

Source: own calculations based on EPEX data

It is evident from Table 6 that Offpeak1 and Offpeak2 exhibit significantly lower price variance. This can be partially explained by reduced trading activity during night hours because the number of market participants is lower and thus liquidity of those hours is lower (Hagemann & Weber, 2013, p. 21; Platen et. al., 2005, p. 739). For smaller market participants it is not cost-effective to utilize 24/7 trade floor and therefore they settle their imbalances on the balancing market. Lower liquidity of these hours is also evident from the analysis – if we compare the number of transactions (N) and volumes traded (see Appendix B), we can see that the number of transactions and volumes is considerably lower during

Offpeak1 & Offpeak2. The total number of all transactions during Offpeak hours is 1.901.166, while the number of transactions during Peak amounts to 3.595.967. If we compare the volumes of Offpeak and Peak hours, we can see that the volumes in Offpeak hours amount to 18.91 TWh, while the volumes in Peak hours reach 37.24 TWh.

Even though Offpeak1 and Offpeak2 exhibit lower price variance than Peak, kurtosis is considerably higher as it can be seen in Table 6. This can be explained with low load during those hours, which intensifies price volatility (Degeilh & Gross, 2015, p. 542). For example, if wind output is higher than forecasted during the Offpeak1 hours, the ramp-down potential of generation capacity is rather low because of the physical impossibility to shut down the base-loaded conventional units for short periods, which leads to lower prices (Hagemann & Weber, 2013, p. 27). In other words, the prices do exhibit lower volatility but are more prone to significant price drops.

3.4 Main price determinants and their effect on volatility

Any kind of variability in end user demand coupled with variations in weather conditions, such as temperature, precipitation, water reservoir levels etc. plays a pivotal role in electricity price behaviour. External events like outages of power plants or imperfection in transmission grid reliability will result in having significant impact and effect on electricity prices (Girish & Vijayalakshmi, 2013, p. 70).

Girish et al. (2013, p. 73) distinguish four groups of factors influencing electricity prices:

(1) fundamental factors, such as: fuel prices, temperature, weather conditions, time indices like day of the week, month of the year, season of the year, cost of production of electricity per unit.
(2) operational factors, such as: power transmission congestion, power system operating condition, electricity production (deficit/surplus), network maintenance, electricity load.
(3) strategic factors, such as: power purchase agreements, bilateral contracts, power exchange, bidding strategy, market design.
(4) historical factors, such as: price, demand.

Janssen & Wobben (2009) use the regression analysis to confirm the main price drivers of electricity future prices. For medium- and long-term, these are fuel and carbon costs which influence the supply side. The demand side is influenced by weather forecasts, economic cycle, political frameworks and consumer behaviour. Borggrefe & Neuhoff (2011, p. 16) observe that the main factors which influence intraday trading are wind uncertainty[9], unforeseen power plant outages, deviations in the supply schedule and intraday changes in

[9] At the time of the research (2011) TSO's were responsible for trading wind deviations on intraday market. With the introduction of direct marketing, the volumes traded by the TSO's fell substantially as the generators are resonsible to balance their own intraday production deviation (see: BNetzA, 2016, p. 163).

demand. Similarly, Hagemann & Weber (2013, p. 1) note that forecast errors of renewable generation, load forecast errors and unplanned power plant outages influence intraday trading.

Hagemann (2013, p. 7) finds that intraday surplus of wind and solar power production significantly decreases intraday prices while unplanned power plant outages or a lacking wind power production lead to purchases and significantly increase intraday prices. Furthermore, the price determinants influence intraday prices differently over the course of the day; e. g. wind forecast errors have a stronger price impact during the time from midnight to eight am than during the rest of the day; which can be explained by an alternating liquidity provision.

Hagemann (2013, p. 5) confirms that wind forecast errors, solar forecast errors and outages have significant influences on intraday prices. However, he notes that only a minor share of power plant outages and solar power forecast errors are traded on the electronic intraday trading platform, so the influence on prices is not as strong as expected. Selasinsky (2015, p. 9) also argues that the direction of the forecast error is a fundamental variable influencing continuous intraday markets. A significant underestimation of the feed-in from renewables predominantly results in average hourly intraday prices which are lower than the corresponding clearing prices from the day-ahead auction (positive spread). A significant overestimation mainly results in negative spreads (Selasinsky, 2015, p. 10).

Furthermore, the most important price determinants will be explained in greater detail and possible reasons for higher intraday price volatility will be outlined.

3.4.1 Renewable energy

Day-ahead predictions are required in order to schedule conventional units. The starting up and shutting down of slow-starting units has to be planned in an optimised way in order to keep the units running at the highest efficiency possible and to save fuel and thus operational costs of power plants. In liberalised electricity markets, this is dealt with at the day-ahead spot market (Ackermann, 2005, p. 155). In order to plan the utilisation of conventional power plants, accurate renewable forecasts are necessary since renewable energy helps save fuel costs and shifts the merit-order curve (Weigt, 2009, p. 2; Hirth, 2013, p. 4). However, power production from renewables is poorly predictable because it strongly depends on weather conditions.

Wind forecasts improve significantly when realised closer to generation (Henriot, 2014, p. 2; Garnier & Madlener, 2014, p. 17), which means that previously traded profiles need to be adjusted according to forecast error and traded closer to delivery. The forecast error is generally defined as the quantity difference between the previously sold day-ahead profile of renewable energy sources and the more precise intraday forecast. For a positive (negative) forecast error, the market participant holds a long (short) position[10] and acts as a seller (buyer)

[10] Market partcipants' long position means he has a surplus of energy which he can sell on the market. Short position means that market participant has a deficit of energy and will be a buyer on the market.

of electricity on the intraday market (Hagemann, 2013, p. 7). Renewables have a varying effect on intraday power prices. In cases of high renewable infeed during high load, this situation is considered favourable due to the fact that a cheaper conventional power plant can set the price. However, in case of high renewable output and low load, conventional power plants need to be ramped down which can prove to be economically or technically problematic. In case of low renewables and high load, there needs to be enough peak load capacity installed in order to have an adequate system which can cope with the demand (Nicolosi & Fürsch, 2009, p. 247).

Overall unintended variation in wind power output is high because wind (in a very similar way to electricity, and quite unlike coal or nuclear fuel), cannot be stored (Harris, 2011, p. 36). Despite the high availability of the wind turbines (98% of the time wind turbines were available to provide the energy to the grid), the capacity factor (or the load factor) rarely reaches beyond 30% for onshore wind power and 40% for offshore wind power. Therefore, 1 installed MW of wind power cannot replace 1 MW of thermal power (Göransson & Johnsson, 2009, p, 1043). Degeilh & Gross (2015, p. 549) came to a similar conclusion while analysing simulation scenarios in American WECC Region or Western Interconnection which extends from Canada to Mexico. They conclude that from a pure system reliability perspective, wind resources constitute rather poor substitutes for conventional resources. Moreover, the root mean square error of the error forecast for the production of a wind farm in six hours can reach 20% of its installed capacity (Aïd, Gruet, & Pham, 2015, p. 2), which means that actions have to be taken closer to real-time in order to minimise the imbalance costs. Garnier & Madlener (2014a, p. 20) notice that trading activity increases dramatically when approaching delivery, indicating a wait-and-see behaviour by operators.

The deepening penetration of intermittent renewable resources presents major challenges in power system planning and operations. Unlike conventional resource outputs, wind and solar resource outputs cannot be controlled by the operator except to be curtailed. Wind and solar outputs do not necessarily track the load pattern and thus cannot always contribute to serve the peak loads. There are also concerns about ‘‘spilling’’ of wind energy at night due to the insufficient load demand and the physical impossibility to shut down the base-loaded conventional units for short periods. While morning and mid-day solar power outputs are aligned with the loads, their quick decline after sunset occurs when the loads are still high. Both wind and solar therefore impose additional requirements on the conventional units to effectively manage the variability/intermittency and uncertainty effects. Wind generation is also shown to exacerbate (reduce) the volatility in electricity prices in hours when the system is moderately (heavily) loaded (Degeilh & Gross, 2015, p. 542).

Overall there is a negative correlation between the wind power infeed and the power prices but it may cause that prices become increasingly volatile (Nicolosi & Fürsch, 2009, p. 247; Weigt & Hirschhausen, 2008, p. 8). During off-peak hours, increased wind generation has little price impact due to the flat gradient of merit-order curve. However, during peak times, even a small shift can cause significant price differences (Weigt, 2009, p. 8). Deeper penetrations of integrated wind resources tend to boost volatility also on the days with lower peak loads, but it can reduce price volatility during periods of high loads (Degeilh & Gross, 2015, p. 549).

3.4.2 Imports and exports

The electricity market is subject to distribution and transmission constraints, such that once fully constrained, the marginal cost of transmission can become practically infinite (Platen et al., 2005, p. 722). (Non)availability of interconnector capacities can also be one of the factors causing extreme price fluctuations (EWEA, 2010, p. 25). For example, a country that consistently exports domestic energy, may simultaneously improve short term security of supply, since exports could be cut in times of shortage (Harris, 2011, p. 483). If there is no transmission capacity available, the market price represents the marginal cost of the next available generator, which can be rather high in cases of high load. In cases of available transmission capacity the prices will be influenced by neighbouring market prices. Commercial flow of energy will go from cheaper to more expensive areas if there is available transmission capacity.

However, the European grid was never designed to cope with large-scale fluctuations in generation and requires extensive upgrading, e.g., major investments in transmission (Weigt, 2009, p. 2). Because of transmission constraints curtailment of energy from renewables needs to be performed at times. Constraints are generated by an excess of renewable and non-dispatchable conventional generation when demand is low. This could occur typically on weekend nights (low demand combined with high wind) or on weekend days (limited demand combined with high photovoltaic generation and high wind) (ENTSO-E, 2016, p. 9).

3.4.3 Outages

If power plant owners experience unplanned outages, they still have to deliver the electricity production that they previously sold on the long-term or day-ahead market. This is advantageous if the marginal costs of free generation units in the producer's portfolio are higher than the benchmark prices on the EPEX platform for intraday trading. In the very short run, they may use highly flexible generation units like pump storages or running steam reserves to compensate the outage within their own portfolio (Hagemann, 2013, p. 5). However, using pumps results in a loss of approximately 30% of the energy (Burger et. al., 2004, p. 2). Very large units increase the vulnerability of systems, as a single unit breakdown has a significant effect on the system (Harris, 2011, p. 32). Outages are significant challenges of risk management in electricity markets. An unplanned failure of a generation unit in spiking markets can have catastrophic financial consequences (Eydeland & Wolyniec, 2003, p. 28).

Neuhoff et al. (2016, p. 14) and Hagemann & Weber (2015, p. 7) find empirical evidence that when larger adjustments are necessary, participants rather negotiate bilaterally than on the intraday market, and only approximately 13% of outages is traded in the continuous intraday market. Nonetheless, bilateral prices cannot deviate substantially from the exchange prices because buyers and sellers always have an arbitrage option at the exchange. Nobody would accept an offer at the bilateral market if the expected outcome at the exchange was more beneficial (Nicolosi, 2010, p. 7295; Pape et al., 2016. p. 1).

3.4.4 Demand variation

Consumption of electricity depends on the ever changing level of activities related to businesses i.e. commercial, industrial, household and also climatic conditions like temperature or the daylight hours available since it affects demand of electricity directly. This also makes demand of electricity seasonal with seasonal patterns within a day, week, month and year (Girish & Vijayalakshmi, 2013, p. 71). Load forecasting is an essential element of power system operation and planning. It involves prognosis of the future level of demand to serve as the basis for supply side and demand side planning. Load requirements are to be predicted in advance so that the power system operates effectively and efficiently (Aggarwal et. al, 2011, p. 24). Nicolosi & Fürsch (2009, p. 247) find that power load in Germany in 2008 exhibited a strong fluctuation between 34,312 MW and 76,763 MW (average load being 56,419 MW). They also find a strong correlation between load and power prices (correlation coefficient is 0.69).

In the intraday market, the TSOs are responsible for managing the load forecast errors (Hagemann, 2013, p. 8). The profit maximizing direct marketers may trade more cautiously than the TSOs in the intraday market in order to increase their profits, which may lead to a different price impact (Hagemann, 2013, p. 26).

3.4.5 Conventional resources availability

The initial supply and demand curves for the intraday market are determined by the available up- and down-ramping capacities of flexible power plants. As new information about deviations from the day-ahead planning enter the market, they are being traded against the available power plant flexibilities or other contrary deviations from the day-ahead planning (Hagemann, 2013, p. 5).

The flexibility of power generation is determined by the mix of installed capacities and reserve power for system security sold at secondary markets. In case of demand increase, it can only be fulfilled by utilising flexible conventional power plants which have not been marketed previously. Adjustable capacity is therefore dependent on the commitment of conventional generation units as part of energy sales in day-ahead and longer-term markets and the ability to adapt this day-ahead commitment to the changes in the market within the last 24 hours before physical dispatch. Many generation assets can only adjust their output close to real-time if they are already operating (nuclear, lignite, coal, and certain gas power plants). Only the plants that are operating can provide negative balancing reserve, while these plants have to operate in part-load to be able to provide positive balancing power (Borggrefe

& Neuhoff, 2011, p. 4). Within the day, upward and downward flexibility is maintained by plants changing load between full load and minimum stable generation. Operating at minimum stable generation is generally benign to plant due to the lower temperatures, but the cycling of the plant can be damaging, particularly for plant with thick metal such as nuclear plant and some older thermal plant (Harris, 2011, p. 52). However, in the short run and especially for greater deviations, increased demand cannot be compensated by hard coal fired power plants because these power plants require lead times of several hours to start production. Thus, the short-run intraday demand may only be compensated by flexible generation units like gas-turbines with high marginal costs. Furthermore, highly flexible water pump storage power plants may supply power in the very short run (Hagemann, 2013, p. 22). Intraday merit-order curve therefore displays greater steepness (Hagemann & Weber, 2015, p. 6; Henriot, 2014, p. 4). For a merit order with a convex and steeply increasing right end, the aggregated capacity of power plants with up-ramping potential decreases as the price level increases and the marginal costs of each next unused power plant increase over proportionately. Consequently, intraday prices may increase as demand rises due to higher costs of the next marginal power plant which has to be activated to satisfy the net surplus of intraday demand (Hagemann, 2013, p. 9).

