TenneT
Taking power further

Market Review 2014

Electricity market insights

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Introduction

The year 2014 has been very interesting and dynamic for those with a professional interest in the European electricity market. In this TenneT Market Review we share our insights and provide an overview of both general and more specific developments in this market in 2014.

Further expansion has created a region from Portugal to Finland in which the system of the Price Coupling of Regions is applied. This allows for increased efficiency in production and the exchange of flexibility that is needed to facilitate the integration of renewable energy production. These effects can be witnessed in the market in 2014.

The interplay of the generation stack, fuel prices and cross-border flows is reviewed to give insight in the dynamics that determined last year's market prices.

Furthermore, this market review will give a preview of the effects of the implementation of Flow Based Market Coupling (FB), which is expected in 2015. We take a look at what prices would have been in 2014 under this new method that optimises the way cross-border capacity is made available to the market.

The focus of the market review will be on the Netherlands and Germany, while general market trends are discussed in a wider European context.

Being a transmission system operator in both the Netherlands and Germany allows TenneT to have an objective view on the developments in the electricity market. TenneT believes that sharing this view can facilitate the public discussion on the trends on the European electricity market.

As in previous editions of the TenneT Market Review, TenneT has collaborated closely with the Institute of Power Systems and Power Economics (IAEW) at RWTH Aachen University.

Price developments

In 2014 we witnessed falling wholesale prices in the first half of the year, followed by a price increase in the second half. Successful expansion of market coupling in 2014 created a vast European Day-ahead market. Overall, the price level was lower than in 2013 for almost all European countries, including Germany and the Netherlands.

The monthly averages of the Day-ahead wholesale prices in the years of 2013 and 2014 are shown in Figure 1 for Germany, the Netherlands, Belgium and France (Central Western Europe or CWE). It can be observed that – in contrast to the first half of 2014 – prices in the second half increased in all of the market areas, beginning in July in the Netherlands and Belgium, and followed by France and Germany in August. However, the overall price level in 2014 was lower than in 2013.

From the second quarter of the year 2014, the Belgian prices showed very high convergence with the Dutch prices. Previously, Belgian prices were highly convergent with French prices.

As in previous years, the price changes in France were strikingly higher than in the other countries over the course of 2014. In comparison to the preceding year, the price drop in summer in France in 2014 was significantly weaker and the lowest price level occurred in August instead of June.

The yearly average in Germany in 2014 was 32.76 €/MWh compared to 41.18 €/MWh in the Netherlands. In 2013 this was 37.77 €/MWh and 52.02 €/MWh respectively. This means the price difference between the two market areas decreased from 14.25 €/MWh in 2013 to 8.42 €/MWh in 2014.

Monthly Average Day-ahead Wholesale Prices in CWE countries

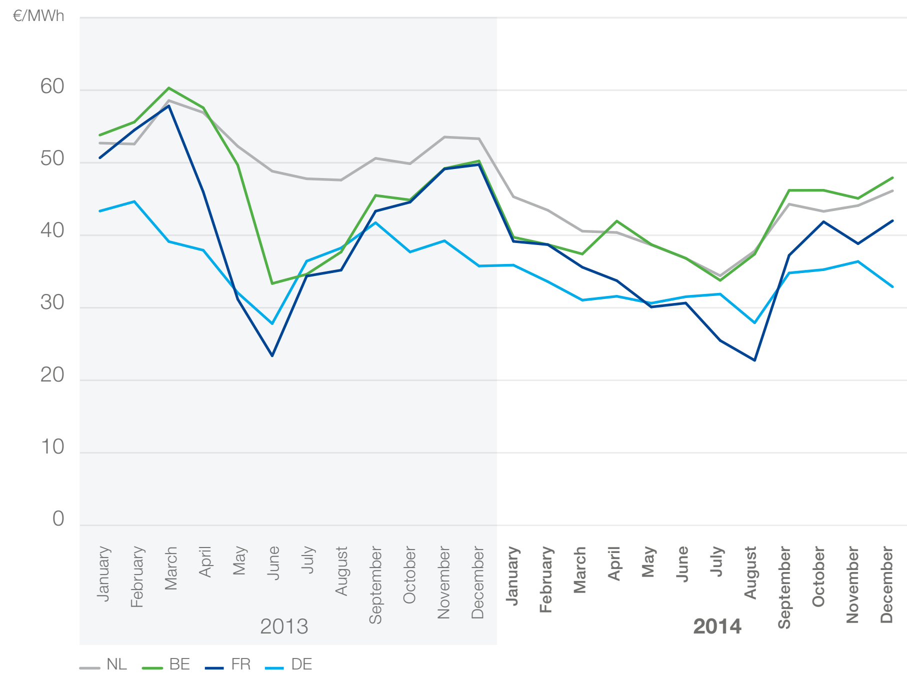

Figure 1: Monthly average of hourly Day-ahead wholesale prices in CWE countries.
Source: EPEX Spot, energate

