Wind power integration, negative prices and power system flexibility - An empirical analysis of extreme events in Germany

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Abstract

This article analyses the flexibility of the German power market with respect to the integration of an increasing share of electricity from renewable energy sources. Flexibility limiting system components, which cause negative prices are explained and illustrated for the German market. Then, the decision of the European Energy Exchange in Leipzig (EEX) to allow negative price bids is explained. Empirical data show the flexibility of conventional generating capacities in Germany during the considered time frame from October 2008 until November 2009. Of the 71 hours with negative spot prices, ten hours were significantly negative with prices of at least -100€/MWh. These extreme hours are analysed in greater detail by the examination of the different system components. Thereby, load, wind power infeed and conventional generation by fuel type are observed as well as the market for negative tertiary reserve as indicators for market tightness. It will be shown that although the market situations were severe, under current conditions it could have been much worse under certain circumstances. Furthermore, the long-run implications of an increasing RES-E share on the conventional generation capacity are discussed. The article concludes with an outlook on additional power system flexibility options.

Keywords: Electricity markets, negative prices, renewable electricity integration, wind power

JEL classification: D41, L94, Q41, Q42

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1. Introduction

The promotion of electricity from renewable energy sources (RES-E) in Germany started in the early 1990s. Since 2000, the deployment of RES-E capacities has grown considerably. In 2009, the RES-E share of gross electricity consumption reached already 16 %. In 2008, 6.3 % of the gross electricity production stemmed from wind power alone. With a total installed capacity of 25.8 GW at the end of 2009, Germany is the largest wind power market in Europe in absolute terms. Since wind is an intermitting energy source the power markets react strongly to the stochastic wind power infeed. In times of high wind power infeed the spot price at the wholesale market tends to be lower compared to times without wind power in the system. This phenomenon became popular under the term merit-order effect (see Sensfuß et al., 2008; Bode, 2007; Moesgaard and Morthorst, 2008; Wissen and Nicolosi, 2008). As wind power already covers a certain share of the load the conventional power market only needs to cover the remaining, so called residual load. This leads to a lower interception of the merit-order curve with the demand function and thus to lower power prices.

In times of low demand and high wind power infeed the market reacts with bids underneath variable costs in order to avoid ramping-down base load power plants. Until September 2008, the consequences were situations with potential oversupply which needed to be cut on an inefficient pro-rata basis. The European Energy Exchange (EEX) in Leipzig reacted to this inefficiency with allowing the possibility of negative price bids. In October 2008, a European wholesale market closed with a negative power price for the first time. Until November 2009, 71 hours with negative prices were observed at the EEX. Among those, ten hours had significantly negative prices of under -100 €/MWh. This article examines these ten hours in detail by analysing the factors which limit market flexibility. To put these factors into perspective, they are compared to the data for the whole period between October 2008 and November 2009.

This article is structured as follows: In the next chapter the demand for market flexibility is explained as well as examples for its limiting factors. The third chapter introduces the German power market with a focus on the particular flexibility characteristics. Then, an empirical analysis of negative prices and the extreme events is presented in the fourth chapter. The fifth chapter discusses the long-term effects of the empirical market observations and the sixth chapter concludes this article.

2. Power System Flexibility and negative Wholesale Power Prices

The flexibility of power markets is characterised by their ability to efficiently cover fluctuating demand. This flexibility is influenced by the installed power plant mix and the interaction with other markets. A power system, consisting of supply, grid infrastructure and demand is adequately designed if it is able to cope with its challenges (see Batlle and Pérez-Arriaga, 2008) for a more detailed discussion on system adequacy). The reserve power markets are responsible for system security in the real-time period. Since they require additional capacity, they also influence the flexibility of the power system. Flexibility becomes an issue in times with either very high or very low demand. In both cases, the market shows wholesale power prices which deviate from the usual pattern. In times with very high demand the market shows occasionally prices above variable cost, while in hours with very low demand, the market shows prices below variable costs of the power plants. This article analyses the flexibility restrictions concerning low demand cases by showing how different markets and market participants behave in these hours.

The system components supply, grid and demand have their own flexibility restrictions. This article abstracts from the grid infrastructure since the price settlement at the market under consideration (the German power market) does not take grid bottlenecks into account for the price settlement.

The Demand Side

The most obvious flexibility requiring factor on the demand side is the fluctuating but almost inflexible demand itself. Depending on the load structure throughout the day and the year this factor alone requires either a flexible power supply system if the load structure is very volatile or a rather inflexible supply system in case of low volatility. The second factor is the amount of must-run generation, which is subtracted from the total load. Since must-run generation is independent of the level of demand the offset of both factors define the residual demand which needs to be covered by the conventional supply system. By trend, the more must-run installations, the more flexibility is required by the remaining generation capacity. Furthermore, the must-run generation can be subdivided: The most important differentiation is the renewable and the conventional side, such as combined heat and power (chp). The focus of this article is the intermitting RES-E infeed from wind power. The more load is covered by wind power infeed, the less needs to be covered from the conventional power market. The fluctuation of the demand in addition to the fluctuation of the wind power forms a challenging requirement for the supply system.

The Supply Side

The flexibility of the supply side is determined by the mix of its installed capacities and the design of its interrelated markets. Base load power plants have high investment costs and low variable costs. Therefore, they require a high utilisation throughout the year to cover the investment costs. In addition, these plants are not designed for ramping-up and down regularly since this reduces the lifetime of the parts that are exposed to high levels of pressure and heat. Consequently, a high share of baseload plants limits the flexibility of the power system. Furthermore, all thermal power plants have a minimum load. Due to the steam stream they are not able to produce electricity below a particular share. If they are willing to lower the generation below this threshold, they need to shut-off the plant. This minimum-load restriction limits the flexibility considerably, especially when big power blocks are required to stay online. The integrated design with the interrelated markets can limit the market flexibility as well. First, the national market for reserve power strongly influences the power system since it reduces the flexibility by the amount of reserve power which needs to be held back for system security. If the auctions for the reserve power markets are not efficiently aligned with the wholesale power market, inefficient capacity commitment could be a result (Weber, 2009) analyses the intraday market design to integrate wind power). Second, the interaction with international markets through interconnectors influences the power market. Again, if the auction of interconnector capacities is not well aligned with the gate-closure of the spot markets, the auctioned flow direction of the interconnector could deviate from the price delta between the two power markets which reduces the efficiency of the market results and therefore the market flexibility. In this case inefficient market results are the consequence (for a more detailed analysis of market splitting see e.g. Wawer, 2009; Brunekreeft et al., 2005).

Tight Market Situation

As explained above, market situation sometimes become critical due to a lack of flexibility. Since this article focuses on negative prices the situations under consideration have a potential oversupply. In case of low load and high wind power infeed the residual load is consequently quite low. The supply system needs to react to this situation by ramping down or shutting off power plants. Until a certain threshold this is not uncommon. However, at a certain point this "negative flexibility" becomes tight. This means that there is a lack of opportunities to further reduce conventional generation.

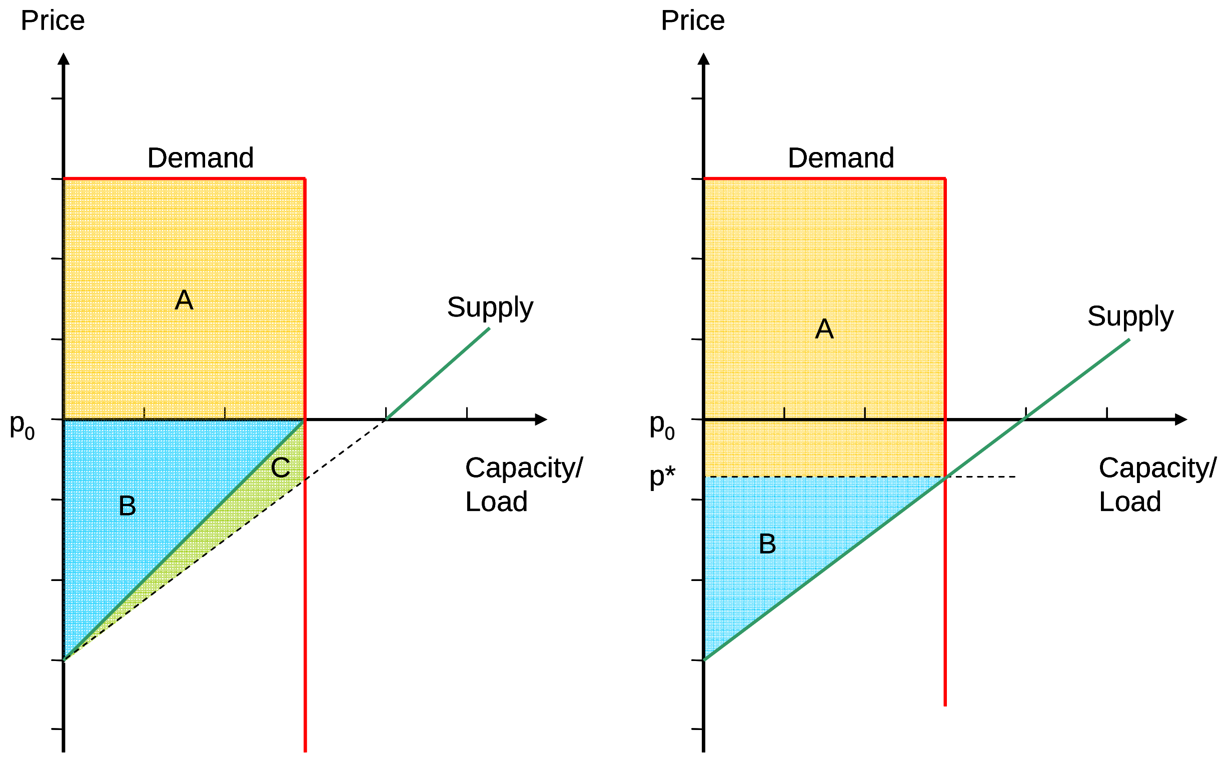
A tight market situation occurs when the plants that are online are not allowed to reduce their generation because they are obligated to supply system services, e.g. through commitments on the reserve power market. In reality, base load plants are likely to generate, too, because they are not willing to shut-off the plant due to very high start-up costs and due to opportunity costs which arise when prices above variable costs occur in the following hours and the plants cannot start-up in time. The base load induced market tightness varies by season. Since power plants need to be in revision once a year they usually choose the season with the lowest demand. During this season a lower baseload share is available which means that the market becomes more flexible.