Another aspect of conventional units' availability is planned maintenance. In Germany, for example, maintenance of power plants is mainly done in summer, when the average load is much lower than in winter. Hence the availability of the power plants is higher in winter compared to summer (Burger et al., 2004, p. 8). In case of increased demand and while large units are unavailable, prices can fluctuate disproportionately due to steeper merit-order curve.

When examining the generator's motivation to respond to price signals on intraday markets we must consider nonconvex operating costs. The cost of starting a generator makes generation costs nonconvex because it makes it cheaper per kWh to produce 2 kWh than to produce 1 kWh. This causes the market to lack a competitive equilibrium and could easily cause inefficiency in the dispatch of an otherwise competitive market (Stoft, 2002, p. 55).

3.4.6 Other

Pape et al. (2016, p. 11) note that (avoided) start-up costs, market state variables (e.g. scarcity of supply) and trading behaviour also influence the price formation on the intraday market.

Another determinant of intraday prices may be intraday trading positions if the market participants are able to transfer their long or short positions from the day-ahead into the intraday market. Market participants could then profit from expected price differences between both markets (Hagemann, 2013, p. 14). Also, aggregate balance of market actors is reflected in the market prices. Hence, in the presence of strong correlation, prices are likely higher for slots with short positions than for slots with long positions (Garnier & Madlener, 2014a, p. 7).

One of the common perceptions is that spikes are the results of the market power caused by suppliers. Also, the uncertainty about system load can be an incentive to speculations that will cause price spikes (Zhao et. al., 2007, p. 377).

4 PRICE FORMATION AND PRICE SPIKES ON GERMAN INTRADAY MARKET

In this chapter, the occurrence of extreme price fluctuations commonly known as price spikes is empirically analysed. To be able to better explain the price jumps on intraday markets, fundamental price formation is explained. The chapter then continues with the examination of transaction data from 1st of January 2015 to 31st of December 2016 in order to find the price spikes which occurred during continuous trading. After this, the scenario analysis of price spikes will be concluded with the purpose of finding the most common reasons behind the price spikes using historical data and previous research.

Electricity prices exhibit some unique features like seasonality (at annual level, weekly and daily level), mean reversion, volatility, price spikes or jumps (Girish & Vijayalakshmi, 2013, p. 70; Platen et al., 2005, p. 722; Janczura et. al, 2013, p. 1). A very strong mean reversion is observed in electricity market (Girish & Vijayalakshmi, 2013, p. 71; Goto & Karolyi, 2004, p. 4; Alvarado & Rajaraman, 2000, p. 3). In instances of increased demand, power plants with higher marginal costs will be used (e.g.: oil, diesel) thereby increasing spot electricity prices. But when demand returns to normal condition, these expensive generating stations will not be required to meet extra demand and are turned off thereby making spot electricity prices to revert back to its mean value (Girish & Vijayalakshmi, 2013, p. 71).

Given the enormous market risk and the complexity of the price process, it is challenging to accurately model the price dynamics in the electricity markets (Frömmel et al., 2014, p. 2).

4.1 Price formation

Price formation in the intraday market can be explained (similarly as on day-ahead) through the merit-order model. The merit-order model assumes that power plant owners will offer electricity only if they can recover at least their short-term variable costs (Hagemann, 2013, p. 3). Pape et al. (2016, p. 19) analysis results indicate that a simple supply stack model is able to explain a large share of the price variance in current day-ahead and intraday markets. Thus, fundamental factors are the main drivers for both day-ahead and intraday markets for electricity. The main differences between fundamental and actual prices can be attributed to (avoided) start up-costs, market states, trading behaviour and possible exercising of market power.

Merit-order is an aggregated marginal cost curve of different suppliers. To explain the behaviour of individual power suppliers, the price model developed by Weigt & Hirschhausen

(2008, p. 4229) is used. The model is designed as a cost-minimizing approach subject to technical characteristics of electricity generation.

$$min\,costs = \sum_{t,p}(c_p^t\, g_p^t) + \sum_{t,p} startup_p^t \tag{1}$$

c_p^t = marginal generation costs of plant *p* in hour *t*
g_p^t = actual output of plant *p* in hour *t*
$startup_p^t$ = occurring startup costs in the case the plant has to go online

However, the output of a plant is restricted by lower and upper boundaries due to the thermal capabilities of the generation process, which is called capacity constraint:

$$on_p^t g_p^{min} \leq\; g_p^t \;\leq\; on_p^t g_p^{max} \tag{2}$$

g_p^{max}= maximal available power output
g_p^{min}= minimal necessary generation output to operate a plant
on_p^t= binary condition variable stating if a plant is online (1) or offline (0)

Ramping costs or start-up costs are an important factor when it comes to intraday price formation and can also be considered as one of the reasons for intraday price peaks. Profit maximizing power plant owners will only activate unused flexible power plants at a price that ensures the recovery of all marginal and ramping costs. Ramping costs like start up depreciation due to increased forced outage rates, additional maintenance and loss of life expectancy increase the costs of a spontaneous short term dispatch (Hagemann, 2013, p. 10).

Weigt & Hirschhausen (2008, p. 4229) use the following formula to account for start-up costs:

$$startup_p^t = \; sc_p^t\, g_p^t\, (on_p^t \; - on_p^{t-1}) \tag{3}$$

sc_p^t = startup fuel cost necessary to heat up the power plant *p*, driven by fuel prices, which vary for the time *t*

However, the formula does not take into consideration the abovementioned increased forced outage rates, additional maintenance and loss of life expectancy increase, which means that market participant will need to add a premium to the account for wear and tear of plants in order to be profitable also in the long run. Cycling operations, which include on/off start-up/shut down operations and on-load cycling, can be very damaging to power generation equipment, especially when the plants have not been designed for cycling operations. Financial costs associated with cycling operation are very high (Lefton & Besuner, 2006, p. 20). The formula is corrected for wear and tear costs (wtc_p^t):

$$startup_p^t = sc_p^t\, g_p^t \left(on_p^t - on_p^{t-1}\right) + wtc_p^t \left(on_p^t - on_p^{t-1}\right) \tag{4}$$

According to the type of plant, start-up can take from a few minutes (small gas turbines) up to several days (nuclear), which means not all power plants can provide additional output on intraday. For instance, nuclear plants are base load plants and are inflexible in the short-run and are considered to be must-run plants[11]. Gas turbines and hydro plants are assumed to be able to go online in less than an hour (Weigt & Hirschhausen, 2008, p. 4229).

Decision of power producers to produce can be attributed to their marginal costs. The marginal generation costs c_p^t of a plant p in any considered hour t consist of the fuel costs based on plant efficiency η and fuel price, operating costs, and opportunity costs for emissions based on plant-specific CO2 emissions and the allowance price at the EEX (Weigt & Hirschhausen, 2008, p. 4229):

$$c_p^t = \frac{1}{\eta_p}\, fuelprice^t + \, operation\, costs_p + \, emissions_p\, CO_2\, price^t \tag{5}$$

To sum up, if the price on the market exceeds the plants' marginal costs and start-up costs (*min costs*) and there is available capacity which was not previously marketed, the producer will offer the power on the intraday market. Generators can also be buyers on the intraday market if the market price allows them to replace the previously sold energy with cheaper purchases on the market and thus save on costs of operation and start-up cost. Capacity constraint formula (2) of a generator must be rearranged in order to depict correct market behaviour of a generator which has previously marketed their output:

$$on_p^t(g_p^{min} + g_p^{sold}) \leq g_p^t \leq on_p^t(g_p^{max} + g_p^{purchased}) \tag{6}$$

Generators which are considered must-run cannot buy energy on the market and shut down below their minimal generating requirement – their g_p^{min} is higher. However, if market participants have bought energy on day-ahead market because it was lower than *min costs*, they have more flexibility on the intraday market if the prices soar.

Uniform-clearing price equals the offer price of the generator that produces the last quantity necessary to satisfy demand (Selasinsky, 2015, p. 5), but in case of continuous trading, there are several clearing prices and market participant may need to trade multiple times because of the forecast changes. The total intraday adjustment need is the sum of intraday demand and supply due to power plant outages, wind forecast errors, solar power forecast errors, load

[11] Must Run Generation: the amount of output of the generators which, for various reasons, must be connected to the transmission/distribution grid. Such reasons may include: network constraints (overload management, voltage control), specific policies, minimum number of units needed to provide system services, system inertia, subsidies, environmental causes etc (ENTSO-E, 2016, p. 163)

forecast errors, trading volumes from foreign demand and supply, combined heat and power plant (CHP) optimizations and intraday trading positions. Furthermore, time of the day and day of the week effects may influence liquidity (Hagemann & Weber, 2013, p. 14). Much of the liquidity in intraday markets is provided by agents with balanced positions which are profit motivated and can choose whether to participate in the market. They are often labelled as ”patient traders” (Selasinsky, 2015, p. 13).

In case of high residual load, the situation in the power market becomes tight which can be seen by atypically high prices as signs of scarcity in the market. In case of low residual demand, very low prices can be observed. Base load plants bid prices under their variable costs, which are mainly fuel and CO2 costs, if they want to avoid ramp-down. This is reasonable if they are required in the hours immediately after the low demand. Then they either need to ramp-up again, which requires additional fuel and CO2 costs, or they are not able to ramp-up in time due to idle time restrictions and miss potential earnings. Basically, in these situations, variable costs become a matter of dynamic pricing due to opportunity costs (Nicolosi & Fürsch, 2009, p. 249).

Another reason for increased volatility is that generators as well as demanders do not bid nor ask their true valuation of the quantities they buy or sell. They only engage in transactions which increase their profit. This can be understood as a premium for offering their flexibility (Selasinsky, 2015, p. 14).

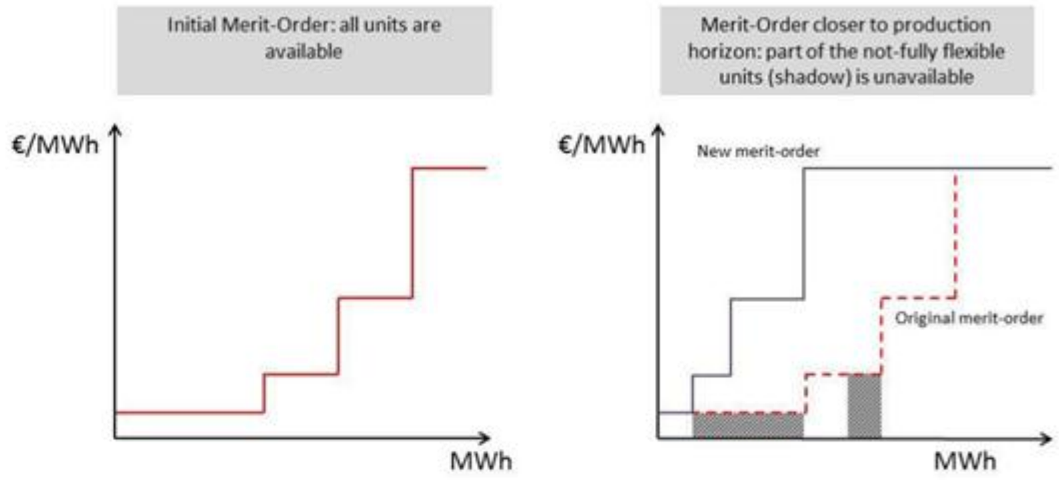
4.2 Reasons for price spikes occurrence

Generally speaking, a price spike is an abnormal market clearing price at time *t* and is significantly different from the price at previous time *t-1* (Zhao et. al., 2007, p. 376). Power markets are prone to very short but high price spikes (Stoft, 2002, p. 336). These extreme prices are created by combinations of unfavourable conditions (Bach, 2009, p. 7). Extremes in temperatures coupled with outages in generation or transmission induce price spikes to occur at random points in time. These price spikes are characteristic for electricity as a traded commodity, which needs to be produced on demand due to limited storage capability. Finally, it appears that the volatility of observed electricity prices tends to rise more with positive shocks than with negative shocks, a phenomenon referred to as the inverse leverage effect (Platen et. al., 2005, p. 723). Prices have the tendency to revert rapidly from price spikes to a mean level. Characteristic times of mean reversion can be explained with changes of weather conditions or recovery from power plant outages (Burger et. al, 2004, p. 3).

Hagemann (2013, p. 9) explains that prices on intraday sometimes react asymmetrically during peak hours when demand meets supply in the steep end of the merit order. The tendency of intraday prices to exhibit peaks strongly above day-ahead prices during peak hours can be explained by the non-linear shape of the merit-order curve, ramping costs and strategic behaviour of market participants.

Prices are more prone to spikes on intraday because of steeper slope of the merit order curve, which is caused by limited flexibility (Hagemann & Weber, 2015, p. 6; Henriot, 2014, p. 4; Selasinsky, 2015, p. 10). Inflexibility of the power generators is caused by technical limitations and potential market commitments. As real-time approaches, the flexibility of the power plant portfolio influences intraday transactions substantially (Selasinsky, 2015, p. 10).

Figure 10. Development of economic merit-order curve due to limited flexibility



Source: Henriot, *Market design with centralized wind power management: handling low-predictability in intraday markets*, 2014, p. 8

The least flexible plants are not able to adapt their production to the demand when getting closer to the production horizon or are only able to adapt it in a restricted way respecting ramping constraints. They therefore withdraw part of their offers from the supply function. The resulting inverse supply function will therefore feature a steeper slope, and prices will get higher when getting closer to the production horizon (Henriot, 2014, p. 4).

Besides fundamental factors of extreme intraday prices, strategic behaviour may also contribute to explain intraday price peaks. In hours with high load, the number of market participants with the ability to deliver upward or downward capacities is already low (Bowden & Payne, 2008, p. 6) and the demand for power production by flexible units is high (Green & Vasilakos, 2010, p. 26). Market participants with flexible power plants may then exploit their temporal monopolistic or oligopolistic market power and charge prices which do not reflect marginal generation or ramping costs but the market participants' willingness to pay in need of upward ramping flexibility. Thus, in addition to ramping costs and the merit-order effect, the market participants' strategic behaviour may contribute to the emergence of price peaks (Hagemann, 2013, p. 11). Stoft (2002, p. 329) also argues that market power can be exercised in real-time markets because market participants can wait no longer.
Market power abuse is expected to occur mainly when demand is close to the capacity limit (Weigt & Hirschhausen, 2008, p. 4231). However, long-term contracts and regulatory obligations to serve load are an often overlooked aspect of market structure. These can greatly increase competitiveness in the spot market. A generator that has sold 90% of its power

forward has only 1/10 the incentive to raise the price in the spot market as an identical generator that has sold nothing forward (Stoft, 2002, p. 80).