Price developments

In February 2014, the Price Coupling of Regions solution was implemented to complete the coupling of the North Western European (NWE) market. This included the full integration of the BritNed HVDC cable between Great Britain and the Netherlands. With the integration of NWE and South Western Europe (SWE), which followed in May, Spain and Portugal were added. Italy and Slovenia joined in early 2015. In the Central Eastern European (CEE) region too, the PCR solution was implemented in 2014, preparing the ground for further integration.

Figure 2 shows the price levels across Europe and the price convergence with Germany and with the Netherlands. The price levels for different European market areas for the years of 2013 and 2014 are visualised by the background colours: the greener the colour of the market area, the lower the price. The percentage of full convergence with the Dutch and German market area are given by the numbers in every country. Germany and Austria constitute one market area, meaning there is full price convergence of 100%.

Comparing both years, it is striking that prices dropped significantly in all of the specified countries, with the exception of the Polish market area. One reason for this exception are plant outages in Poland[1]. Limited availability of interconnection capacity results in such incidents not being dampened by imports, but fully reflected in the domestic price level.

Furthermore, we note that considerable differences in price levels across Europe persist despite market coupling. Great Britain and Italy show higher average prices compared to other European countries. Germany and the Nordic countries show lower prices, together with most CEE countries. Iberia, Belgium and the Netherlands are in between. Where the French average price was at the level of the Spanish price in 2013, it was reduced to nearly the German price level in 2014.

A relatively high level of full price convergence can be observed between France and Germany at about 50%, which is about the same level for Denmark West and Germany. Price convergence between the Netherlands and Germany was at around 29% on average, whereas the convergence between Germany and the neighbouring Polish market area is below 1%, indicating congestions at this border. On the German-Czech border, hours with full price convergence are rare despite the comparable price level[2]. The German and Czech market prices are the result of their respective generation mix. On average they led to similar outcomes, but in this case this is not the result of market coupling.

[1] European Commission – Quarterly Report on European Electricity Markets – Volume 7.

[2] Comparison requires currency exchanges for Poland and the Czech Republic. Convergence is assumed, if price difference below 0.01 €/MWh. Higher tolerance leads to higher price convergence, but distinction between convergence considering currency exchange accuracy and non-convergence is not decisive.