Negative Wholesale Power Prices

Although the possibility of negative prices seems to be contra intuitive for an "ordinary" good, the particular attributes of electricity – mainly non-economic storage possibilities of large amounts and unit commitment in combination with very limited flexility of demand – lead to the occurrence of bids below variable costs, even negative ones. Before negative price bids were allowed in Germany, oversupply was cut on pro-rata basis which led to inefficiency (see the left side of Figure 1). This oversupply was due to the fact that opportunity costs are marginal cost relevant (Cramton, 2004): e.g. if a power plant needs to ramp-down, additional costs occur for the later ramp-up.[1] Therefore, it is efficient to integrate these opportunity costs into the bid to avoid the ramp-down and to produce even though prices do not cover the short term variable costs. Taking these dynamics into account the merit-order curve does not start at zero but has a slope which leads into the negative area until the negative price cap is reached (see the right side of Figure 1).

[1] Hofer (2008) quantifies a ramp-up of a combined cycle gas turbine with 2.500 – 5.000 €.

Figure 1: Price Pro-rata allocation (left) and negative prices (right)



Source: Adapted from Viehmann and Sämisch (2009).

With the occurrence of negative prices, as illustrated on the right side of Figure 1, the new price is settled at p*. The result of the negative price mechanism increases the overall welfare since an efficient dispatch is possible and the welfare loss in area C on the left side of Figure 1 is avoided. Allowing negative price bids consequently leads to an efficient market result which takes opportunity costs into account. Negative prices have also effects on the distribution between producer and consumer rents. A brief explanation is provided according to Viehmann and Sämisch (2009). In Figure 1, A is the consumer rent and B the producer rent. As illustrated on the left side, the price limit of zero reduces the producer rent by C, since producers would have been willing to bid differently into the market and are forced to deviate from their optimal strategy and to run the power plants inefficiently. With the occurrence of negative prices (right side of Figure 1), the consumer rent is increased and the producer rent is decreased The producers gain from changing to their efficient operation strategy[2] i.e. from avoiding pro-rata cuts is overcompensated by their additional payments due to negative prices which – on the other hand – are (in theory) directly transferred to the consumer. Nonetheless, the overall efficient dispatch of the power plants increases welfare, although the producer rent shrinks.

In this section, the flexibility limiting factors have been explained. The next chapter illustrates these factors for the German market and therefore lays the basis for the analysis of the extreme events.

[2] Although the producer rent decreases in this static illustration the change in the production schedule induced by the omission of pro-rata cuts is still profitable for the producers since it allows for the optimal consideration of opportunity costs and future price developments which cannot be depicted in Figure 1.

3. The German Power Market

The German power market is the biggest market in Europe when it comes to consumption. The four largest power producers are RWE, E.ON, Vattenfall and EnBW and account for a market share of between 70 and 85 % (Liese et al., 2008; Weight and v. Hirschhausen, 2008). The four transmission system operators (TSOs) are either legally unbundled from the four main power producers or even sold by now. When it comes to bottlenecks within the grid infrastructure, the TSOs are obligated to redispatch the power plant operation after the market settlement of a single price zone. This is common for most power markets in Europe. Other market designs, such as zonal or nodal pricing are widely applied by now (e.g. Nordpool or PJM) but the benefits of one single, liquid and transparent market are valued higher than the more efficient price settling mechanisms which take grid constraints into account (for a more detailed discussion on market designs in carbon constrained power systems see e.g. Green, 2008).

In the following, a brief overview on the wholesale market will be provided including its interdependence with other international markets as well as with the reserve power market due to their importance for the market flexibility. Then, the flexibility characteristics of the supply side of the power market will be discussed, since the ability of the conventional power mix in combination with RES-E generation and its regulation are the underlying motivation of this analysis.

3.1 The Wholesale Market

The German wholesale market is fragmented into an over-the-counter (OTC) market and the European Energy Exchange (EEX) in Leipzig. While the OTC market has a continuous trade, the EEX has a single auction with a gate closure for the day-ahead market at 12 p.m. on the day before physical delivery. Although three fourth of the trading volume is settled via bilateral OTC contracts, the EEX spot price is of fundamental importance as benchmark and reference point for other markets such as OTC or forward markets. Since buyers and sellers have always an arbitrage option at the EEX, the price expectations on both sides cannot systematically deviate from the expected outcome of the other markets. Nobody would accept an offer at the OTC market if the expected outcome at the EEX was more beneficial. Thus it is possible that e.g. forward prices deviate from the day-ahead EEX price due to different information or risk perception, but not systematically (see Ockenfels et al., 2008 for a discussion on different auction designs). The price settling mechanism at the EEX is a uniform price auction.

After the day-ahead market closure trade is still possible at the intraday market. However, the main share of the trades is settled with the gate closure of the EEX. The intraday market still lacks liquidity and the resulting market price is therefore not a valid benchmark. The hour before the physical delivery falls into the responsibility of the reserve power market, which is operated by the TSOs. Within this short time frame they are obligated to balance the deviations between supply and demand, which arise due to prognosis errors of the load and the wind infeed as well as unplanned power plant outages.

Since September 2008, the EEX allows negative price bids and the first negative market result has occurred in October 2008.

Market Interaction

The interaction with other markets influences the ability of the whole system to react efficiently to new information and adapt its generation mix accordingly. First, international interactions through interconnectors are discussed and second, the German reserve power market.

The German wholesale power market is influenced by its surrounding markets since it has interconnectors to most of them (Denmark, Sweden, Poland, Czech Republic, Austria, Switzerland, Luxembourg, France and the Netherlands) of total net transfer capacities of 17 GW import and 14.8 GW export capacities (ENTSO-E, 2010). Transmission rights are required to enable the international exchange between the power markets. Depending on the individual interconnector either implicit or explicit auctions settle the transmission rights. The current trend is to integrate the markets as closely as possible to increase the economic use of the interconnector capacities (see e.g. Wawer, 2009 and Brunekreeft et al., 2005 for a discussion on market splitting). In general, the individual interconnectors serve as either additional supply in the merit-order in case of imports or as flexible demand options in case of export. Since many interconnector capacities are explicitly auctioned before gate closure of the individual power markets, the auction results do not reflect the market results and are therefore not included in this analysis. However, the general trend to implicitly integrate the auctions into the settlement of the market results (market splitting) is supported by the increasing demand for the efficient utilisation of the interconnector capacities.

The reserve power market interacts with the wholesale power market since generation capacities are required for assuring the security of supply. In the reserve power market, 5.7 to 7.2 GW for positive reserve and 4.3 to 6.2 GW for negative reserve were auctioned within the time frame under consideration and were therefore not available for the economic settlement of the wholesale power market. These capacities were required for primary, secondary and tertiary reserve (see Table 1 for an overview of the reserve products).

Table 1: Overview of auctioned reserve power products (10/2008-11/2009)[3]

Reserve Power Products		Minimum [MW]	Maximum [MW]
Primary	negative/positive	656	664
Secondary	negative	2,064	2,340
	positive	2,678	3,013
Tertiary	negative	1,559	3,238
	positive	2,376	3,508
Total	negative	4,279	6,242
	positive	5,710	7,185

Source: author, based on data from Regelleistung.net.

[3] This overview abstracts from additional reserve products, which are less transparently traded and under the obligation of either the independent TSOs (wind reserve) or the individual utilities (Dauerreserve) which are responsible for back-up power after the official reserve power time frame is over.

Primary reserve is required to react instantly in case of frequency imbalances. This product is responsible for a five minute time frame and is substituted by secondary reserve afterwards for the next 10 minutes. These two products are automatically controlled by the TSO. Since primary and secondary reserve power is spinning reserve, these plants need to generate power in order to supply positive and negative reserve power. Tertiary reserve needs to be online within 15 minutes and can therefore also be met by non-spinning reserves, e.g. by open cycle gas turbines. While the tertiary reserve is auctioned every workday for the following workday and weekend, primary and secondary reserve is auctioned every month. In other words, power plants which win the auctions for primary and secondary reserve are obligated to stay online for the whole month, independent of spot market results. The power plants that supply negative reserve are required to generate according to the contracted margin above their minimal load restriction in order to reduce the infeed when required. In consequence, the flexibility of the German power generation was significantly lowered by the negative reserve power requirements of 4.279 to 6.242 MW in the considered time frame, of which 2,720 to 3,004 MW were auctioned monthly and 1,559 to 3,238 MW were auctioned daily. Because tertiary reserve is auctioned every workday, the auction results serve as indicator for market tightness. Since the additional opportunity costs result in higher reserve power prices in tight market situations. Therefore, these market results are analysed in the hours with extremely negative prices.

3.2 The Supply Side

Due to its broad technology mix the German Power market is a good example for an investigation of the flexibility of power systems. A substantial base load plant fleet (see Table 2) satisfies the base demand throughout the year. Load following is mostly done by hardcoal plants and gas-fired power plants.[4]

Table 2: Installed generation capacity in the German power market

Technology	Capacity [GW]
Nuclear	20,4
Lignite	21,3
Hardcoal	29,4
Gas	24,6
Hydro	4,7
Wind	23,9
Biomass	4,5
Photovoltaics	5,3

Source: author, data provided by BMU (2009a), EWI Power Plant Database.

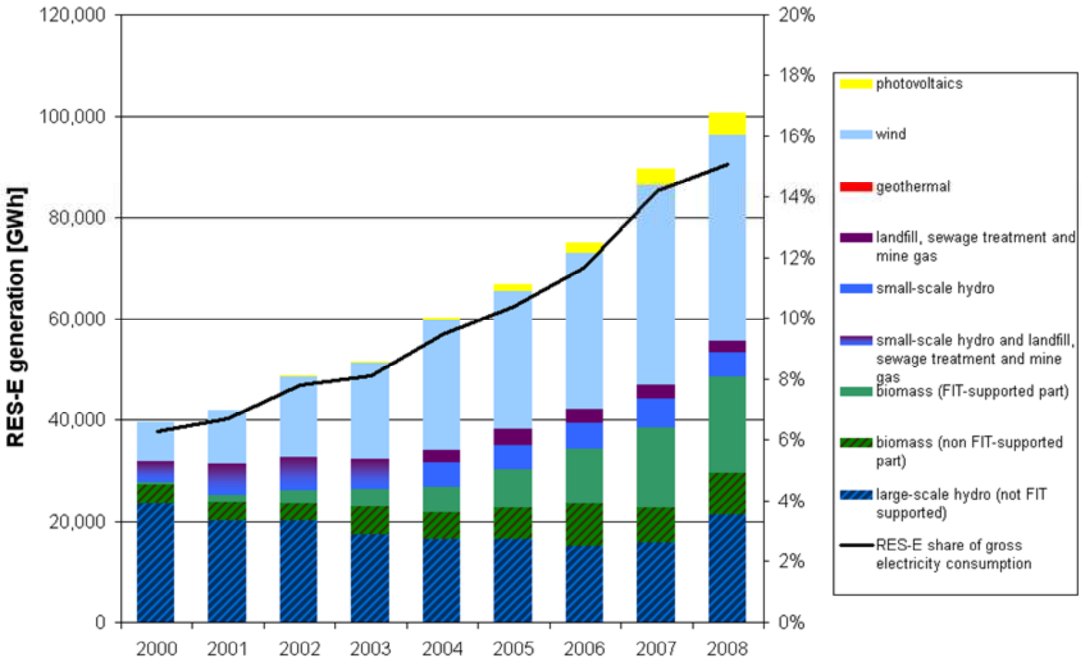
The RES-E market growth has been substantial within the last years. Germany started in 1990 with a feed-in tariff system. The so called “Stromeinspeisegesetz” was technology neutral and linked to the end consumer price. In 2000, the renewable energy sources act (EEG) came into force and implemented a technology specific, highly diversified feed-in tariff structure to allow for deployment

[4] Roughly 42.5 GW of the total capacity are flexible and inflexible combined heat and power plants (chp).

in less efficient locations on the one hand and to lower the producer rents at favourable locations on the other hand.

The TSOs are obliged to buy any amounts of RES-E from the plants and integrate them into the market. Since 2010, the TSOs directly sell RES-E to the EEX (before 2010 distributors were forced to integrate a fixed RES-E share into their portfolio). This has to be done at any time without consideration of the demand. On the one hand, the fixed feed-in tariff in combination with the guaranteed purchase increased the investment security and thereby led to a significant growth of installed capacity and market share as can be seen in Figure 2.

Figure 2: RES-E development in Germany



Source: BMU, 2009.

On the other hand, the forced RES-E market integration independent of the level of demand covers an increasingly high share of the demand. This leads to challenging situations in low demand hours which can easily be identified via the resulting market prices.

4. Empirical Investigation

For the first time in Europe, a negative power price at a power exchange occurred in October 2008 at the EEX. Until November 2009, 71 hours closed with a negative power price in the day ahead market. This article investigates the market situation in the top ten negative hours to identify the flexibility limiting factors.

4.1 The data

The data for this investigation stem from different sources which in combination explain the market situation of supply, demand and market result. The market result comprising spot power prices as well as the actual generation and the available capacity on the supply side has been provided by EEX.

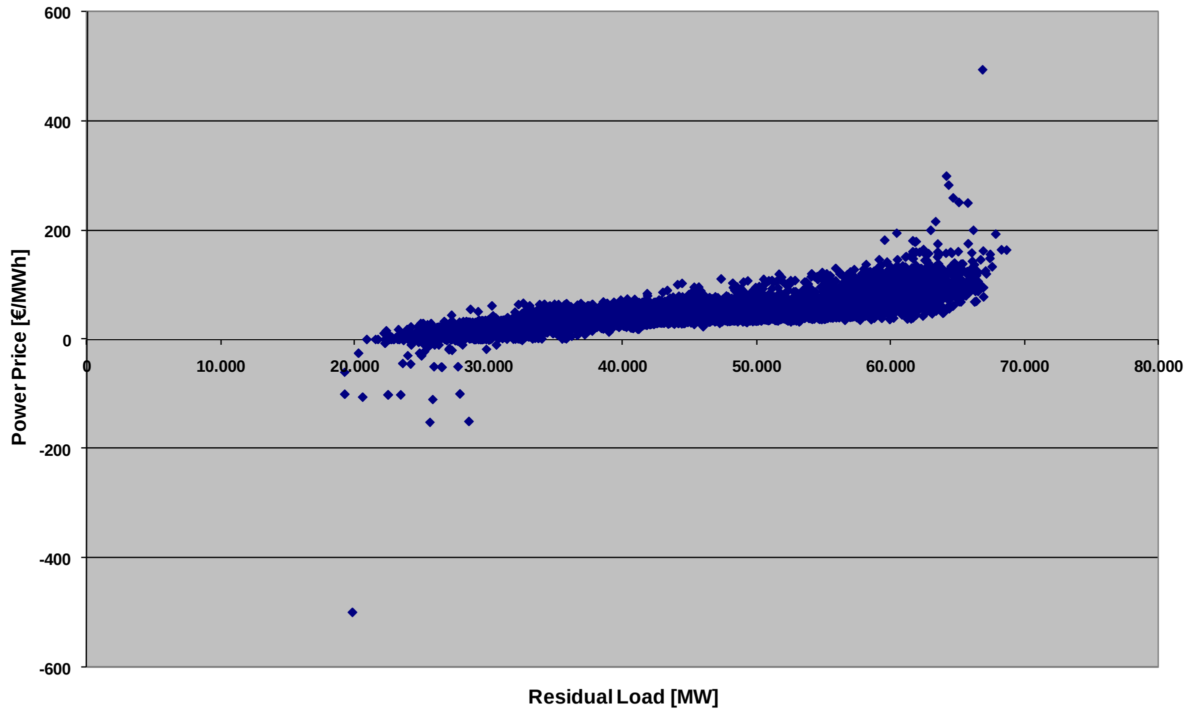
The actual wind power infeed has been provided by the German Energy and Hydro Association (BDEW). Although the day-ahead wind power forecast would have provided a better explanation of the market results the actual wind power infeed is the value every market participant tries to predict. There are numerous wind forecasts available and every market participant uses a different one or a combination of several. But since in this article the actual market situation is analysed the realised values are used. The fact that the spot price is settled day-ahead and is therefore based on slightly different information is of minor importance for the investigation of tight market situations. The same is true for the realised load which has been provided by the European Network of Transmission System Operators for Electricity (ENTSO-E). BDEW also supplied monthly data on the total RES-E generation. Reduced by the hourly wind power infeed, the RES-E data have been calculated as a monthly band in order to take this must-run generation into account. Thus load and wind power infeed in combination with a band of the remaining RES-E form the residual load.

The reserve power market gives an additional hint of the market tightness. The data of the auction results stem from the shared website of the German TSOs regelleistung.net. In the following, the data will be aligned in a way that the relative tightness of the market becomes apparent.

4.2 Overview of the the market behaviour in the whole time frame

For a first impression, Figure 3 provides an overview of the data for the time frame between October 2008 and November 2009. First, the time frame is observed from the demand side. In Figure 3, the residual load is expressed on the x-axis and the power price on the y-axis. The scatterplots' shape resembles the merit-order curve. It can be seen that in tight market situations on both ends of the curve the market reaction deviated from the usual pattern.

Figure 3: EEX spot prices and residual load (10/2008 – 11/2009)

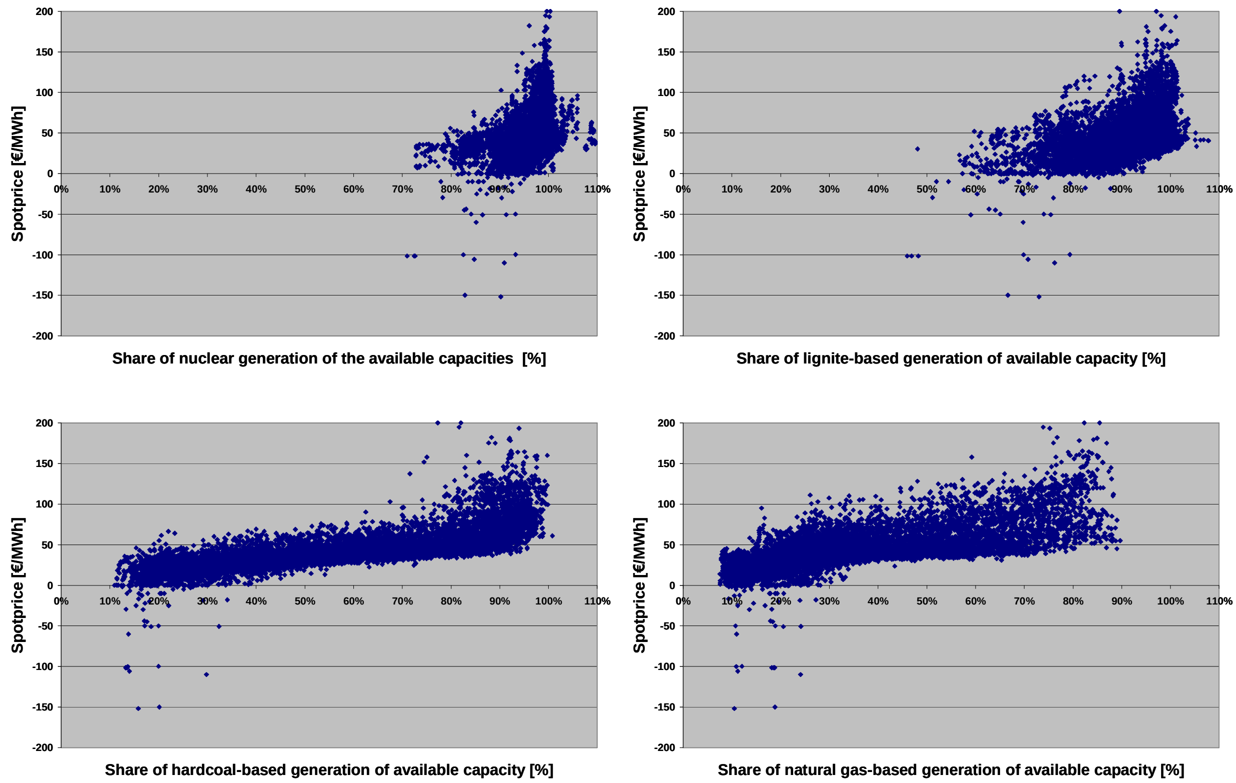


Source: author, based on data from EEX, BDEW and ENTSO-E.

One can easily see that all hours with negative prices have a residual load below 30 GW. The reason why these dots are not aligned more nicely is that the flexibility shortage of the power market depends on the power plants that are online. This strongly depends on the season. When a significant amount of base load plants is in revision the residual load can become much lower before a negative price occurs. On the other hand, if all plants are online the system will be under pressure much earlier.

The next step is to observe the market behaviour in the time frame from the supply side. Figure 4 provides an overview of the utilisation of the conventional generation from nuclear, lignite, hardcoal and gas. The y-axis denotes the spot price and the x-axis the share of generation from a given energy source in the registered available capacity for each day. Through this approach one can analyse how the relative utilisation has been without the above explained seasonality.

Figure 4: Power plant utilisation by fuel[5]



Source: author, data provided by EEX.

It can be seen that power generation from nuclear power plants (upper-left corner) shows very little fluctuation. The total generation has never been below 70 % of available capacity with a strong concentration above 90 %. The generation from lignite (upper-right corner) shows a little more flexibility. However, the share has never been below 45 % of available capacity and the concentration is above 80 % utilization. The distribution of hardcoal-based generation (lower-left corner) and natural gas-based generation (lower-right corner) is quite different from these two base load technologies. While no energy source ever falls below a 10 % share, the generation from hardcoal fluctuates between 10 % and 100 %. On the other hand generation from natural gas is never above 90 % utilisation which is probably due to system security requirements. If the whole power plant mix is highly utilised, natural gas-fired power plants are most likely used to provide positive reserve power.

Table 3 summarises the observations for the whole time frame and for comparison adds the data from the 71 hours with negative prices. The table thus illustrates whether the generation patterns of the different energy sources differ from their usual pattern in hours with negative prices. One can see that the conventional generation of some fuels is still relatively high which can partly be interpreted as a sign of low flexibility. Of course, a power plant with lower variable costs generates in more hours due to its position in the merit-order.

[5] The generation values above 100 % show that thermal power plants are able to generate above their capacity rating for short time periods.

Table 3: Overview of generation from different fuels in hours with negative power prices and all hours of the considered time frame 10/2008 – 11/2009

Hours with	Min	Max	Difference	Average	Median	Std.Dev.
	Generation [MW] and generation share of avaiable capacity [%]					
				Nuclear		
negative prices	10.308	16.026	5.718	13.456	13.161	1.284
	71,0%	95,7%	24,7%	88,3%	89,3%	5,5%
all prices	9.361	18.121	8.760	14.712	14.699	1.726
	71,0%	109,6%	38,6%	95,9%	96,8%	4,0%
				Lignite		
negative prices	8.300	15.045	6.745	11.672	11.407	1.427
	46,0%	88,3%	42,3%	70,6%	70,5%	10,1%
all prices	7.695	18.465	10.770	14.981	15.109	1.655
	46,0%	107,8%	61,8%	91,3%	93,0%	7,3%
				Hardcoal		
negative prices	1.375	4.357	2.982	2.581	2.477	753
	10,9%	34,1%	23,2%	19,0%	17,6%	5,2%
all prices	1.375	16.014	14.639	8.420	8.504	3.592
	10,9%	100,8%	89,9%	59,4%	60,7%	23,2%
				Gas		
negative prices	873	3.095	2.222	1.791	1.389	702
	8,9%	28,1%	19,2%	15,7%	14,5%	4,7%
all prices	748	11.410	10.662	4.121	3.595	2.282
	7,5%	89,7%	82,1%	36,6%	31,6%	19,3%
				Total		
negative prices	26.175	39.195	13.020	32.318	32.212	2.981
	39,9%	60,0%	20,1%	51,3%	51,0%	4,9%
all prices	26.175	63.790	37.615	45.354	45.522	7.566
	39,9%	92,2%	52,3%	71,4%	71,4%	9,8%

Source: author, data provided by EEX.

One can see that the average infeed in negatively priced hours is much lower than on average. However, the absolute and relative generation (i.e. relative to available capacity) figures tell us that the market becomes tight and reacts with negative prices even if there is still significant generation from all energy sources. As mentioned earlier this is partly due to inflexibility of base load plants and commitments on the reserve power market. In the next step, the hours with significantly negative prices are analysed in greater detail.

4.3 The top ten negative Prices

In Table 3, it has been analysed for a first intuition how the absolute and relative generation bandwidths of different fuels have been for all observed hours and for hours in which negative prices occurred. Table 4 shows the generation by fuel in the ten most negatively priced hours in this period.

Table 4: Supply-side data of ten hours with substantially negative prices

Index	Day	Date	Hour	Price	Nuclear absolute [MW]	share [%]	Lignite absolute [MW]	share [%]	Hardcoal absolute [MW]	share [%]	Gas absolute [MW]	share [%]	Total absolute [MW]	share [%]
		22.12.2008		**avail.Cap**	**17.814**		**18.050**		**15.683**		**13.872**		**47.605**	
1	Mo	22.12.2008	3	-101,5	12.938	72,6%	8.462	46,9%	2.085	13,3%	2.523	18,2%	29.102	40,4%
2	Mo	22.12.2008	4	-101,5	12.646	71,0%	8.300	46,0%	2.074	13,2%	2.575	18,6%	28.686	39,9%
3	Mo	22.12.2008	5	-101,5	12.904	72,4%	8.713	48,3%	2.121	13,5%	2.606	18,8%	29.424	40,9%
		08.03.2009		**avail.Cap**	**14.989**		**17.201**		**13.103**		**11.502**		**62.821**	
4	Su	08.03.2009	7	-109,97	13.629	90,9%	13.112	76,2%	3.907	29,8%	2.771	24,1%	36.239	57,7%
		04.05.2009		**avail.Cap**	**14.453**		**16.819**		**14.000**		**10.660**		**63.123**	
5	Mo	04.05.2009	2	-151,67	13.034	90,2%	12.284	73,0%	2.218	15,8%	1.119	10,5%	32.181	51,0%
6	Mo	04.05.2009	5	-99,72	13.478	93,3%	13.344	79,3%	2.798	20,0%	1.285	12,1%	34.275	54,3%
		04.10.2009		**avail.Cap**	**13.138**		**15.666**		**12.911**		**9.475**		**56.928**	
7	Su	04.10.2009	2	-105,76	11.136	84,8%	11.089	70,8%	1.809	14,0%	1.061	11,2%	26.690	46,9%
8	Su	04.10.2009	3	-500,02	10.913	83,1%	11.042	70,5%	1.765	13,7%	1.035	10,9%	26.361	46,3%
9	Su	04.10.2009	4	-100,09	10.842	82,5%	10.942	69,8%	1.763	13,7%	1.034	10,9%	26.175	46,0%
		24.11.2009		**avail.Cap**	**17.013**		**17.420**		**15.416**		**12.156**		**68.379**	
10	Tu	24.11.2009	4	-149,94	14.098	82,9%	11.608	66,6%	3.103	20,1%	2.292	18,9%	32.703	47,8%

Source: author, data provided by EEX.

It strikes the eye that the generation from nuclear and lignite power plants accounts for much higher percentages of available capacity than hardcoal and gas fired power stations. Even at the lowest spot price of -500 €/MWh on October 4th, the total capacity had an utilisation of 46% (generation as share of available capacity) which corresponds to a thermal generation of 26 GW in this hour. Nuclear power plants were 83 % utilised and lignite power plants 71 %. Only on December 22nd 2008, both fuels were less utilised. An explanation could be that some plants were already shut down for the holidays, but registered as available. The share of gas-fired power stations was probably higher in December 2008 than in October 2009 due to power generation from gas-fired chp.

A look on the demand side in Table 5 shows how the mix of load and wind infeed leads to the residual load which the conventional market needs to cover. The hour with the most extreme negative price of -500 €/MWh occurred on October 4th.

Table 5: Demand-side data of ten hours with substantially negative prices[6]

Index	Day	Date	Hour	Price [€/MWh]	Wind [MWh]	Load [MWh]	res.Load [MWh]
1	Mo	22.12.2008	3	-101,5	15.787	41.763	25.976
2	Mo	22.12.2008	4	-101,5	15.897	41.845	25.948
3	Mo	22.12.2008	5	-101,5	16.022	42.919	26.897
4	Su	08.03.2009	7	-109,97	8.722	38.488	29.766
5	Mo	04.05.2009	2	-151,67	4.965	34.922	29.957
6	Mo	04.05.2009	5	-99,72	4.786	36.973	32.187
7	Su	04.10.2009	2	-105,76	17.607	42.051	24.444
8	Su	04.10.2009	3	-500,02	17.188	40.874	23.686
9	Su	04.10.2009	4	-100,09	17.072	40.176	23.104
10	Tu	24.11.2009	4	-149,94	17.614	50.041	32.427

Source: author, data provided by EEX, BDEW and ENTSO-E.

[6] For the calculation of the residual load, other than in Figure 3 above, only the wind power infeed is subtracted from the total load to correctly illustrate the hourly available data.

With an average wind power infeed of 4.5 GW within the considered time frame, the wind power infeed on May 4th, 2009 was not considerably above that average. However, the low load in these hours in combination with the modest wind power infeed resulted in one of the most negative prices so far. In contrast, on October 4th the wind infeed was quite significant. The load on the other hand was not uncommonly low. Nonetheless, this combination led to the lowest price observed in Europe so far. In comparison, the residual load on November 24th was almost 9 GW above the level of October 4th. On November 24th a significant negative price occurred independently from a weekend or a holiday for the first time. Since at that time more plants were online the market became less flexible in terms of the possibility to further reduce the generation e.g. due to minimal load restrictions. These fundamental flexibility reducing factors can also be observed as high capacity prices on the market for negative tertiary reserve. Table 6 provides an overview of the market results for the extreme events.[7]

Table 6: Tertiary reserve prices of ten hours with substantial negative prices

Index	Day	Date	Hour	Price [€/MWh]	Tertiary Reserve positive [€/MW]	Tertiary Reserve negative [€/MW]
1	Mo	22.12.2008	3	-101.5	0.1	31.3
2	Mo	22.12.2008	4	-101.5	0.1	31.3
3	Mo	22.12.2008	5	-101.5	0.3	29.4
4	Su	08.03.2009	7	-110.0	2	75
5	Mo	04.05.2009	2	-151.7	1	13
6	Mo	04.05.2009	5	-99.7	5	14
7	Su	04.10.2009	2	-105.8	0	81
8	Su	04.10.2009	3	-500.0	0	81
9	Su	04.10.2009	4	-100.1	0	81
10	Tu	24.11.2009	4	-149.9	1	68

Source: author, data provided by EEX and Regelleistung.net.

Although the market for tertiary reserve has gate-closure at the last workday for the next workday, the overall expectation of the market tightness can clearly be seen in the market results. Together, the information of the Tables 4, 5 and 6 provide an overview on the main market characteristics which triggered the extreme negative price events. A low demand with eventually high wind power infeed in combination with an inflexible power mix, which is observable as high negative reserve power prices, leads to highly negative power prices.

Since the market situation has obviously been very tight on October 4th, Figure 5 shows the generation of the main energy sources on the right axis as well as the spot price and the price for negative tertiary reserve on the left axis.[8]

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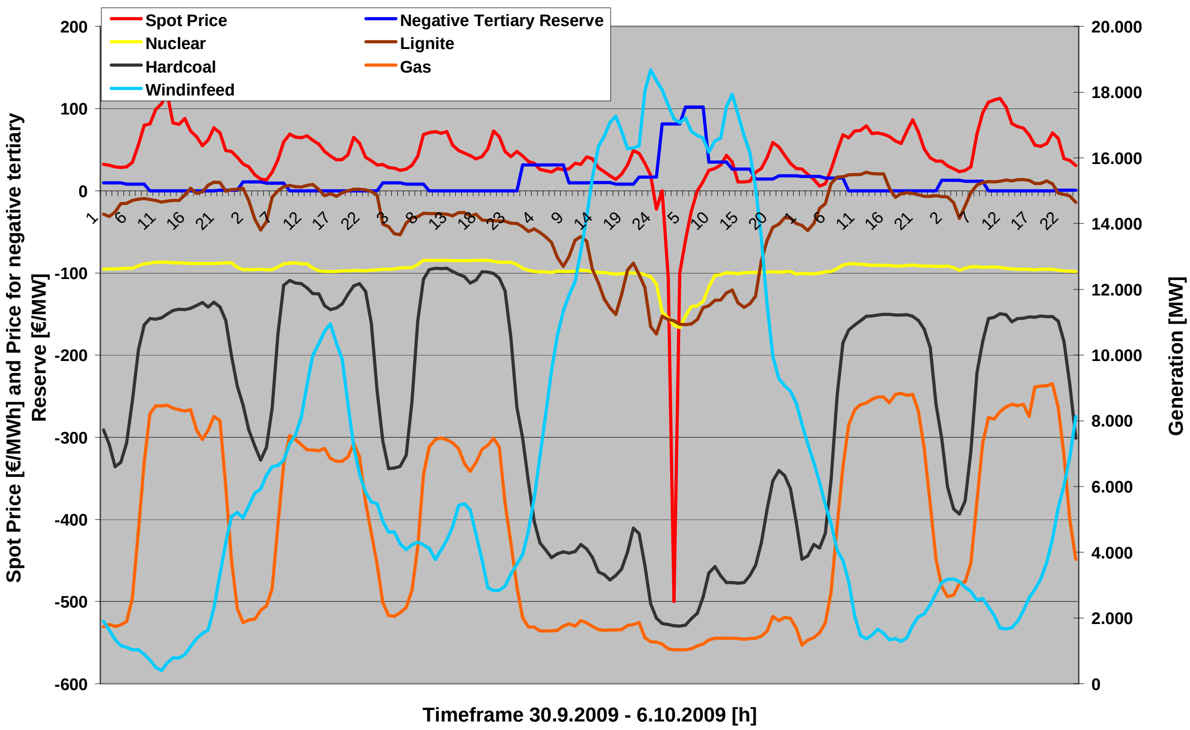
[7] The tertiary reserve power is auctioned in four-hour blocks. For comparability, the prices in this analysis are broken down to hourly prices.

[8] The visualisation of the remaining extreme events can be found in the appendix.

Figure 5: Power market on October 4th 2009



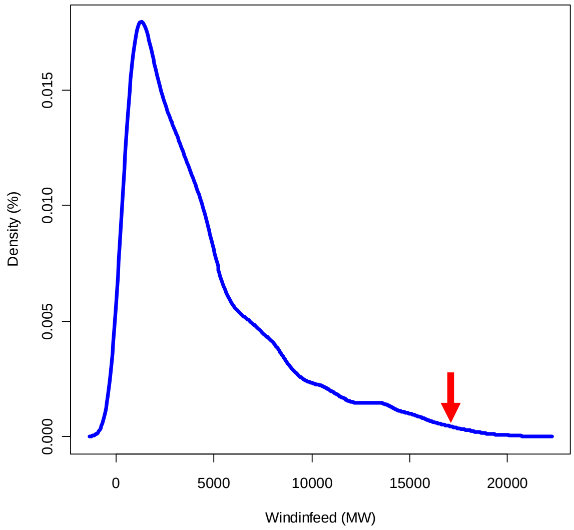
Source: author, data provided by EEX, BDEW and Regelleistung.net.

The first observation in Figure 5 is that the spot prices and the price for negative tertiary reserve are clearly negatively correlated which leads to the highest price for negative tertiary reserve when the spot price has its negative peak with –500 €/MWh. The second observation which catches the eye is that no energy source reduces its generation to zero. Natural gas- and hardcoal-based generation is strongly reduced in the hours with negative prices. Also lignite-based generation is reduced quite significantly for a base load technology. In contrast the generation from nuclear plants is hardly reduced. These observations confirm the lessons learned from Figure 4 which shows – more or less – the fluctuating generation of the different energy sources. In sum, one can say that the flexibility of the aggregated supply side is probably lower than expected since all technologies show limited bandwidths of flexibility and altogether were not able to reduce the generation below 46% of the available capacity. Especially base load technologies show thresholds which seem to be at relatively high levels.

4.4 How extreme were the extreme events?

The analysis in the previous chapter has shown that the low load and high wind power infeed event on October 4th resulted in an extreme situation for the German power market which reacted with a significant price drop. The question arises whether the circumstances in terms of load/wind constellation can be called extreme as well when analysed separately from the (extreme) price drop it triggered. Figure 6 therefore shows the distribution of wind power infeed for the considered time frame.

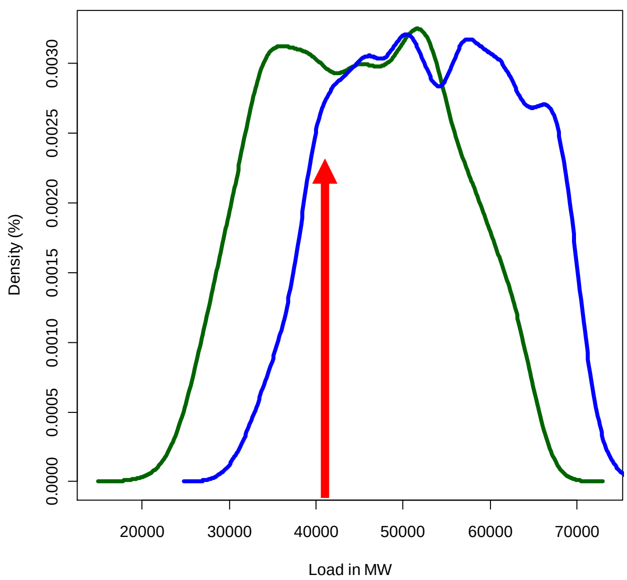
Figure 6: Kernel density estimation of wind power infeed (10/2008 – 11/2009)



Source: author, data provided by BDEW.

The red arrow indicates the level of wind power infeed on October 4th. Although an infeed of 17.2 GW is quite substantial for the German power market, 63 hours in the considered time frame had a higher infeed. Nonetheless, this translates into only 0.62 % of the hours within the time frame. However, the maximum infeed has been 20.8 GW and these additional 3.6 GW would have had a significant impact on the power system.

Figure 7: Kernel density estimation of load (blue line) and residual load (green line) (10/2008 – 11/2009)



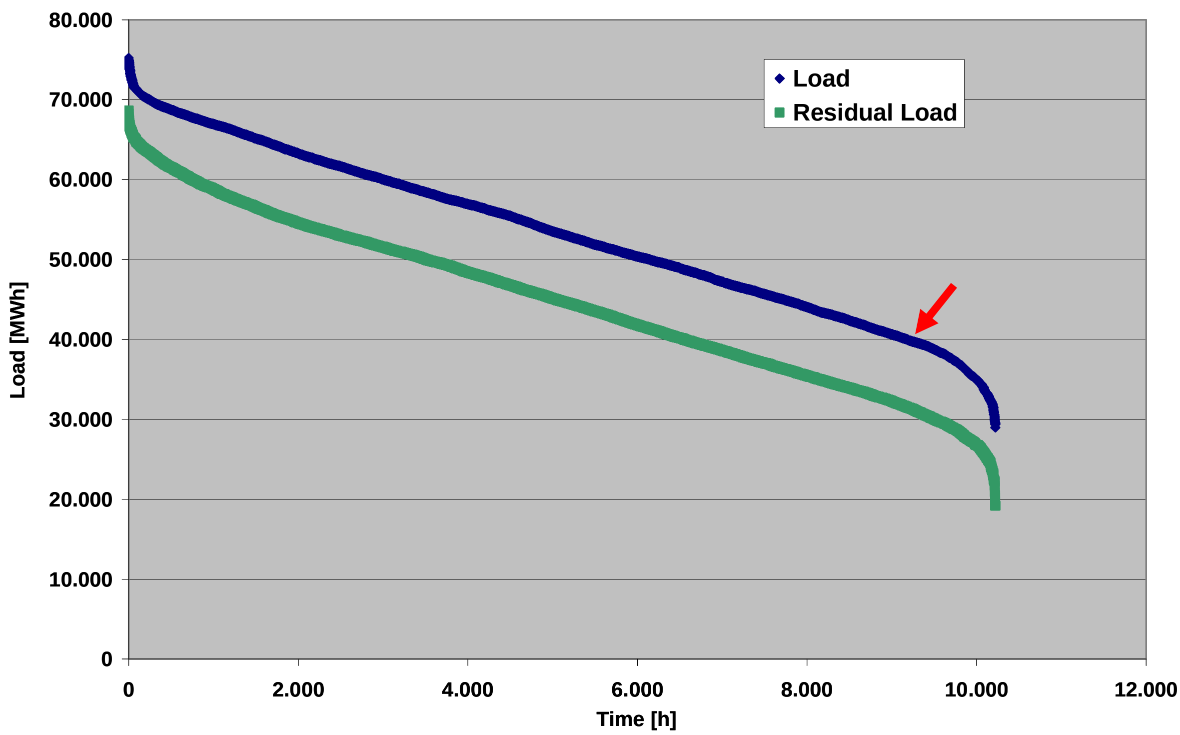
Source: author, data provided by ENTSO-E and BDEW.

The probability for this event is however quite low although the installed wind power capacity has reached 25.8 GW by the end of 2009 and therefore sets the theoretical maximal level. The second originating factor is the load. Figure 7 provides the distribution of all load levels within the considered time frame as the blue line and the residual load as the green line.

Again, the red arrow points at the level of the extreme event on October 4th. This load level does not seem to be unusually low. Actually, 1,295 hours of the considered time frame had lower load levels. This means that 12.67 % of the considered hours had a load level lower than 40,874 GW. The lowest load has been 28,984 MW. The RES-E induced shift of the load is illustrated by the green residual load distribution. Here, in addition to wind infeed, all other renewable sources have been considered as a monthly band as in Figure 1. One can already observe that the RES-E infeed substantially changes the shape and the position of the distribution of the load, the conventional power market needs to cover. An alternative visualisation of the load is provided in Figure 8 by load duration curves.

The load duration curves show all load levels of the considered time frame in a subsequent order. The red arrow points again at the load level of October 4th. Based on this illustration, the long-term effects for the conventional power market are explained in chapter 5.

Figure 8: Load and residual load duration curves (10/2008 – 11/2009)



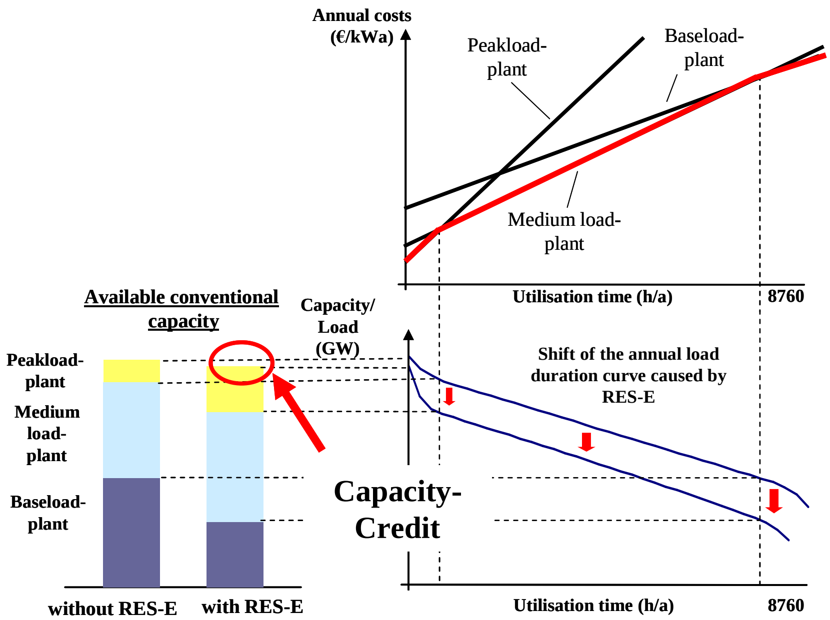
Source: author, data provided by ENTSO-E and BDEW.

An additional factor for the analysis of the market situation is the state of the base load capacity. The available capacity of nuclear power was quite low at that point of time. Only 13,138 MW were labelled as available. The maximal available nuclear capacity within the considered time frame was 18,266 MW and the average 15,325 MW. With the low flexibility observed in Figure 4 in mind, one could assume that a higher available capacity on October 4th probably would have had resulted in a more severe market reaction. The available lignite capacity on October 4th was 15.666 MW, a little less than the average of 16.419 MW, and therefore also added a little to the relative flexibility of the supply system. Although the wind power infeed has been quite substantial on October 4th, the load as well as the low level of available nuclear capacity has prevented a more severe event. Therefore, the situation on October 4th is by far not the most extreme case that could materialize.

5. Discussion of Long-Term Effects and Requirements of a Future Power System

The increasing RES-E share in a non-growing system necessarily leads to a reduction in the utilisation of the conventional power capacity. In the long-run, under consideration of investment decisions, this leads to a shift towards less base load capacity since base load requires a high utilisation due to the high fixed costs as can be seen in Figure 9.

Figure 9: Adaptations of the conventional power plant mix due to RES-E increase



Source: Wissen and Nicolosi (2008), see also Nabe (2006).

The upper right corner shows marginal cost curves with annuity capacity costs as starting point at the ordinate. It can be seen that base load plants have relatively high investment costs and low variable costs (i.e. fuel and CO_2 costs). Peak load plants on the other hand have low investment costs and relatively high variable costs. The abscissa shows the annual utilisation time at which the plant types become efficient. Base load plants are economically viable when a high utilisation time can be reached and peak load plants are the efficient choice when the utilisation remains at a low level (see e.g. Stoft, 2002). In the lower right graph, the two annual load duration curves which have already been discussed are depicted. The shift of the shares of the different power plant types can be seen in the lower left graph. This shift stems from the relation between the relatively high RES-E infeed compared to its relatively low share of secured capacity, since the RES-E generation is not guaranteed in the hours of peak demand. However, because of regional distribution it is also unlikely that there is no wind in all regions simultaneously. That means that a certain amount of wind capacity can be accounted as guaranteed nonetheless. This guaranteed capacity, which is called capacity credit, is able to substitute a certain amount of conventional capacity in the power plant mix. Compared to the RES-E infeed however, the share of substitutable capacity is relatively low. Dena (2005) has shown that a wind capacity of 14.5 MW in Germany in 2003 had a capacity credit of between 7 and 9 %, meaning that between 1.0 and 1.3 GW of conventional capacity could have become substituted. One important implication is that an increasing penetration reduces the relative capacity credit. The above mentioned study also calculated that the considered 35.9 GW wind capacity in 2015 would be associated with a capacity credit of only 5 to 6 %. The result of high RES-E infeed with a relatively low capacity credit is an increase in peak load capacity and a decrease in base load capacity.

In addition to the utilisation based shift, negative power prices catalyse this trend by penalising less flexible generation capacity. With the two predominant power system attributes of inflexible demand and forced RES-E infeed, the conventional power capacity is the only flexibility option of the current power system. If this was a static system, one would probably argue that the limitation of wind power infeed in low demand hours would be the solution. However, having the dynamics of the power system evolution in mind, it becomes apparent that this approach is short-sighted as it reduces the market signals that reward flexibility and facilitates the necessary structural change. Due to its climate policy Germany has ambitious targets for its renewable energy deployment. Table 7 provides an overview of the envisaged RES-E deployment of the German environmental ministry in the upcoming years.

Table 7: Current and envisaged RES-E capacities in Germany

	2008	2010	2015	2020	2025	2030	2040	2050
				[GW]				
Wind Power	**23.89**	**26.94**	**32.93**	**41.94**	**50.80**	**59.67**	**71.50**	**76.00**
Onshore	*23.89*	*26.76*	*30.48*	*32.94*	*34.40*	*35.87*	*38.00*	*39.00*
Offshore		*0.18*	*2.45*	*9.00*	*16.40*	*23.80*	*33.50*	*37.00*
Photovoltaics	**5.33**	**8.91**	**16.60**	**23.16**	**25.75**	**28.35**	**30.50**	**34.00**
Biomass	**4.45**	**5.34**	**6.78**	**7.85**	**8.17**	**8.50**	**8.70**	**8.72**
Hydro	**4.74**	**4.83**	**5.02**	**5.12**	**5.15**	**5.18**	**5.20**	**5.22**
Geothermal	**0.01**	**0.02**	**0.10**	**0.29**	**0.64**	**0.99**	**2.32**	**5.30**
Total	**38.42**	**46.04**	**61.43**	**78.36**	**90.51**	**102.69**	**118.22**	**129.24**

Source: adapted from BMU (2009b).

Table 7 shows that the RES-E capacity installed today could theoretically already cover low demand situations. One can assume that very soon situations will become very tight when RES-E infeed is treated as non-dispatchable. However, if RES-E infeed is curtailed in every oversupply situation the remuneration costs are going to increase since RES-E operators in Germany receive compensation if they need to be curtailed. In other words, additional costs arise without an increase of the RES-E share. Therefore, all discussed system components need to be flexibilised to enable the system to integrate an increasing RES-E share.

- The flexibility of the demand side is currently quite limited. The upcoming discussion on smart-grids could trigger demand-side management applications. Household systems could become more flexible to a certain degree. If e-mobility becomes more popular in the coming years, the storage possibilities within home systems could increase the possibilities. Industrial consumers need to think about ways to shift demand peaks as well. For example, a first approaches is a more flexible operation of cooling facilities.

- Power storage possibilities are very limited. Most hydro pumped-storage potentials within Europe are already developed. Higher RES-E induced price volatility in addition to experiences with compressed air energy storages (CAES) could motivate further developments of this storage option. Currently, the Dena II grid-study analysis the economics of this option for applications in northern Germany.

- As the RES-E deployment plans in Table 7 indicate, RES-E generation needs to be dispatched at some level to maintain system security. Which particular RES-E support scheme is most suitable for this task, without jeopardising the investment stimulation, is still a challenging research question.

- The dominant part of this article already discusses the flexibility of the conventional generation system. In order to cover the residual demand and still provide sufficient secured capacity a higher peak load share seems to be unavoidable. The challenge is to find an adequate investment framework. This capacity can either become financed by high price spikes or through capacity markets (see e.g Cramton and Stoft, 2008; Joskow, 2008).

- Since the power markets in Europe are highly intermeshed, an adequate auction mechanism for the interconnector capacities further increases the flexibility of the whole system. Additional national and international interconnector capacities are nevertheless required to increase the geographical flexibility of regional demand / supply imbalances.

- In addition to the integration of international power markets, national power markets need to become better integrated as well. Especially the reserve power market auctions need to be aligned with the spot market and intraday market. Having power plants committed for one month for primary and secondary reserve power reduces the power system flexibility and thus shorter periods would be beneficial. Also tertiary reserve markets should be settled in a shorter time-period. Instead of a workday-ahead auction, at least a day-ahead auction would be favourable since spot market auctions are day-ahead as well. When it comes to prognosis data, the time span from Friday to Monday includes unnecessarily high forecast errors. Since an increase in intermitting RES-E generation comes with an increasing importance of forecast errors reducing the time span between market settlement and physical delivery is crucial. A more liquid and integrated intraday market e.g. as in operation in Spain with intraday auctions would increase the ability to integrate intermitting RES-E as proposed by Weber (2009).

To equip power systems for the tasks of integrating substantial amounts of RES-E all of the above illustrated components need to be developed to a certain degree. This process is probably not going smoothly from a political economy point of view since different stakeholders certainly propose more static efficient solutions in order to benefit in the short run. Nonetheless, the opportunities for power companies along the whole supply chain to adapt to these structural changes are numerous. Thus a long-term oriented strategy on the political planning and the industrial side has the potential to accomplish the task.

6. Conclusion

In the presence of climate policy and a politically desired RES-E increase intermitting RES-E is going to play an increasingly important role in power systems globally. Therefore, the flexibility of power systems becomes increasingly important as well. Various factors of the power system are challenged by a high share of intermitting RES-E infeed in low demand hours. The introduction of the German power market, its installed capacities and its particular design characteristics, followed by an empirical analysis has shown that flexibility limits are earlier reached than probably anticipated. The most extreme negative power price of -500 €/MWh on October 4th 2009 substantially challenged the power system. The utilisation of the generating capacity was still 46 % (26 GW), and the price for negative reserve power further indicated that the situation in these hours was tight. The view on the originating side, namely the load and the wind power infeed, revealed that the wind power infeed was substantial, while the load on the other hand was not unusually low and had a sizeable downside potential of almost 12 GW.

With an increasing RES-E share, these situations become much more likely in the future as substantial additional RES-E capacities are deployed. Therefore, the power system needs to be flexibilised through adaptations of all system components. Negative wholesale power prices serve as market signal for these additional requirements. The flexibility of the demand side, the grid and the supply side needs to be increased. Demand-side management applications, power storages, grid enhancements, a more flexible generation capacity mix and a dispatchable RES-E support scheme are some of the tasks ahead. In addition, the integration of international power markets as well as national adjacent markets, such as the intraday market and the reserve power markets, need to be better aligned timely.

7. Acknowledgement

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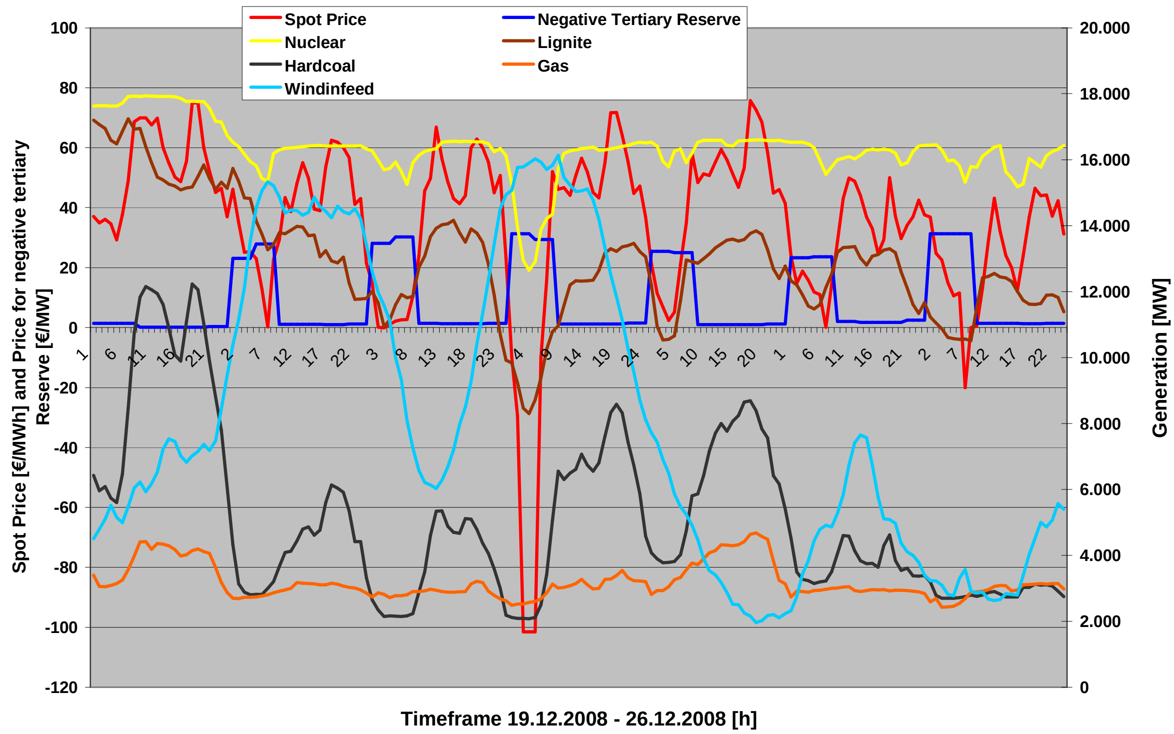
Appendix

Appendix 1:



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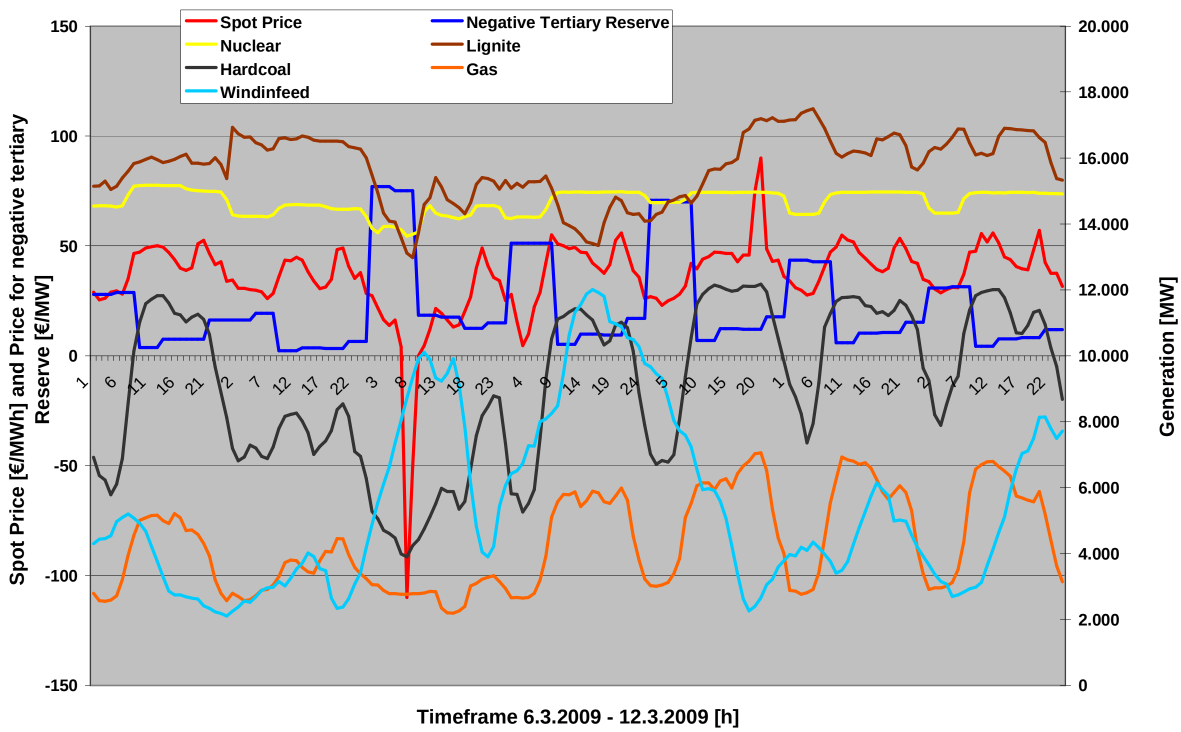
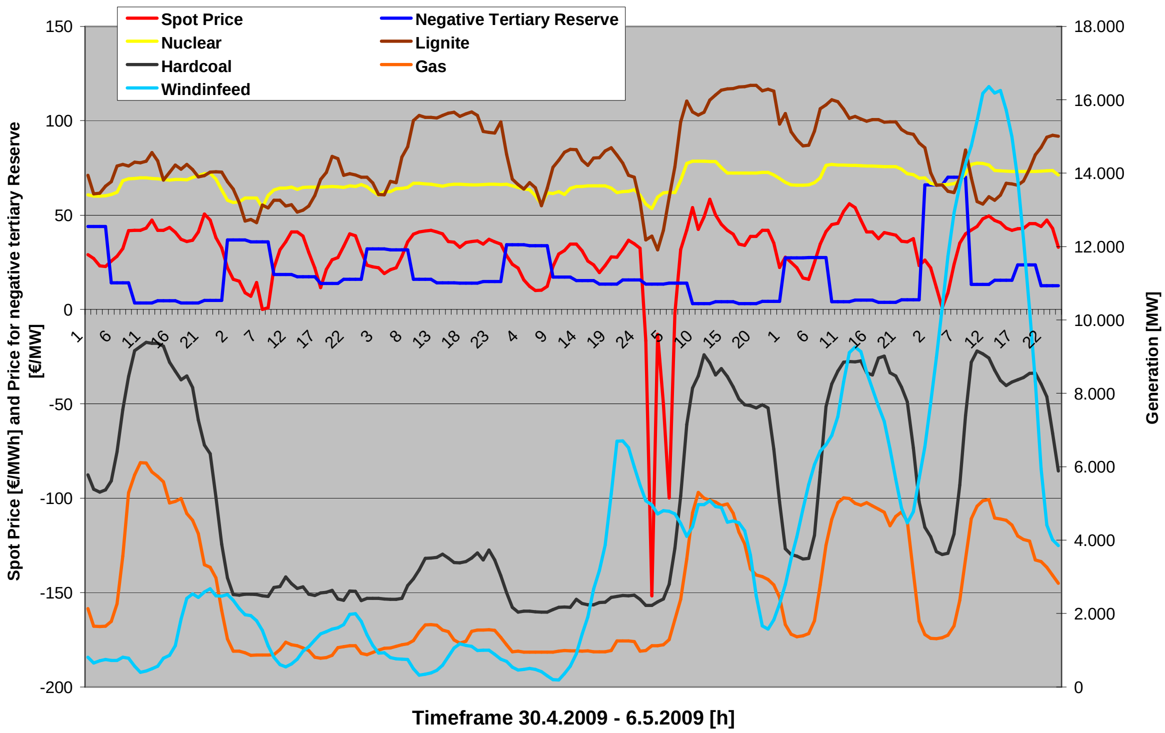


Appendix 3



Appendix 4