The missing office occupation of small market participants during the off-peak periods and on Sundays reduces the total number of market participants and thus seems to reduce competition. Reduced competition during these hours may influence trading strategies like the retention of capacity or offering available power plant capacities at non-competitive prices with the aim of maximization of trading profits, which can lead to higher prices (Hagemann & Weber, 2013, p. 27). Combination of limited flexibility of power production and reduced competition during out-of-office hours can result in price spikes. For instance, if the wind production is high during night hours with low load, the producers with ramp-down flexibility may wait for prices to significantly drop before they offer their flexibility on the market. Low residual loads imply that only few power generators were dispatched in the day-ahead auction. It is hence more likely that relatively inflexible generators, e.g. base-load plants and producers of combined heat and power (CHP), reduce their output. Their inflexibility can lead them to require a high spread between their day-ahead offer price and their intraday bid price. They may therefore bid very low or negative prices in the intraday market. This lowers the probability of having to reduce output but ensures an adequate compensation if respective transactions come about (Selasinsky, 2015, p. 10).

4.3 Price spikes in German intraday power market

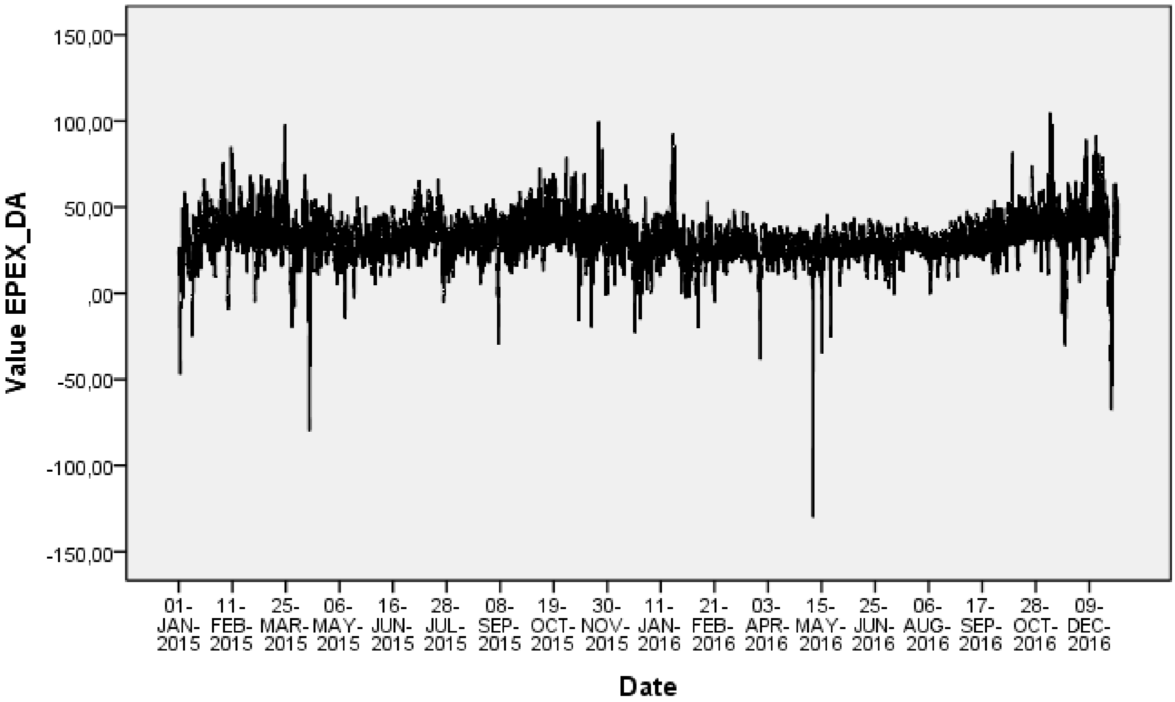
To determine the occurrence of price spikes in German intraday power market, historical data is analysed. Figure 11 depicts the distribution of day-ahead auction prices (EPEX_DA) and Figure 12 represents weighted average intraday prices (Cont_WA) for a time period from 1st January 2015 to 31st December 2016. It is evident from Figure 13 that both markets exhibit price spikes and that the prices follow a similar pattern.

Figure 11 represents hourly prices traded on the day ahead auction (EPEX_DA). It is visible from the graph that prices sometimes reached extremely high or low levels and then quickly reverted back to mean (mean reversion). It is evident from the chart that prices vary considerably and are prone to spikes, as already noted in the previous chapters of this thesis.

Figure 12 represents the distribution of weighted average hourly prices traded on continuous intraday market (Cont_WA). We can see that intraday prices follow a similar pattern as day-ahead prices, but can, however, deviate significantly. This deviation is depicted in Figure 13.

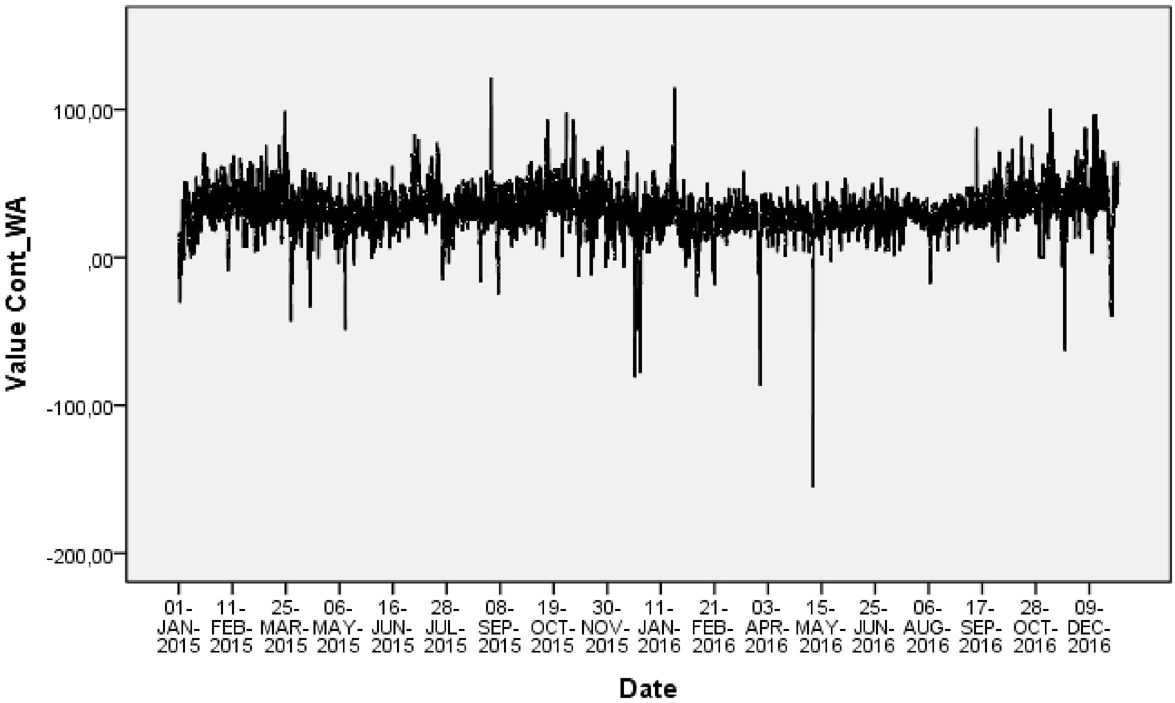
Figure 13 presents the difference between EPEX_DA and Cont_WA. It is evident that the differences can be very significant which confirms the assumption that price spikes on day-ahead do not necessarily correspond to intraday spikes and vice-versa. This can be contributed to changes of the fundamental factors after day-ahead market closes.

Figure 11. Price distribution of hourly blocks for EPEX_DA for 2015 and 2016 (EUR/MWh)



Source: own calculations based on EPEX data

Figure 12. Price distribution of hourly blocks for Cont_WA for 2015 and 2016 (EUR/MWh)

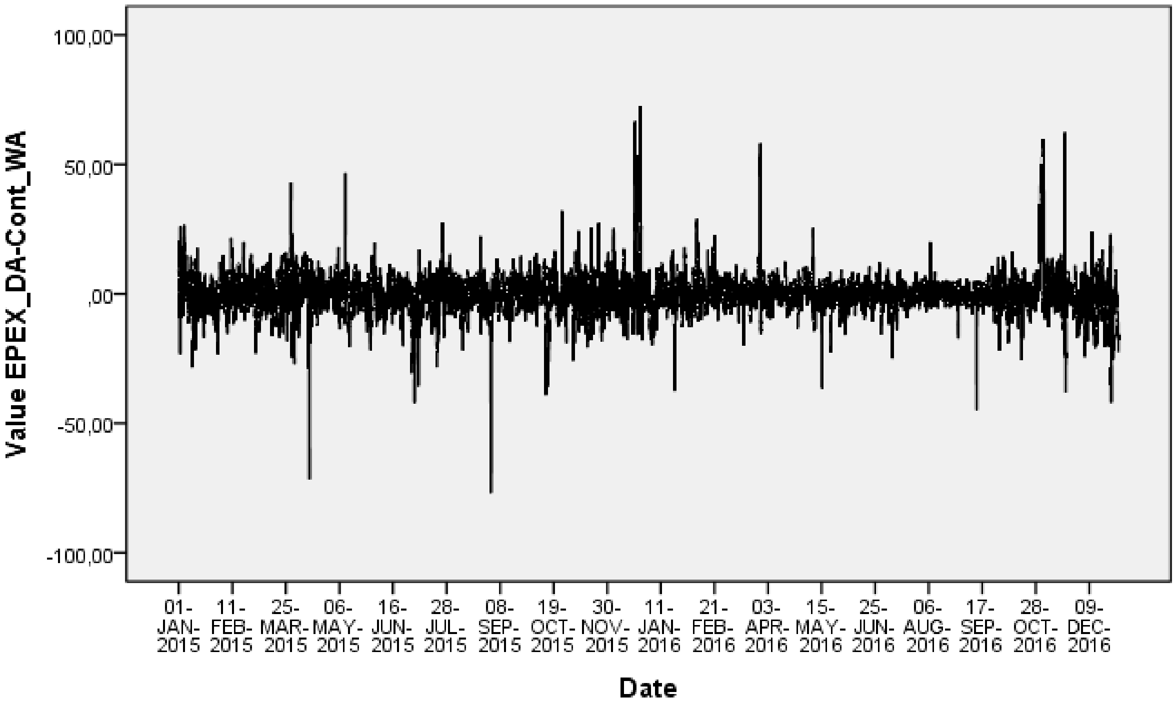


Source: own calculations based on EPEX data

Furthermore, price spikes which occurred during the observed period need to be outlined and further investigated. The focus will be on price spike occurrence on intraday level. However, EPEX_DA will be taken to evaluate if the market was regarded as tight for the delivery period.

In order to determine the price spikes, data is analysed using boxplot diagrams in order to represent more transparently extreme price behaviour. The boxplot diagrams are based on full transaction data of continuous intraday trading in order to correctly represent the price movements.

Figure 13. Difference between EPEX_DA and Cont_WA in 2015 and 2016 (EUR/MWh)

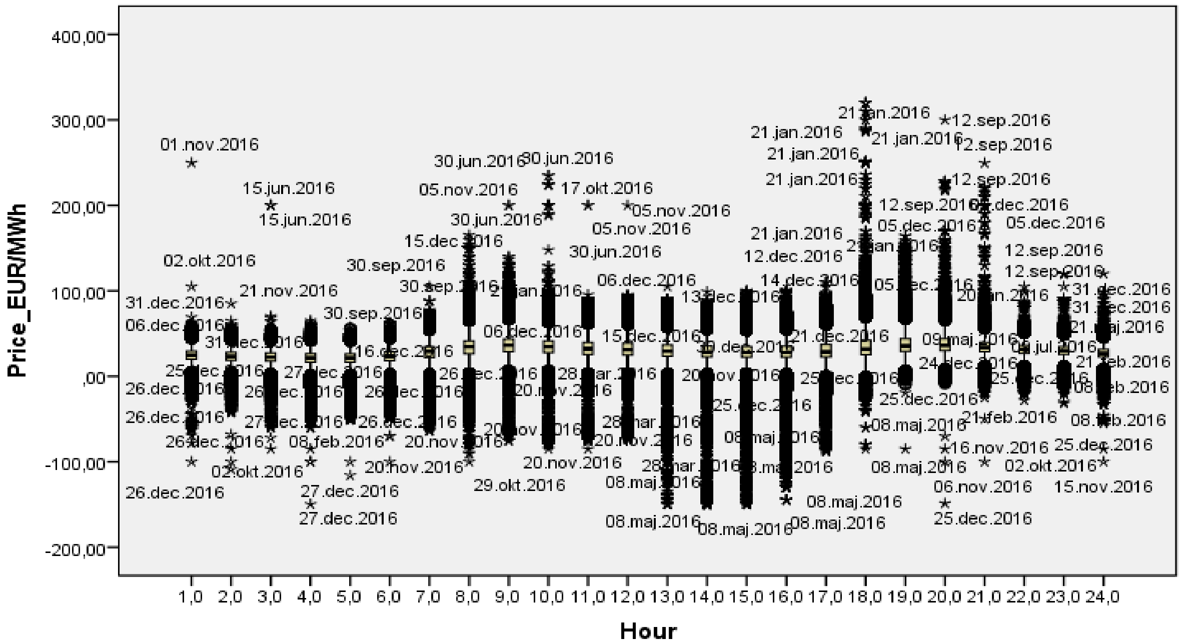


Source: own calculations based on EPEX data

The boxplot of 2016 data reveals (see Figure 14) two dates with the occurrence of high prices, which is interesting for further qualitative scenario analysis – 21st January 2016 and 12th September 2016. In the negative prices area, another two dates can be highlighted – 28th March 2016 and 8th May 2016. To capture all price spikes in 2016, analysis has to be conducted based on monthly data because the seasonal influence has a big effect on price variance (Janczura et. al., 2013, p. 1). Monthly boxplots of price distribution are available in APPENDICES 4 - 26. Because most of the price spikes are caused by similar reasons, only four scenarios from 2016 will be presented.