Price developments

European Wholesale Prices and Price Convergence

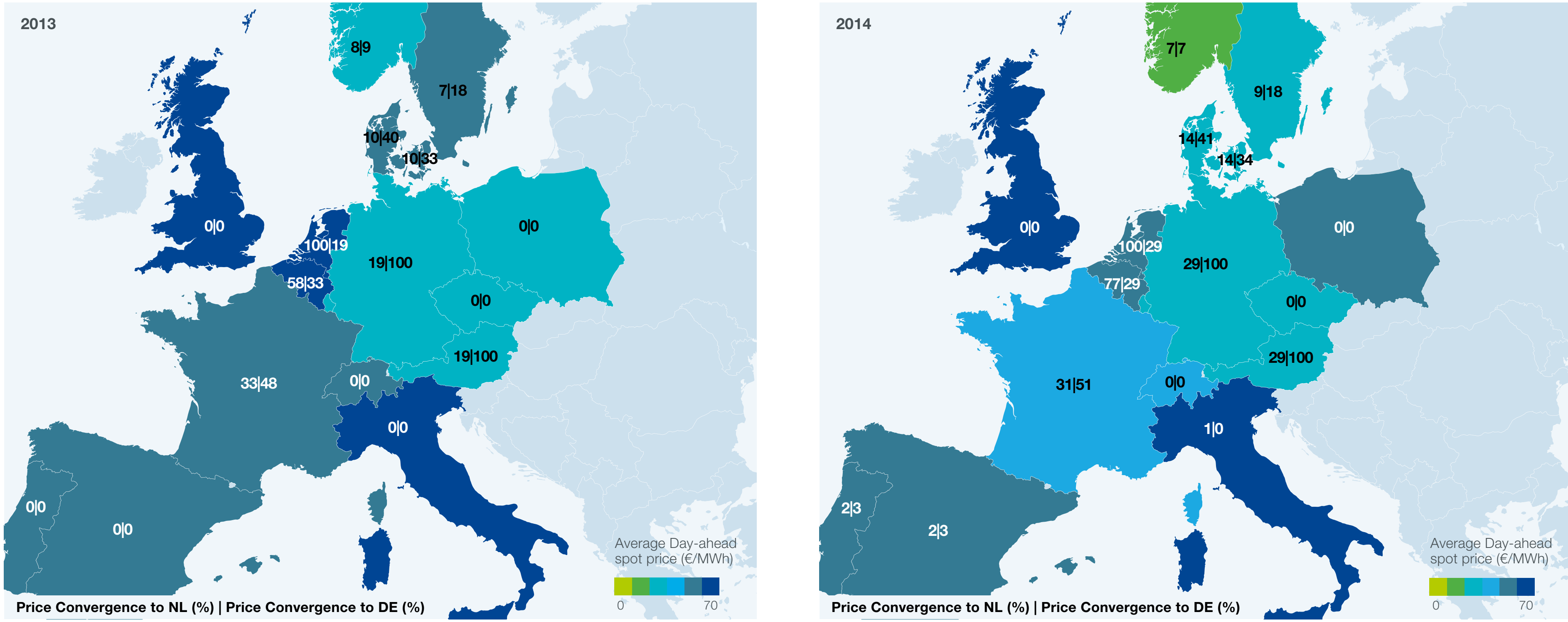

Figure 2: Yearly average of hourly Day-ahead prices and % hours full price convergence (in relation to the Dutch and German market area) of different market areas in Europe[3].
Source: energate, APX, EEX, Nordpool Spot, POLPX, OTE, GME, OMIP

[3] For countries with multiple market areas, the market area interconnected to a market area in another country was chosen: Italy: Nord, Norway: NO2, Great Britain: GB2.

Price developments

The convergence shown in Figure 2 are yearly averages. In order to get information that is more specific to the development for the CWE region, we show the percentages of hours with full price convergence for each month in Figure 3.

Price Convergence between CWE countries

Figure 3: Share of hours with full price convergence between CWE countries. Source: EPEX Spot, energate

Price developments

The convergence between German and Dutch prices levels is in a range between 17% and 56%, with outstanding convergence in June and July.

Between the Netherlands and Belgium, the convergence shares are consistently above 50% with almost completely equal prices in summer from April to August.

Apart from December, the French-German convergence is relatively high in 2014.

The Belgian price and the French price almost fully converged in the first months of 2014.

In Figure 4 we see how the hourly prices vary throughout the day in Germany and the Netherlands. Obviously, the price difference will vary much more for individual hours, but by comparing these averages we can conclude that the price difference between the Netherlands and Germany is structural. Furthermore, we see that the German curve and the Dutch curve have a different shape, indicating that the price difference varies throughout the day. The difference is lower in the peaks in the morning and the evening and higher around noon and at night. The shape of the price curve mirrors the shape of the residual load, thus driven by electricity demand and zero marginal cost generation. The differences between the two markets will be examined in more detail in chapter 3.

Variation of Wholesale Prices over the day in Germany and the Netherlands

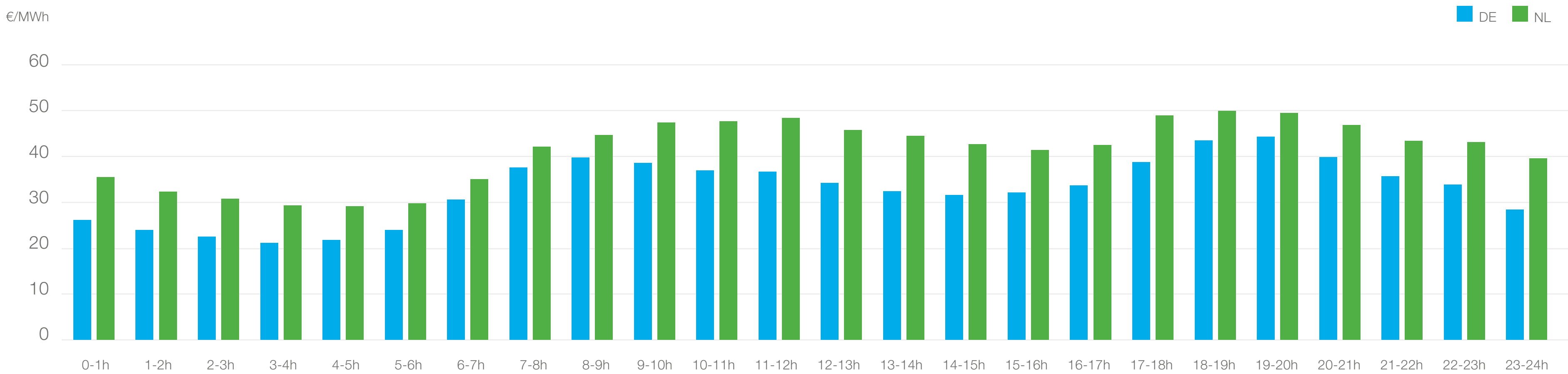

Figure 4: Yearly average of hourly Day-ahead wholesale prices for each hour of the day in Germany and the Netherlands in 2014. Source: energate

Price developments

Despite the progress of the Price Coupling of Regions, leading to an increasing number of countries participating in the market coupling, large price differences across Europe still remain. Although an overall decrease of the average wholesale prices in the different market areas from 2013 to 2014 is observable, high price convergence is only given between some market areas in specific months. Besides limits to the capacity of interconnectors, price developments are primarily determined by European electricity demand and supply. To explain these in more detail, the next chapter provides insight into relevant price drivers.

Consumption and production

As in any market, prices for electricity are set at a level where demand and supply meet. On the demand side we have seen a steady decrease, despite economic recovery in Germany. On the supply side we have witnessed a continuing increase in renewable capacity in Germany and new coal-fired power generation in the Netherlands. Within the framework set by these gradual developments, the dynamics of fuel prices and the weather determine the prices.

Consumption

As depicted in Figure 5 the consumption of electricity in CWE has been decreasing over the last few years. Overall electricity consumption was 8% lower in 2014 than in 2010. Between 2013 and 2014, consumption was stable in the Netherlands whereas in the other three countries consumption fell. The overall trend of declining demand contributes to the decrease in wholesale prices from 2013 to 2014.

Temperature is one of the main drivers of variation in consumption due to e.g. demand for electric heating or cooling. In 2014 a mild winter contributed to lower electricity consumption. In France, where electricity plays an important role in domestic heating, electricity consumption fell by 6% in 2014 after two years of growth.

Besides the impact on the total consumption of electricity, this temperature effect leads to a seasonal pattern, which is apparent from Figure 6, showing the monthly electricity consumption of the CWE countries in 2013 and 2014.

Development of Yearly Electricity Consumption in CWE countries

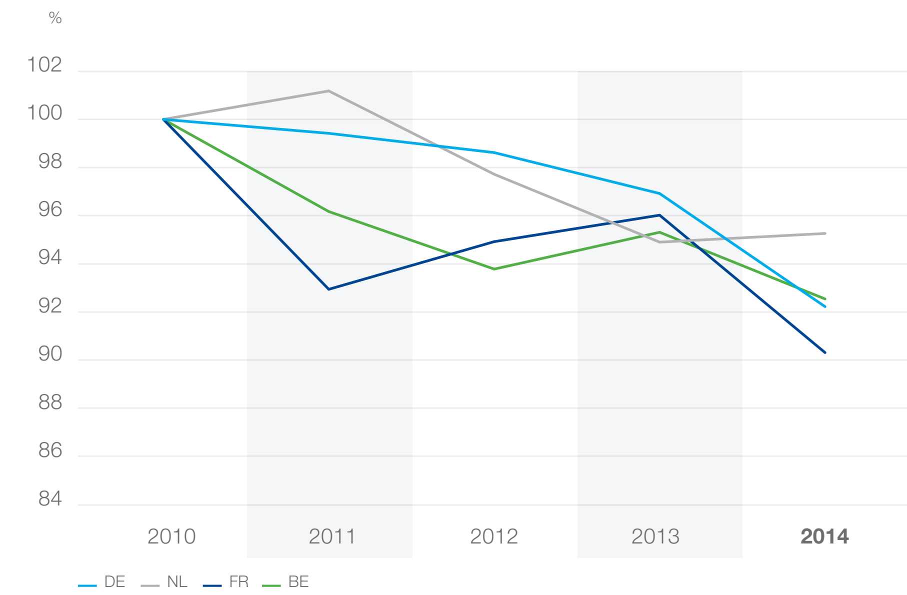

Figure 5: Annual electricity consumption compared to the base year 2010 in CWE countries.
Source: ENTSO-E

Consumption and production

For all of the depicted countries the average load is higher in winter than in summer. Especially in France, a seasonal characteristic of the electricity demand is visible. Obviously, this also has an effect on peak load. The peak electricity load in 2014 of France was 82,500 MW with a temperature of -2 °C in Paris in comparison to the peak of 102,100 MW in 2012 with a temperature of -7 °C[1]. This high seasonal sensitivity of the electricity consumption in France explains the price development over the year in this market area.

[1] Source: Réseau de transport d'électricité: France Electricity Report for 2014, Temperatures obtained from http://www.wunderground.com

Development of Monthly Electricity Consumption in CWE countries

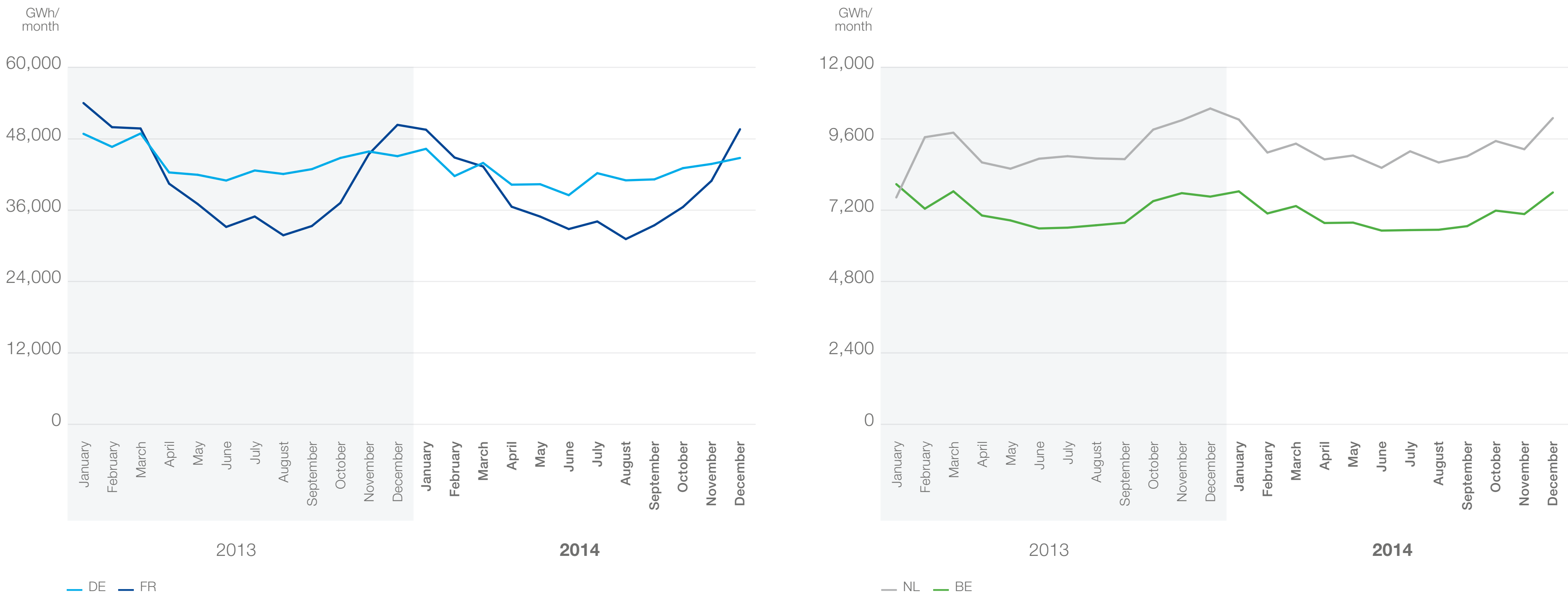

Figure 6: Monthly electricity consumption in CWE countries. Source: ENTSO-E

Consumption and production

Obviously, different factors such as the energy efficiency and the economic growth have an impact on the electricity demand, besides the temperature. These factors do not necessarily push in the same direction at all times. For example, one of the EU 20-20-20 targets is a 20% improvement in European energy efficiency. On the one hand, efforts to reach this target can lead to a decreasing consumption of electricity, but on the other hand this target (in combination with the renewable energy target and the emission target) can also lead to an increased use of electricity as a replacement for other energy sources. It may trigger, for instance, an increased use of electric vehicles, electric heat pumps or power-to-heat in industry.

Historically, economic growth was accompanied by a growth in electricity consumption. As a result of the economic crisis, a decrease in consumption is visible, which can partly be explained by a reduction of baseload electricity consumption in industry. However, this relation between economic growth and electricity consumption does not hold for Germany in recent years, where we observe a decrease in consumption despite economic growth. Partly this can be explained by the electricity price payable by the consumer, which did not decrease in line with the wholesale prices as a result of levies and taxes, inducing electricity savings.

Any investment in power generation capacity that was based on an assumption of economic growth and accompanying growth in electricity demand is likely to experience the negative consequences on the return of investment as a result of the downward trend in consumption.

Consumption and production

Production

In this section, the supply side of the power system is analysed. The following sections give an overview of Dutch and German electricity production by looking at the three main drivers of wholesale prices namely generation base, fuel prices and renewables. