

# Market Review 2017

Electricity market  
insights

# Introduction

TenneT publishes this yearly Market Review for everyone interested in the electricity markets. We describe the developments in the Central Western European electricity markets, particularly in the Netherlands and Germany, where TenneT as a transmission system operator (TSO) has a central role in facilitating the market. This publication gives a brief description of the different market elements, describes the past year's highlights in the European electricity markets and puts most important developments into perspective.

The wholesale price for electricity is a central element within European electricity markets. The ongoing market integration in Europe has led to an increased number of hours where wholesale electricity prices are equal in different countries, but most of the time prices still differ between countries due to the differences in access to energy sources and in energy policies. The Market Review describes price developments and identifies the causes for certain developments.

Conventional power plants require fossil fuels to generate electricity. As long as electricity generation is mostly fossil-based, the fossil fuel prices are, together with the CO<sub>2</sub> emission price, a major driver for the electricity price and the profitability of these plants. Therefore, the Market Review shows the development of hard coal, natural gas and the CO<sub>2</sub> emission prices, and shows the gross margins for conventional power plants resulting from these fuel prices and the electricity prices.

As the electricity prices are influenced by supply and demand, these factors will also be discussed in the Market Review. The Market Review shows the electricity consumption within Central Western Europe in 2017 and the developments regarding generation capacity and gross electricity generation in the Netherlands and Germany.

Most industrialized countries intend to increase the share of renewables in electricity generation, and incentivise investments in renewables. The Market Review describes the developments in the Dutch and German renewable support schemes, including insights in outcomes of renewable auctions.

The European power system is characterized by a high number of interconnections between individual markets. This enables the transport of

electricity across national borders and makes the buying and selling of electricity more efficient and more effective. The Market Review shows the physical and commercial import and export volumes in Central Western Europe. In addition, the available interconnection capacity between the Netherlands and Germany is displayed.

Electricity is a commodity with the property that generation has to equal consumption on an instantaneous basis. Otherwise the grid frequency will start deviating from its reference value, which can result in a system collapse. In other words: the system needs to be in balance. In order to achieve this, TSOs procure and call upon balancing reserves and market parties are penalized when they provide adverse contributions to the system balance. This review analyzes the imbalance volumes and prices of the Dutch and the German balancing market, as well as the prices paid for balancing reserves, to see the impact of increasing intermittent renewable capacity and of different balancing market designs.

Since transmission lines can only transport a limited amount of power, congestion can occur when the power flows are expected to exceed the available capacity. To prevent or resolve these congestions, TSOs use grid-related redispatch measures within or between market areas. This Market Review describes the redispatch volumes and resulting costs over 2017 for both Germany and the Netherlands, and the relationship with wind feed-in.

The winter of 2016/2017 experienced an unusual cold spell. Highlighting this special event gives a more practical understanding of the impact on market prices of all other previously addressed aspects. It clearly shows the weather-dependency of European electricity markets and completes this review.

# Main findings

The year 2017 started where 2016 left off. In the winter, electricity prices in France and Belgium were substantially higher than those in the Netherlands and Germany/Austria. However, during the spring and summer, prices in France and Belgium decreased and the Central Western European (CWE) region reached full price convergence up to 60% of the time. At the end of the year, the Belgian and French prices rose significantly again, while the German price remained on the same level, with the Dutch price somewhere between the two.

In the futures markets, the main event was the upcoming split of the German-Austrian bidding zone into two separate bidding zones. Prices for power futures show that market participants expect higher prices in Austria in comparison to Germany after this split.

European fuel prices increased in the second half of 2017, pushing electricity prices upwards. Compared to 2016, differences in the gross margin between coal and gas plants decreased, mainly because hard coal prices increased more than gas prices. Overall, Dutch conventional power plants remained more profitable in comparison to the German power plants due to higher electricity prices in the Netherlands against almost equal fuel prices.

Except for January – when a cold spell led to a very high electricity demand – the electricity consumption in the CWE region in 2017 was comparable to previous years. The renewable generation in the Netherlands and Germany peaked with new records in 2017 due to both an increase of installed renewable capacity and beneficial weather conditions for wind. In Germany, wind even became the second-largest source for electricity generation, surpassing nuclear and hard coal.

With decreasing costs for renewables, less financial support is required. This is clearly visible in the downward trend in requested subsidy levels in renewable auction schemes. Also, an absolute breakthrough for offshore wind was reached this year, when market parties offered to build offshore wind farms in both the Netherlands and Germany without requiring any subsidy.

The total yearly physical net import and export volumes stayed relatively stable from 2016 to 2017, but significant differences can be observed throughout the year. Especially France showed a large swing over the year, with an importing net position at the beginning and end of 2017 and a high exporting position during the summer, while the opposite was true for the Netherlands.

Germany experienced a decrease in imbalance volumes, while the imbalance volumes in the Netherlands have been continually increasing since 2013. Although Germany experienced record high-imbalance prices of up to 24,455 €/MWh in October 2017, the average difference between the day-ahead price and the imbalance price in 2017 was comparable to 2016.

The total redispatch costs for TenneT in Germany significantly increased to a record high of almost 1 billion euros in 2017. In the Netherlands, the redispatch costs decreased compared to 2016 as the construction of a temporary line solved significant congestions in the Eemshaven region, but they are still significantly above those in 2015.

Finally, the cold spell in Europe in January 2017 is treated in depth as a special event. Cold temperatures resulted in a high electricity demand, especially in countries with a large share of electric heating, such as France. In combination with high plant unavailability and limited renewable generation, this led to a tight market situation with high day-ahead prices. Nevertheless, via cross-border electricity trade and good TSO cooperation, an adequate supply was ensured throughout Europe.

# Electricity market prices

In the beginning and end of 2017, low temperatures led to higher electricity prices, caused by higher electricity demand. In periods with high prices, prices in France and Belgium were significantly higher than the Dutch and German/Austrian prices, caused by a more temperature-sensitive load profile in these countries. Overall, the price convergence in the CWE region was relatively similar in 2017 compared to 2016.

No major developments were visible in the intraday market, except for slightly higher German and Dutch trading volumes. The prices of futures rose over 2017, caused by higher fuel prices and expectations about higher CO<sub>2</sub> allowance prices. Also, in anticipation of the split of the German-Austrian bidding zone into two separate bidding zones, separate futures for Germany and Austria were traded. The price of these futures indicated that market participants expect higher prices in Austria compared to Germany after the split.

## 3.1 Background

Electricity generators compete in wholesale electricity markets to sell electricity to large industrial consumers and electricity suppliers. Suppliers compete in the retail electricity market to sell electricity to the final consumer. This TeneT Market Review focuses on wholesale electricity markets.

Electricity is a commodity with the property that generation has to equal consumption (plus grid transmission losses) on an instantaneous basis. The design of electricity markets is adapted to deal with this particular property.

Different elements of the electricity market are arranged in a sequential order, running from years before the actual physical delivery to real time, as displayed in Figure 1.

## Market Timeframe and Balancing

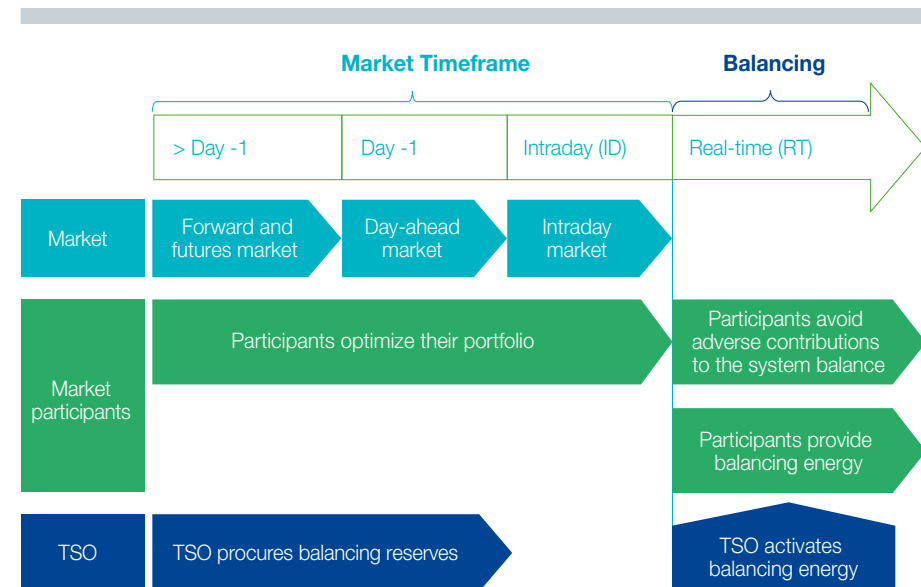


Figure 1: Market timeframes and balancing.

# Electricity market prices

Electricity markets are organized into geographical areas (i.e. bidding zones) in which market participants can exchange electricity freely without any capacity allocation. If interconnector capacity is available, cross-bidding zone trade is possible. Every bidding zone has a single price, but the market outcome could be that several bidding zones form a single price area.

Apart from the organized markets for electricity at power exchanges, market participants are able to trade bilaterally (i.e. over-the-counter) as well, without using a power exchange. Since these transactions are non-transparent, they are not taken into account in this Market Review.

The forward and futures markets span the time intervals from years before up to the day before delivery. Forwards and futures are financial products, which are settled against spot market prices of future delivery periods. Quite often, these contracts include the option for physical fulfilment, meaning that a certain amount of electricity is delivered or consumed at a certain time in the future for a price agreed upon today. Futures are standardized contracts on power exchanges, forwards are traded bilaterally over-the-counter and are not standardized. Market participants trade in these markets to reduce their risks,

also known as hedging. Electricity generators use forward and futures markets to ensure future sales and reduce their vulnerability to possible electricity price decreases. Other market participants, e.g. large electricity consumers, might use these markets to secure their future electricity consumption at upfront known costs and reduce their vulnerability to possible price increases.

In the day-ahead market, electricity is traded one day before actual delivery. The day-ahead market is the market with the highest trading volumes and number of participants and therefore the price from the day-ahead market is most often referred to as “the electricity price”. The available interconnector capacity between different bidding zones is also optimized and allocated based on the outcome of the day-ahead market.

In the intraday market, electricity is traded on the delivery day itself. The intraday market enables market participants to correct for shifts in their day-ahead nominations due to better renewable feed-in forecasts, demand changes, unexpected power plant outages, etc.

The principles of the balancing market are covered in detail in [chapter 8](#).

# Electricity market prices

## 3.2 Day-ahead market developments

The monthly average day-ahead prices in Central Western European<sup>1</sup> (CWE) bidding zones are significantly different between winter and summer months, as can be seen in Figure 2.

### Monthly Average Day-ahead Wholesale Prices in the CWE Region

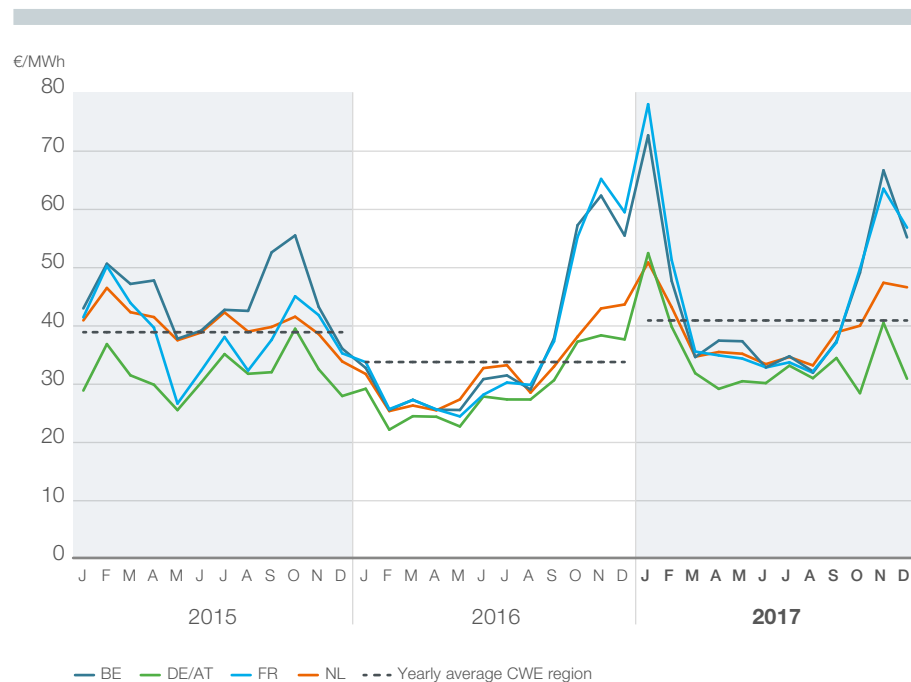


Figure 2: Monthly average of hourly day-ahead wholesale prices in the CWE region.  
Sources: MRC Market Coupling

In January and February 2017, as well as from October until December 2017, prices were substantially higher compared to the rest of the year. Prices in France and Belgium decoupled from German/Austrian and Dutch prices and reached average values of almost 80 €/MWh at the beginning of the year, and average values close to 70 €/MWh at the end of 2017. In 2017, the yearly average price of the four bidding zones was about 7 €/MWh higher than the average price in 2016, and about 2 €/MWh above the price of 2015. This is partly a result of increasing fuel prices, which will be discussed in [chapter 4](#).

Just like in previous years, the German/Austrian day-ahead price was lower in 2017 compared to the other regions, followed by the Dutch price. The price difference between Germany/Austria and the Netherlands was relatively small, as was the price difference between France and Belgium. In situations with high overall CWE prices, the French and Belgian prices are significantly higher than the German/Austrian and Dutch prices, whereas price convergence between the four zones was higher with lower overall prices. The difference between the German/Austrian and Dutch average price in October and December 2017 results partly from the feed-in of renewable energy sources (RES), which is further addressed in [section 5.4](#). The extreme prices in January and February 2017 will be covered in detail in [chapter 10](#), which focuses on the cold spell at the beginning of 2017.

<sup>1</sup> The Central Western European market region formed by Austria, Belgium, France, Germany, Luxembourg and the Netherlands. The single German-Austrian-Luxembourgian bidding zone will be referred to as German/Austrian bidding zone in this report.

# Electricity market prices

Figure 3 shows the time distribution of the number of price areas in the four bidding zones in the CWE region. When there is full price convergence between all countries, there is one price area; while there are four price areas if all four countries have different prices.

The trends observed in Figure 2 are also visible in Figure 3. From March to September 2017 there was high price convergence (full price convergence up to 60% of the time), whereas there was more price segmentation

between market areas in the other months (four different price areas more than 50% of the time). Furthermore, the amount of time with two different price areas, mostly convergence between Germany/Austria and the Netherlands on one hand and Belgium and France on the other hand, increased during these months. There was full price convergence for 34% of the time in 2017, comparable to 2016. In 2015, when flow-based market-coupling was introduced in May, the price convergence was much lower at 19%.

## Monthly Distribution of Day-ahead Price Areas in the CWE Region

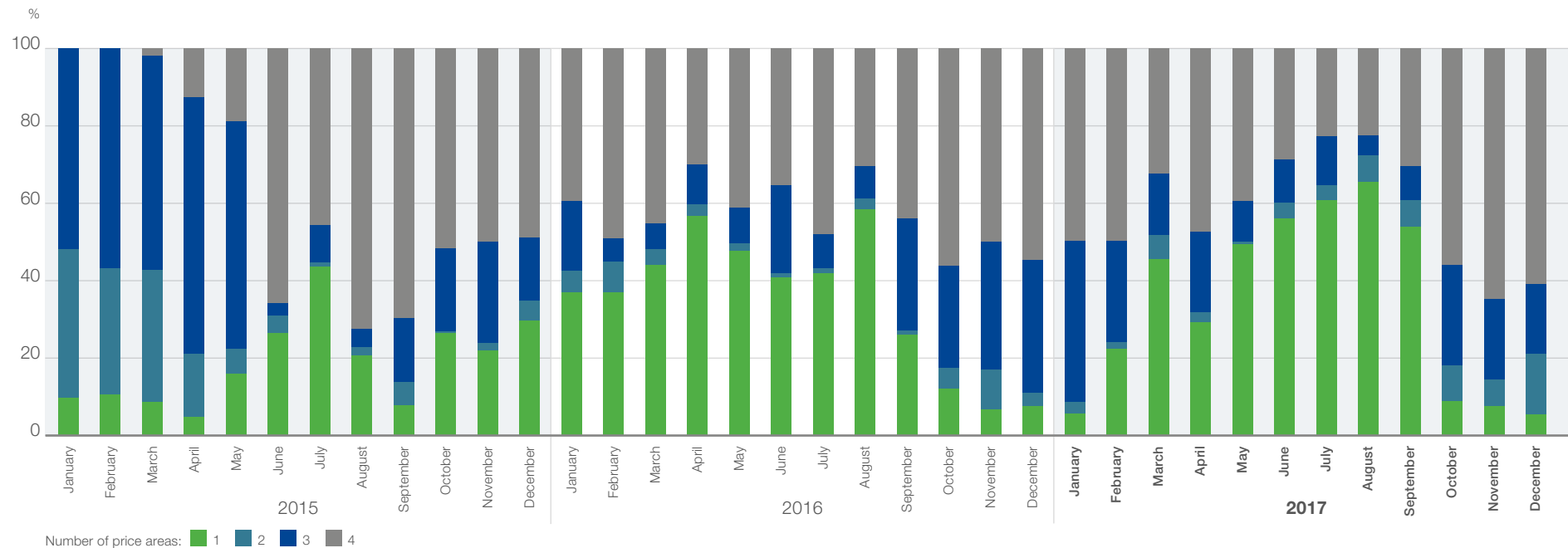


Figure 3: Monthly distribution of Day-ahead Price Areas in CWE countries.  
Source: MRC Market Coupling

# Electricity market prices

## 3.2.1 Europe

Figure 4 illustrates the average day-ahead prices in 2016 and 2017 as well as the price convergence of different bidding zones to the Netherlands and Germany. The day-ahead price levels are reflected through different colors.

The price zones with the lowest average prices are colored bright green and high price levels are marked bright red. The numbers in every bidding zone show the percentage of hours in which a country had the same wholesale price as the Dutch and the German/Austrian price zone respectively (NL|DE).

### Wholesale Prices (Color) and Price Convergence (NL|DE)

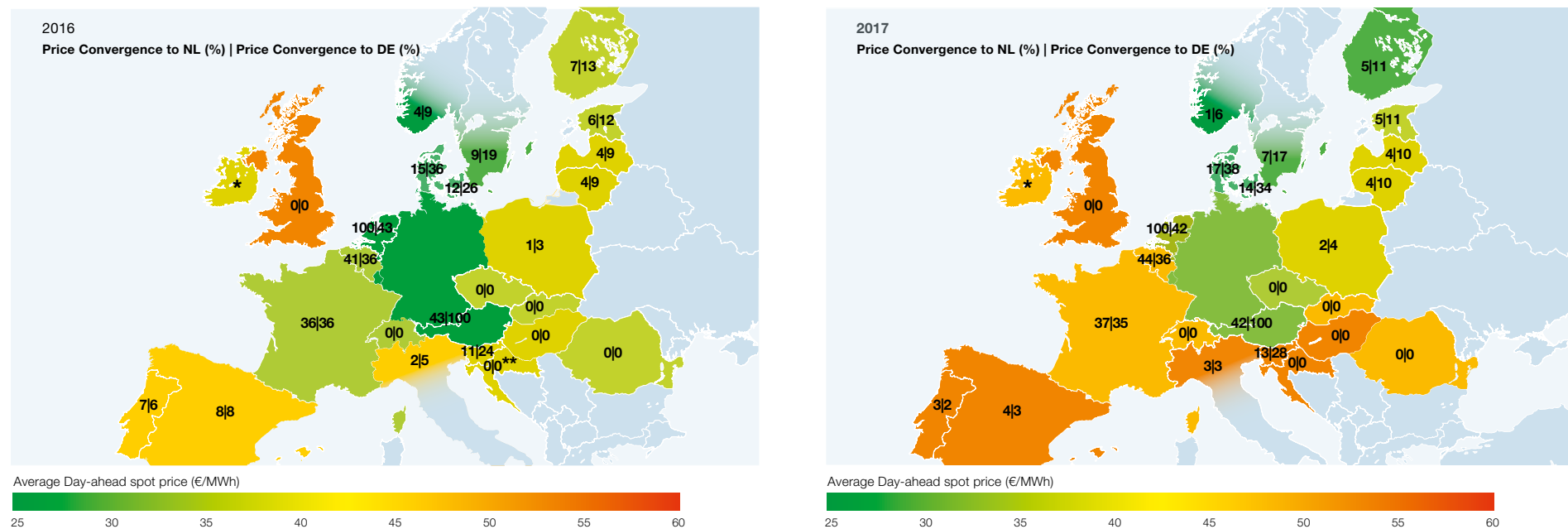


Figure 4: Yearly average hourly day-ahead prices and percentage hours with full price convergence (in relation to the Dutch and German/Austrian bidding zone) of different bidding zones<sup>2</sup> in Europe<sup>3</sup>. Source: MRC Market Coupling, APX, EEX, Nord Pool Spot, POLPX, OTE, GME, OMIP, CROPEX.

<sup>2</sup> For countries with multiple bidding zones, the bidding zone which has the most direct connection to the Netherlands and Germany is used for the visualization: Italy: North, Norway: NO2 and SE: SE4. For non-euro countries, a 1% margin is used to take price deviations caused by currency exchange rates into account.

<sup>3</sup> \* Ireland has 30-minute products only, therefore convergence cannot be calculated.

\*\* Day-ahead trading in Croatia started in February 2016.



# Electricity market prices

From 2016 to 2017 the average price in Europe slightly increased, similar to the developments in the CWE region in Figure 2. This trend occurred in most European bidding zones, except for bidding zones in the Nordic and Baltic regions. This increase is described in more detail in [chapter 4](#), which focuses on fuel prices. The average price in countries on the outer areas of Europe (Spain, Portugal, United Kingdom and Romania) was generally higher.

In 2017, price convergence of the Netherlands and Germany with other European countries was on the same level as for 2016, with only some minor increases and decreases. In principle, price convergence is higher with bidding zones of the CWE region, and lower with other countries of the MRC region<sup>4</sup>. Since Germany and Austria constitute one price zone, there is full price convergence between these countries. For some borders, e.g. the German-Swiss or the German-Czech border, there is no implicit market coupling. Instead, market participants explicitly need to buy transmission rights. Consequently, there is no price convergence at all on these borders.

## 3.2.2 Price volatility

Figure 5 depicts the distribution of hourly day-ahead prices for 2017 for a selection of European bidding zones.

### Yearly Box Plot of selected European Countries Day-ahead Wholesale Prices 2017

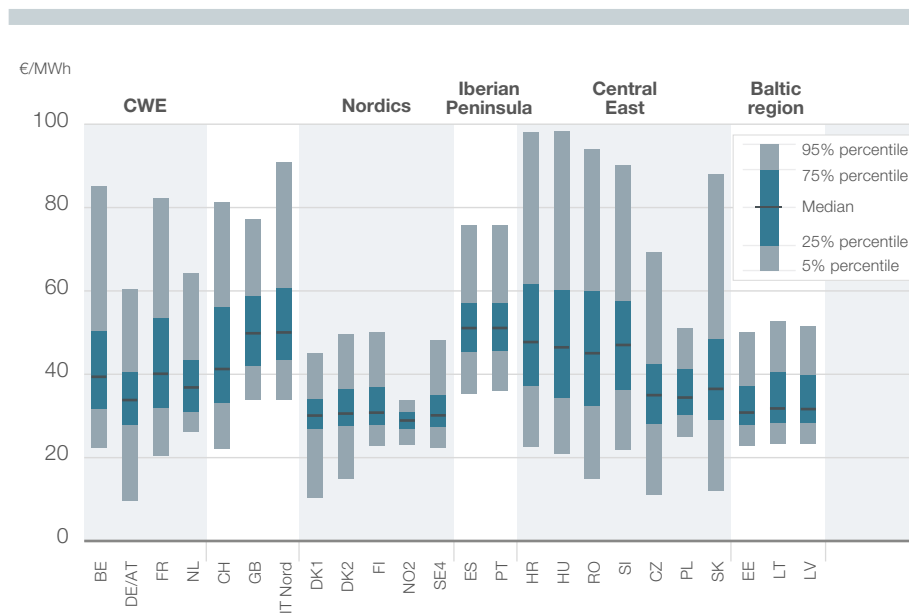


Figure 5: Yearly box plot of day-ahead prices of European bidding zones (selection).  
Source: MRC Market Coupling, OTE

<sup>4</sup> The MRC (Multi Regional Coupling) project covers Central Western Europe, the Nordics, the Baltics, UK, Italy, Slovenia and the Iberian Peninsula.

# Electricity market prices

For most bidding zones, the median prices and spreads are comparable with neighbouring zones due to market coupling. The highest median price occurred in the Iberian bidding zones Spain (ES) and Portugal (PT: 51.1 €/MWh), while the lowest median price appeared in the bidding zone of southern Norway (NO2: 28.9 €/MWh).

The difference between the 5<sup>th</sup> and 95<sup>th</sup> percentiles of day-ahead prices gives an insight in the price volatility. Price volatility is highest in the Central East European bidding zones Croatia (HR), Hungary (HU), Romania (RO) and Slovakia (SK), with highest volatility in the Romanian bidding zone. On the other hand, the volatility was lowest in the southern Norwegian bidding zone (NO2), mainly caused by the high generation share of hydro power, which has a high availability and is a flexible energy source.

The monthly median day-ahead prices were relatively similar between the Dutch and the joint German/Austrian bidding zone, see Figure 6. These median prices as well as the maximum prices (shown by upper outliers) were generally higher during the winter of 2016/2017 due to the cold weather and low generation capacity availability (see [chapter 10](#)). Furthermore, the price volatility tends to be higher in winter and lower in summer due to the seasonal electricity demand pattern (see [section 5.2](#)).

Negative prices occurred for 146 hours in 2017 in nine months in the German/Austrian bidding zone, which constitutes the highest number of hours of negative prices ever. 2016 experienced 97 hours of negative prices. The lowest price of the year occurred in October 2017, with a value of -83 €/MWh. The high share of RES and thermal 'must run' power plants are commonly named as the main causes for these negative prices. On the one hand, some RES even feed-in with low prices, because they do not react to market price signals due to guaranteed tariffs and unlimited priority feed-in. In addition, 'must run' cogeneration power plants need to produce heat and therefore cannot reduce electricity generation even when the RES are able to (largely) cover electricity demand in Germany and Austria.

## Monthly Box Plot of German/Austrian and Dutch Day-ahead Wholesale Prices 2017

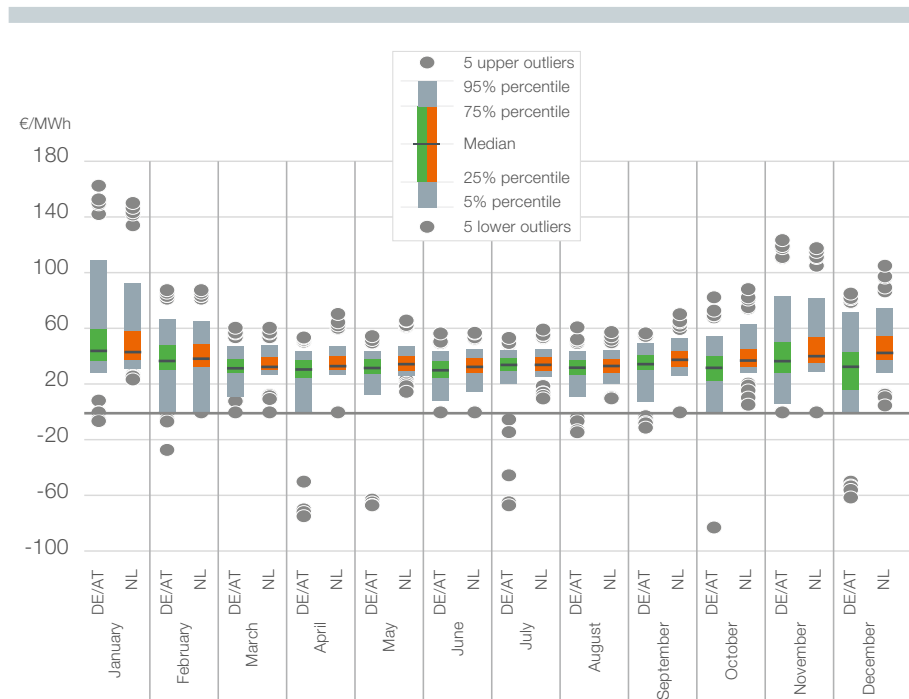


Figure 6: Monthly box plot of day-ahead prices of the German/Austrian and Dutch bidding zone. Source: MRC Market Coupling

Just like in 2016, the Netherlands did not experience negative prices in 2017. The lowest observed price in 2017 was 1.7 €/MWh, compared to 2.8 €/MWh in 2016. This decrease is probably caused by a higher installed renewable capacity.

# Electricity market prices

## 3.2.3 Day-ahead trading volumes

There are different exchanges for day-ahead trading in Europe. Before 2015, the Netherlands and Belgium had their own exchanges (APX, BELPEX). They merged into EPEX Spot in 2015, which is now the predominant exchange for the CWE market region. EXAA is a smaller Austrian exchange which operates in the German/Austrian day-ahead market. From 2015 to 2017 the traded volumes declined, with a significant decrease from 2015 to 2016 and a slight decrease from 2016 to 2017, as illustrated in Figure 7. One cause for this decrease could be a move of market transactions from the day-ahead to the intraday market, which experienced higher trading volumes, as RES generation forecasts are better closer to actual delivery.

### Volumes Traded on the Day-ahead Exchanges

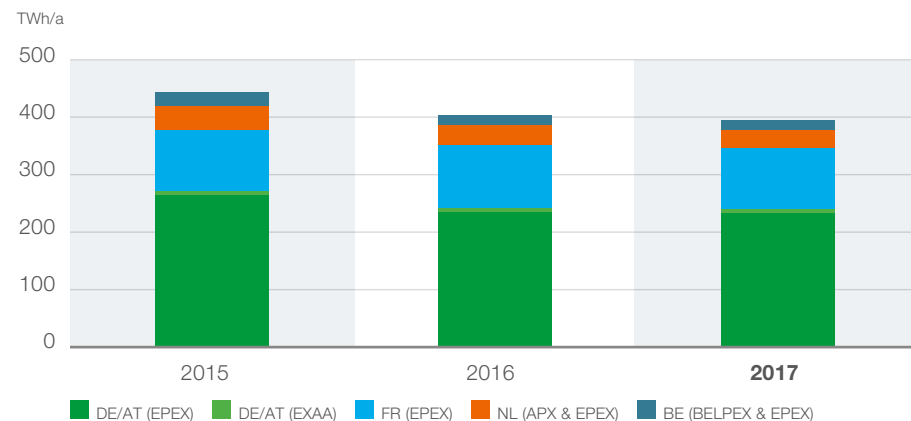


Figure 7: Annual trading volumes at day-ahead exchanges<sup>5</sup>.  
Source: APX, BELPEX, EPEX Spot, EXAA

Trading volumes on EPEX Spot in Germany and Austria are much higher than EXAA trading volumes. With about 233 TWh/a traded on EPEX Spot, the traded volumes on EXAA amount to 3.6% of this value.

The EPEX Spot exchange covers different bidding zones. The German/Austrian bidding zone is responsible for about 60% of the EPEX Spot trading volumes. The traded volumes in the French bidding zone equal 27% of the total traded volumes on EPEX, whereas Dutch and Belgium bidding zones are responsible for respectively 8.5% and 4.5% of the traded EPEX volumes.

The traded volumes for the French bidding zone amount to about 45% of the German/Austrian volumes, even though the load in France is 80% of the German/Austrian total load. There are multiple reasons for the relatively low French share in day-ahead trading volumes compared to Germany. Firstly, TSOs have to buy renewable electricity from generators which receive a feed-in tariff, and are obliged to sell this generation directly on the day-ahead and intraday markets since the introduction of the German Renewable Energy act (EEG) in 2009. This increases the number of trades compared to a situation in which market parties have to market this electricity and are also able to trade over-the-counter instead of via the exchanges. Secondly, the different generation structure in both countries could contribute to this difference. France has much more (nuclear) base load generation, which is typically not sold in the day-ahead market but in the futures markets. Lastly, a large share of the French generation is dominated by EDF, which is also active in French retail. Therefore, a large share of this generation by EDF is not traded on the exchanges.

<sup>5</sup> The trading volume of EXAA comprises two day-ahead products, namely green and conventional hourly products.

# Electricity market prices

## 3.3 Intraday market developments

### 3.3.1 Background

Due to information becoming available after closure of the day-ahead market, like new RES forecasts, plant outages or changed demand situations, market participants trade at the intraday market to optimize their positions.

The German/Austrian intraday market consists of two parts, in addition to the possibility for OTC trades. Firstly, there is a daily intraday auction at 15.00 on the previous day, which functions similar to the day-ahead market except that quarter-hourly products instead of hourly products are traded. Secondly, there are two continuous intraday markets: one operated by EPEX Spot with quarter-hourly, 30-minute (since 2017) and hourly products, and one operated by Nord Pool Spot. Nord Pool Spot offers 15-minute, 30-minute, hourly and block products. The fact that quarter-hourly products, are traded in the intraday market, in contrast to the hourly products in the day-ahead market, enables market participants to have a better approximation of the real demand ramps and generation variability (e.g. from solar or wind power generation). This is especially important since imbalance settlement periods are on a quarter-hourly basis.

The intraday market in the Netherlands is organized differently. Firstly, the Dutch intraday market does not have an intraday auction. Secondly, the Dutch continuous intraday market contains only hourly products. In the Netherlands, it is possible to trade intraday hourly products on both Nord Pool (only for cross-border trading between the Netherlands and Norway) and EPEX spot.

### 3.3.2 Yearly intraday trading prices in Germany/Austria

Figure 8 depicts the distribution of price differences between the weighted average intraday prices and day-ahead prices. It shows that the price difference was lower in 2016 compared to 2015 and 2017.

On average, the intraday prices are slightly higher than the day-ahead prices, with average differences between  $-0.08$  €/MWh and  $-0.03$  €/MWh in the years 2015-2017. The 95% percentile values of the difference between the intraday and day-ahead prices range from  $-9.5$  €/MWh to  $8.9$  €/MWh, thus overall the difference between day-ahead and intraday prices is typically below  $10$  €/MWh.

### Differences between German Day-ahead and Intraday Prices

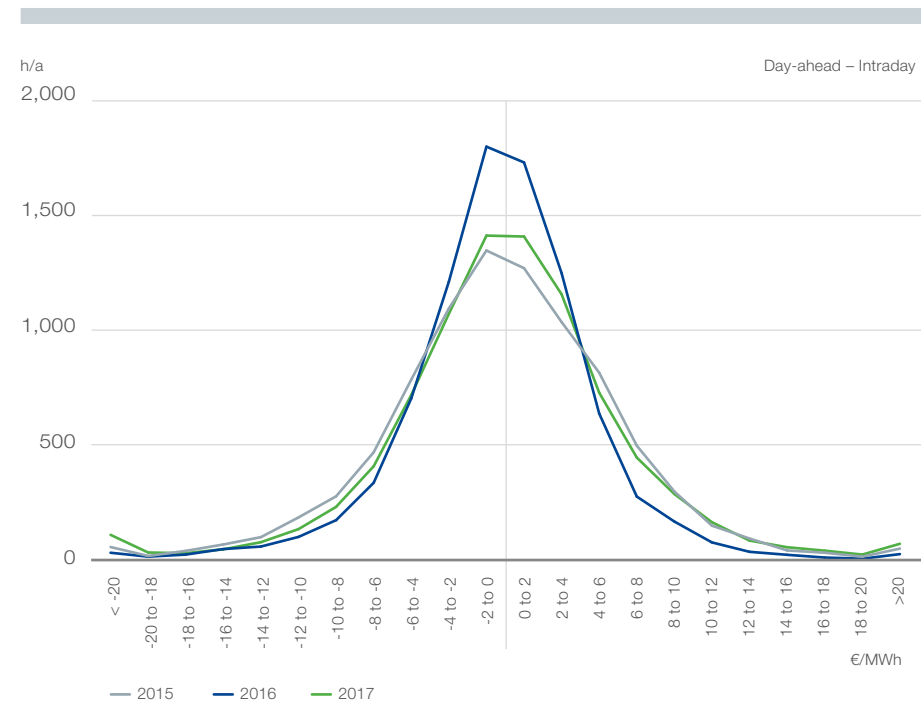


Figure 8: Distribution of price differences between German day-ahead and intraday prices<sup>6</sup>.  
Source: EPEX Spot

<sup>6</sup> Since intraday trading takes place in a continuous auction, there is not one single price for a specific hour, as in the day-ahead market. Therefore, the intraday price has been determined by taking the hourly weighted average price based on trading volumes.

# Electricity market prices

## 3.3.3 Intraday trading volumes

With the increase in renewable generation, there is a rise in trading volumes on the German/Austrian intraday markets, which becomes visible in Figure 9.

### Intraday Trading Volumes in Germany/Austria and in the Netherlands



Figure 9: Intraday trading volumes in Germany/Austria and in the Netherlands, with a zoom-in on the Dutch intraday trading volumes. Source: EPEX Spot, Nord Pool Spot

The trading volumes in the German/Austrian intraday auction increased by 54% from 4.6 TWh/a in 2016 to 7.1 TWh/a in 2017. The trading volume of hourly products in Germany and Austria increased from about 30 TWh/a in 2016 to 36 TWh/a in 2017, and the volume of the quarter-hourly products slightly increased from 4.75 TWh/a in 2016 to 4.83 TWh/a in 2017. In addition, 0.05 TWh of the newly-introduced 30-minute products were traded in 2017 in the German/Austrian intraday market.

The decrease of intraday volumes on Nord Pool from 2015 to 2016 and the increase of EPEX in the Netherlands can be explained by the migration of APX Power NL and Belpex intraday markets from the Nord Pool trading platform Elbas to the EPEX trading platform Eurolight in September 2015, which caused a shift in trades from Nord Pool towards EPEX. Only intraday trading between Norway and the Netherlands over the NorNed interconnection continued on the Elbas platform of Nord Pool. Traded intraday volumes on EPEX Spot increased by 63% from 2016 to 2017.

The traded intraday volumes in EPEX Spot are equal to 4% of the traded day-ahead volumes in 2017 at EPEX Spot in the Netherlands, while the aggregated volumes of all German/Austrian EPEX intraday market products are about 20% of the traded day-ahead volumes at EPEX Spot in this bidding zone.

There are three main reasons which explain this difference. One is that there is much more intermittent renewable capacity installed and generated in Germany, and market parties use the German intraday market to update their position based on updated forecasts. The second is the obligation of German TSOs to sell renewable electricity on the day-ahead or intraday market (see [section 3.2.3](#)), while if market participants would have to market the electricity themselves they could also sell (part of it) it over-the-counter instead of on the intraday market. Lastly, the financial risk of being in imbalance in the German imbalance market is in general higher than in the Dutch imbalance market (see [section 8.2.2](#)), which provides an additional incentive to close open positions on the German intraday market.

# Electricity market prices

## 3.4 Futures markets

### 3.4.1 Background

Market participants trade long-term contracts in the futures market. The purpose of this market is the reduction of financial risk by hedging through selling or buying a certain amount of electricity for delivery in the future.

A future is a standardized contract, where the buyer agrees to purchase a certain volume of electricity at a certain price at a specified date or period in the future and the seller agrees to deliver this electricity through a financial settlement. One of the most common electricity products is the baseload future for one year, which represents a delivery in each hour of the corresponding year.

In general, the long-term futures prices depend on the futures for fuel prices since those are the most important factors for the cost of thermal electricity generation.

### 3.4.2 Futures prices

After reaching a record low of just 21 €/MWh in February 2016 (see Figure 10), all futures prices have increased. At the end of 2016, the futures prices for different delivery years started to diverge and especially futures with delivery in 2017 experienced a significant price increase.

This was caused by an increasing demand for 2017 futures, as the market was tight at the end of 2016 (see also the TenneT Market Review 2016) and market participants wanted to hedge themselves for higher prices and unexpected events in 2017.

After the winter, the prices stabilized and decreased slightly, but from May 2017 onwards the German/Austrian and Dutch futures prices continually increased. The main cause can be found in increasing fuel prices throughout 2017 (see [chapter 4](#)).

### German/Austrian and Dutch Base Load Futures Prices

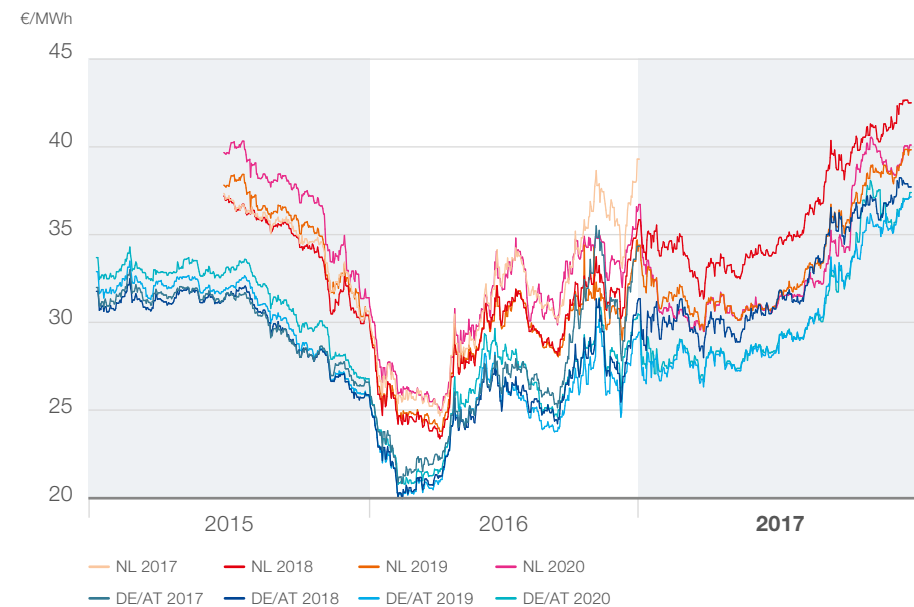


Figure 10: German/Austrian and Dutch base load futures prices for electricity. Source: EEX

# Electricity market prices

The German/Austrian and Dutch futures prices show similar trends, but the Dutch futures prices are always higher than German/Austrian futures prices, which implies that market participants expect higher electricity prices in 2018, 2019 and 2020 in the Dutch bidding zone compared to the German/Austrian bidding zone. Between 2015 and 2017, the difference between the German/Austrian and the Dutch 2019/2020 futures decreased from about 8 €/MWh to about 2 €/MWh.

At the end of 2017, the price of 2020 futures was higher than the price of 2019 futures, which can be explained by the announcement of ambitious climate goals by different national governments and plans for implementation of CO<sub>2</sub> minimum prices after 2020 in different countries. From the beginning of 2017, the price for 2018 futures was significantly higher than the price for futures for 2019 or later. This may be due to the scarce market situation in the winter of 2016/2017. Market participants expected that this scarce market situation would continue in the winter of 2017/2018 and wanted to hedge against these events, resulting in a higher demand for 2018 futures.

### 3.4.3 German-Austrian bidding zone split

To anticipate on the intended split of the joint German/Austrian bidding zone into two separate bidding zones in 2018, EEX issued separate futures for Germany and Austria in 2017. Figure 11 shows the price difference between the combined German-Austrian Phelix baseload futures and the separate Austrian and German Phelix baseload futures for 2018 and 2019.

### Settlement of German/Austrian futures

Financial settlement of the German/Austrian futures after the bidding zone split will take place according to a common virtual day-ahead spot price, which is calculated by taking the weighted average of the day-ahead prices in Germany and Austria, weighted in the ratio 9:1. According to current knowledge, physical fulfilment can take place in one or both market areas, depending on where the buyer has a balancing agreement contract (BRP). The difference between the settlement price of the derivative and the spot price in either the German or the Austrian bidding zone still needs to be covered by the market participant.

It is evident that the price difference between the combined futures and the German futures is smaller compared to the difference between the combined future and the Austrian futures. This can be traced back to the larger German market size. Fundamental demand and supply factors that determine the price of the joint German/Austrian futures can be allocated to assets that largely remain in the separate German bidding zone. As a consequence of differences in the generation mix, and of different support schemes for RES, market parties are expecting higher day-ahead prices in Austria after the split, and slightly lower prices in Germany. The difference between the joint German/Austrian futures and the separated futures is larger in 2019 than in 2018. This is because the split will only take place in the second half of 2018, meaning that the 2018 futures will only be effective on 1 October 2018. Therefore, the futures reflect the situation of separated markets for a period of three months only.

# Electricity market prices

## Price Spread between Different Futures for Germany and Austria

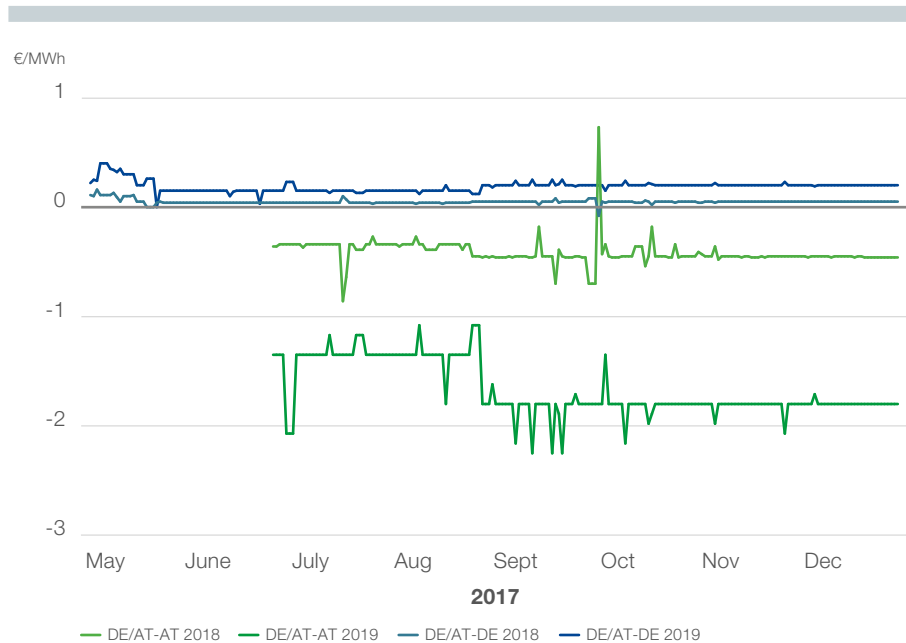


Figure 11: Price spread between different baseload futures for Germany and Austria.  
Source: EEX

Figure 12 illustrates the development of the volume share of the German and Austrian futures examined in Figure 11.

## Share of Traded Futures Volumes for the German/Austrian Market

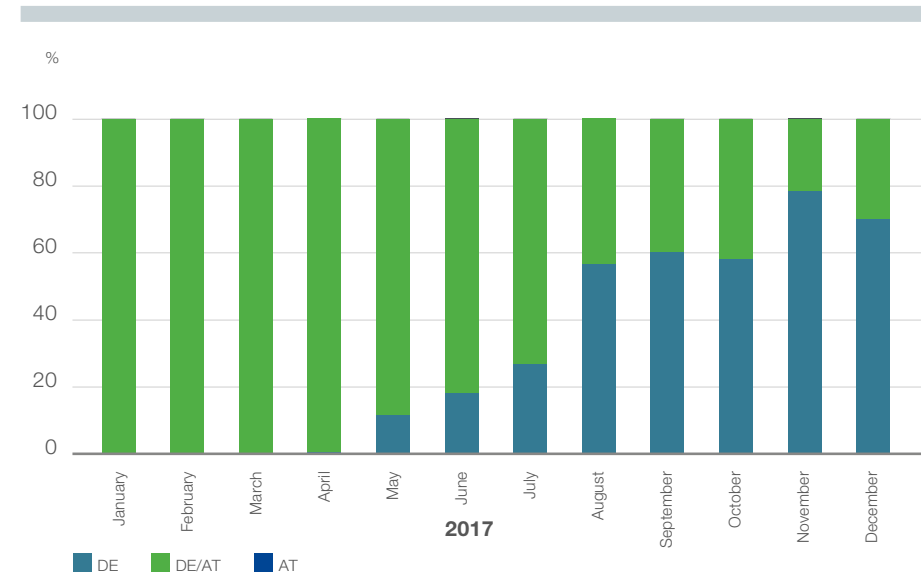


Figure 12: Share of traded volumes for the German market (baseload year futures 2019).  
Source: EEX

With the introduction of the German baseload year future 2019, the share of the German futures constantly increased, while at the same time the share of the German/Austrian futures decreased. Market participants obviously are expecting separated markets in 2019, and therefore the liquidity of pure German futures has already overtaken combined DE/AT futures. However, liquidity of separated Austrian futures is very low, and therefore conclusions regarding price levels in Austria after the bidding zone split are hardly possible. With the current low liquidity of the local futures, Austrian market participants need to hedge their positions with the German futures, leaving the potential difference between the prices on the separated spot market unhedged after the split.



# Fuel prices and generator margins

Generation costs for conventional power plants have increased significantly in 2017, as the natural gas, hard coal and CO<sub>2</sub> emission allowance prices increased. The difference between the gross margins for hard coal and gas plants decreased, as hard coal experienced a strong price rally from end of 2016 to early 2017, while the increase in the average gas price was much lower.

While in Germany the average generator gross margins were most of the time close to or slightly below zero, even for hard coal, they were positive for the Netherlands due to the higher electricity prices there. For both Germany and the Netherlands, a clear seasonal difference is observed, with higher gross margins in winter and lower gross margins in summer.

## 4.1 Background

Fossil power plant operators require fuel to generate electricity. Fuel costs constitute a large share of the total generation costs. Furthermore, European power plant operators need to purchase CO<sub>2</sub> emission allowances equal to

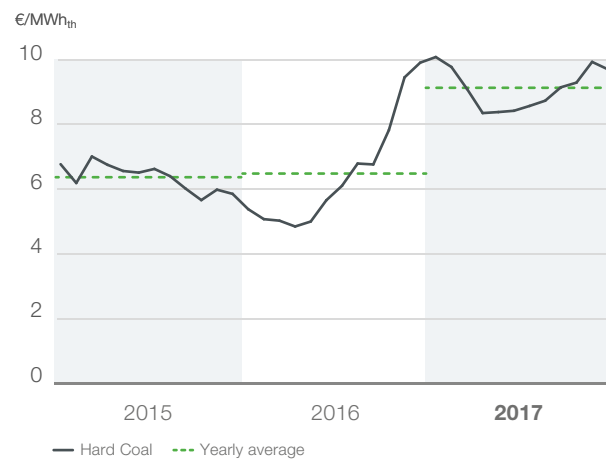
the amount of CO<sub>2</sub> their plants emit. The price of these emission allowances also contribute to the electricity generation costs and could make costs for electricity generation based on CO<sub>2</sub>-intensive fuels higher than costs for electricity generation based on less CO<sub>2</sub>-intensive fuels.

For some fuels, liquid global and European markets exist, while other fuels are not traded on global markets. Hard coal, natural gas and crude oil are traded on global markets and therefore have a transparent price. Lignite or uranium on the other hand are not traded on global markets, which makes their prices non-transparent. For lignite, this is because the transportation costs are

### Natural Gas Price



### Hard Coal Price



### CO<sub>2</sub> Emission Allowance price

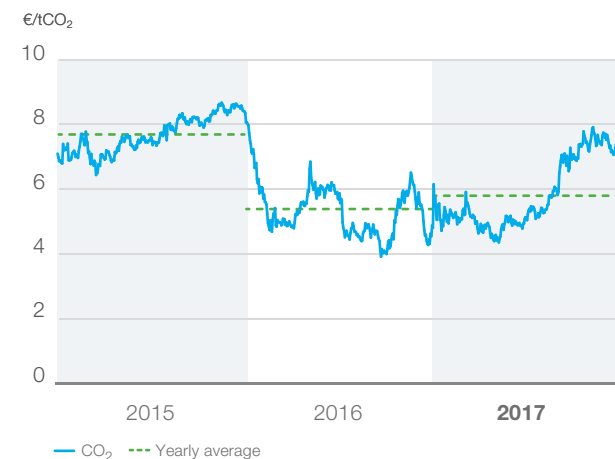


Figure 13: Natural gas (TTF)<sup>7</sup>, hard coal (API#2)<sup>8</sup> and CO<sub>2</sub> emission allowance price (ASK CO<sub>2</sub> Emission Certificate Futures). Source: energate

# Fuel prices and generator margins

too high in relation to its low specific energy density, so lignite power plants are usually in close proximity to lignite pits. For uranium, legal conditions restrict mining and trading. CO<sub>2</sub> emission allowances are traded on international exchanges.

## 4.2 Development of European fuel prices

Figure 13 shows the development of European fuel prices from 2015 to 2017. The graph on the left shows the natural gas price<sup>7</sup> and the middle graph illustrates the development of the hard coal price since 2015<sup>8</sup>. On the right, the futures prices for CO<sub>2</sub> emission allowances are depicted.

The natural gas price increased by 22% from an average price of 14 €/MWh<sub>th</sub><sup>9</sup> in 2016 to 17.2 €/MWh<sub>th</sub> in 2017. The price peaked in the 2016/2017 winter months with values up to almost 23 €/MWh<sub>th</sub> in February 2017. This sharp increase was caused by higher demand for natural gas triggered by cold temperatures, which will be discussed in depth in [chapter 10](#). After this peak, the prices stabilized at a level around 15 €/MWh<sub>th</sub>, which was above the average value for 2016. At the end of 2017, prices increased again to above 21 €/MWh<sub>th</sub>, again caused by lower temperatures.

The price for hard coal substantially increased in 2017 compared to 2015 and 2016. The average price in 2017 was about 40% higher compared to the average price of 2015 to 2016 (2015-2016: 6.4 €/MWh<sub>th</sub>; 2017: 9.1 €/MWh<sub>th</sub>). The price rally started halfway 2016 and peaked close to 10 €/MWh<sub>th</sub> in November 2016. This was mainly caused by the political decision of China in March 2016 to limit coal mines' annual operation days as it seeks to restructure its coal industry. In November 2016, China relaxed the operating limit to meet its heating season demand. This resulted in a price decline in the first months of 2017, which was accelerated by Chinese New Year holidays and reduced industrial consumption in early February. Afterwards, the price stabilized on a much higher level compared to 2016.

After a significant decrease of the price for CO<sub>2</sub> emission certificate futures in 2016, the average price slightly rose from 5.4 €/tCO<sub>2</sub> in 2016 to 5.7 €/tCO<sub>2</sub> in 2017. Until end of June 2017, the prices oscillated around an average value of 5 €/tCO<sub>2</sub> until prices started to increase from July 2017 onwards, reaching values of 7.9 €/tCO<sub>2</sub>, which is close to the average value of 2015. There are many causes behind this development. One cause could be that the European Commission submitted a legislative proposal to revise the ETS Directive on February 15<sup>th</sup> 2017, which proposes a faster reduction in the number of emission allowances after 2019. Moreover, the Dutch government plans to introduce a CO<sub>2</sub> floor price of 18 €/tCO<sub>2</sub> after 2020 and China is also considering developing an emission trading scheme. Altogether, these developments led to speculation about future price increases of CO<sub>2</sub> emission certificates among market participants, causing them to stock allowances. This resulted in sharp price increases in 2017.

## 4.3 Generator margins

### Clean Dark Spread and Clean Spark Spread

The clean dark spread (CDS) and clean spark spread (CSS) are indicators for profitability per unit of electricity generated for respectively coal or gas power plants. The CDS/CSS equals the difference between the electricity price and the marginal costs. The marginal price is based on the fuel and CO<sub>2</sub> emission allowance costs. All other costs (e.g. fixed construction costs) must be covered with these spreads.

The clean dark spread is calculated using the average day-ahead base price, as coal plants usually act as baseload power plants. The clean spark spread is calculated with both the average day-ahead base price (CSS base) and with the average day-ahead peak price<sup>10</sup> (CSS peak), to show the difference in profitability of running a natural gas plant in baseload or in start-stop operation during peak hours.

<sup>7</sup> The illustrated natural gas price is based on the day-ahead natural gas prices at the Dutch virtual exchange Title Transfer Facility (TTF).

<sup>8</sup> The illustrated hard coal price is based on the API#2 price index.

<sup>9</sup> Fuel prices are expressed in €/MWh<sub>th</sub>, where MWh<sub>th</sub> is the amount of heat released during the combustion of the fuel (heating value).

<sup>10</sup> Peak hours are between 8:00 and 20:00 on working days.

# Fuel prices and generator margins

Figure 14 shows the resulting monthly average CDS, CSS base and CSS peak values for Germany/Austria from 2015 to 2017. Note the peaks for all spreads at the beginning of 2017 due to the high day-ahead prices at this time, which led to higher profit margins of all power plants. Furthermore, natural gas-fired generation had a positive spread in peak hours in 2017 and therefore remained profitable, but had baseload spreads of around 0 €/MWh from February to the end of 2017. The spread for coal-fired generation also was around 0 €/MWh throughout most of 2017, but still a little higher than spreads for baseload gas-fired generation.

## German/Austrian Monthly Average Clean Dark Spread Base and Clean Spark Spread Base/Peak

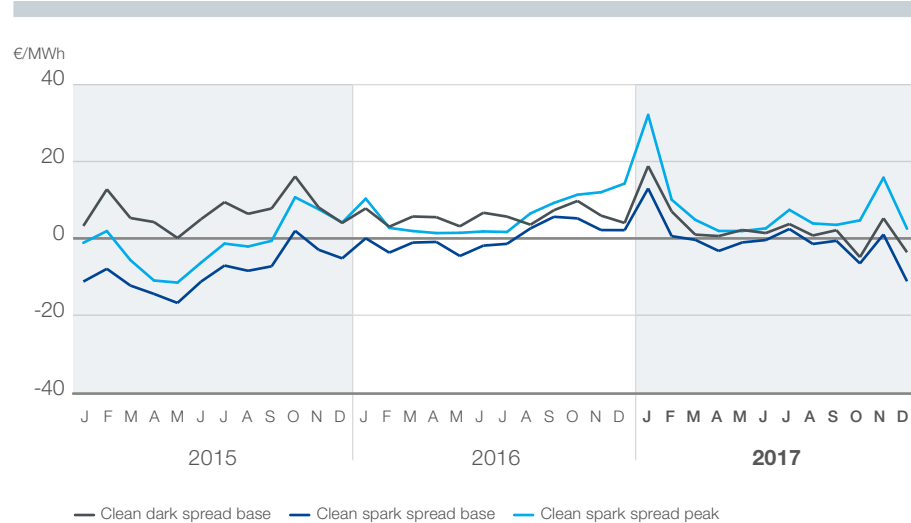


Figure 14: Monthly average clean dark spread base and clean spark spread base/peak in Germany/Austria<sup>11</sup>. Source: MRC Market Coupling, EPEX Spot, energeat

Figure 15 shows the same spreads for the Netherlands. The spreads for the Netherlands were positive and higher than the spreads for Germany in 2017, as the average day-ahead price in the Netherlands is higher than the German/Austrian day-ahead price, while fuel costs are similar. The Dutch spreads sharply increased in January 2017 to 28.3 €/MWh for the CSS peak. Following an equally sharp decrease, spreads remained stable from March to August on a positive level and increased again during the last months of 2017, again caused by higher day-ahead prices.

## Dutch Monthly Average Clean Dark Spread Base and Clean Spark Spread Base/Peak

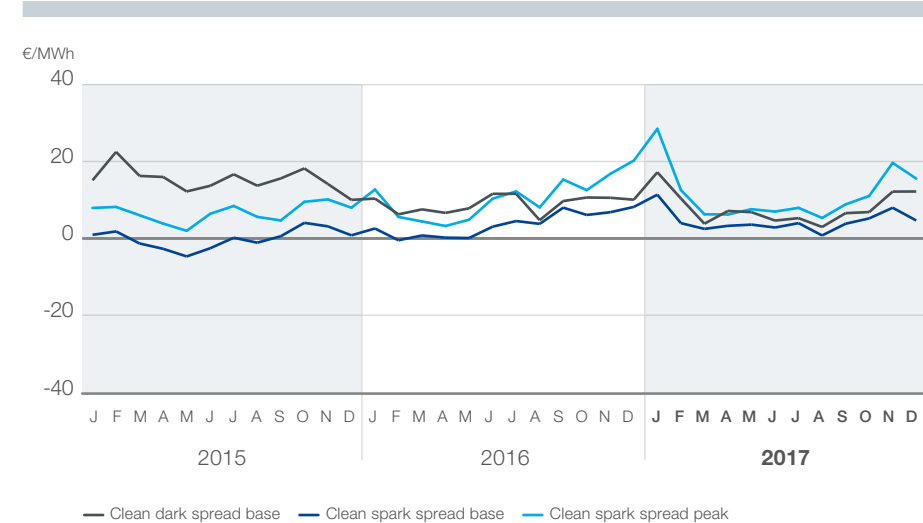


Figure 15: Monthly average clean dark spread base and clean spark spread base/peak in the Netherlands<sup>11</sup>. Source: MRC Market Coupling, EPEX Spot, energeat

<sup>11</sup> Assumption for calculating spreads: Efficiency of coal-fired power plants: 40% efficiency of gas-fired power plants: 55%, emission factor coal: 0.0917 tCO<sub>2</sub>/GJth, emission factor gas: 0.0556 tCO<sub>2</sub>/GJth, heating value of 1 kg coal amounts to 25.1 MJ.

# Electricity consumption and generation

Overall, the electricity consumption in CWE countries throughout the year 2017 was comparable to previous years. January was one notable exception, where the electricity demand was significantly higher, induced by low temperatures and the corresponding demand for electric heating.

The electric power system in the Netherlands and Germany continuously evolves to a system with a lower amount of conventional generation capacity and an increasing amount of renewable generation capacity. This trend continued in 2017, with mainly coal plants exiting the market and wind capacity entering the market. This increase in renewable capacity, together with beneficial weather conditions, resulted in a record-high renewable share of 38% in German electricity generation. Also, wind became the second-largest source for electricity generation in Germany, surpassing nuclear and hard coal. In the Netherlands, the loss in coal generation caused by the closure of the last coal plant from the 80's was taken over by gas plants. It is also interesting to note that battery systems are emerging in Germany, with an increase in installed capacity from 0 MW to more than 200 MW in the past five years.

## 5.1 Background

All consumers need electricity for their specific applications, which can include household appliances as well as industrial processes. The consumption depends on various factors, with time and weather being major influencing factors. In cold weather, the demand for electric heating and therefore the electricity consumption to be covered, increases. In contrast, high temperatures lead to higher demand for electric air conditioning.

Power plants transform primary energy into electricity, which is called production or generation. A distinction between conventional power plants, using fossil fuels, and RES units based on renewable sources (wind, solar) can be made. The generation of these two types mainly differ in terms of controllability. The intermittent generation of RES highly depends on weather conditions, whereas the conventional generation mainly depends on the supply costs for fuel and emission allowances as well as their availability due to revisions and outages.

# Electricity consumption and generation

## 5.2 Consumption

### 5.2.1 Monthly consumption CWE

Figure 16 shows the monthly electricity consumption in the CWE region in 2016 and 2017 as well as the bandwidth of monthly consumption between 2010 and 2015.

In Germany, France and the Netherlands, the demand in January 2017 is higher than the demand in 2016 and higher or almost as high as the maximum demand in January between 2010 and 2015. This can be traced back to the cold spell in this month and the corresponding demand for electric heating. This behavior is in particular visible in France, due to the high share of electric heating systems in this country. The Belgian demand follows the lower values of the 2010-2015 bandwidth and is very similar to the demand in 2016, especially from April to December. In the Netherlands and France, the demand in 2017 shows no clear deviations compared to previous years.

### Development of Monthly Electricity Consumption in the CWE Region

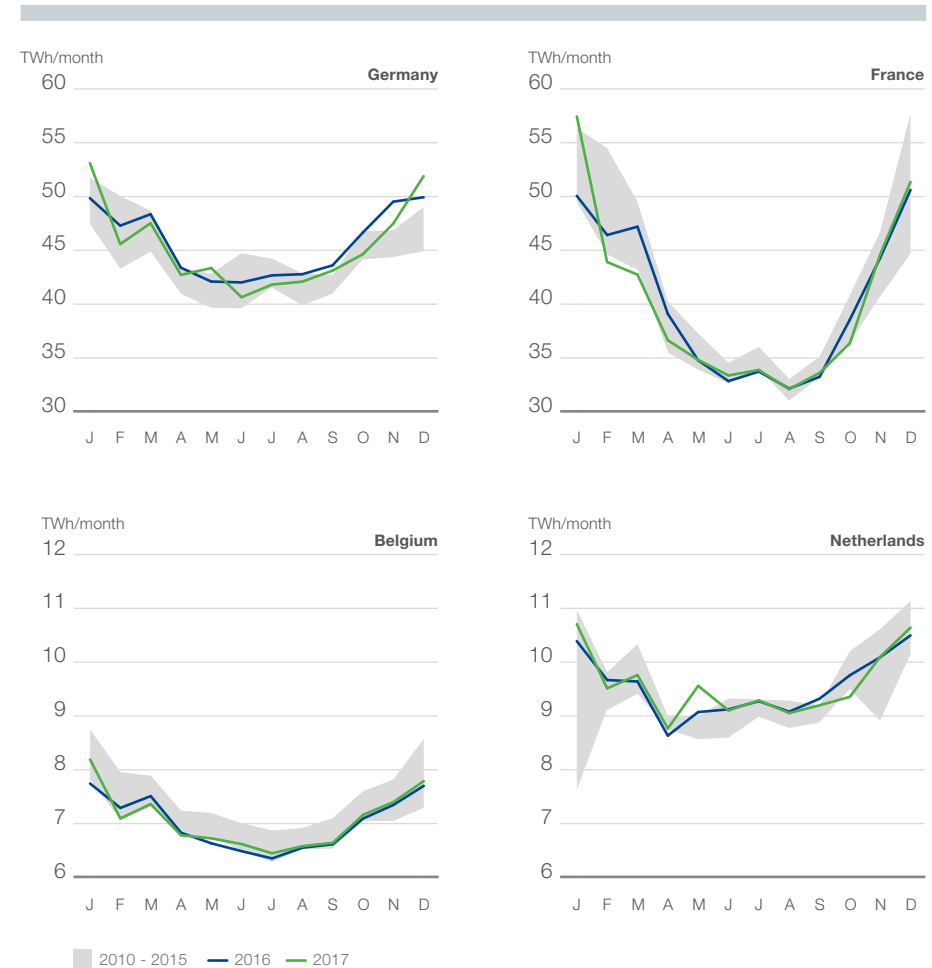


Figure 16: Monthly electricity consumption in CWE region.

Source: ENTSO-E monthly values from country packages (2010-2015), ENTSO-E monthly values from power statistics (2016-2017) for Germany, France, the Netherlands and Belgium, RTE 30-min data for October, November and December 2017 in France

# Electricity consumption and generation

## 5.3 Conventional and RES capacity

### 5.3.1 Generation capacity developments in Germany

The trend of increasing renewable generation capacity in Germany continued in 2017, as shown in Figure 17.

#### German Operational Generation Capacity

#### German Reserve and Motballed Capacity

#### Changes

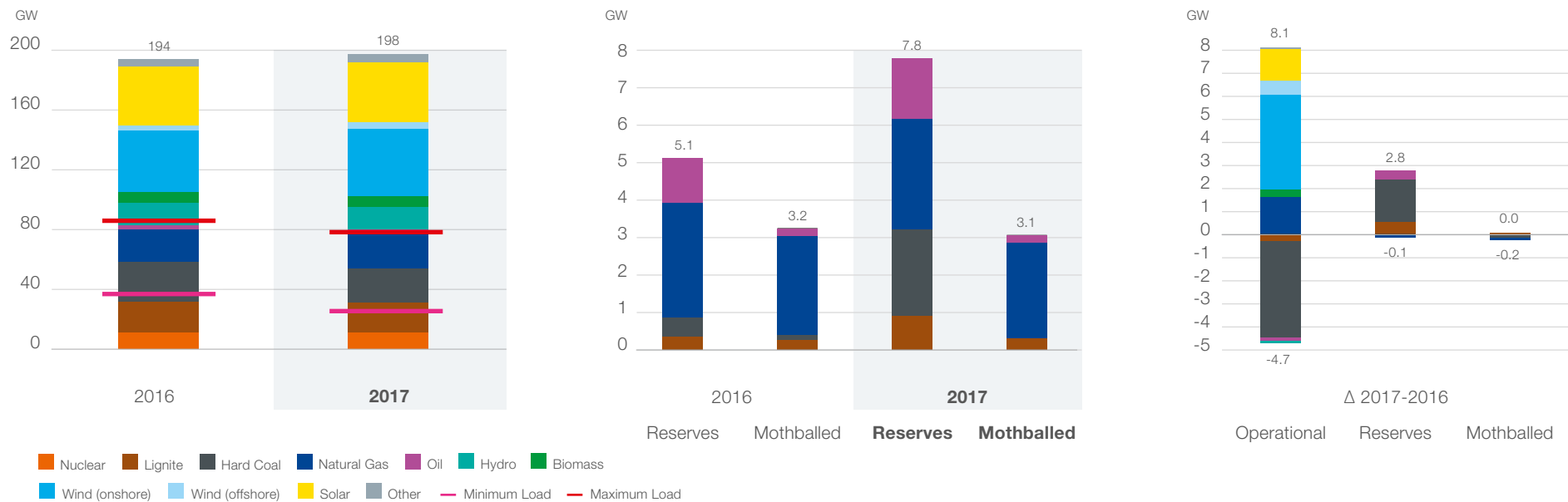


Figure 17: Operational, reserve and mothballed generation capacity in Germany in 2016 and 2017. Source: Kraftwerksliste, BNetzA

The renewable capacity in Germany increased by more than 6 GW in 2017, the majority of which is onshore wind with an increase of 4.1 GW. Besides onshore wind, offshore wind increased about 590 MW and the installed solar capacity increased by about 3.5%. As in previous years, the decrease in the total operational conventional capacity continued. In 2017, a total conventional capacity of 4.6 GW was phased out of the market, whereas 1.6 GW of gas-fired plants entered the market. The reserve capacities increased to almost

8 GW, the majority coming from hard coal and gas-fired plants. The hard coal plants that went into the "Netzreserve" were Weihler III (656 MW), ALT HKW 1 (433 MW) and BEX (726 MW). German TSOs also contract reserve capacity in neighbouring countries. In 2017, about 4 GW was contracted in neighbouring countries, similar to 2015 and 2016. In contrast to the reserve power capacity, the mothballed capacity decreased due to demothballing of natural gas plants. By contrast, the mothballed lignite capacity increased.

# Electricity consumption and generation

## Reserve power plants in Germany

Three different types of reserve power plants currently exist in Germany. The first reserve is the so-called “Netzreserve”, which was introduced in 2013. Every winter, German TSOs contract generation capacity, which is activated if the required redispatch capacity exceeds the capacity available on the market. TSOs refund the operating costs. The Netzreserve stack consists of units currently not in operation as well as units registered for shutdown by the plant operator, but declared as system relevant by the TSO.

The second type of reserve is “Kapazitätsreserve”, which will be set up from winter 2018/2019 onwards. The contracted units are not allowed to participate in the markets anymore and are only used for securing supply in case of extreme situations at the electricity market.

The last reserve type, called “Sicherheitsbereitschaft”, “Klimareserve” or “Braunkohlereserve”, consists of 2.7 GW of lignite-fired units, which has been built up from October 2016 onwards. The units in this type of reserve will be completely shut down after four years. Those stand-by plants will be activated in the case of insufficient Netzreserve and Kapazitätsreserve, as a last resort to avoid load-shedding.

## 5.3.2 Storage capacity developments in Germany

Figure 18 shows the installed utility-scale battery and power-to-gas capacity in Germany.

### Capacity of Utility-scale Battery and Power-to-gas Technologies in Germany

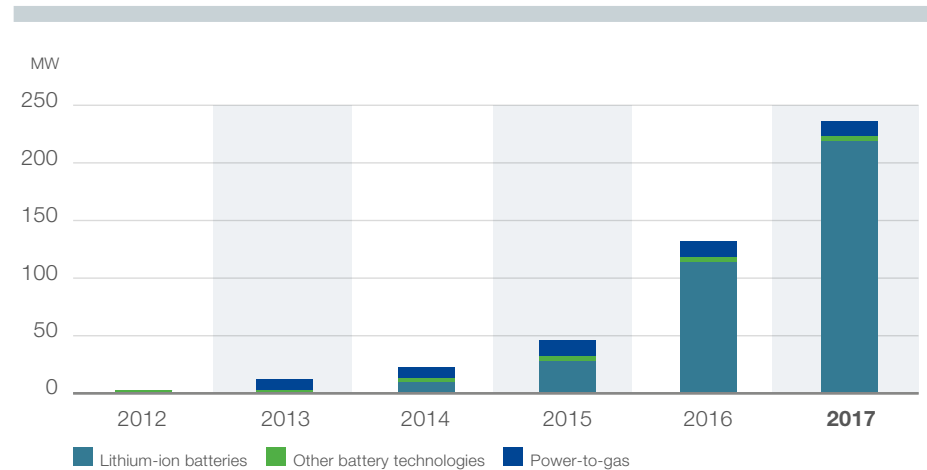


Figure 18: Installed capacity of utility-scale battery and power-to-gas storage technologies in Germany. Source: DOE Global Energy Storage Database

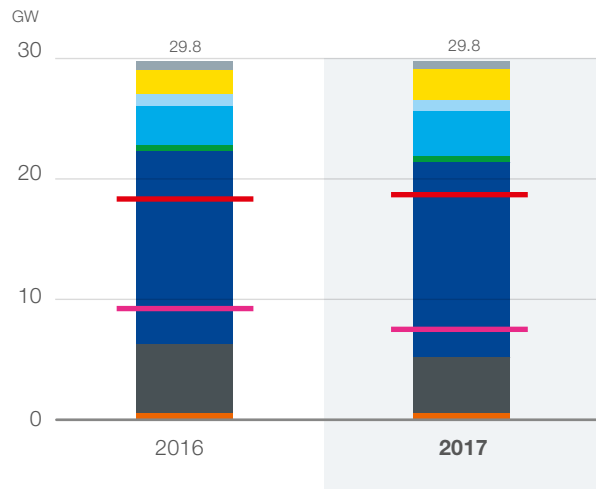
New types of energy storage technologies have been emerging in Germany since 2012. Figure 18 shows that the installed lithium-ion capacity has grown from 0 MW to more than 200 MW, mainly driven by the strong cost reductions that this technology experienced. The installed power-to-gas capacity also increased, but is not growing as quickly as the installed lithium-ion capacity. However, note that both the installed battery and power-to-gas capacity are still relatively small compared to the installed capacity of pumped hydro storage in Germany (9.3 GW<sup>12</sup>).

The majority of the installed battery capacity is primarily intended for providing frequency containment reserves (FCR) to the German balancing market. Other battery and power-to-gas systems are used for renewable capacity firming and back-up purposes.

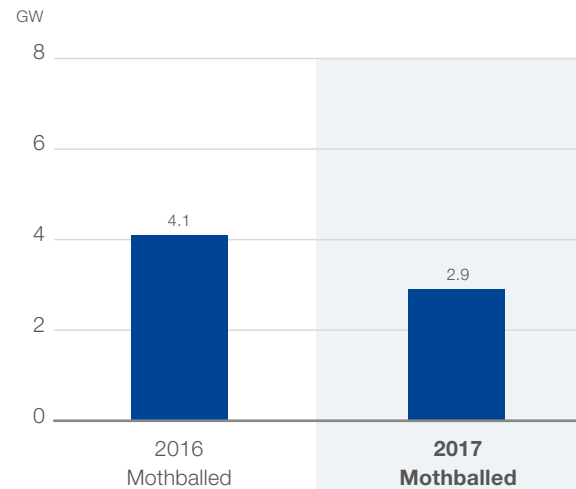
<sup>12</sup> Source: BNetzA

# Electricity consumption and generation

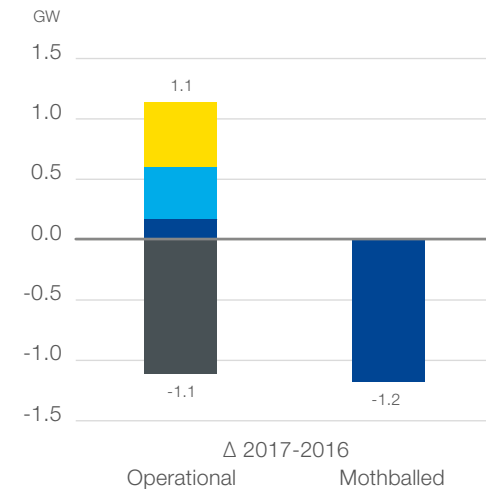
## Dutch Operational Generation Capacity



## Dutch Mothballed Capacity



## Changes



■ Nuclear ■ Hard Coal ■ Natural Gas ■ Hydro ■ Biomass ■ Wind (onshore) ■ Wind (offshore) ■ Solar ■ Other — Minimum Load — Maximum Load

Figure 19: Operational and mothballed generation capacity in the Netherlands in 2016 and 2017. Source: TenneT NL, ENTSO-E Power Statistics, Nationale Energieverkenning 2017

### 5.3.3 Generation capacity developments in the Netherlands

Figure 19 displays the operational generation capacity in the Netherlands, which has increased by 60 MW in the Netherlands. The renewable capacity increased by 1 GW to a total installed renewable capacity of 7.2 GW, while the conventional capacity decreased by 0.9 GW to a total capacity of 21.3 GW<sup>13</sup>.

The increase of renewable capacity can be attributed to a higher onshore wind and solar PV generation capacity. The onshore wind capacity grew by 13% from 3.2 to 3.7 GW and the solar PV capacity increased by 27% from 2.0 to 2.6 GW. The offshore wind capacity remained constant at 1.0 GW. The decrease of conventional capacity is mainly caused by the closure of two units of the

Maasvlakte hard coal plant (1.1 GW in total), as agreed upon in the Energy Agreement for Sustainable Growth.

For gas plants we observe different decisions between plant operators. On the one hand, the Rijnmond power plant (0.8 GW) has been demothballed in 2017, presumably partly induced by the high electricity prices during the cold spell (see chapter 10). On the other hand, Engie announced to mothball and decommission units of the Eemscentrale power plant in 2017 and some other plant operators decided to decommission plants which were mothballed<sup>14</sup>. Therefore, the total (long-term) mothballed capacity decreased in 2017 to 2.9 GW.

<sup>13</sup> Renewable capacities are estimated based on data from Nationale Energieverkenning 2017.

<sup>14</sup> The total generation capacity per technology and statements about decisions of power plant operators concerning their power plants are based on announcements by plant operators made to TenneT. TenneT has observed that the actual decisions of power plant operators sometimes deviate from their announcements.



# Electricity consumption and generation

## 5.4 Electricity generation

### 5.4.1 Gross electricity generation in Germany

The increasing share of renewables in the German generation stack is reflected in the generation volumes per fuel type in 2017, as shown in Figure 20.

Compared to 2016, the share of RES in the total electricity generation increased from 33% to about 38% in 2017 in Germany. The main driver for this increase was beneficial weather conditions, which resulted in an increase

### German Gross Electricity Generation

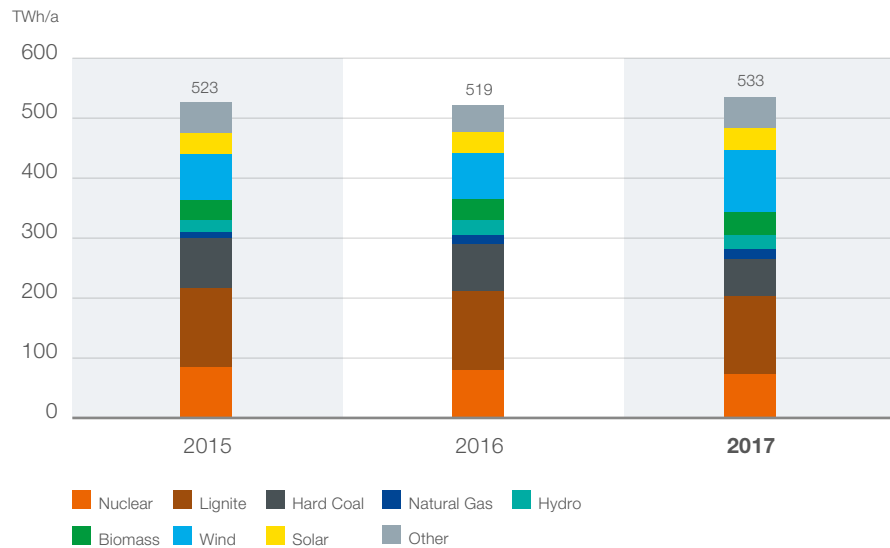


Figure 20: German gross electricity generation. Source: SMARD, BNetzA

in wind generation from 76 TWh in 2016 to above 100 TWh in 2017. Consequently, wind became the second-largest electricity source, after lignite. Generation by hard coal decreased significantly, caused by the phasing out of hard-coal-fired plants in 2017, as discussed in [section 5.3.1](#). The overall generation in 2017 increased by 2.6% in comparison to 2016.

### 5.4.2 Monthly generation and load in Germany

Figure 21 depicts the monthly generation as well as the net imports (import minus export) of Germany.

### German Monthly Generation, Imports and Exports

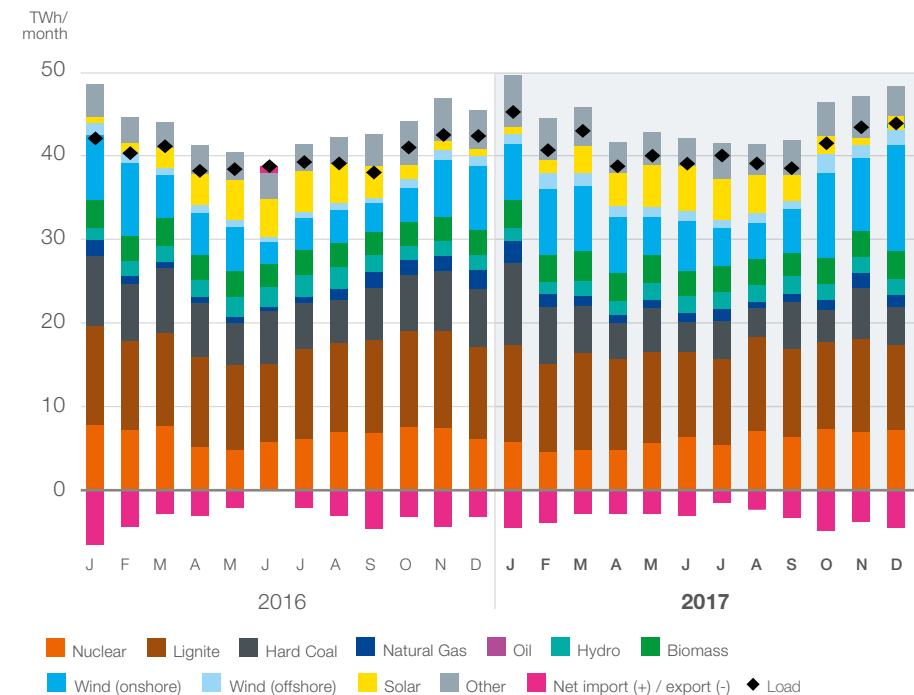


Figure 21: Monthly generation, imports and exports of Germany. Source: SMARD, BNetzA.

# Electricity consumption and generation

Generation is typically higher in winter compared to summer. This is not only caused by the higher domestic load in winter months, but also by higher exports to neighbouring bidding zones like France, which show a more extreme seasonal demand pattern due to the high installed capacity of electric heating systems. In addition, it is noticeable that a change in generation especially comes from a change in natural gas and hard-coal-fired generation. These power plants provide the flexibility to meet seasonal demand patterns.

## 5.4.3 Zooming in on German RES feed-in

Corresponding to the monthly values shown in Figure 21, the rising feed-in of RES is displayed more explicitly in Figure 22.

### German Monthly Feed-in of RES

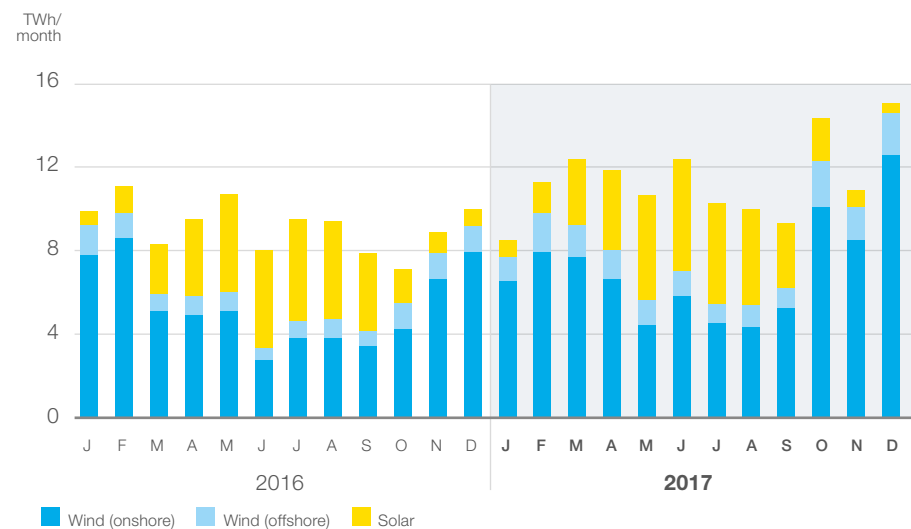


Figure 22: Monthly feed-in of RES in Germany.  
Source: SMARD, BNetzA

The graph shows that wind feed-in tends to be higher in fall and winter months, whereas solar feed-in is higher in summer months. The overall rise in wind generation in 2017 is caused by the higher installed capacity, as displayed in Figure 17, and the extraordinary beneficial weather circumstances in October and December 2017. The solar feed-in of 5.4 TWh in June 2017 was the highest German monthly solar feed-in so far.

## 5.4.4 Gross electricity generation in the Netherlands

Figure 23 shows that the gross electricity generation in the Netherlands measured as infeed on the public grids (~82-85%) increased from 91 TWh in 2015 to 97 TWh in 2016 and 98 TWh in 2017<sup>15</sup>.

### Dutch Gross Electricity Generation

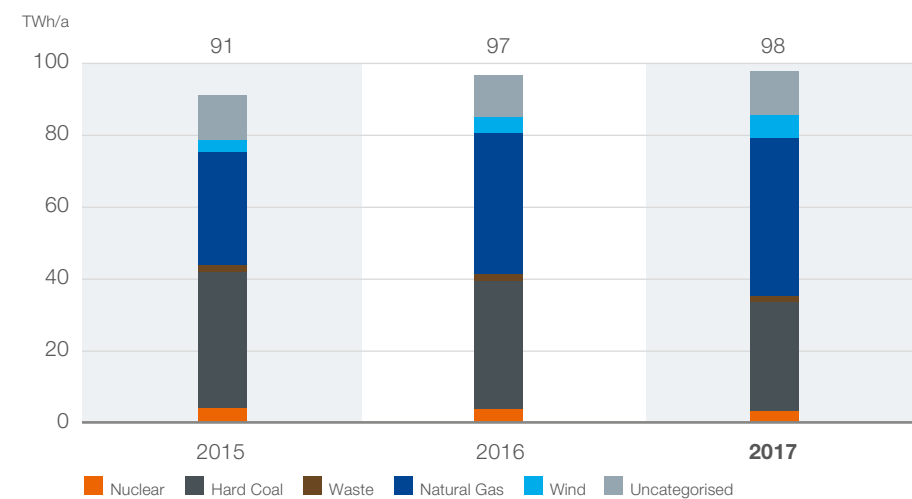


Figure 23: Dutch gross electricity generation<sup>16</sup>.  
Source: TenneT NL

<sup>15</sup> The total generation in NL including generation on industrial grids or generation directly consumed "behind the meter" can be found at CBS.

<sup>16</sup> Generation shown is from electricity infeed measured on public grids; ~ 82-85% of total NL generation. Uncategorised generation consists of generation from units smaller than 10 MW, which cannot be linked to specific fuel types.

# Electricity consumption and generation

The share of different fuel types in the total electricity generation has changed considerably. Generation from hard coal has decreased considerably from 36 TWh to 30 TWh per year, mainly caused by the closure of a coal plant in the Netherlands, as described in [section 5.3.3](#). The lower coal generation has been mainly taken over by natural gas plants, whose total generation rose from 39 TWh in 2016 to 44 TWh in 2017. Wind generation also increased significantly from 4.5 TWh in 2016 to 6.4 TWh in 2017. This 43% increase in wind generation is considerably higher than the 10% increase in installed wind capacity (see [section 5.3.3](#)), which implies that this increase is also caused by more beneficial wind conditions in 2017 compared to 2016.

## 5.4.5 Monthly generation and load in the Netherlands

Figure 24 shows the monthly generation in the Netherlands.

The generation in winter is higher than the generation in summer, caused on the one hand by a higher domestic load in winter and on the other hand by lower imports (on some occasions even exports) to serve increased and by more temperature-sensitive loads in other countries.

In particular, generation from natural gas increased in winter months. This is induced by a higher profit margin for natural gas generation in these months, as reflected in the improved clean spark spread in Figure 15. Although the clean dark spread also improved in the winter months, coal generation only increased slightly as coal plants generally operate at full capacity throughout the year.

## Dutch Monthly Generation, Imports and Exports

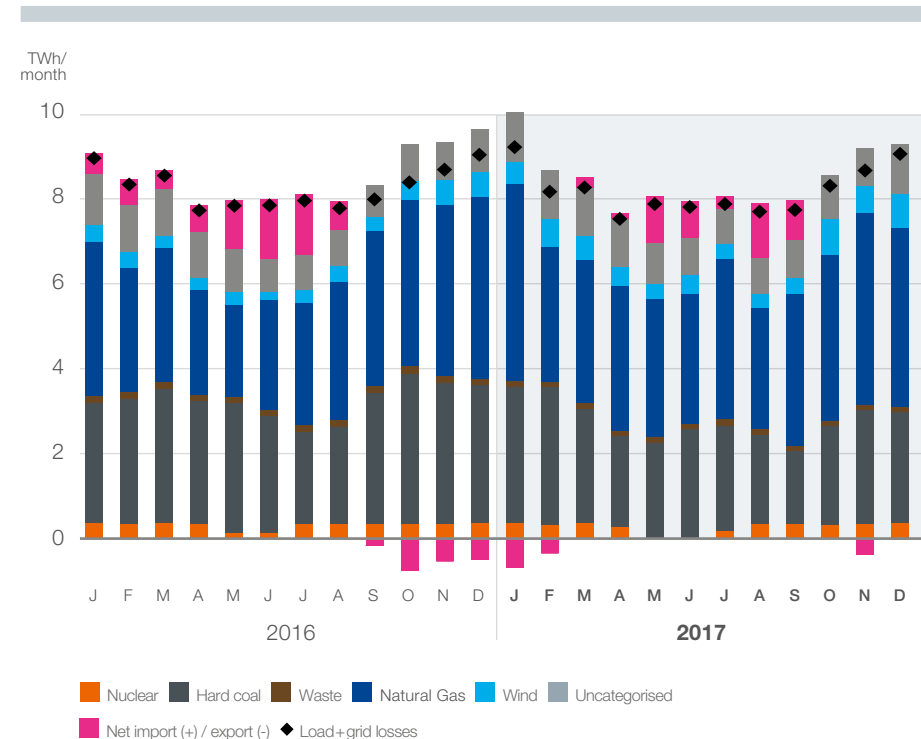


Figure 24: Monthly generation, imports and exports of the Netherlands<sup>16</sup>.  
Source: TenneT NL

# RES support schemes

The German and Dutch governments have implemented renewable support schemes to incentivize investments in renewables. Costs for renewables are decreasing, which can be observed in a downward trend in requested subsidy levels in renewable auctions in both the Netherlands and Germany. An absolute breakthrough for offshore wind was reached this year, as in both the Netherlands and Germany zero-subsidy bids were offered in offshore wind auctions.

## 6.1 German developments

### 6.1.1 Background

RES generation must be financially supported in order to incentivize and guarantee a reliable investment in most cases.

German RES operators can receive support in two ways. Firstly, operators can decide to sell their RES generation to the DSO for a fixed, technology-specific feed-in tariff (“EEG-Einspeisevergütung”). The DSO sells this electricity to the TSO, which is obliged to sell it on the day-ahead or intraday market.

Secondly, RES operators can decide for direct commercialization (“Direktvermarktung”), in which RES operators sell their energy on the spot markets and additionally receive a market premium (“Marktprämie”), covering the difference between feed-in tariff and market price, and an additional premium (“Managementprämie”) for their expenditures in management.

The German RES subsidies are paid through the EEG levy, which every end-consumer of electricity pays for their electricity consumption.

### 6.1.2 EEG feed-in tariff and EEG Umlage

#### Average EEG feed-in tariff and EEG Umlage

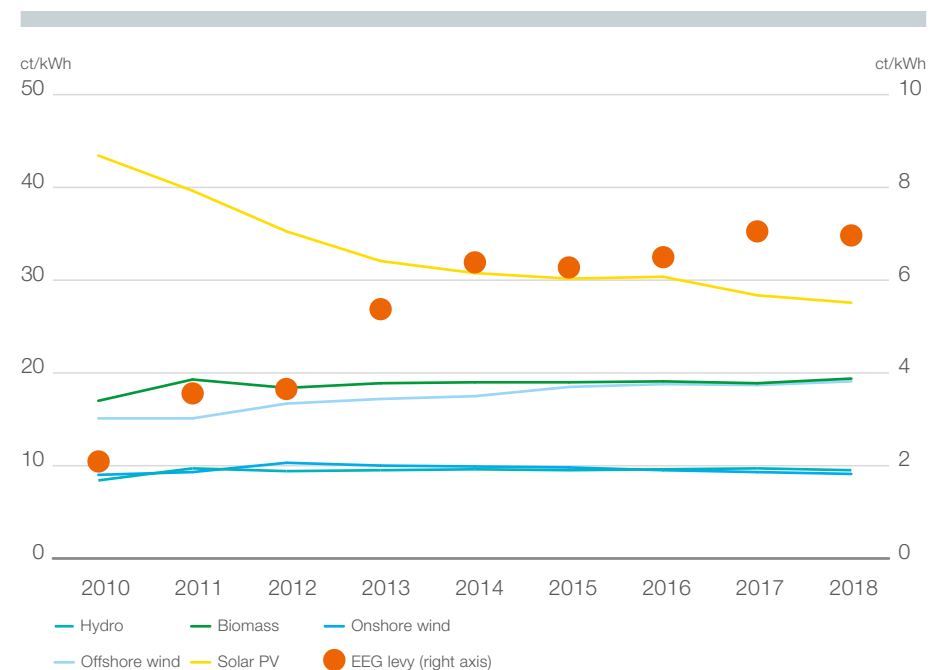


Figure 25: Average EEG Einspeisevergütung (left axis) and EEG levy (right axis).  
Source: BDEW

# RES support schemes

With increasing RES generation volumes and low spot market prices, the German EEG levy rises. As Figure 25 depicts, the price for the EEG levy started at 2 ct/kWh in 2010. By 2017, it had reached 6.8 ct/kWh and increased by about 0.5 ct/kWh compared to 2016.

The average RES feed-in tariff shows different trends between 2010 and 2017. The graph shows that the average feed-in tariff for wind onshore and biomass electricity generation remained relatively constant. The feed-in tariff for solar generation decreased by 35% from about 43 ct/kWh in 2010 to 28 ct/kWh in 2017, indicating that the German government expects the costs for solar generation to decrease. Offshore wind turbines were included in the regular “EEG-Einspeisevergütung” between 2009 to 2017, but since 2017 financial support to offshore wind projects is granted through auctions.

## 6.1.3 Renewable auctions of solar panels and onshore wind turbines

### German RES capacity auctions

New ground-mounted PV systems and wind onshore turbines with a capacity of at least 750 kW can only receive financial support if they participate in auctions for new RES capacity, which take place three times per year. Every auction, the German government determines a maximum capacity per technology which will be granted support, based on the expansion target of each technology. Participants can make single bids, which includes the capacity of the project and a subsidy level in ct/kWh. The auctions follow the pay-as-bid principle, i.e. the subsidy level corresponds with the individual bid. Participants with the lowest bids will be granted subsidy, until the maximum capacity for the specific technology has been reached.

Since April 2015, RES capacity has been auctioned in a pilot project in Germany. This pilot project introduces competitive bidding for new ground-mounted solar panels and onshore wind turbines to stimulate competition among suppliers (see textbox). The auction results in Figure 26 showed significant price decreases for both onshore wind and solar capacity, with an average price of 3.4 ct/kWh for onshore wind in October 2017.

### Average Solar PV and Wind Onshore Auction Results in Germany

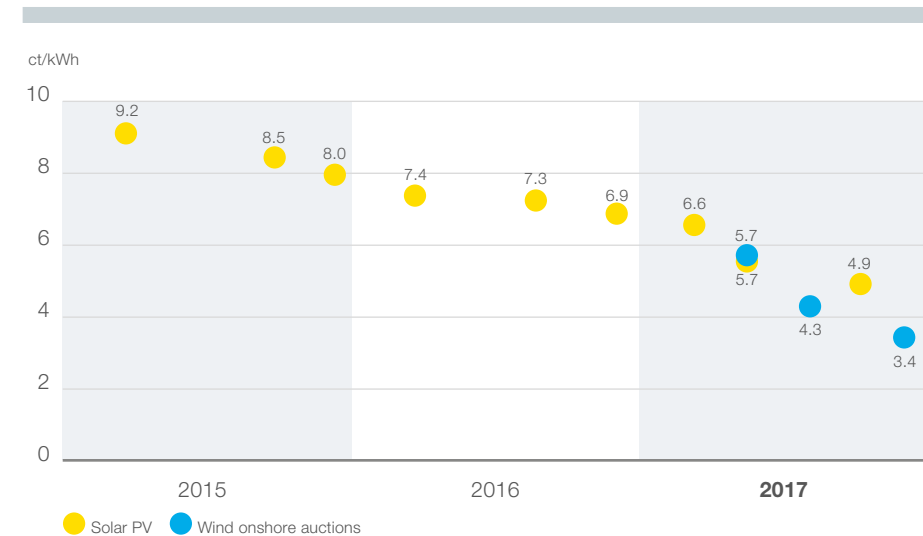


Figure 26: Average auction results for solar panels and wind onshore turbines in Germany. Source: BNetzA

# RES support schemes

## 6.2 Dutch developments on SDE+

### 6.2.1 Background

The *Dutch Stimulerend Duurzame Energieproductie+* (SDE+) subsidy scheme was introduced in 2011 as a follow-up to former renewable energy subsidy schemes. It is an operating subsidy where producers receive financial compensation for their renewable energy generation. The SDE+ compensates producers of renewable electricity, gas and/or heat for the difference between the cost price and the market price of renewable energy supplied.

SDE+ grants are distributed in rounds. Until 2017, 11 rounds were held; two rounds focused on specific offshore wind locations, while nine rounds were open for all other renewable energy technologies. The Minister of Economic Affairs and Climate Policy sets a budget for every SDE+ round. This budget is the maximum subsidy that will be allocated to the producers during the whole subsidy period. To enhance competition between different renewable generation technologies, no distinction is made between generation technologies when allocating the budget.

The cost price for the generation of renewable energy is set in the base amount for the technology. The market value of the energy supplied is recorded in the correction amount. Owners of renewable energy projects can bid for a certain base amount. The producer receives the difference between the base amount and the correction amount throughout the subsidy period of 8, 12 or 15 years, depending on the technology used. As the energy price – and therefore the correction amount – changes over the years, the subsidy received by a producer differs per year. However, the sum of the energy price and the subsidy per unit produced remains the same.

Each SDE+ round is divided into phases, each of which is subject to a maximum phase amount. Project owners are only allowed to make bids below the maximum phase amount and the maximum base amount for each technology, which is determined by the Netherlands Enterprise Agency (RVO). As the budget is allocated based on a first-come-first-serve basis, the risk is relatively high that the budget will no longer be available in a later phase. In this way, producers are motivated to make a competitive bid.

### 6.2.2 Auction results

The number of SDE+ rounds has increased from one to two from 2016 onwards, while the budget per round has also increased significantly. This is the consequence of increased governmental actions to meet its RES targets.

While the majority of the budget was allocated to renewable heat, gas or CHP technologies in the first SDE+ rounds, renewable electricity technologies dominated the later rounds. Figure 27 shows that the distribution between different electricity technologies fluctuated. Biomass co-firing captured a large share of the budget in the 2016 rounds, but did not receive any subsidy in the 2017 rounds as the biomass co-firing generation limit from the 2013 Energy Agreement for Sustainable Growth had been reached. Although bids for solar technologies are generally higher than bids for other technologies (see [section 6.2.3](#)), they still received a high share in the 2014 rounds due to a low amount of applications for a subsidy by wind projects. The high share of solar and wind in the 2017 round can be explained by the increase in budget and the restrictions on biomass co-firing subsidy applications.

### Budget Distribution per SDE+ round

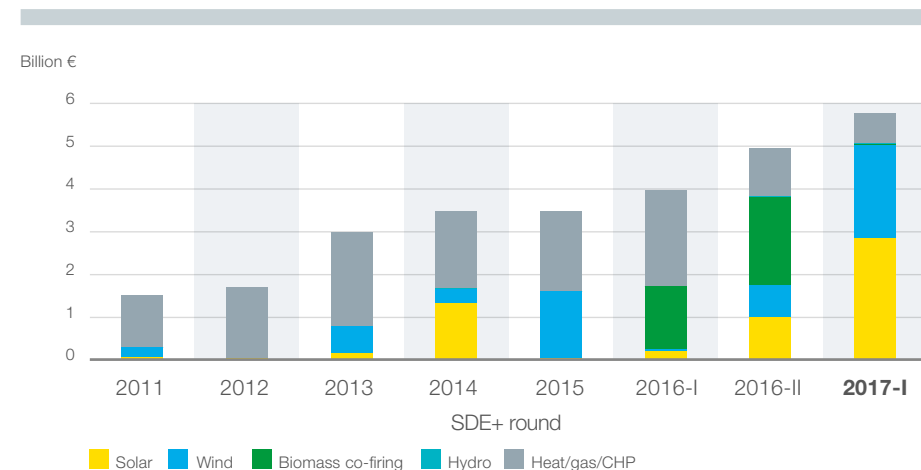
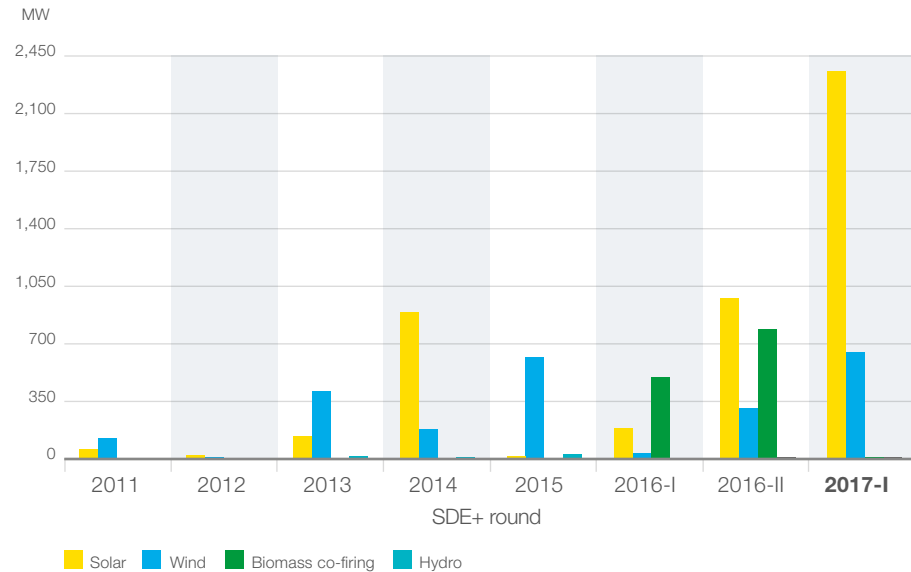


Figure 27: Budget distribution per SDE+ round. Source: RVO

# RES support schemes

## Awarded Capacity per SDE+ round



## Awarded Electricity Generation per SDE+ round

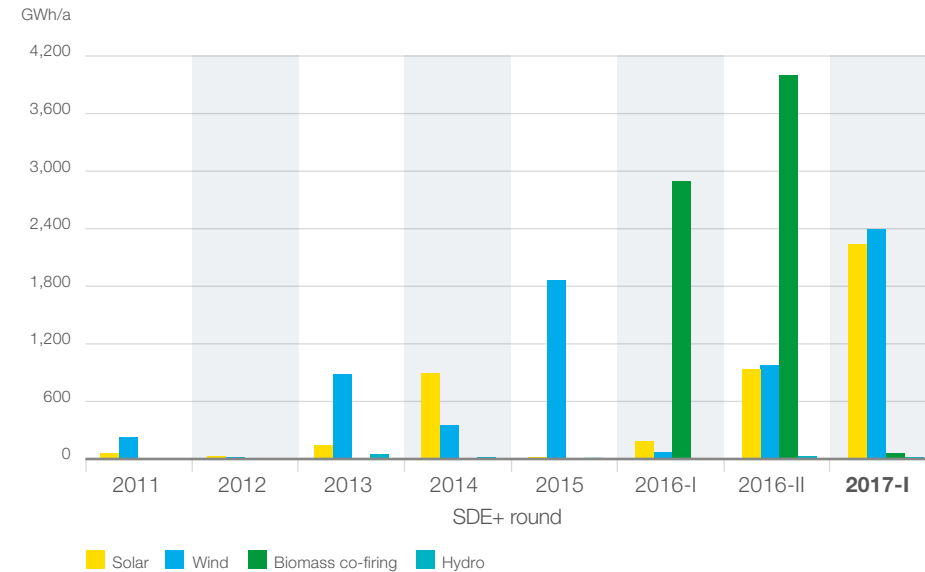


Figure 28: Awarded capacity and electricity generation volumes per technology per SDE+ round.  
Source: RVO

In the last SDE+ rounds, the majority of the capacity was awarded to solar technologies, see Figure 28. However, the majority of subsidised electricity generation will be from wind and biomass co-firing. This discrepancy can be attributed to the higher load factor of these technologies.

# RES support schemes

## 6.2.3 Bid price developments

The budget allocation among different technologies can be seen in Figure 29. This figure displays the accepted bids per technology in ascending order against the cumulative generation. This figure indicates that subsidy bids for co-firing and wind technologies are generally lower than bids for solar technologies. Therefore, solar projects were only granted a significant share of the SDE+ budget if the total subsidy demanded by cheaper technologies did not exceed the maximum budget. The high competitiveness of offshore wind compared to other renewable electricity technologies is illustrated by the significantly lower subsidy bids made in the offshore wind SDE+ rounds.

The line of every technology shifts downwards for every SDE+ round in Figure 29. This indicates that the subsidy bids decrease, implying a cost reduction over time. However, the increase in budget in the 2017-I round means that projects which applied for a higher base amount are also accepted in the SDE+ program. Therefore, the highest accepted bids for solar and wind technologies in the 2017-I round are higher than the highest accepted bids in previous rounds.

## Base Amount of Accepted SDE+ bids

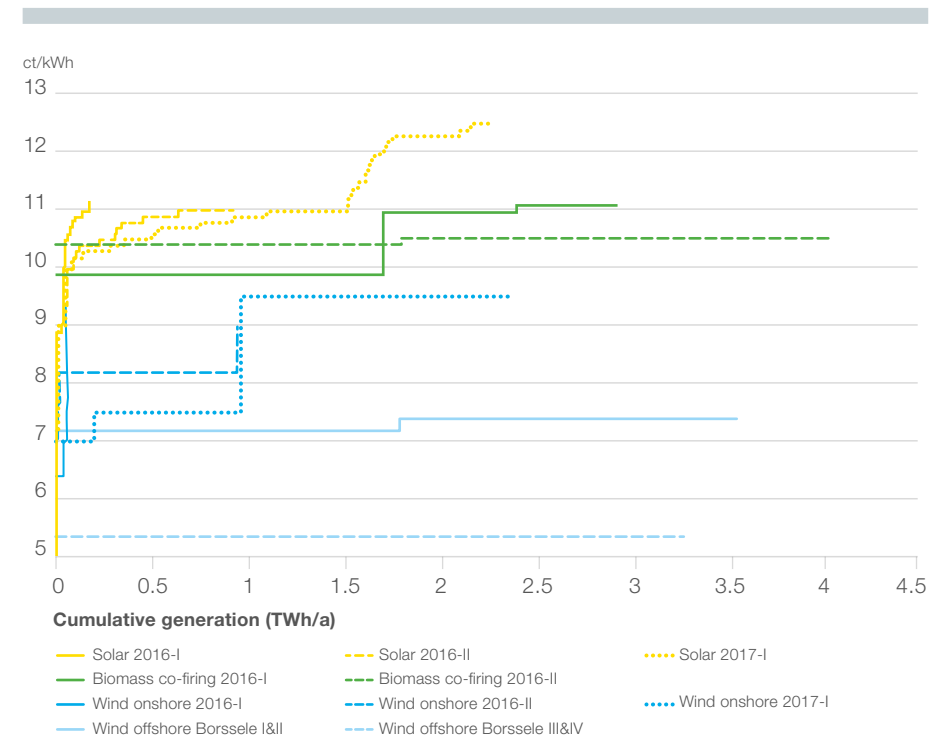


Figure 29: Accepted base sum bids and cumulative generation per SDE+ round per technology. Source: RVO



# RES support schemes

## 6.3 Offshore wind auction results

Besides the decrease in subsidy levels for German and Dutch solar and onshore wind projects, European offshore wind auctions strike prices decreased significantly in 2017. In the Energy Agreement for Sustainable Growth, the Dutch government agreed with the offshore wind industry on a 40% cost reduction target between 2014 and 2024. This target does not take into account grid connections.

Figure 30 shows that the subsidy levels in the majority of offshore wind auctions are significantly below this target. The outcomes of the Dutch tenders for the Borssele I & II wind farm (72.2 €/MWh, won by Ørsted) and the Borssele III & IV wind farm (54.4 €/MWh, won by a consortium of Royal Dutch Shell, Van Oord, Eneco and Mitsubishi/DGE) in 2016 were already much lower than expected. Also the strike price in the Danish auction for Kriegers Flag was already below 50 €/MWh in 2016.

The outcome of the first German offshore wind auction in the beginning of 2017 was a historical milestone; the first zero-subsidy bid was accepted. ENBW offered a strike price of 0.0 €/MWh for 900 MW of the He Dreiht wind farm, which is to be constructed before 2025. As the subsidy bids for the remaining 590 MW of the He Dreiht wind farm were up to 60 €/MWh, the average strike price of this auction ended up at 4.4 €/MWh. At the end of 2017, zero-subsidy bids were offered by four market participants for the Hollandse Kust Zuid I & II wind farms in the Netherlands (700 MW). After a quality assessment, the Dutch government granted a license to Vattenfall for constructing and operating this wind farm for 15 years, which should start operation in 2022.

Note that the strike prices between the different countries cannot directly be compared as the scope of the wind farm projects differ with regards to the responsibility for the grid connection. In the UK, the responsibility for developing the grid connection lies with the wind farm developer. In Germany, the substation on sea has to be developed by the owner of the offshore park, whereas in Denmark and the Netherlands only the wind turbines have to be installed and the responsibility for developing the grid connection lies with the TSO. This difference is reflected in the strike prices in the different countries, with higher strike prices for projects which also need to develop (part of) the grid connection.

### Strike Prices of Offshore Wind

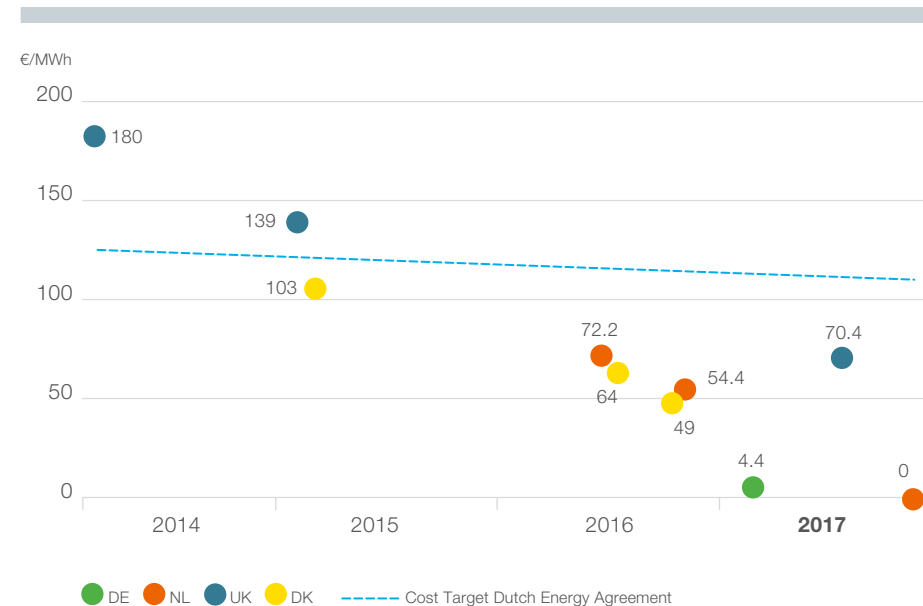


Figure 30: Strike prices of offshore wind auctions<sup>17</sup>.  
Source: TKI Wind op Zee, energate, BNetzA, RVO

<sup>17</sup> These values show the average result of all projects in one auction irrespective of their realization date.

# Market integration and interconnection flows

There are different ways to classify import and export volumes of electricity. On the one hand there are physical flows – the flows as measured during operations on interconnections – and on the other hand there are the commercial flows, which are calculated based on the outcome of the day-ahead and intraday markets.

The net positions based on physical import/export show that the Dutch importing position decreased with 1.4 TWh, while the German exporting position increased with 1.6 TWh in 2017 compared to 2016.

When looking at the monthly net position based on commercial flows, we see strong fluctuations throughout the year for the CWE countries, especially for France. On average, France imported electricity during the winter months, caused by higher electricity demand due to cold temperatures, and exports electricity during the rest of the year. For the Netherlands it is the other way around; the Netherlands on average exported electricity during the winter and imported during the summer. However, looking at the distribution of net positions, it can be seen that all countries experience both imports and exports within each quarter of the year.

A detailed look at the available commercial interconnector capacity between Germany and the Netherlands shows that this capacity has increased from Germany to the Netherlands, but decreased in the reverse direction.

## 7.1 Background

The European transmission network provides the physical backbone for further integration of the European electricity market. Market integration enables the transport of electricity across national borders and makes the buying and selling of electricity more efficient, more effective and increases the overall welfare of society<sup>18</sup>.

The European electricity market consists of a number of interconnected markets, called bidding zones or market areas. Typically, bidding zones borders correspond with country borders, such as is the case for the Netherlands, Belgium and France. However, there are multiple countries which constitute a single bidding zone, such as Germany, Luxembourg and Austria, and countries which host multiple bidding zones, such as Denmark, Italy, Norway and Sweden.

Within each bidding zone, electricity can be traded freely without taking into account network constraints. In contrast, trading between bidding zones is limited because of the physical limitations of the transmission networks and limited interconnection capacity. For this trade, most often referred to as cross-border trade, the available interconnection capacity needs to be taken into account in the trading process.

<sup>18</sup> The contents of this background section are largely based on: El Fact sheet: Cross-border electricity trading: towards flow-based market coupling by KU Leuven Energy Institute.

# Market integration and interconnection flows

Coordination across bidding zones is essential since electricity flows cannot be restricted by commercial arrangements but follow the law of physics. For example, when Germany exports to France, part of the electric power will flow through the Netherlands and Belgium instead of following a direct path between the two countries. Therefore, the impact of this transaction needs to be taken into account for the available capacity at the Dutch and Belgium borders. This is also the reason why TSOs make a distinction in electricity flows between commercial and physical flows.

European TSOs make use of coordinated capacity calculation and congestion management methodologies to determine the amount of capacity for cross-border trading which can be offered to the market, while ensuring a reliable operation of the power system. TSOs either use the Available Transfer Capacity (ATC) or Flow Based (FB) methodology to calculate the available interconnection capacities. The Flow-Based methodology is preferable for short-term capacity calculations in highly meshed and interdependent grids, such as the grid in the CWE region, as it can lead to higher imports and exports and consequently to higher social welfare. Therefore, the countries in the CWE region implemented Flow-Based market coupling in 2015.

## 7.2 Physical import and export volumes

Figure 31 shows the yearly aggregated import and export volumes based on physical flows for 2016 and 2017 for different countries throughout Europe. The numbers show the total physical import volumes (negative) and export volumes (positive) of each country, the colour indicates the net export position (export – import) of the corresponding country. Physical cross-border flows only follow Kirchhoff's circuit laws and depend mainly on the location of generation and consumption as well as on the transmission grid configuration and state.

Between 2016 and 2017, no country changed from a net importing position to a net exporting position, or vice versa. Focusing on the CWE region, we see that Austria and Germany had slightly higher export volumes in 2017 and increased their net exporting position. Belgium and the Netherlands increased their net exporting position as well, but based on slightly lower export volumes and even lower import volumes. On the other hand, the net exporting position of France decreased from 2016 to 2017.

# Market integration and interconnection flows

## Yearly Aggregated Physical Import and Export Volumes

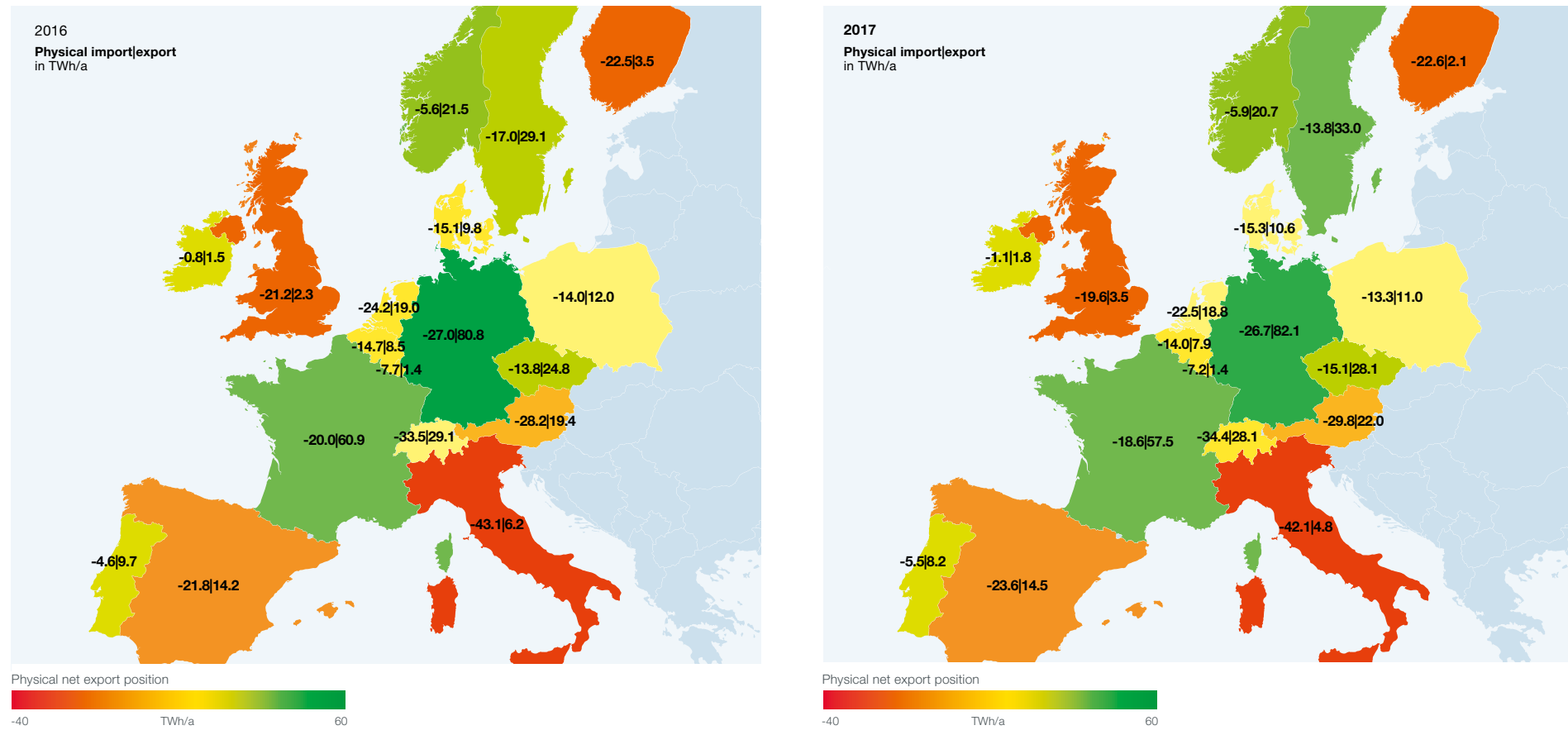


Figure 31: Yearly aggregated physical import and export volumes for different European countries<sup>19</sup>. Source: ENTSO-E Transparency Platform

<sup>19</sup> Volumes for 2016 based on ENTSO-E Power Statistics. Volumes for 2017 based on ENTSO-E Power statistics as well, but are supplemented by ENTSO-E Transparency Platform if not available.

# Market integration and interconnection flows

## 7.3 Physical cross-border flows in CWE region

This section focuses on the actual physical cross-border flows on specific borders in the CWE region.

### Physical Cross-Border Flows in CWE region

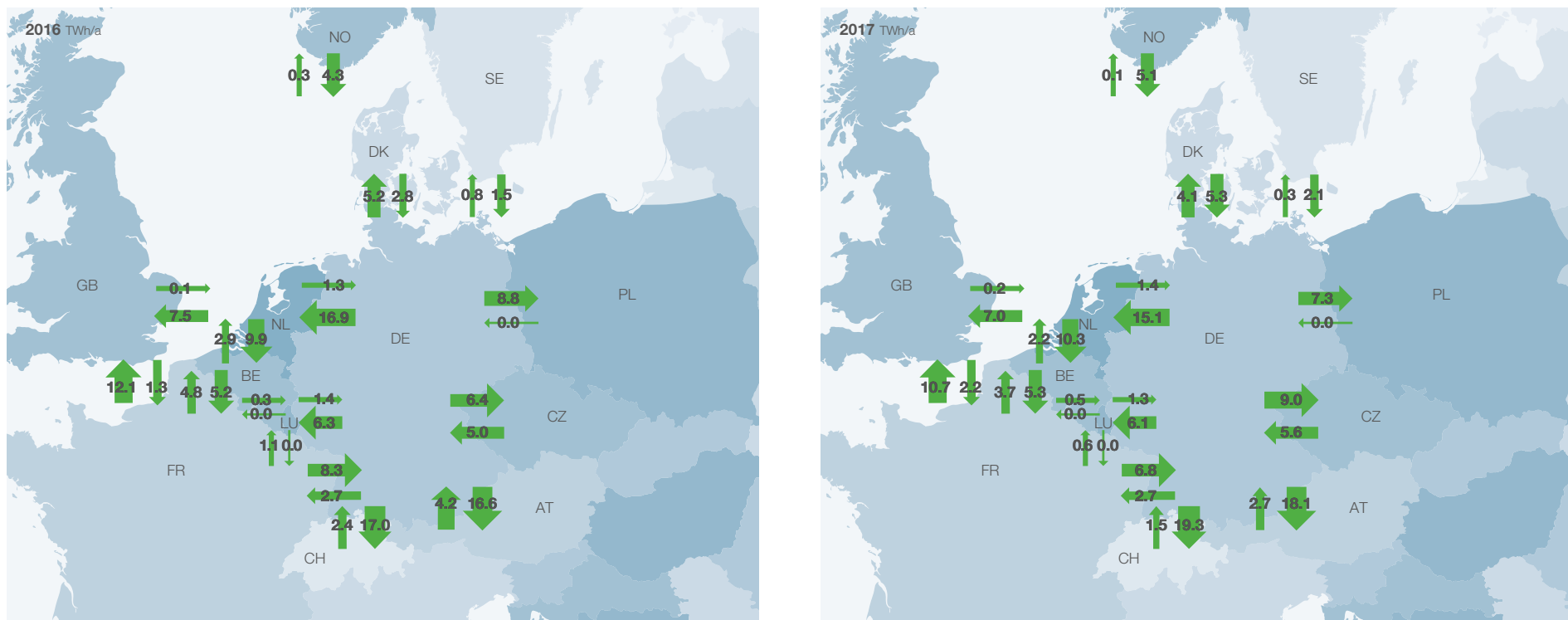


Figure 32: Annual total of physical cross-border flows on specific borders in the CWE region.  
Source: ENTSO-E Power Statistics, ENTSO-E Transparency Platform<sup>20</sup>

<sup>20</sup> Volumes for 2016 based on ENTSO-E Power Statistics. Volumes for 2017 based on ENTSO-E Power statistics as well, but are supplemented by ENTSO-E Transparency Platform if not available.

# Market integration and interconnection flows

Some changes between 2016 and 2017 in physical flows can be observed in Figure 32. Most notable are the decreasing flows from Germany to Poland and increasing flows from Germany to the Czech Republic, caused by new phase shifters in Poland and the Czech Republic. Another result of these phase shifters is the significantly increased export from Germany to Austria and Switzerland. Imports to Germany from the Czech Republic, Austria, Switzerland and France decreased, while imports at the northern borders from Norway, Denmark and Sweden increased. The Dutch exports to Belgium increased by about 0.4 TWh/a, whereas exports to Great Britain and Norway decreased. Imports to the Netherlands from Norway increased, while imports from Germany, Belgium and Great Britain decreased.

## 7.4 Net positions

Figure 33 depicts the monthly net positions of implicitly allocated capacity of the CWE region for 2016 and 2017.

Overall, France exports a relatively high amount of electricity. However, at the end of 2016 and during the cold spell in January 2017, which will be covered in detail in [chapter 10](#), France was importing electricity. The Netherlands shows a reverse trend. In most months the Netherlands imports electricity, but at the end of 2016 and the beginning of 2017 Netherlands exported electricity due to high prices in Belgium and France. Germany had an exporting net position for all months, except for July 2017. The importing net position in this month was most likely caused by a combination of low German demand, full nuclear availability in Belgium and low German wind feed-in. Except for some summer months, Belgium had an importing net position.

## Monthly Net Positions in CWE region

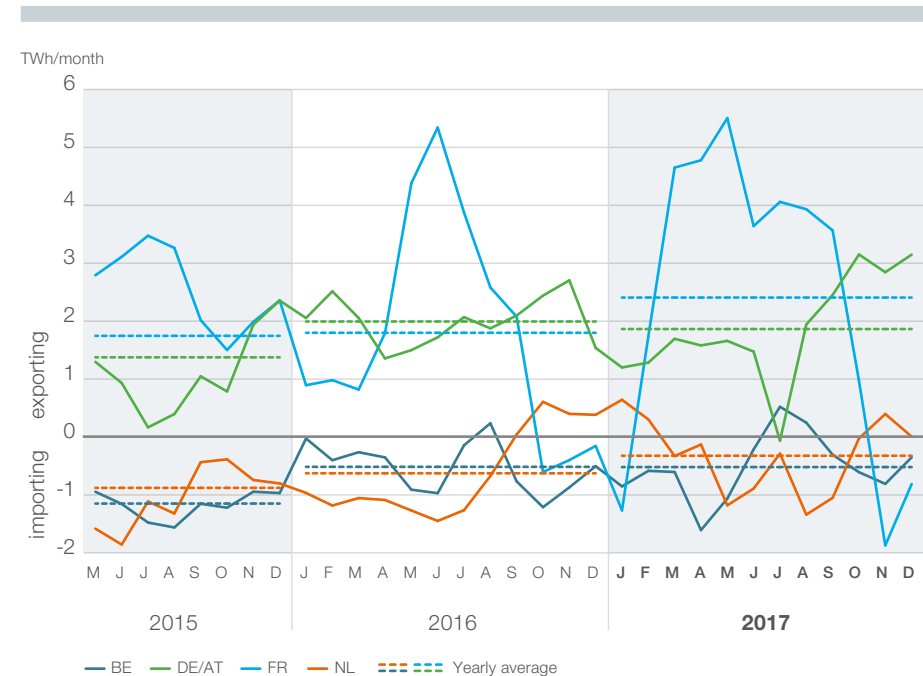


Figure 33: Monthly net positions in CWE bidding zones<sup>21</sup>.  
Source: MRC Market Coupling

<sup>21</sup> Net positions represent the electricity exports minus the electricity imports with all surrounding bidding zones per market time unit. These values represent the commercial net positions after the closure of the day-ahead market.

# Market integration and interconnection flows

Figure 34 gives more insight in the net positions in the CWE bidding zones by displaying the distribution of hourly net positions per quarter in 2017.

The figure shows that during some quarters some bidding zones were almost always exporting (France in Q2 and Q3, Germany/Austria in Q4) or importing (Belgium in Q1 and Q4). However, the outliers show that every bidding zone experiences at least a few hours every quarter with positive and negative net positions.

It also shows that the net positions of Germany/Austria and France are much more volatile compared to Belgium and the Netherlands. This can largely be explained by the higher interconnector capacity of the German/Austrian and French bidding zones, which enables a wider range of net positions.

Interesting differences between quarters can be identified. The German/Austrian net position was most volatile in Q3, probably related to a relatively high fluctuation in wind generation during these months. In contrast to the previous quarter, the volatility in Germany in Q4 was low and Germany was almost continually exporting, caused by high prices in other bidding zones. The Dutch and Belgium volatility were relatively constant throughout the year, except for the low volatility of the Dutch net position in Q4, also most likely caused by higher prices in other bidding zones. This figure shows significant outliers and a very high volatility for the French net position in the first and fourth quarters, caused by the French importing position with low temperatures.

## Distribution of Hourly Net Positions in CWE Countries per Quarter for 2017

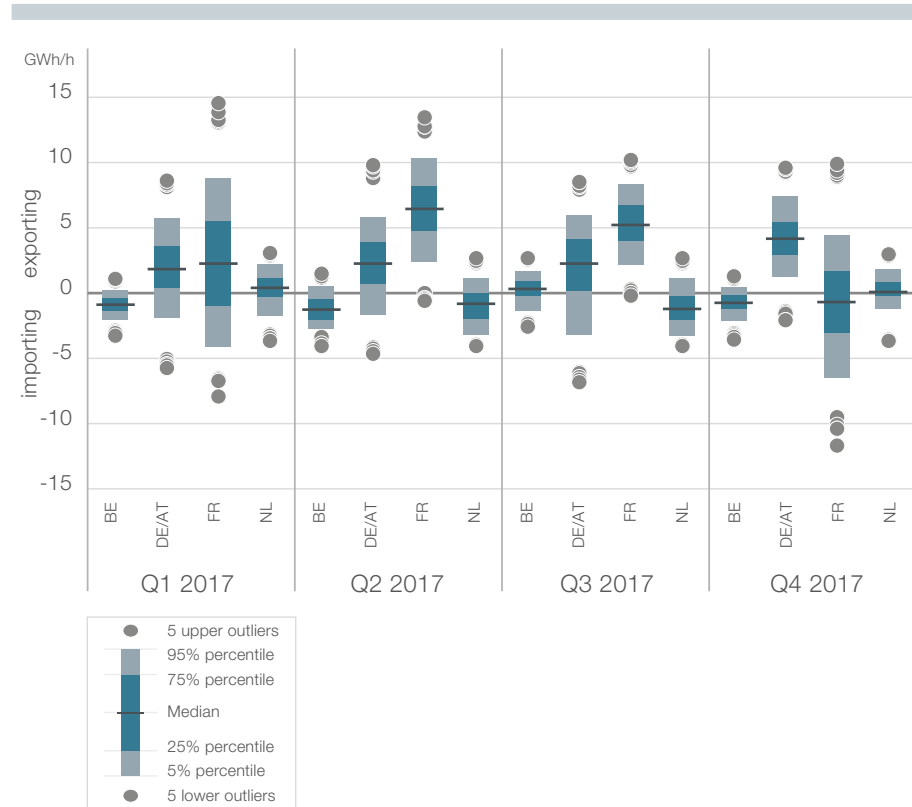


Figure 34: Distribution of hourly net positions in CWE bidding zones per quarter for 2017. Source: MRC Market Coupling

# Market integration and interconnection flows

## 7.5 Interconnector capacity

The available commercial interconnector capacity which is offered to the market for cross-border trade is not equal to the physical interconnector capacity. TSOs always have to ensure that the electricity system remains in a secure state, even in the case of a contingency. Therefore, TSOs adjust interconnector capacity to anticipate upon potential failure of other grid elements and avoid overload of the interconnector capacity in such an event. In addition, interconnector capacity is adjusted to take into account the expected loading due to internal and external trades and loop flows, as well as planned maintenance in the high-voltage grid.

Interconnector capacity is offered in different timeframes. Part of the available interconnector capacity is offered by the TSOs through auctions for yearly and monthly long-term rights. These long-term transmission rights entitle the holder to receive the price difference between the two bidding zones from the TSOs.

When the long-term transmission rights are allocated in the form of physical transmission rights, the holder is entitled to nominate the respective volume as cross-zonal exchange of electricity.

The majority of the capacity is offered in the day-ahead market. The total available day-ahead capacity is determined based on the outcome of the Flow-Based market coupling calculations. Long-term transmission rights which are nominated are deducted from the offered capacity for the day-ahead market. Depending on changes in the grid situation, additional cross-border capacity becomes available for the intraday market.

Figure 35 and 36 display the monthly average available interconnector capacity from Germany to the Netherlands and in the reverse direction since the introduction of Flow Based Market Coupling in May 2015.

### Available Commercial Interconnector Capacity from Germany to the Netherlands

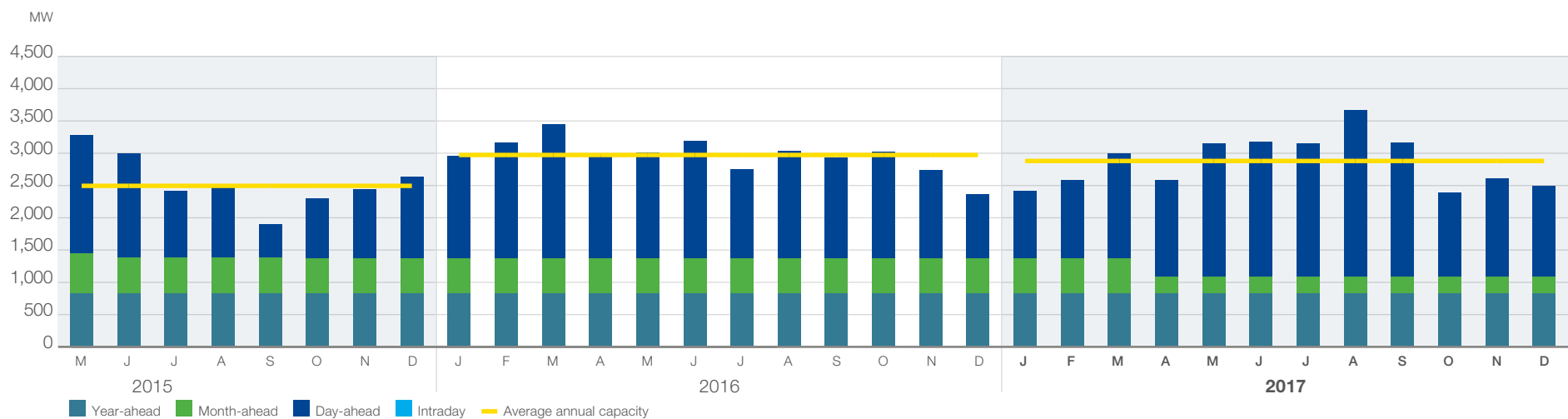


Figure 35: Monthly average available interconnector capacity from Germany to the Netherlands<sup>22</sup>. Source: Joint Allocation Office (JAO)

<sup>22</sup> The day-ahead capacity in Figure 35 represents the bilateral exchange capacity.



# Market integration and interconnection flows

Since 2015 the average annual capacity from Germany to the Netherlands has increased significantly, but in the reverse direction it has decreased. This is caused due to the capacity optimisation process in the market direction as part of the Flow Based capacity calculation process. As the dominant market direction is from Germany to the Netherlands, more capacity will be provided in this direction.

The available capacity from Germany to the Netherlands also shows a seasonal pattern; this capacity is generally lower in winter months compared to summer months. This is caused by higher loading of the grid due to increased consumption and higher wind feed-in in Germany during winter compared to summer, which results in more congestion issues.

From the Netherlands to Germany, no such seasonal trend is observable, as a trade in this market direction often relieves congestions. The decrease in month-ahead capacity in 2017 compared to 2016 is because of several planned maintenance works.

## Available Commercial Interconnector Capacity from the Netherlands to Germany

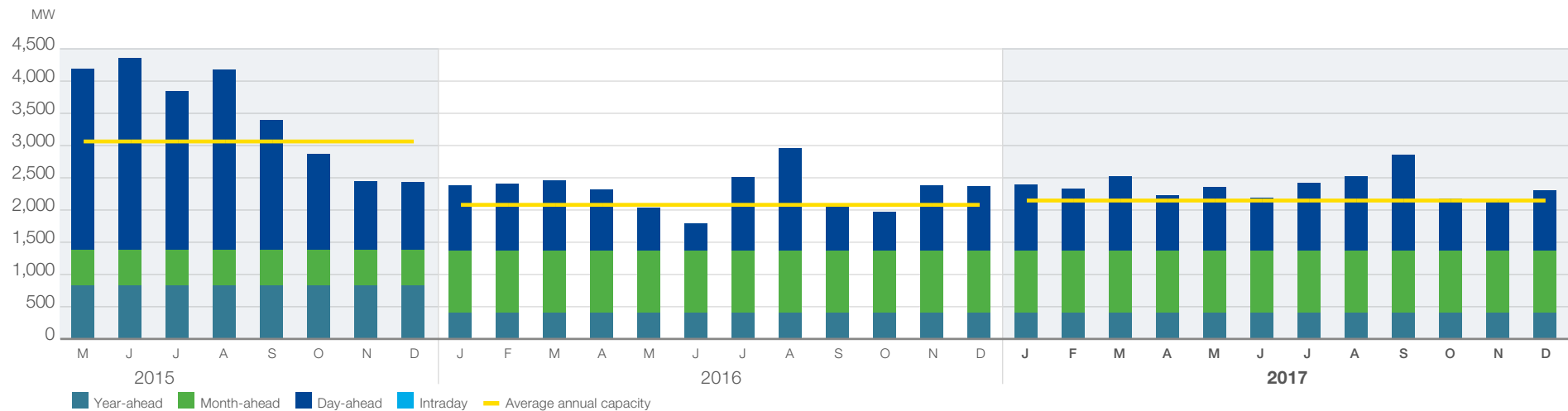


Figure 36: Monthly average available interconnector capacity from the Netherlands to Germany<sup>23</sup>. Source: Joint Allocation Office (JAO)

<sup>23</sup> The day-ahead capacity in Figure 36 represents the bilateral exchange capacity.

# Balancing

If the actual total generation and/or consumption of market participants deviates from their netted trading schedules, a grid imbalance occurs. Imbalance volumes in Germany decreased in 2017 compared to 2016, while the Netherlands experienced an increase in imbalance volumes. The difference between the imbalance price and the day-ahead price is the penalty for being in imbalance. This penalty has decreased for both countries, largely caused by more exchange of imbalances between TSOs, resulting in lower reserve activation volumes. Germany has experienced record-high peaks of imbalance prices. Reserve capacity prices have remained relatively constant during 2017.

## 8.1 Background

The limited storage options for electricity cause that electricity injections and withdrawals from the grid continuously needing to be in balance to prevent the grid frequency from deviating too much from its reference value, which could result in a system collapse.

TenneT uses a system of balance responsibility to keep the supply and demand of electricity in check. All connected parties are responsible for informing grid administrators of their planned electricity production, consumption and transport needs. In practice, this task is performed by Balance Responsible Parties (BRPs). A BRP is a private legal entity that monitors the balance of one or multiple access points to the electricity grid. Every generator and offtaker in the grid is obliged to have a contract with a BRP (typically via the electricity supplier), or alternatively be their own balance responsible party. In general, BRPs have a large portfolio consisting of many generators and/or offtakers.

These BRPs inform TenneT on a daily basis about their planned transactions for the next day via trade schedules. If the total generation and/or consumption of the BRPs deviates from their netted trade schedules, an energy imbalance

occurs. The portfolio deviations for every BRP is measured for each imbalance settlement period (ISP), which equals fifteen minutes in Germany and the Netherlands. These deviations are settled against the imbalance price, which is based on the price for activation of balancing reserves (see textbox in [section 8.2.2](#)).

TenneT is responsible for resolving imbalances within one ISP and for resolving residual imbalances over ISPs that are left unresolved by the market. TenneT uses balancing reserves with different technical characteristics for resolving these imbalances. A frequency deviation automatically activates Frequency Containment Reserves (FCR) across Europe within 30 seconds. When the frequency deviation has been stabilized, FCR is relieved with automatic Frequency Restoration Reserves (aFRR) to get the frequency back to its reference value. In the case of sustained aFRR activation, TenneT manually activates manual Frequency Restoration Reserves (mFRR) to free aFRR capacity for other incidents.

TSOs are obliged to contract a minimum capacity of all types of reserves to assure sufficient reserves can be activated to fulfil their local demand. Contracting of balancing capacity happens through auctions.

# Balancing

There are notable differences between the German and Dutch balancing system. One key difference with a major impact is that TenneT provides market participants in the Netherlands live updates on reserve activation volumes and prices, while German market participants do not receive such updates. By providing these updates, TenneT financially stimulates Dutch market participants to deviate from their portfolio if this reduces the overall system imbalance, a mechanism which is called passive balancing. Another key difference is that the Dutch system allows free bids for aFRR, in contrast to Germany. This means that only contracted market participants of balancing capacity can provide aFRR energy in Germany, while also non-contracted market participants can bid-in for balancing energy bids for one or multiple ISPs in the Netherlands.

## 8.2 Balancing markets developments

### 8.2.1 Imbalance volumes

The development of the imbalance volumes in Germany and the Netherlands is shown in Figure 37 and 38. These figures show the total number of ISPs per year in which the net imbalance volume fell within a certain range of net imbalance volumes.

### Imbalance Volume Distribution in Germany

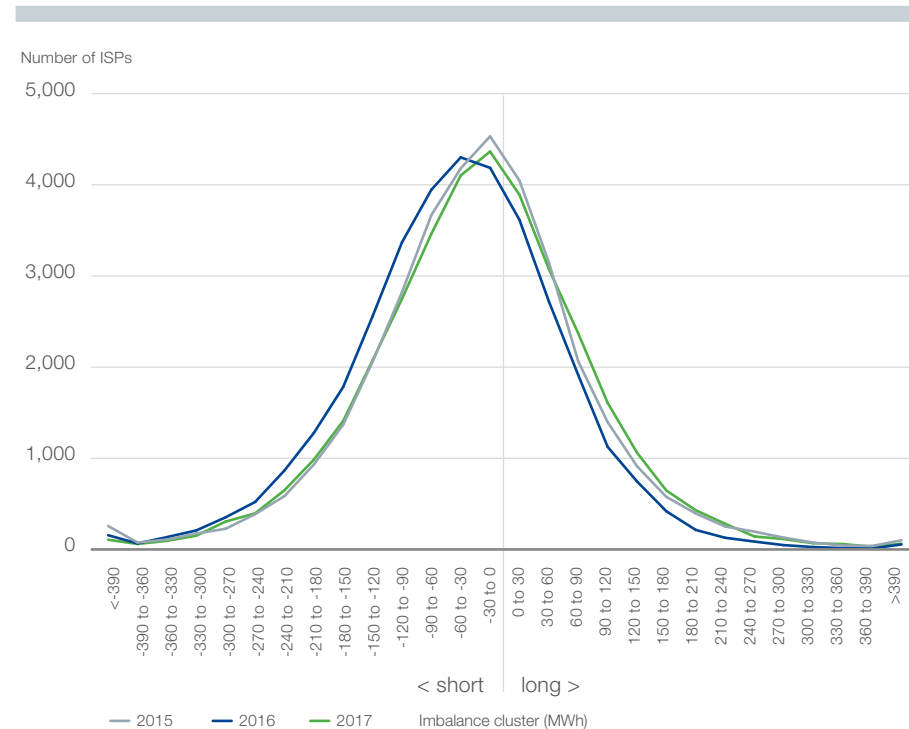


Figure 37: Distribution of net TSO balancing effort per ISP in Germany.  
Source: Regelleistung.net<sup>24</sup>

<sup>24</sup> The imbalance volumes in Figure 37 do not show the net ISP imbalance from market participants, but the combined IGCC and activated balancing energy volumes, as this data is not available to TenneT for all four German TSOs.

# Balancing

## Imbalance Volume Distribution in the Netherlands

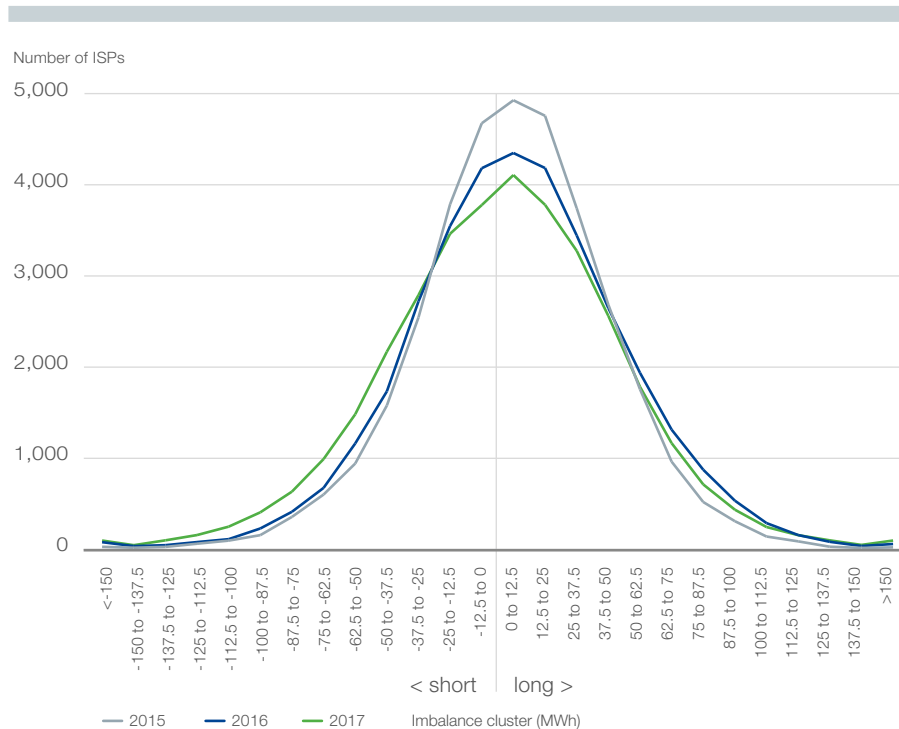


Figure 38: Distribution of net BRP imbalance volumes per ISP in the Netherlands.  
Source: TenneT NL

The total absolute imbalance volume was 3.1 TWh in Germany and 1.1 TWh in the Netherlands in 2017. Figure 37 indicates that the German imbalance volume in 2017 is similar to the imbalance volume in 2015, while it has decreased compared to 2016. A different trend is visible for the Netherlands in Figure 38. Since 2013, the number of ISPs with low net BRP imbalance volumes has continually decreased, while the number of ISPs with higher imbalance volumes has increased.

These trends can be partially attributed to developments in the average imbalance price delta, which has decreased for both countries (see section 8.2.2). The imbalance price delta can be seen as the incentive to stay balanced, because the larger the price delta, the higher the financial penalty for imbalance. In the Netherlands, the decrease in imbalance price delta reduced the incentive for market participants to stay balanced or to provide passive balancing services. The lower imbalance price delta did not result in higher imbalance values in Germany. German imbalance prices are generally higher and Germany has occasionally faced extreme imbalance prices in recent years. These developments, together with the fact that German market participants do not have live insight in the volume and price of activated reserves, make the risk of being in imbalance in the wrong direction higher in Germany.

The skewness to the left in Figure 37 indicates that market participants in Germany generally tend to undersupply the system (short system), while Figure 38 shows that Dutch market participants tend to oversupply the system (long system). An explanation for this trend can also be found in the imbalance price delta, which is higher for long systems in Germany and higher for short systems in the Netherlands.

### 8.2.2 Imbalance prices

As indicated in Figures 39 and 40, the imbalance price delta (see textbox) has significantly decreased in both Germany and the Netherlands since 2015. Increased utilisation of International Grid Control Cooperation (IGCC, see textbox and Market Review 2016) since the French TSO RTE joined in 2016 is one likely cause of this development; the exchange of imbalance energy between countries leads to lower reserve activation and thus to lower imbalance prices. The German decrease can also be attributed to the lower imbalance volumes, as reported in section 8.2.1.

# Balancing

## Imbalance price

Balancing can be seen as real-time buying or selling electricity by a TSO. The price of this real-time market is the imbalance price. If a BRP generates more or consumes less electricity than its trade schedule (imbalance surplus), it receives the imbalance price for this difference. If a BRP generates less or consumes more electricity than its trade schedule (imbalance shortage) it has to pay the imbalance price for its shortage.

Generally, the difference between the imbalance price and day-ahead price (i.e. imbalance price delta) incentivises market participants to provide beneficial contributions and refrain from adverse contributions to the system balance. Hence, the imbalance price is generally higher than the day-ahead price when additional infeed or reduced withdrawal of power is required (short system), but lower when the system requires higher withdrawal or lower infeed of power (long system).

Germany and the Netherlands use different methods to determine the imbalance price. Germany uses a pay-as-bid system for aFRR and mFRR, meaning that the price received by activated aFRR and mFRR providers is equal to the price they bid in. The German imbalance price for BRPs is determined by dividing the total balancing costs by the total imbalance volumes in an ISP<sup>25</sup>. Financial settlement in the Netherlands happens through marginal pricing. The imbalance price is equal to the highest activated aFRR or mFRR bid in an ISP, and applies to BRPs in imbalance, as well as all activated aFRR/mFRR bids.

## International Grid Control Cooperation (IGCC)

Every TSO is responsible for grid balancing within their TSO area. In the past, situations with an imbalance surplus in one TSO area and an imbalance shortage in another TSO area were balanced independently from each other. In 2010, the four German TSOs set up Grid Control Cooperation, in which imbalance volumes in opposite directions are exchanged between TSO areas before reserve activation, as long as the interconnector capacity is sufficient. In this way, simultaneous reserve activation in opposite directions in different TSO areas is avoided, resulting in lower total balancing costs and a more resilient balancing process. In recent years, Austrian, Belgian, Czech, Danish, Dutch and French TSOs joined the program, resulting in the foundation of the International Grid Control Cooperation (IGCC).

<sup>25</sup> A detailed method for determining the German imbalance price can be found [here](#).

# Balancing

## Imbalance Price Delta in Germany

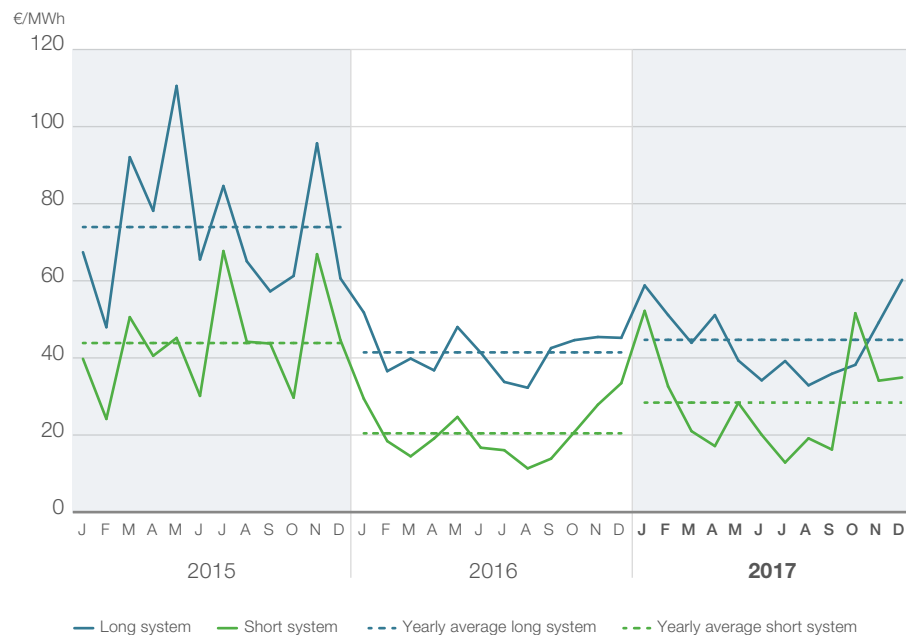


Figure 39: Development of imbalance price delta in Germany<sup>26</sup>.  
Source: Regelleistung.net, MRC Market Coupling

Figures 39 and 40 show that the imbalance price delta in Germany is higher compared to the Netherlands. This can be ascribed to the difference in balancing market design between Germany and the Netherlands. The German system does not maximise the participation for passive balancing, since no real-time information on imbalance prices and volumes is shared, and since it does not allow free bids. Both these factors have an upward effect on the imbalance price delta.

This imbalance price delta in the Netherlands is higher if the system is short and upwards balancing energy is required. This can partly be explained by the fact that the number of market participants that can provide downward balancing energy is generally higher than the number of participants that can provide upward balancing energy, as power plants operating at full capacity cannot provide upward balancing energy, while all flexible power plants in operation could ramp down and provide downward balancing energy.

## Imbalance Price Delta in the Netherlands

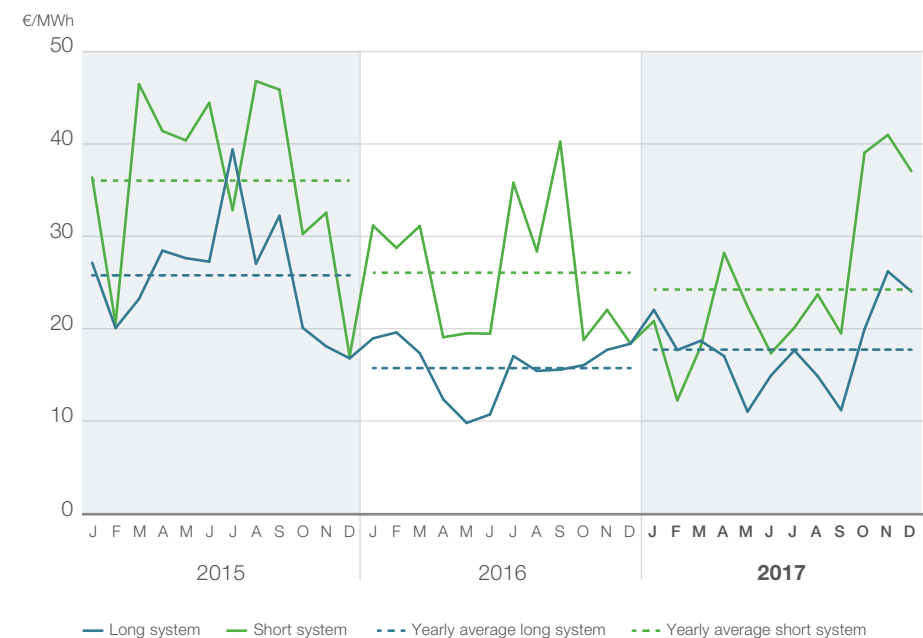


Figure 40: Development of imbalance price delta<sup>26</sup> in the Netherlands<sup>27</sup>.  
Source: TenneT NL, MRC Market Coupling

<sup>26</sup> The imbalance price delta has been calculated differently for short and long systems, as both systems require different incentives. For short systems: imbalance price delta=imbalance price – day-ahead price.  
For long systems: imbalance price delta=day-ahead price – imbalance price.

<sup>27</sup> ISPs with dual pricing were not considered in this analysis.

# Balancing

However, in Germany it is the other way around, which could be induced by the structure of the German installed capacity. Germany has a high share of baseload conventional generation and a high share of renewables. Renewables may not be ramped down in Germany, while ramping down baseload generation is not always technically feasible. Consequently, the options for downward balancing energy are limited in Germany, resulting in high imbalance prices when the system is long.

As the incentive to stay balanced or help restore the system balance should be larger with larger system imbalance volumes, one expects the imbalance price delta to be higher in such situations. Figures 41 and 42 show that in both countries, the imbalance price delta spreads at high imbalance volumes are higher compared to low imbalance volumes. In contrast to previous years, the imbalance price delta at high imbalance volumes in the Netherlands has periodically been very low or even negative, which can be attributed to the depressing effect of IGCC on imbalance prices.

## Spreads of German Imbalance Price Delta

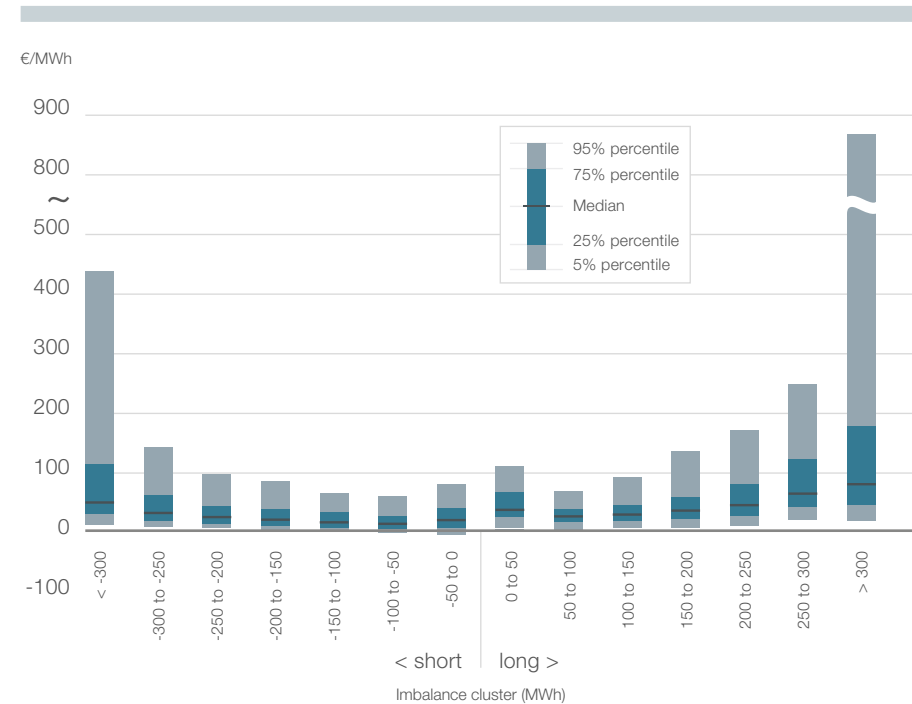


Figure 41: Spreads of imbalance price delta at different imbalance volumes in Germany in 2017<sup>28</sup>. Source: Regelleistung.net, MRC Market Coupling

<sup>28</sup> The imbalance price delta has been calculated differently for short and long systems, as both systems require different incentives. For short systems: imbalance price delta=imbalance price – day-ahead price. For long systems: imbalance price delta=day-ahead price – imbalance price.

# Balancing

## Spread of Dutch Imbalance Price Delta

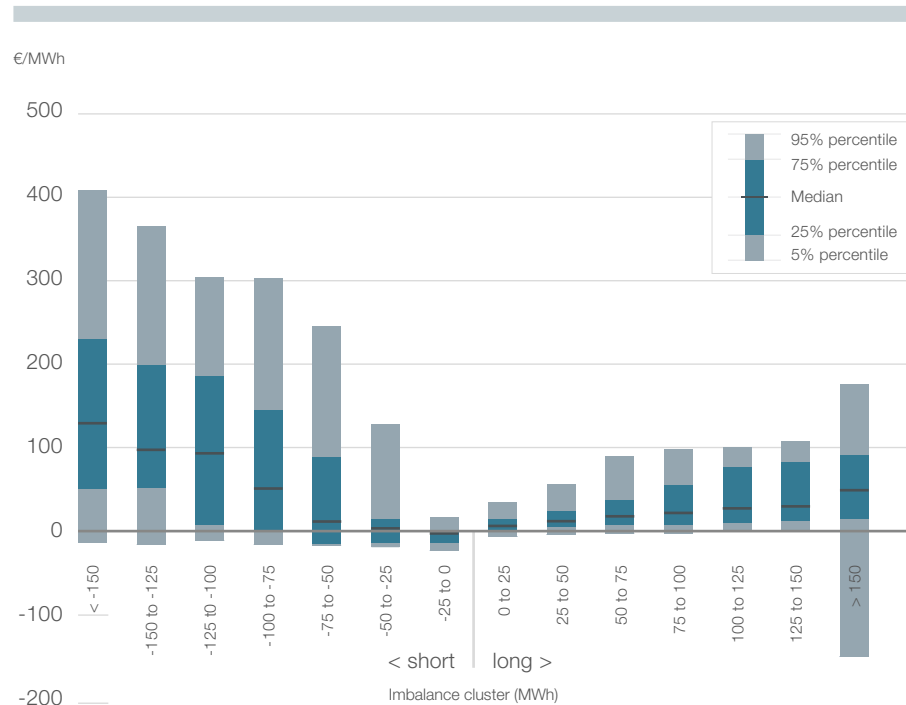


Figure 42: Spreads of imbalance price delta at different imbalance volumes in the Netherlands in 2017<sup>29</sup>. Source: TenneT NL, MRC Market Coupling

The German method for determining the imbalance price (see textbox on page 45) induces the higher spreads in imbalance price delta around an imbalance volume of 0. With low imbalance volumes, the chance of counter activations is relatively high. This leads to high total imbalance costs with low imbalance volumes, which results in a high imbalance price in Germany.

Germany experienced the increasing occurrence of extreme imbalance prices, reflected in the high spreads in Figure 41, with a record-high imbalance price of 24,455 €/MWh for a certain ISP on 17 October 2017. This is caused by the absence of free bids in the German balancing system, which limits competition for aFRR activation. This has motivated contracted market participants to place balancing energy bids with very high prices, which resulted in the high 95% percentile values. The negative spike in the Netherlands for imbalance volumes of at least 150 MWh can be attributed to a prolonged incident with sustained mFRR activation in combination with inexplicable high and sustained passive support from market participants.

<sup>29</sup> The imbalance price delta has been calculated differently for short and long systems, as both systems require different incentives. For short systems: imbalance price delta=imbalance price – day-ahead price. For long systems: imbalance price delta=day-ahead price – imbalance price.



# Balancing

## 8.3 Reserve capacity price developments

Figure 43 shows the aFRR and FCR capacity prices in Germany and the Netherlands.

### FCR & aFRR Capacity Prices

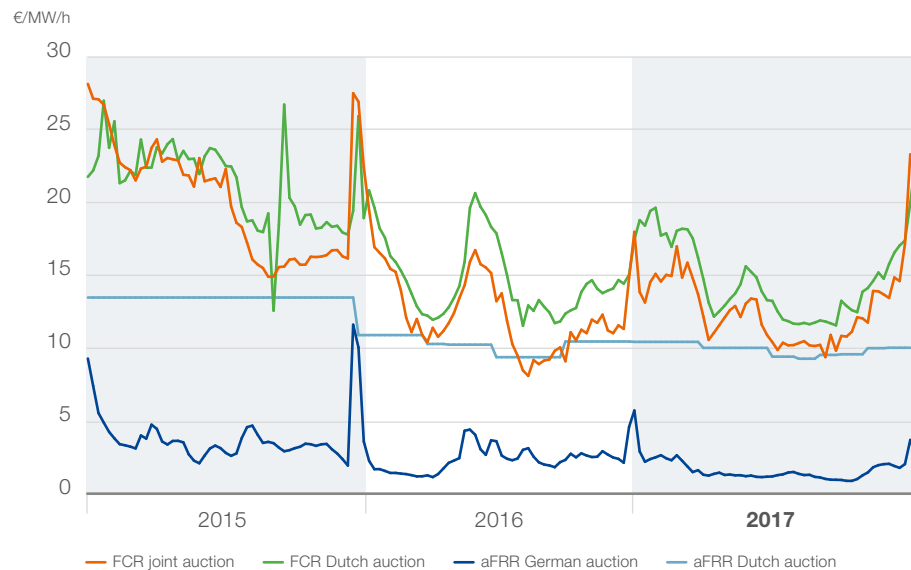


Figure 43: Average FCR and aFRR capacity price developments<sup>30</sup>.  
Source: Regelleistung.net, ENTSO-E Transparency Platform

The FCR capacity price is higher than the aFRR capacity price in both Germany and the Netherlands. This difference can on the one hand be attributed to the more stringent technical requirements of FCR compared to aFRR and on the other hand to the fact that aFRR capacity providers receive an energy price for provided balancing energy, in contrast to FCR capacity providers.

Germany contracts all its FCR capacity through a joint auction with TSOs from Austria, Belgium, France, the Netherlands and Switzerland. The Netherlands has an additional national tender to meet the ENTSO-E requirement to contract 30% of FCR within the TSO control area. As more FCR providers can participate in the joint auction, the competition in this auction is higher and prices are generally lower compared to the Dutch FCR auction.

The different nature of the balancing system in Germany and the Netherlands induces the large difference between the average aFRR capacity price in both countries. The Dutch system allows free bids into the aFRR merit order of balancing energy, while the German aFRR merit order only comprises contracted providers. Due to the absence of free bids in the merit order, additional competition for aFRR balancing energy is lower in Germany, enabling aFRR providers to bid in and receive higher balancing energy prices. This motivates German market participants to make relatively low aFRR capacity bids to ensure inclusion in the aFRR merit order. The same is valid for mFRR.

A clear decrease in the average capacity price for the German aFRR auction and both FCR auctions since 2015 is visible, indicating an increasingly competitive market. Every year during the Christmas period the average German aFRR capacity price peaked. This is the consequence of higher contracted volumes during this period, to account for higher forecast errors in BRP trading schedules caused by lower employee availability for BRPs during the holiday season. The lower average capacity price from 2016 onwards in the Dutch aFRR market is caused by a change in market design. Before 2016, Dutch aFRR capacity was only contracted through yearly auctions, but since 2016 this happens through quarterly (until July 2017), monthly (since July 2017) and yearly auctions. In 2018, this will only happen through monthly auctions. This enabled more competition as it requires shorter commitment from FCR providers and therefore resulted in lower average capacity prices.

<sup>30</sup> The German aFRR price is the weighted average price of the four different aFRR products offered to the market.

# Redispatch

If it is physically impossible to transport the electricity flows following from the market outcome throughout the grid in a secure way, TSOs request redispatch measures to relieve these so-called congestions.

Germany experiences recurring high redispatch volumes and costs in the winter months, caused by high generation volumes in these months. The redispatch costs in the TenneT control area increased significantly to values close to 1 billion euros in 2017. Congestion management volumes using renewables in Germany are particularly high with high wind feed-in.

The redispatch and restriction agreement costs in the Netherlands increased from 14 million euros per year in 2015 to 64 million euros in 2016 and 48 million euros in 2017. However, these costs are still relatively low compared to German redispatch costs. Most congestion problems in the Netherlands were related to the Eemshaven region, but the construction of a temporary line solved many of the congestion problems.

## 9.1 Background

Based on forecasts performed up to seven days in advance, and based on the dispatch schedules of market participants after the closure of the day-ahead market, TSOs make estimations about the loading of the grid. Since the transmission grid can only transport a limited amount of power, the market result can be incompatible with the available network capacity. If necessary, TSOs request redispatch measures to relieve possible congestions and assure security of supply even in the case of a contingency. The Netherlands and Germany have differing processes in place to manage congestions.

In Germany with conventional redispatch, German TSOs order selected power plants to increase or decrease generation and thereby relieve congested grid elements. In addition to conventional redispatch, congestion measures with renewables (“Einspeisemanagement”) are used as a last resort in Germany. Due to the rising share of renewables, especially in northern Germany, this measure has been applied more frequently since 2013. TSOs can also use countertrade as a congestion measure, in which TSOs trade on short-term markets to remove bottlenecks. If redispatch requirements are expected to be particularly high, TSOs can also decide to activate Netzreserve (see [section 5.3](#)). Congestions are also alleviated through multilateral cross-border remedial actions in cooperation with other TSOs.

In the Netherlands, TenneT uses a market-based mechanism to solve congestions. Market parties provide bids of the product “reserve capacity for other purposes” to TenneT. In the case of a congestion, TenneT activates a selection of those bids which are economically most efficient to alleviate the congestion. When there are not sufficient bids available, TenneT sends out a message to market parties with a request to provide additional bids and then selects the economically most efficient bids.

# Redispatch

## 9.2 Redispatch volumes and costs

### 9.2.1 German TenneT Control Area

Figure 44 illustrates the monthly redispatch volumes by type of redispatch measure from 2015 to 2017 in the German TenneT control area.

#### Redispatch Volume in German TenneT Control Area from 2015 to 2017

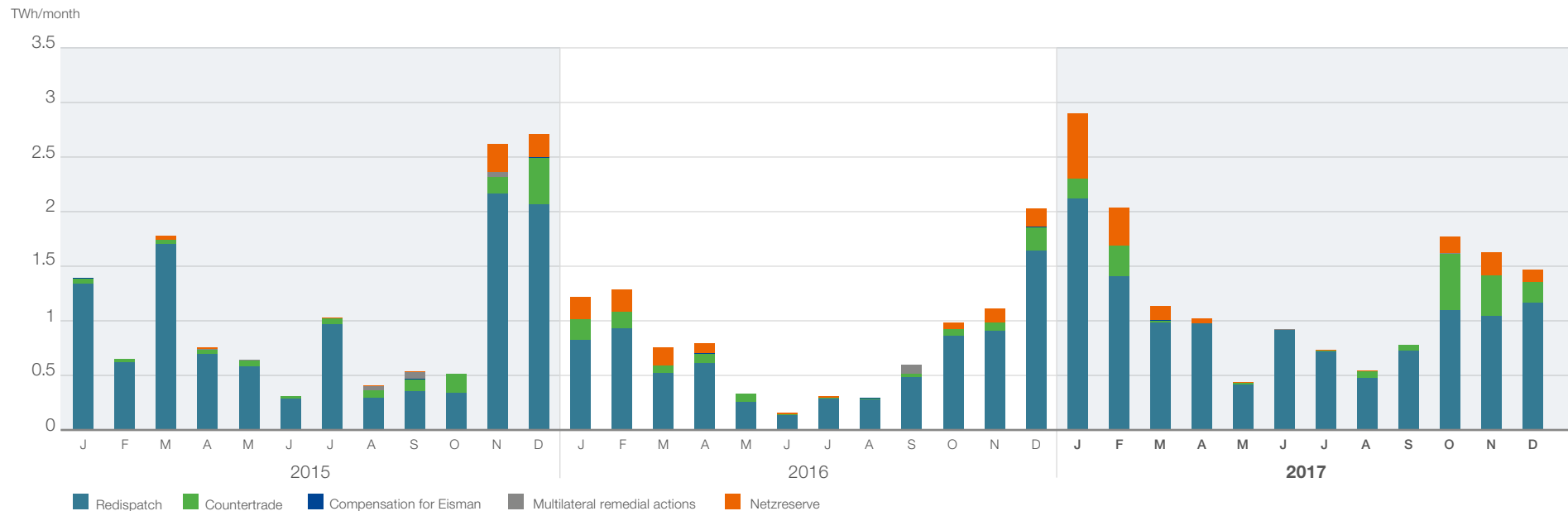


Figure 44: Redispatch volumes in the German TenneT control area. Source: TenneT DE, ENTSO-E Transparency Platform

It shows a typically higher need for redispatch during winter months, when wind feed-in in northern Germany is often strong, whereas solar feed-in in southern Germany is weak, resulting in grid congestion problems. The redispatch volumes were particularly high during the cold spell of early 2017, with significant Netzreserve activation volumes and total redispatch volumes of

close to 3 TWh per month. This was required to enable additional export capacities to France. The utilization of all redispatch measures decreased over the course of the summer, with a minimum volume of 0.44 TWh in May 2017. Towards the end of 2017, the redispatch volumes increased again, but did not get as high as the volumes of January 2017.

# Redispatch

The redispatch costs in the TenneT control area are displayed in Figure 45.

## Redispatch Costs in the German TenneT Control Area between 2015 and 2017

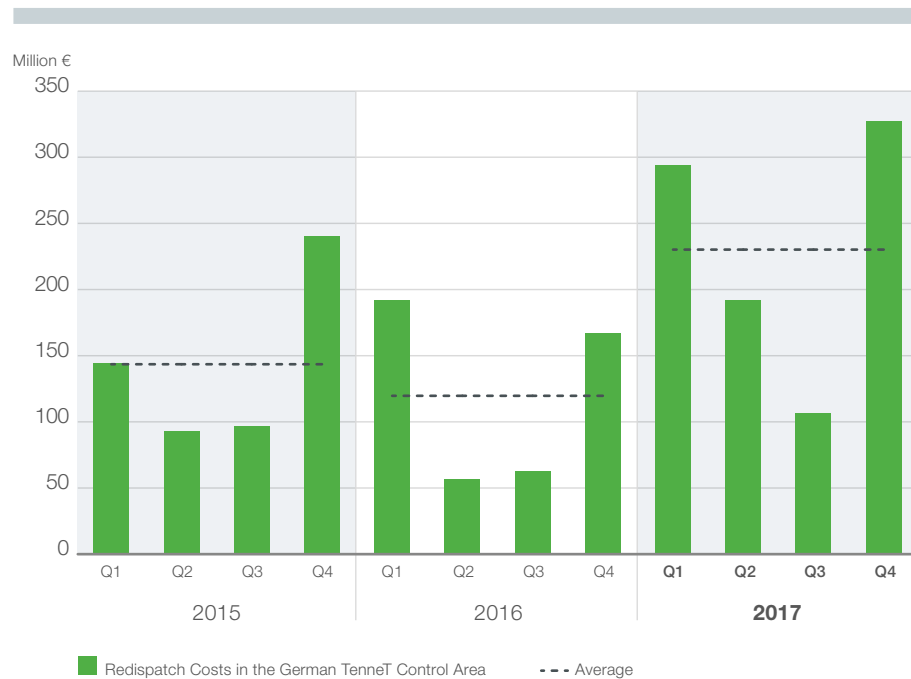


Figure 45: Redispatch costs in the TenneT control area between 2015 and 2017<sup>31</sup>.  
Source: ENTSO-E Transparency Platform

The figure shows higher redispatch expenditures in winter months, mainly caused by higher redispatch volumes. Redispatch costs in 2017 increased significantly, reaching values close to 1 billion euros in the TenneT control area. Since redispatch costs depend on the actual availability and generation costs

of conventional power plants that are required to relieve the congestion, the average redispatch costs can differ over time.

The curtailment of wind feed-in is the main driver for congestion management with renewables (“Einspeisemanagement”), as wind power is the renewable source with the highest installed capacity in Germany and in the TenneT control area. Within this context, Figure 46 shows the correlation between wind feed-in and the average Einspeisemanagement volumes TenneT had to take to ensure security of supply. It clearly shows a positive correlation between wind feed-in and curtailment, with particularly high curtailment needs with wind feed-in above 15 GW.

## Average Daily EisMan Volumes versus Daily Average Wind Feed-In in German TenneT Control Area for 2017

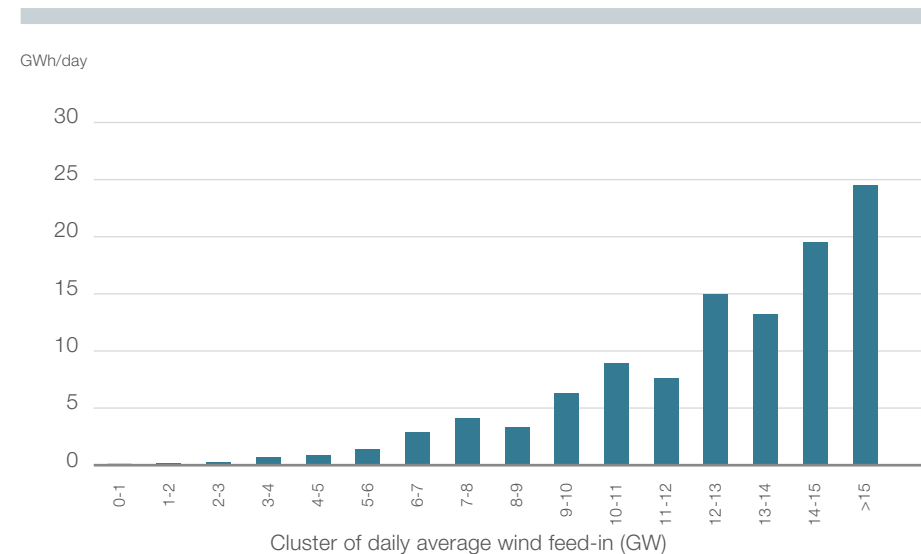


Figure 46: Average daily Einspeisemanagement volumes versus average wind feed-in in the TenneT control area. Source: Tennet DE, SMARD

<sup>31</sup> Redispatch costs consist of conventional redispatch and countertrading costs, as well as the costs of multilateral remedial actions, interruptible loads (units with a large amount of electricity, which are able to quickly reduce their consumption for relieving congestions, Einspeisemanagement and activation of reserve power.

# Redispatch

## 9.2.2 The Netherlands

The redispatch volumes in the Netherlands fluctuated over 2017, as displayed in Figure 47. The highest amount of redispatch took place in November, due to a combination of high prices in France and Belgium, which resulted in high generation volumes in the Netherlands, as well as some planned outages in the Dutch high-voltage grid for maintenance works. These together led to severe congestions which required redispatch.

A distinction can be made between redispatch measures on critical branches and redispatch measures on other network elements. Critical branches are electricity lines which are included in the CWE flow-based market coupling mechanism, as they significantly impact CWE cross-border exchanges. Redispatch on these lines has taken place to ensure that the cross-border capacity available for day-ahead flow-based market coupling is at least equal to the long-term capacity offered to the market by TenneT.

Most redispatch takes place to ensure sufficient capacity on critical branches, but early 2017 also a significant amount of redispatch volumes on other network elements took place. This was mostly to resolve congestions in the 150 kV grid in Noord-Holland.

Besides the application of redispatch, TenneT also resolves congestion problems through restriction agreements with market participants in the case of insufficient bids or frequent congestion problems in a specific area. The involved market participants limit their electricity generation or offtake in a specific region when called upon by TenneT, in return for a negotiated compensation.

The total redispatch and restriction agreement costs were 14 million euros in 2015, but increased to 64 million euros in 2016 and 48 million euros in 2017, as displayed in Figure 48. The highest redispatch and market restriction costs occurred during the winter of 2016/2017, mainly induced by high electricity generation volumes in the Netherlands and congestion issues in the Eemshaven region where almost all power plants were generating electricity to enable exports from the Netherlands to Belgium and France. The congestion issues in the Eemshaven region have largely been resolved through the construction of a temporary high-voltage line between the substations Eemshaven Oudeschip and Eemshaven, which came into operation during 2017.

### Redispatch Volumes in the Netherlands

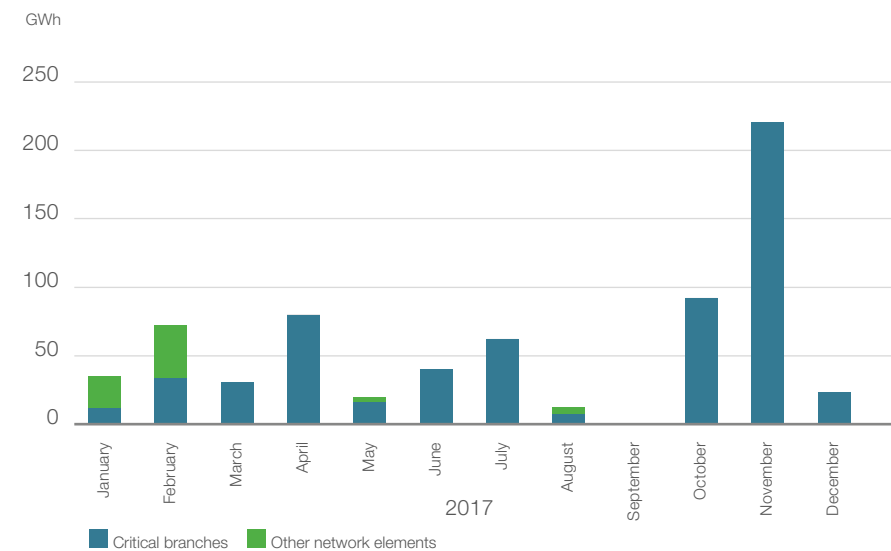


Figure 47: Redispatch volumes in the Netherlands.  
Source: TenneT NL

# Redispatch

## Redispatch and Restriction Costs in the Netherlands

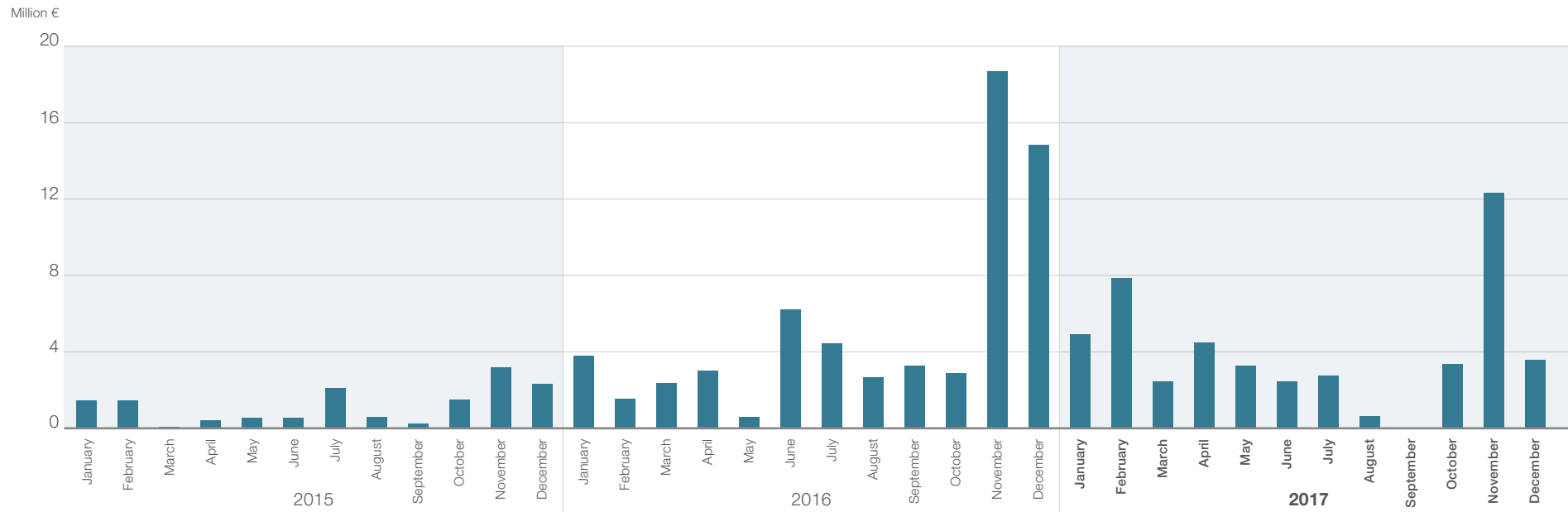


Figure 48: Redispatch and restriction costs in the Netherlands.  
Source: TenneT NL

# Special event: Cold spell winter 2016/2017

In January 2017, Central and Eastern Europe experienced cold spells with unusually low temperatures, which persisted for several weeks. In different countries, the mean temperature was below freezing point and minimum temperatures below  $-20^{\circ}\text{C}$  were reached in some countries<sup>32</sup>. This resulted in a high electricity demand, especially in countries with a high share of electric heating systems. This caused a tight market situation with high day-ahead prices in France.

The first cold spell began on 4 January and led to cold records in different countries. A second cold spell followed in the middle of the month. It initially covered a large part of Western Europe and then moved eastwards. The impact of these two cold spells is visible in Figure 49, which shows the mean temperatures across Europe in January 2017 and the difference between this mean temperature and the mean temperature in January in the reference period 1962-1990. These figures show that the temperatures in Central, Eastern and Southern Europe were significantly lower compared to the reference period.

Overall, electricity demand correlates with temperatures, in the way that lower temperatures lead to higher electricity consumption. This is predominantly caused by increased consumption of electrical heating when temperatures decrease, and thus electricity demand in countries with high shares of electrical heating systems is more temperature-sensitive than for countries which have a higher share of gas heating systems.

## Mean Temperature and Temperature Anomaly

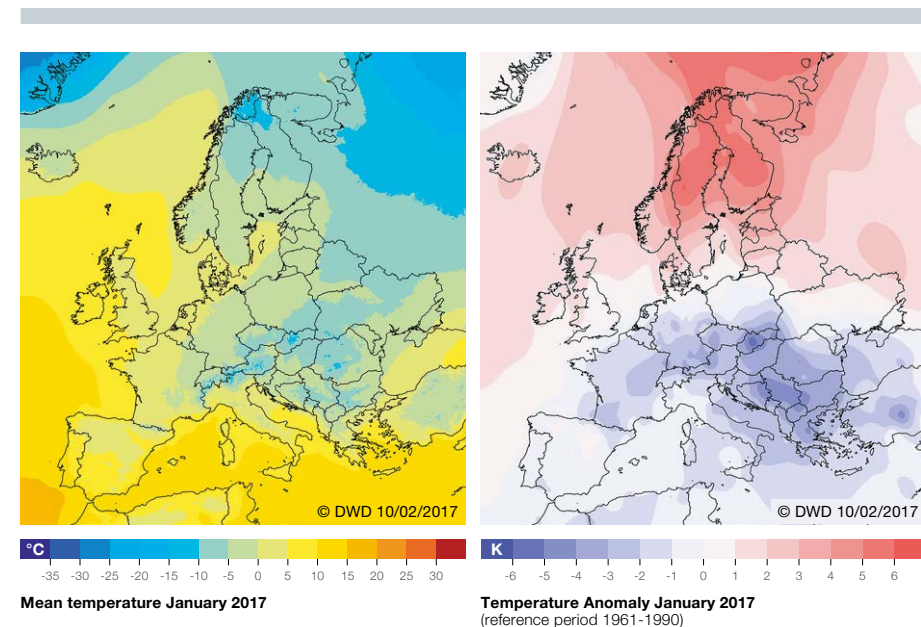


Figure 49: Mean temperatures in January 2017 and comparison to reference period in Europe.  
Source: Deutscher Wetterdienst (DWD)

<sup>32</sup> The [DWD summary of the winter 2016/2017](#) from March 2017 gives a detailed description of the weather phenomena in January 2017.

# Special event: Cold spell winter 2016/2017

France has one of the highest temperature-sensitive load profiles in Europe. Approximately 40% of the residential heating systems in France are electrical heating systems, resulting in France being responsible for 40% of the total temperature-sensitivity in Europe. The estimated temperature-sensitivity of demand was 2,400 MW/°C at 19:00 in 2016<sup>33</sup>. The impact of temperature on the electricity demand is illustrated in Figure 50, showing the total demand in France for three typical weekdays with different temperatures in January 2017. It can be seen that the demand on the coldest day during the cold spell (18 January) is significantly higher than the demand on the warmest day in January 2017 (31 January).

**French Demand on Three Different Weekdays in January 2017**

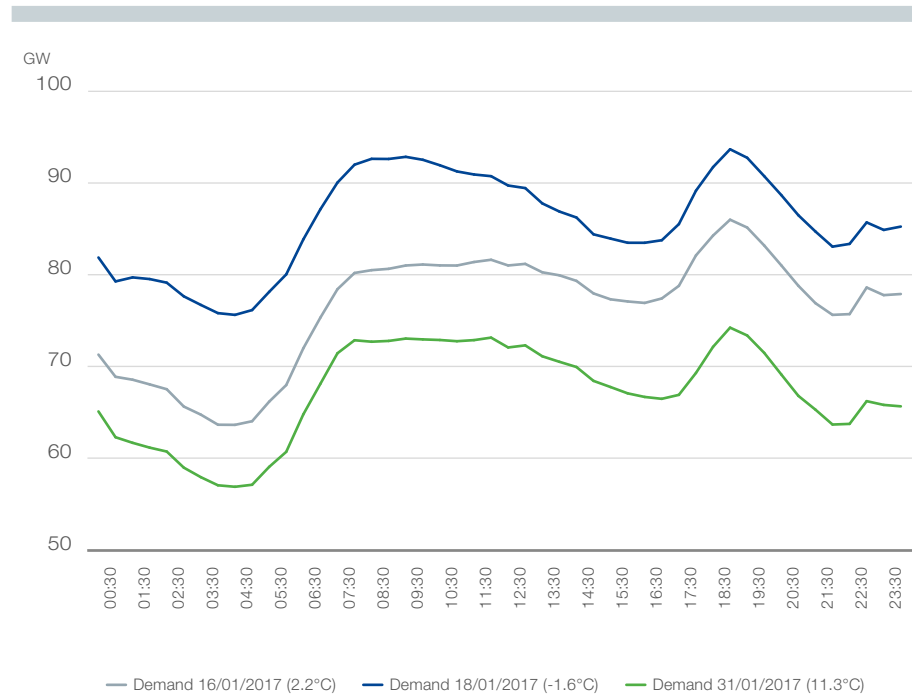


Figure 50: French demand on three weekdays with different temperatures (daily average temperatures in Paris) in January 2017.  
Source: RTE, meteociel

<sup>33</sup> This and further information can be found in the "Generation Adequacy Report 2016" of the French TSO RTE.



# Special event: Cold spell winter 2016/2017

The high demand in France during the cold spell caused tightness in the French electricity market. Figure 51 depicts the market situation in France in January 2017. The blue line shows the residual load (i.e. the load minus generation from intermittent renewables PV and wind) minus the net imports, and therefore reflects the load that has to be served by French firm capacity. The orange line represents the available firm capacity in France, which is equal to the installed firm capacity<sup>34</sup> minus unavailable generation capacity and the capacity reserved for balancing purposes.

The figure shows that the low temperatures between 18 January and 27 January resulted in a higher load. A relatively large share of this increase in load had to be fulfilled by hydro plants. It shows that in this period, the margin between the available domestic firm capacity and the required domestic firm capacity became smaller. This resulted in more expensive generators being required to fulfil this demand, resulting in a period with high overall prices and recurring price peaks close to or above 200 €/MWh.

Overall, the cold spell clearly shows the weather-dependency of European electricity markets as well as how the availability of generation capacity influences the electricity price.

## French Day-Ahead Prices, Residual Load and Firm Generation Capacity during Cold Spell

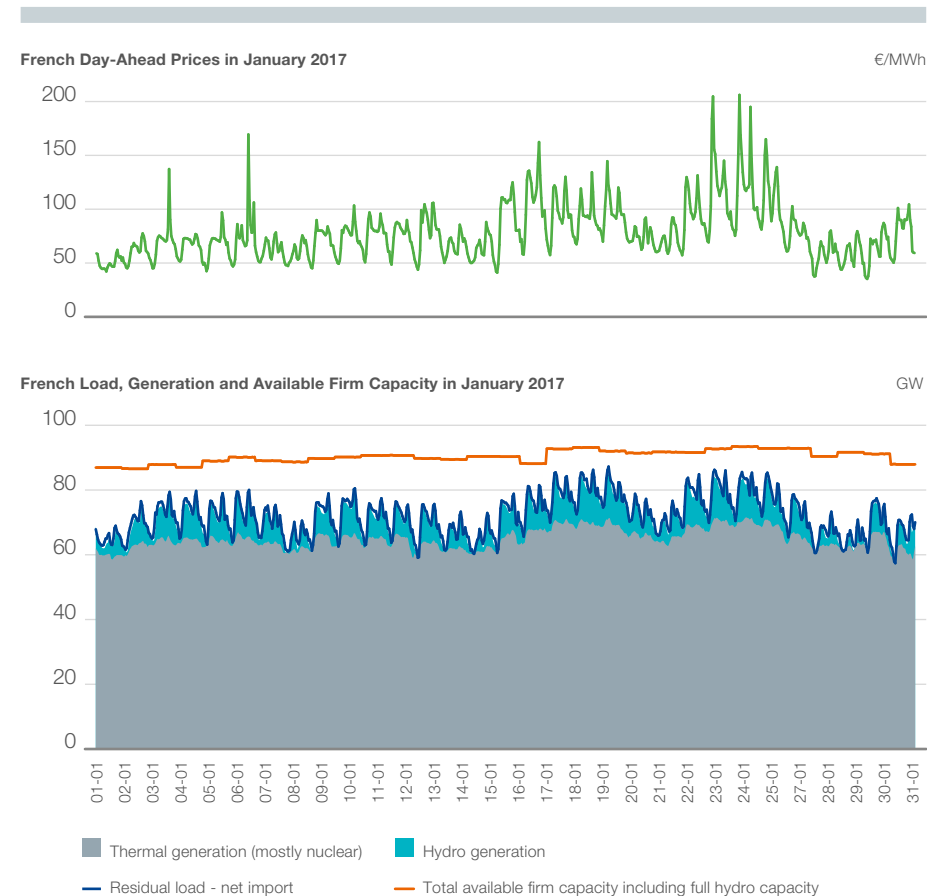


Figure 51: French day-ahead prices, actual generation, residual load and firm generation capacity during January 2017.

Sources: RTE, ENTSO-E Transparency Platform, MRC Market Coupling

<sup>34</sup> Hydro capacity is considered as firm capacity in this figure.

# Colophon

This Market Review is a publication of TenneT.

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