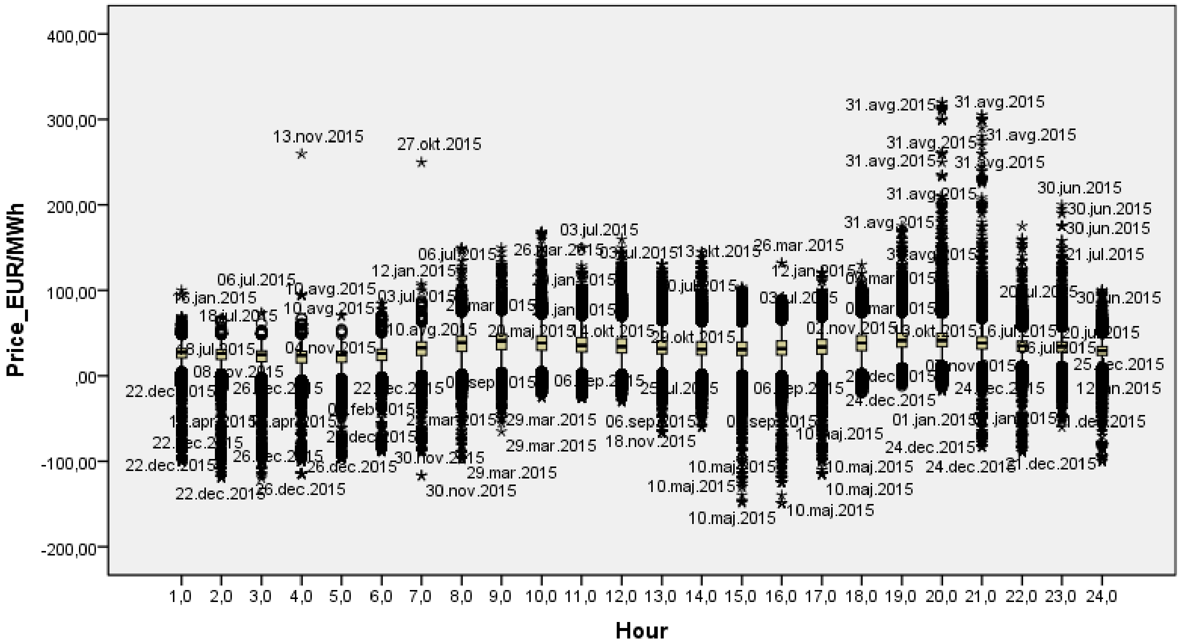
In case a price spike is detected, the scenario which caused the occurrence is examined using qualitative research by examining historical data and/or literature review. The case analysis of price spikes is also useful in the sense that price spikes will become ever more occurrent with the rising share of installed renewables. Janczura et al. (2013, p. 97) classified all prices exceeding the mean price level as spikes by three standard deviations.

Figure 14. Price distribution of continuous trading in 2016 (outliers removed)



Source: own calculations based on EPEX data

Figure 15. Price distribution for continuous trading in 2015 (outliers removed)



Source: own calculations based on EPEX data

If we apply the criterion of three standard deviations, prices below –13.26 EUR/MWh and above 76.97 EUR/MWh can be considered as price spikes (see Table *7*).

Table 7. Descriptive Statistics for 2015 and 2016

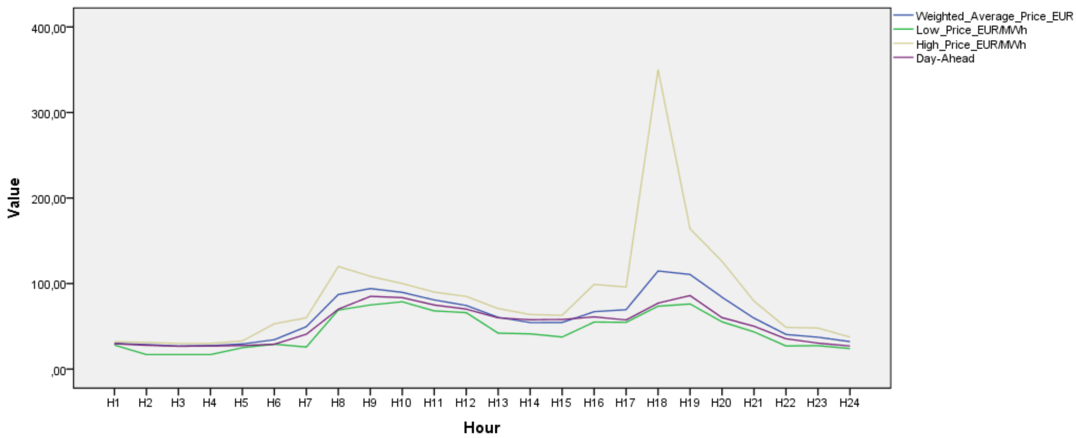
	N	Mean	Std. Deviation
Price_EUR/MWh	5497133	31.8549	15.03932

Source: own calculations based on EPEX data

Case 1: 21st January 2016

The scenario occurred in the situation when market was tight as it is noticeable in high day-ahead prices. However, weighted average price on continuous market exhibits higher values in most hours. This was due to a high system deficit amid lower-than-expected wind power, thermal power generation and strong demand. Wind power averaged at 1.6 GW which was 1.4 GW below earlier forecasts. Also the demand-intensive early evening hours exhibited below zero temperatures in many parts of Germany lifting peak demand (Argus European Electricity, 2016a, p. 16).

Figure 16. Day-ahead and continuous intraday prices (high, low, weighted average) for the delivery day of 21st January 2016 (in EUR/MWh)



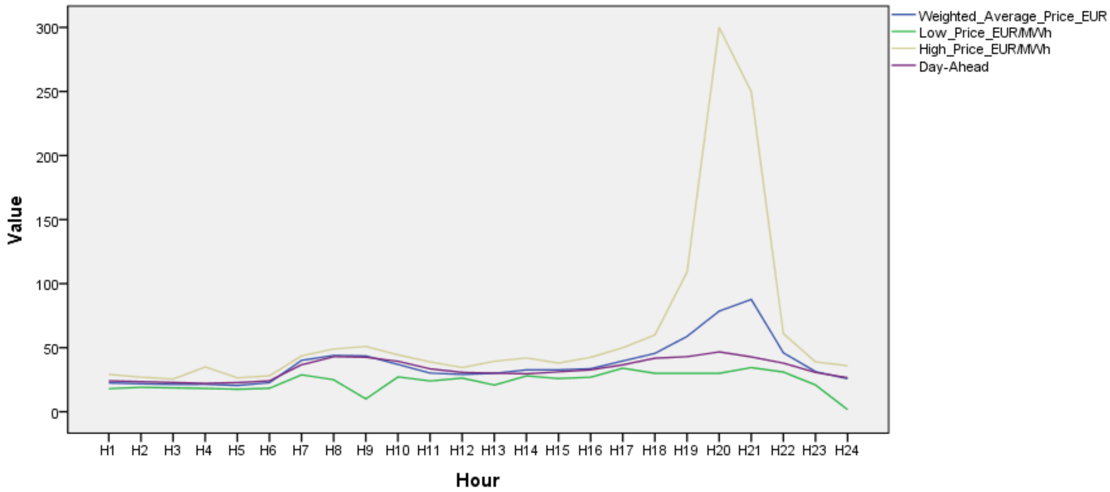
Source: own calculations based on EPEX data

Hour 18 traded the highest, reaching its peak at 350 EUR/MWh (day-ahead price was 77.13 EUR/MWh). For this hour, an average system deficit of 2.3 GW was reported, wind generation was 1.3 GW less than forecast. TSOs called on nearly 1.3 GW of secondary control reserve and 875 MW of minute control reserve from 17:00 to 18:00 which might have further tightened capacity available to the wholesale power market amid already lower-than-scheduled thermal power output. At 17:00, hard coal-fired power plants fed around 19 GW into the grid, lignite plants contributed 18.1 GW and gas-fired plants 9.4 GW, which was around 2 GW, 600 MW and 700 MW, respectively, below scheduled output (Argus European Electricity, 2016a, p. 16).

Case 2: 12th September 2016

In this scenario, prices again peaked because of the combination of strong demand and low wind. However, price spikes were intensified because of unavailable nuclear generation, which was around 8.9 GW due to on-going maintenance at the Neckarwestheim reactor (-1.3 GW) and Grohnde (-260 MW). A major factor which intensified price spikes was high solar production during the day (Argus European Electricity, 2016b, p. 18). Solar was up to 22.55 GW at 13:00 (Fraunhofer ISE, 2017) and dropped to 0 MW by 20:00. Prices started to spike in hours when solar generation was in decline. This sharp decline caused increased demand for conventional generation ramp-up which is associated with high costs. Unavailability of nuclear reactors resulted in a steeper merit order curve which resulted in a more pronounced price jump.

Figure 17. Day-ahead and continuous intraday prices (high, low, weighted average) for the delivery day of 12th September 2016 (in EUR/MWh)



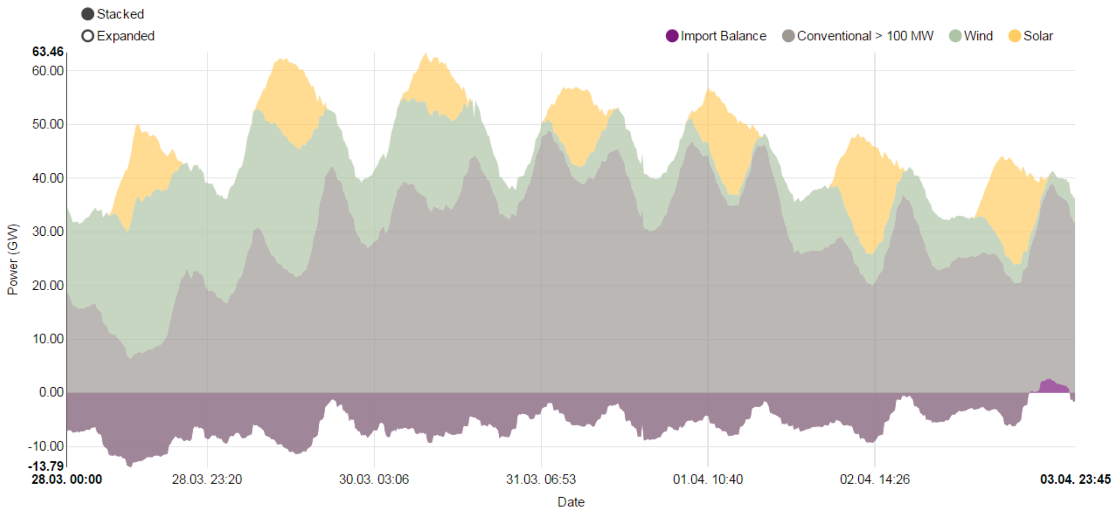
Source: own calculations based on EPEX data

Case 3: 28th March 2016

28th March 2016 was a public holiday in Germany. Holidays are characterised with low demand levels due to reduced economic activity. In case of high renewable in-feed, this can cause prices to significantly drop due to inability to quickly reduce conventional generation.

Hourly and 15-minute contracts on 28th March 2016 settled at a weighted average below 0 EUR/MWh as combined wind and solar power generation made up around 60% of peak demand, with must-run thermal capacity and limited intraday cross-border trading opportunities adding to an oversupplied German system. Solar power generation averaged 8.3 GW and peaked at 13 GW, while wind power generation averaged 20.4 GW (Argus European Electricity, 2016c, p. 18). For example, must-run capacity is estimated at 20 GW (Fraunhofer ISE, 2016, p. 40), which means it is technically challenging to lower the conventional output below this level. Market participants that can offer ramp-down flexibility may only be willing to do so at a substantial premium. At the beginning of the merit-order, must-run capacities and base load plants satisfy the electricity demand. To ramp base load plants down below their minimum load threshold or up from a downtime is costly (Hagemann, 2013, p. 11).

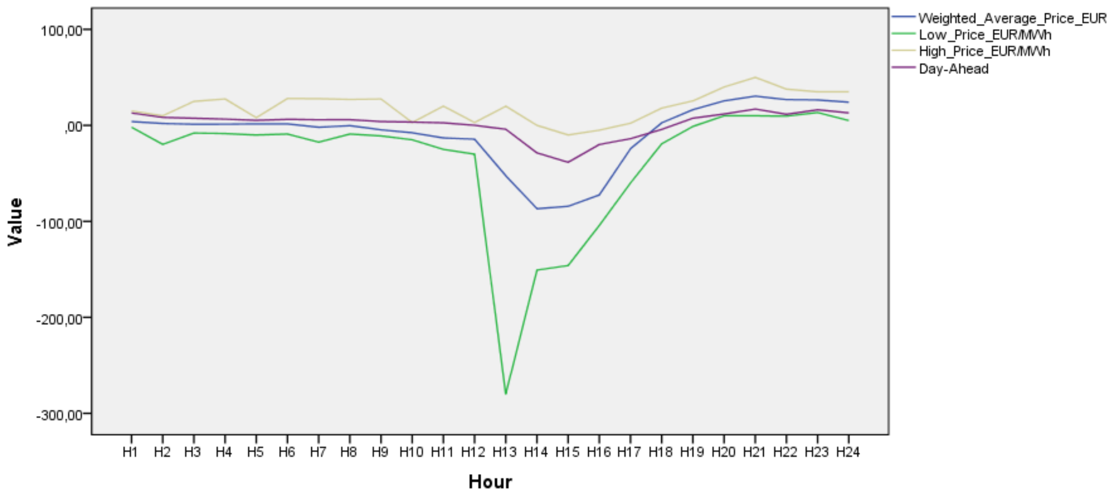
Figure 18. Electricity production in Germany in week 13, 2016 in GW



Source: Fraunhofer ISE, n.d.

Combined wind and solar power generation averaged 38.7 GW in hour 12, around 450 MW more than forecast and making up around 69% of domestic demand. Hard coal-fired power generation was already scheduled at a low level of 2.5 GW on average and a peak output of 4 GW with actual production largely in line with that forecast, suggesting that must-run capacity could not be reduced further to avoid oversupply. Lignite-fired generation averaged 9.7GW yesterday, just around 851 MW less than scheduled (Argus European Electricity, 2016c, p. 19).

Figure 19. Day-ahead and continuous intraday prices (high, low, weighted average) for the delivery day of 28th March 2016 (in EUR/MWh)



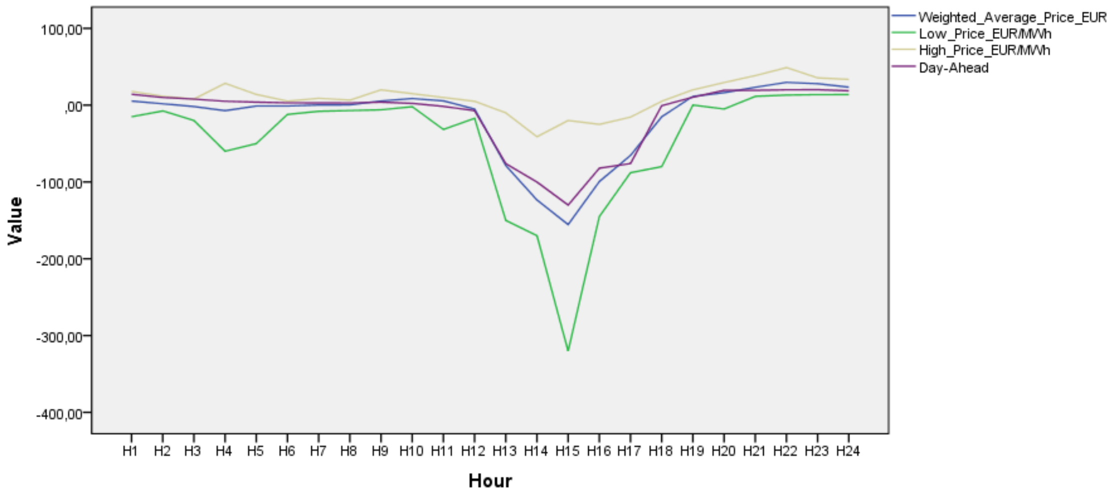
Source: own calculations based on EPEX data

Case 4: 8th May 2016

Similarly, as on 28th March 2016, on 8th May prices were already negative on day-ahead because of low demand on Sunday, high wind and solar output and the inability of must-run capacity to shut down. Cross-border capacity was also limited, which contributed to the even higher excess supply of the German power (Argus European Electricity, 2016d, p. 20).

If prices are low in Germany on day-ahead, cross-border capacity is limited on intraday because market participants use available capacity in order to benefit from the difference in price between the markets. If the renewable feed-in is higher than expected, this has a significant impact on intraday prices, pushing them further down.

Figure 20. Day-ahead and continuous intraday prices (high, low, weighted average) for the delivery day of 8th May 2016 (in EUR/MWh)



Source: own calculations based on EPEX data

CONCLUSION

The thesis consists of two parts, divided into four chapters. The first part is dedicated to a general economic analysis of power markets, while the second part focuses on power price volatility.

In the first chapter, the power markets are analysed in general from the economic point of view. Main recent developments in the policies of the power market are also shortly presented, since new policies are the basis for market development and also have an effect on price volatility. The second chapter is dedicated to an analysis of German power market, as one of the most liquid power markets in Europe. In this section the market structure, policies and models, and basic fundamentals of the German power market are determined.

In the third chapter, volatility of German intraday power market is assessed and main price determinants are outlined. Fourth chapter provides an analysis of fundamental price formation to better explain price volatility. Furthermore, scenarios of price spikes are analysed in order to determine the causes of price jumps.

The main finding of our research is that intraday prices are indeed more volatile than day-ahead prices. After analysing the main determinants and price spike scenarios, it is arguable that price spikes could occur more often due to rising shares of intermitted sources penetration and reduced incentives to invest in conventional generation due to the phase-out strategies and low market prices.

Understanding of price spikes is crucial for further market development, since frequent price spikes can bring unfavourable financial consequences to some market players, while others can benefit greatly from it and even induce them to exercise market power.

The price spikes are caused by non-linearity of merit order curve which causes prices to soar in cases of tight supply and fall when the market is oversupplied. The effect is further induced by ramping costs and possible unavailability of flexible generation on short notice. Inflexibility is caused by technical limitations and possible market commitments. Strategic behaviour can also induce price spikes, for instance, when producers demand a high premium for offering their flexibility on the market. Intraday markets are arguably a good environment for market participants to exercise possible market power.

Market development should take into consideration how to avoid price spikes which arise from exercising market power in the future. Given that four largest companies own merely 5% of renewable generation and around 60% of total installed capacity, they can ask for substantial price premiums for offering flexibility and set the price level at customers' willingness to pay. Buyers will try to avoid often costly and uncertain imbalance costs. As real-time approaches, the risk for market manipulation is higher because the demanders can wait no longer due to the approaching delivery. By exercising wait-and-see trading behaviour because of uncertainty of intermittent power sources forecast, merit-order curve gets even steeper.

Exercising market power can be limited by increasing cross-border transfer capacity and shortening the time for cross-border trade execution in order for renewables' deviations to be traded as close to real time as possible.

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APPENDIXES

TABLE OF APPENDIXES

APPENDIX A: EPEX continuous intraday prices for years 2015 and 2016

Table 1. EPEX continuous intraday prices for years 2015 and 2016 (outliers removed with threshold -151 > Price > 401)

Hour		N	Mean	Variance	Skewness		Kurtosis	
		Statistic	Statistic	Statistic	Statistic	Std. Error	Statistic	Std. Error
1	Price_EUR/MWh	127153	24,5	128,556	-3,105	0,007	25,271	0,014
2	Price_EUR/MWh	130834	22,8423	146,259	-3,663	0,007	28,82	0,014
3	Price_EUR/MWh	140723	21,533	153,679	-3,268	0,007	24,084	0,013
4	Price_EUR/MWh	146026	20,7522	141,831	-2,696	0,006	19,746	0,013
5	Price_EUR/MWh	147624	20,9265	129,955	-2,643	0,006	17,3	0,013
6	Price_EUR/MWh	144205	22,9561	128,443	-2,264	0,006	14,116	0,013
7	Price_EUR/MWh	150410	28,7757	178,079	-1,574	0,006	8,752	0,013
8	Price_EUR/MWh	176249	35,0531	235,663	-0,759	0,006	4,856	0,012
9	Price_EUR/MWh	199229	37,5308	239,268	-0,271	0,005	3,572	0,011
10	Price_EUR/MWh	234169	36,2097	207,215	-0,143	0,005	6,391	0,01
11	Price_EUR/MWh	272902	34,514	199,368	-0,199	0,005	4,855	0,009
12	Price_EUR/MWh	303566	33,8083	203,376	0,137	0,004	4,186	0,009
13	Price_EUR/MWh	324170	31,7608	222,573	-0,917	0,004	11,34	0,009
14	Price_EUR/MWh	328466	30,4661	244,217	-1,376	0,004	15,614	0,009
15	Price_EUR/MWh	319148	29,8585	252,553	-1,298	0,004	12,796	0,009
16	Price_EUR/MWh	309021	30,305	248,909	-1,254	0,004	11,49	0,009
17	Price_EUR/MWh	295593	32,085	244,315	-0,225	0,005	4,432	0,009
18	Price_EUR/MWh	285142	37,0999	289,654	1,417	0,005	8,89	0,009
19	Price_EUR/MWh	278549	39,8961	216,962	1,111	0,005	3,976	0,009
20	Price_EUR/MWh	269763	40,1354	203,926	1,934	0,005	18,475	0,009
21	Price_EUR/MWh	247312	36,202	155,271	1,969	0,005	35,623	0,01
22	Price_EUR/MWh	228287	32,4917	114,645	-0,889	0,005	10,829	0,01
23	Price_EUR/MWh	222315	31,4539	111,316	0,091	0,005	9,074	0,01
24	Price_EUR/MWh	216277	26,9961	111,213	-1,664	0,005	11,176	0,011

APPENDIX B: EPEX continuous intraday volumes for years 2015 and 2016

Table 2. EPEX continuous intraday volumes for years 2015 and 2016

Hour		N	Sum	Mean
1	Volume_MW	127153	1296691	10,198
2	Volume_MW	130834	1266364	9,679
3	Volume_MW	140723	1372986	9,757
4	Volume_MW	146026	1428967	9,786
5	Volume_MW	147624	1477287	10,007
6	Volume_MW	144205	1469031	10,187
7	Volume_MW	150410	1537395	10,221
8	Volume_MW	176249	1756139	9,964
9	Volume_MW	199229	2036460	10,222
10	Volume_MW	234169	2407685	10,282
11	Volume_MW	272902	2831066	10,374
12	Volume_MW	303566	3186733	10,498
13	Volume_MW	324170	3424795	10,565
14	Volume_MW	328466	3495074	10,641
15	Volume_MW	319148	3387984	10,616
16	Volume_MW	309021	3220017	10,42
17	Volume_MW	295593	3031178	10,255
18	Volume_MW	285142	2876085	10,086
19	Volume_MW	278549	2822847	10,134
20	Volume_MW	269763	2762163	10,239
21	Volume_MW	247312	2477080	10,016
22	Volume_MW	228287	2227167	9,756
23	Volume_MW	222315	2162837	9,729
24	Volume_MW	216277	2194642	10,147

APPENDIX C: Boxplots for continuous transaction data for individual months of 2015 and 2016

Figure 1. Boxplot for January 2015

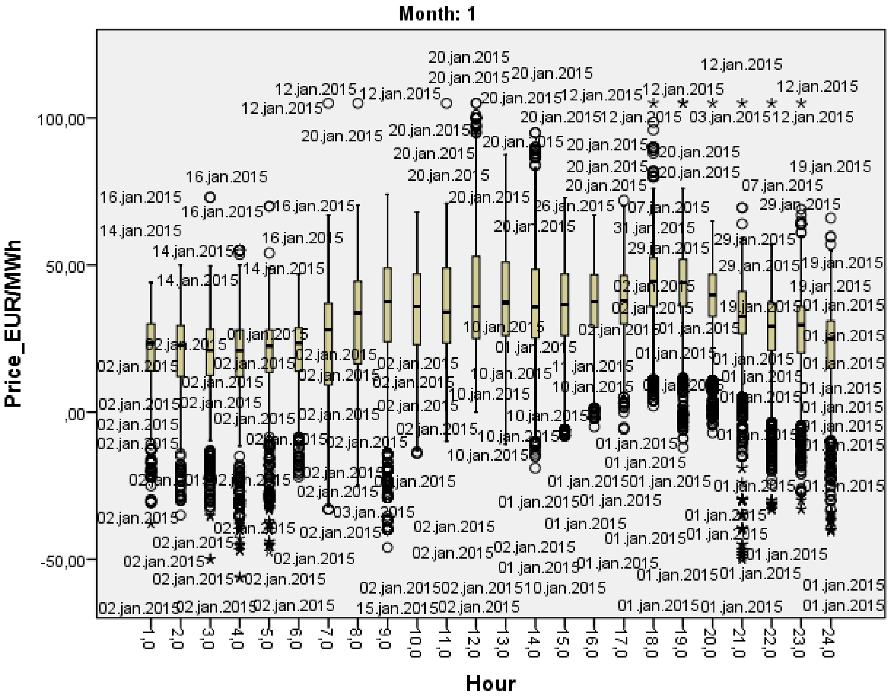

Figure 2. Boxplot for February 2015

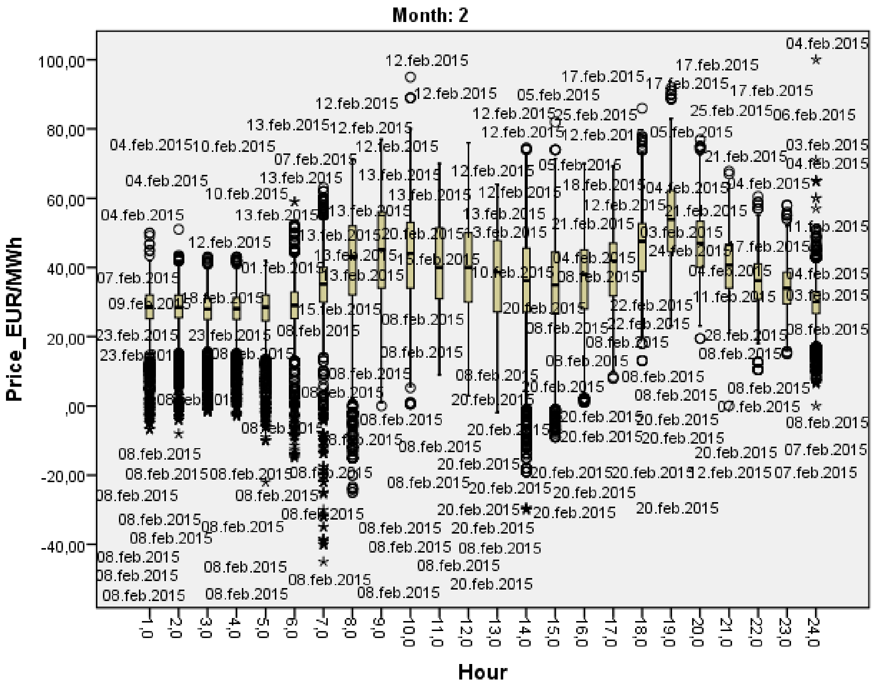

Figure 3. Boxplot for March 2015

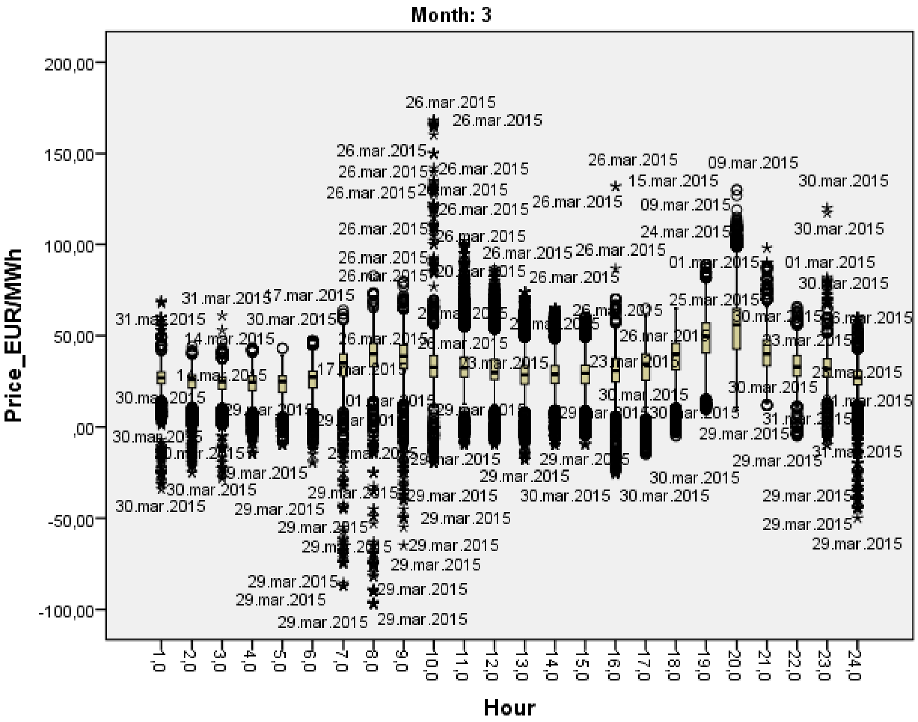

Figure 4. Boxplot for April 2015

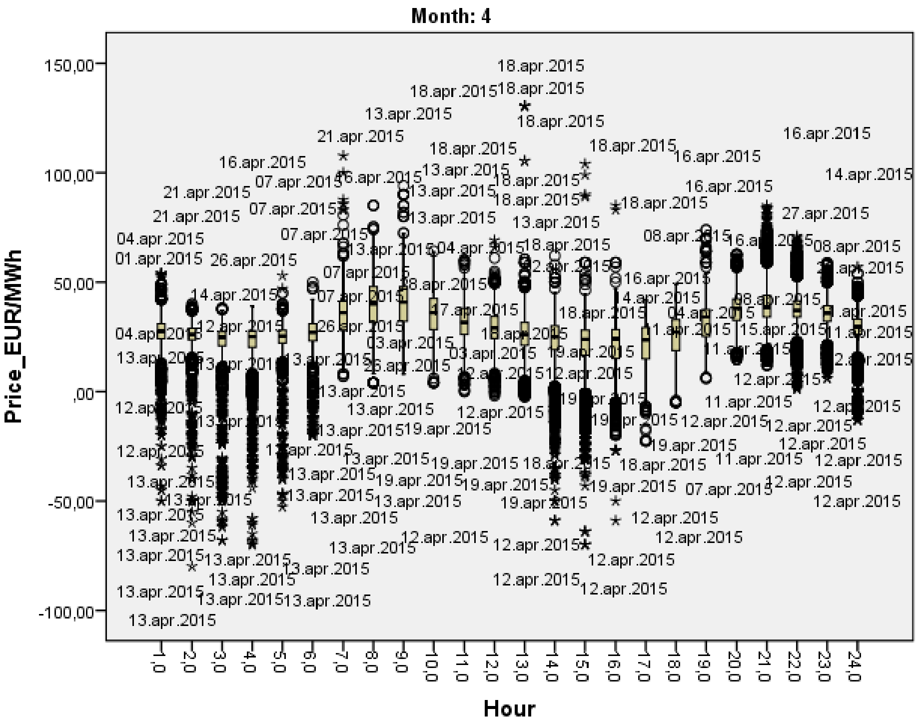

Figure 5. Boxplot for May 2015

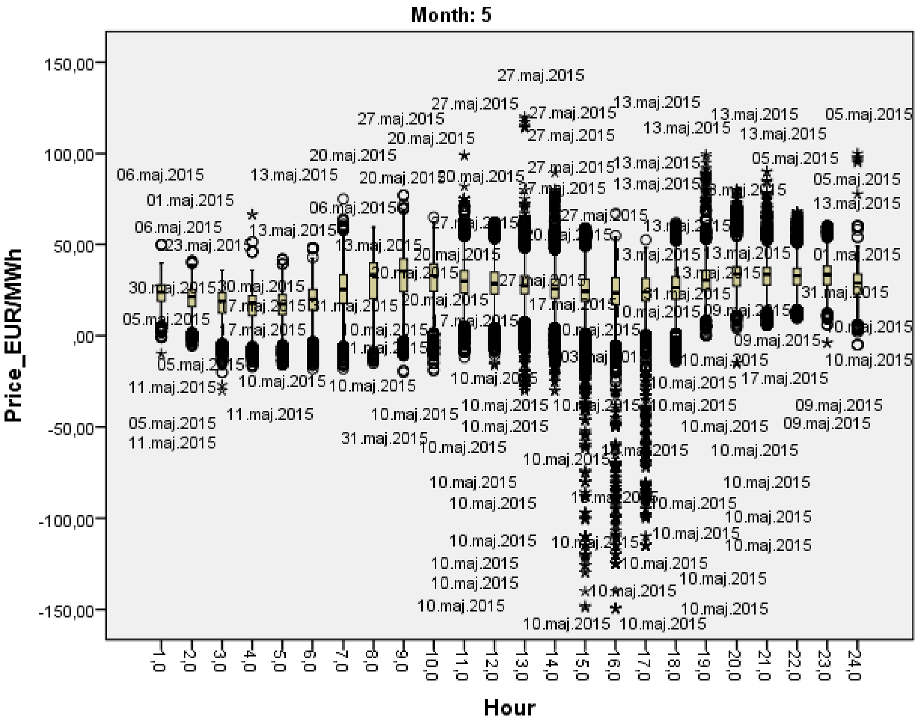

Figure 6. Boxplot for June 2015

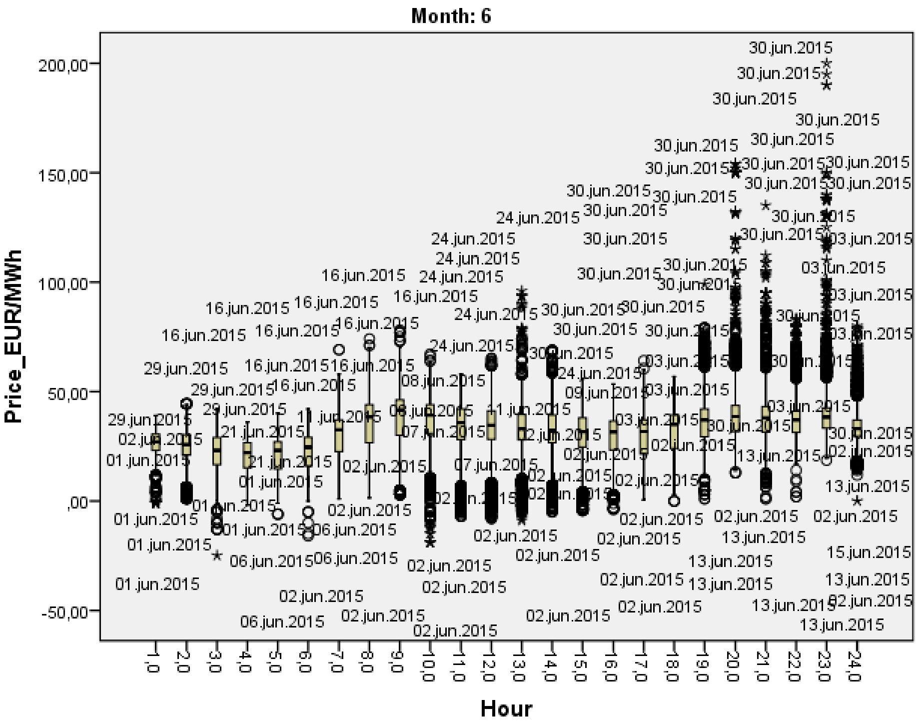

Figure 7. Boxplot for July 2015

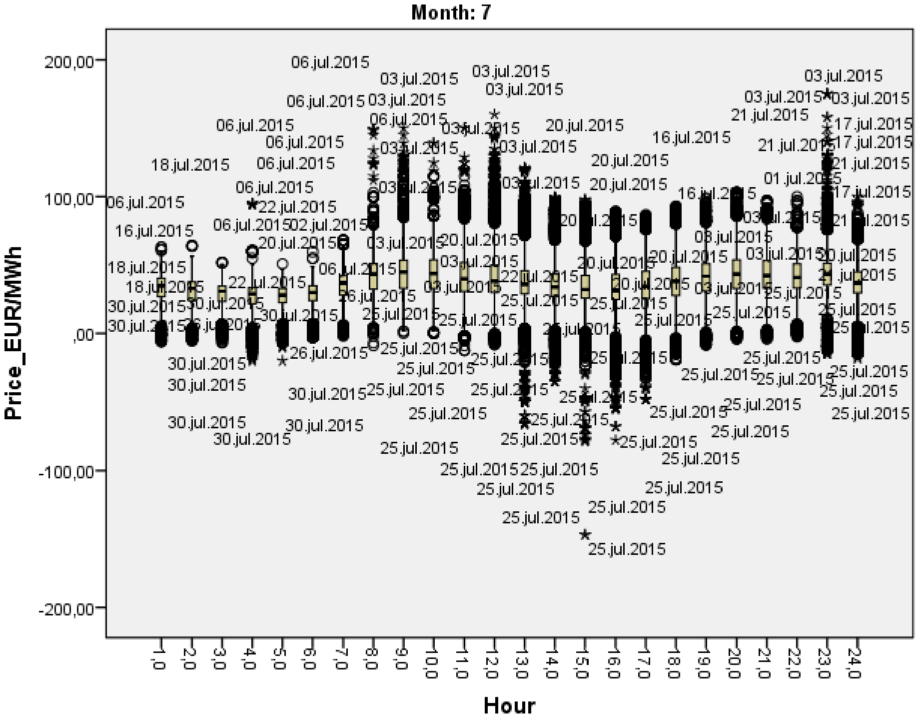

Figure 8. Boxplot for August 2015

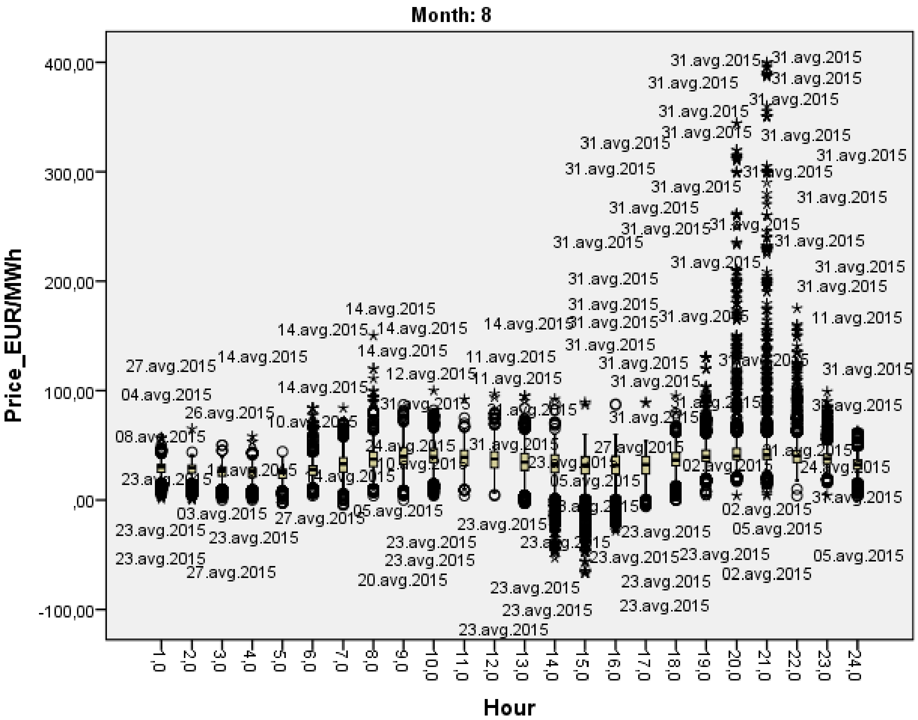

Figure 9. Boxplot for September 2015

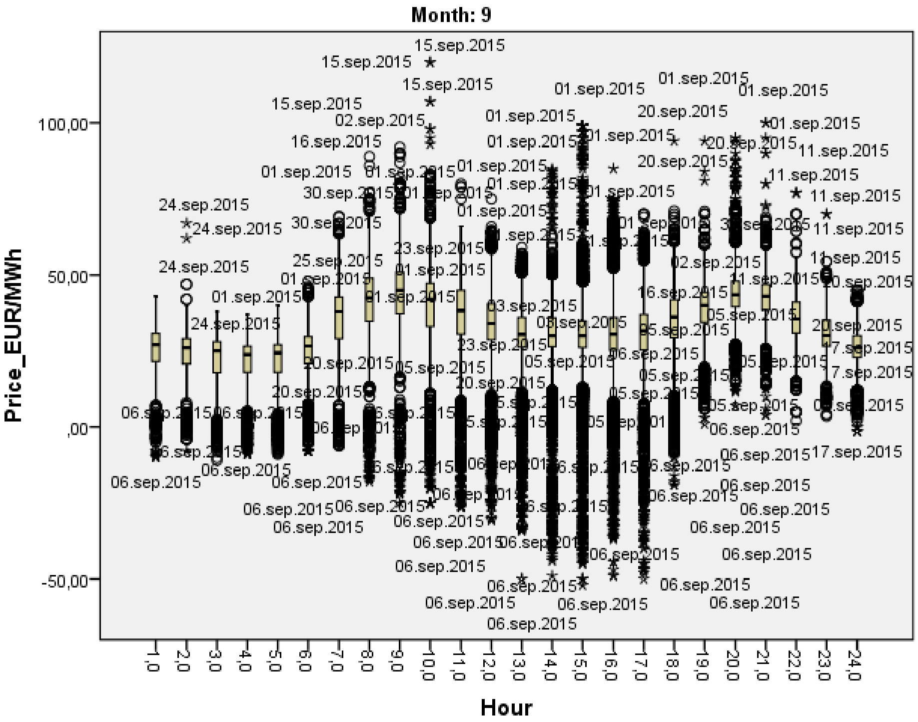

Figure 10. Boxplot for October 2015

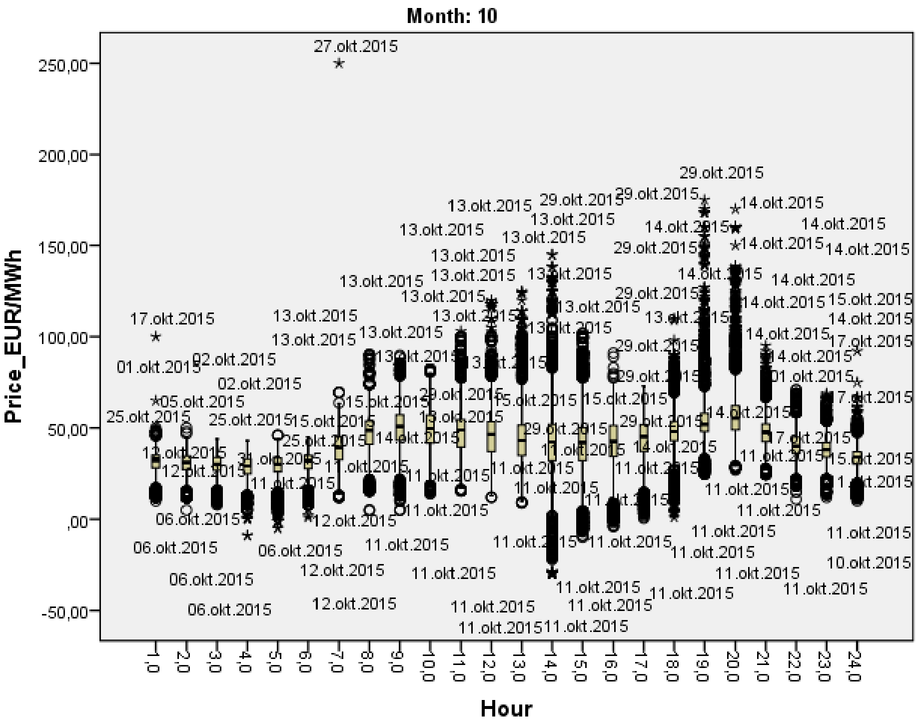

Figure 11. Boxplot for November 2015

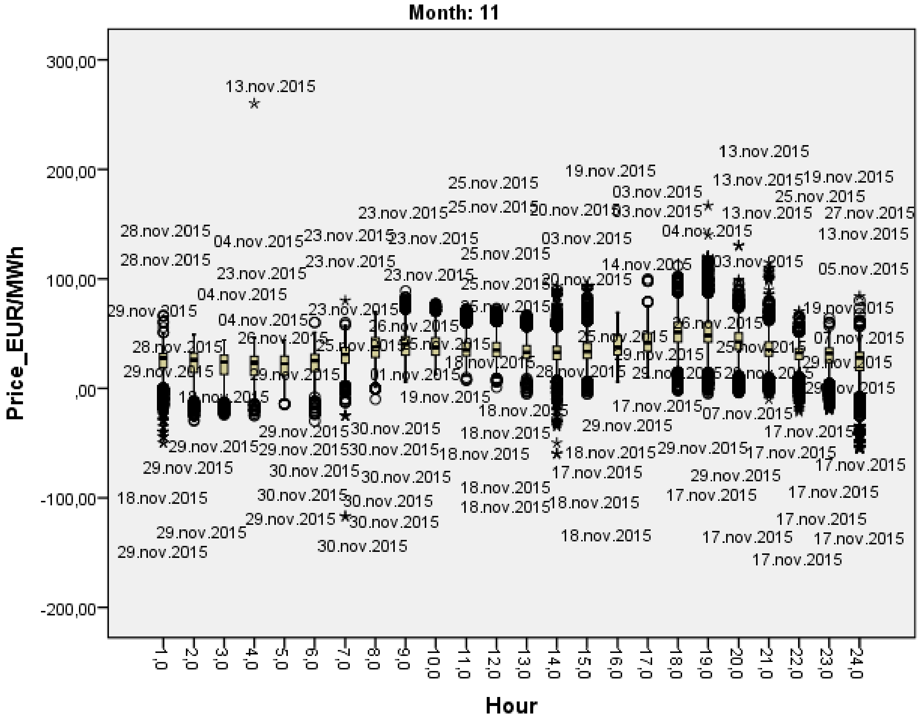

Figure 12. Boxplot for December 2015

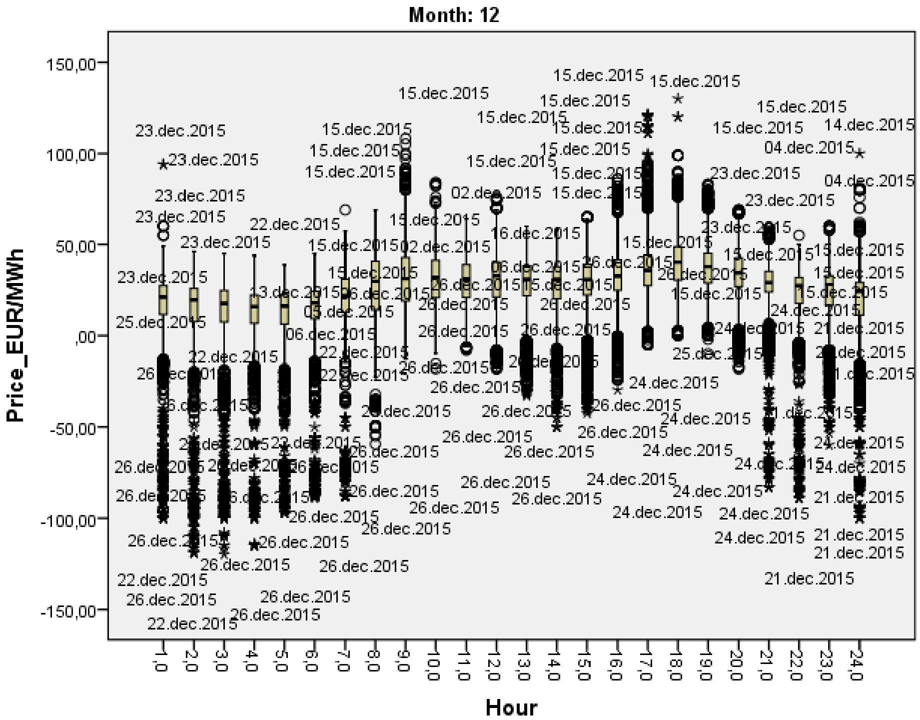

Figure 13. Boxplot for January 2016

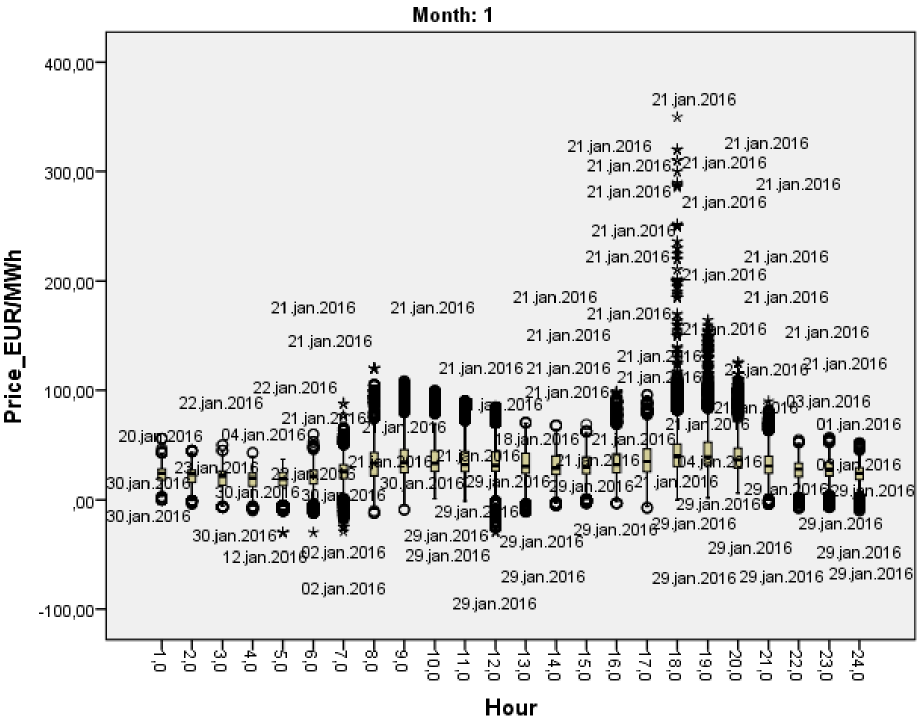

Figure 14. Boxplot for February 2016

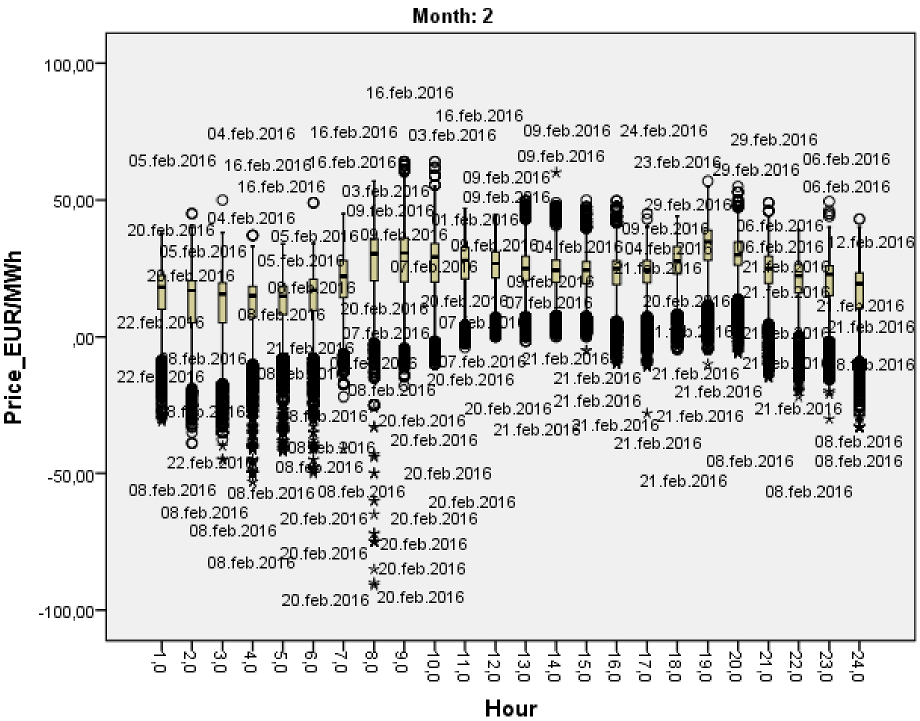

Figure 15. Boxplot for March 2016

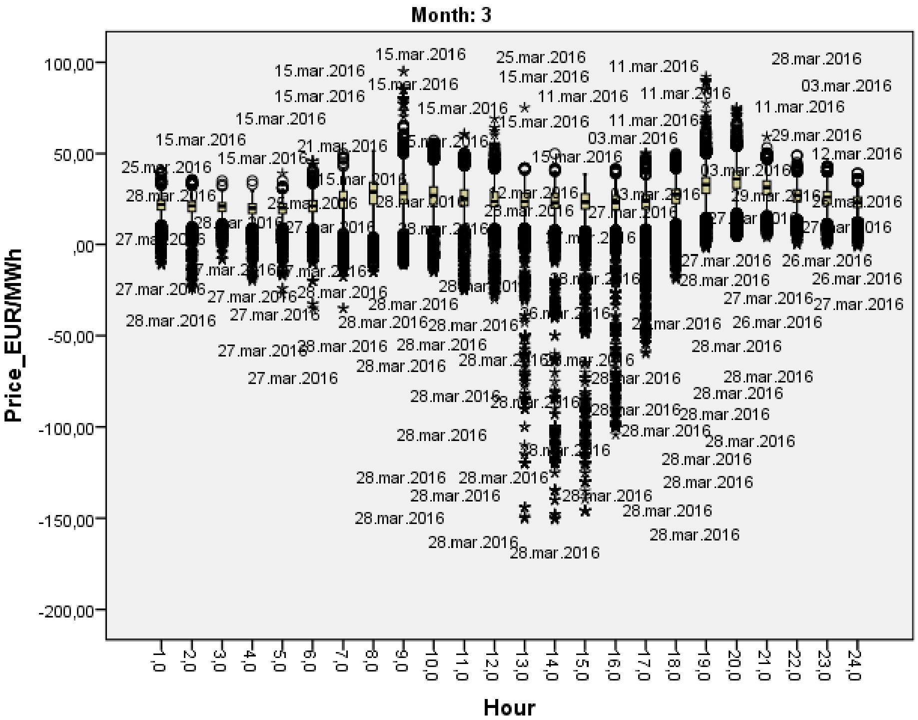

Figure 16. Boxplot for April 2016

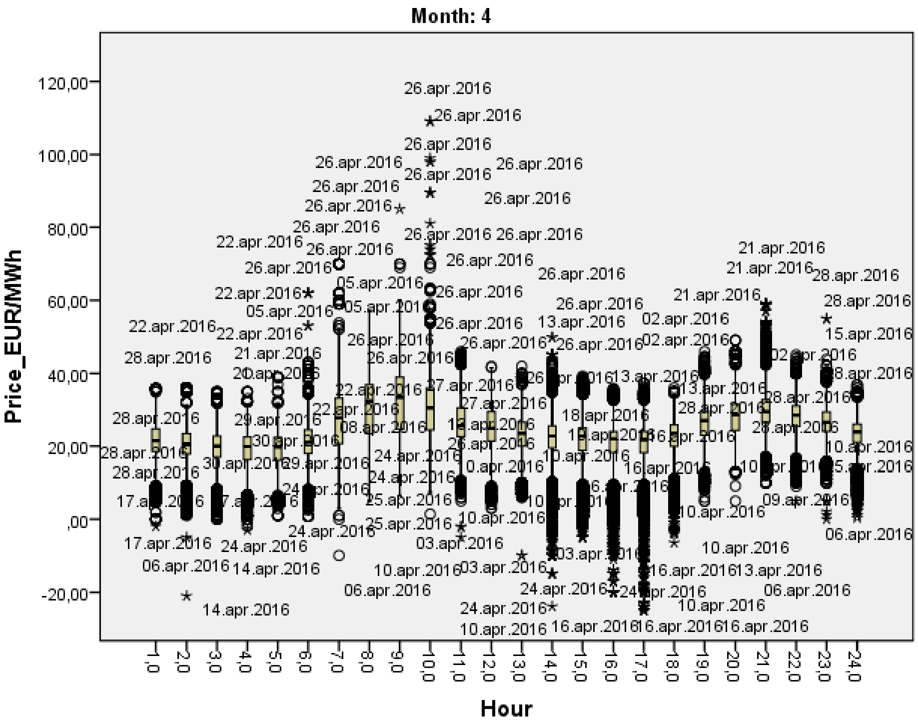

Figure 17. Boxplot for May 2016

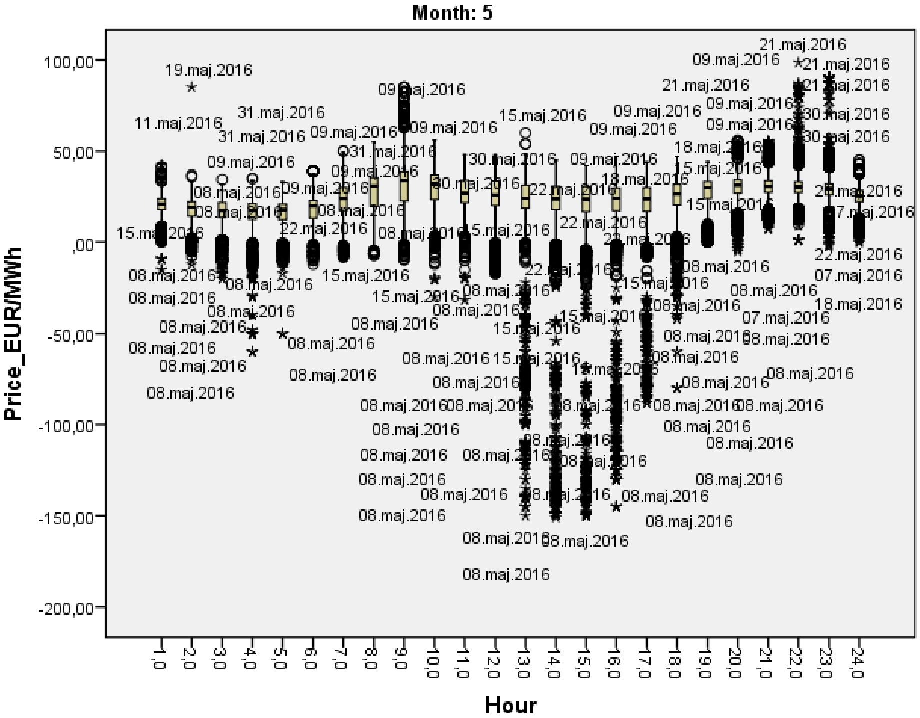

Figure 18. Boxplot for June 2016

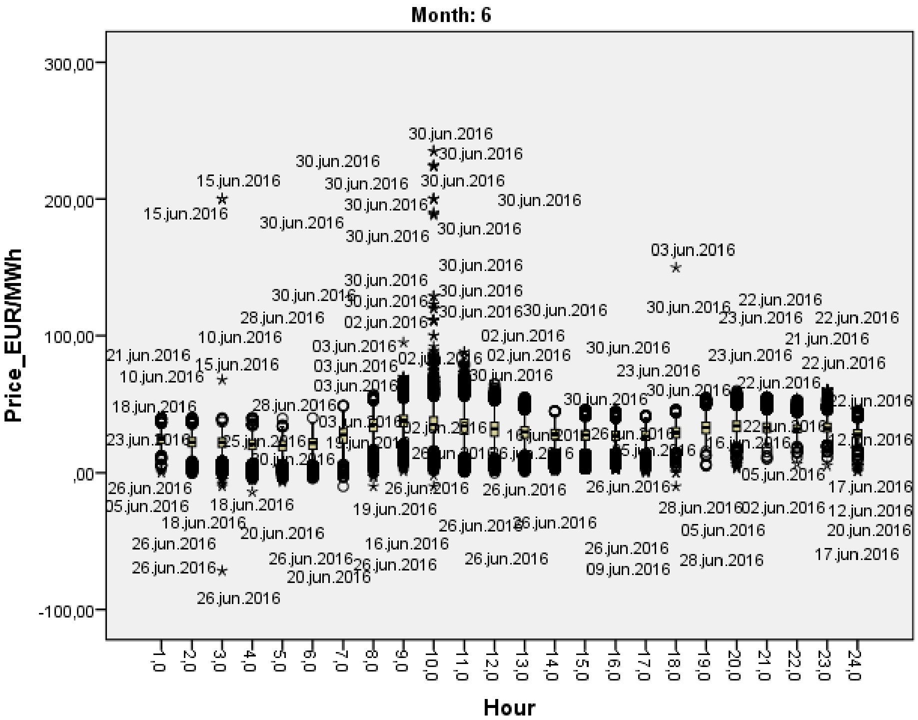

Figure 19. Boxplot for July 2016

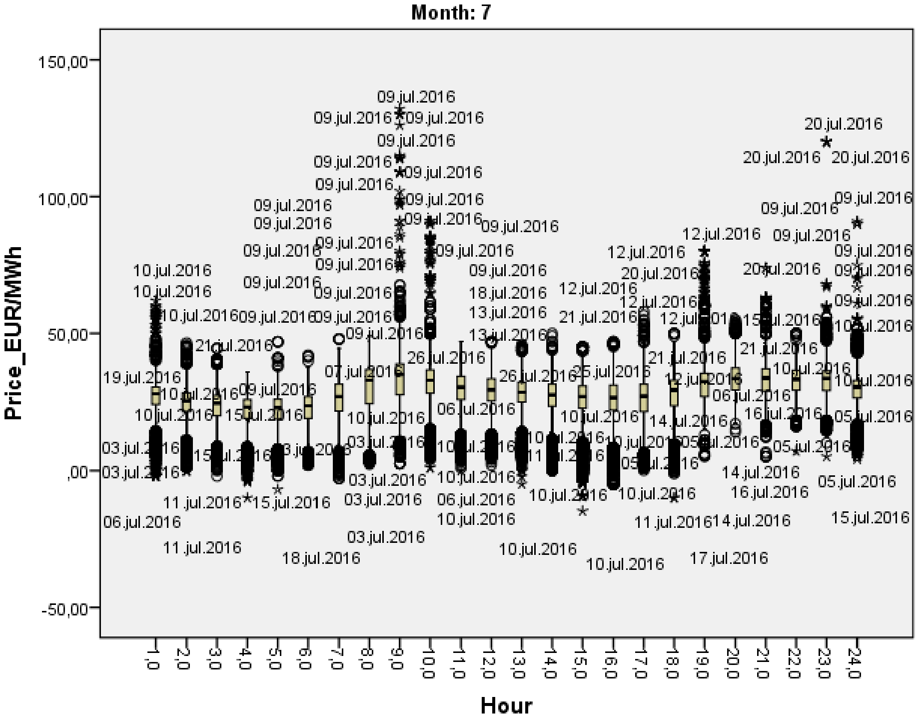

Figure 20. Boxplot for August 2016

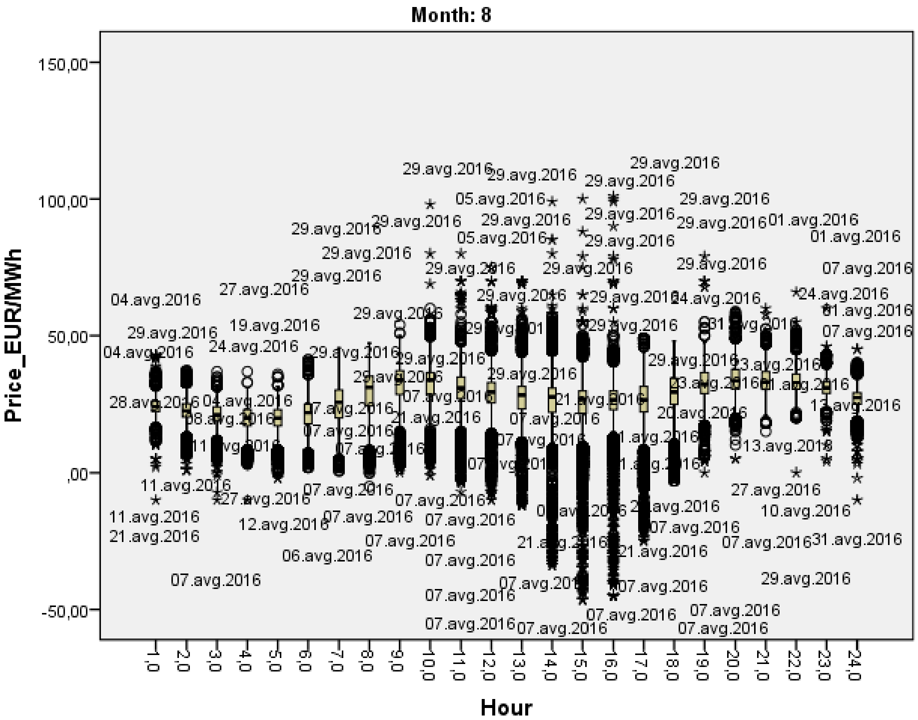

Figure 21. Boxplot for September 2016

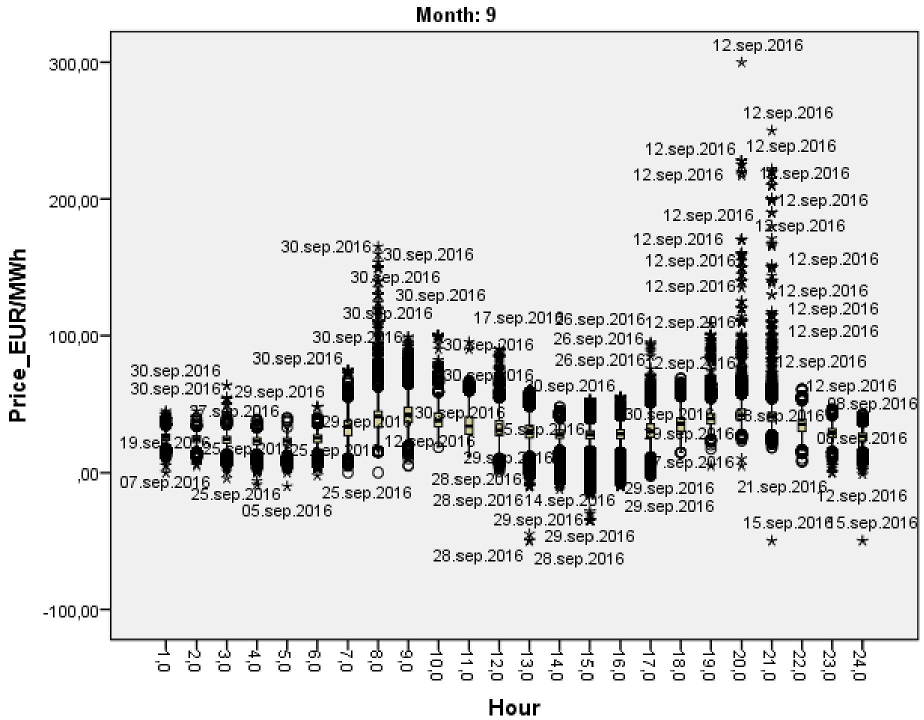

Figure 22. Boxplot for October 2016

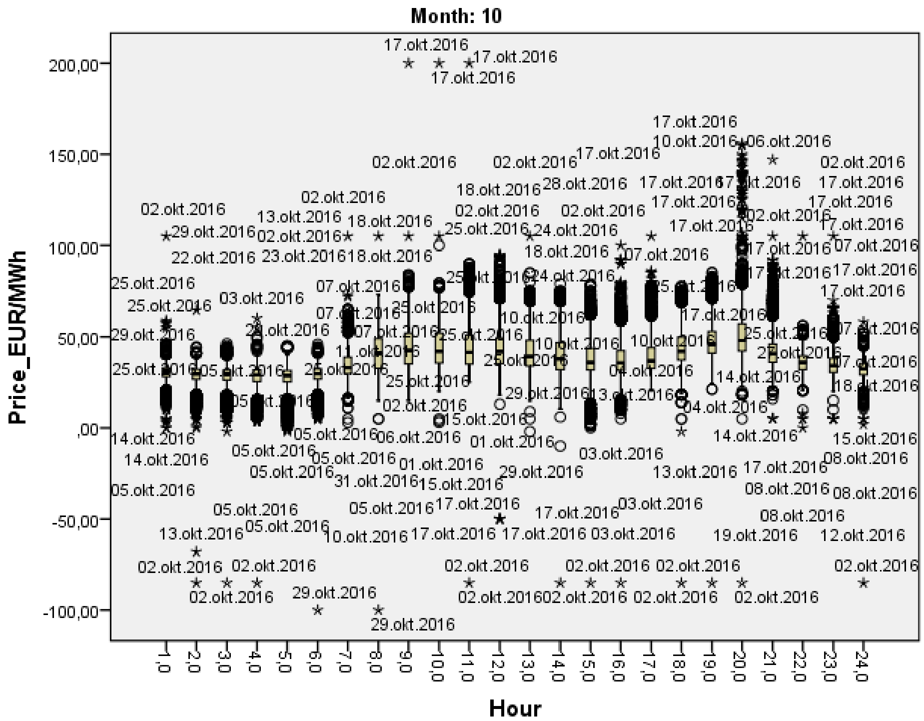

Figure 23. Boxplot for November 2016

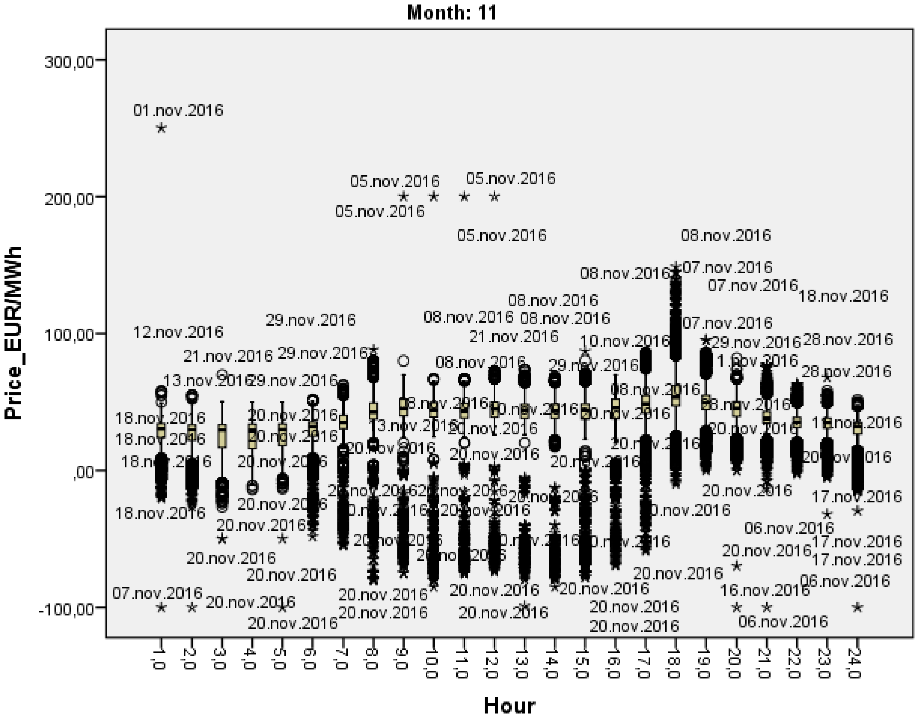

Figure 24. Boxplot for December 2016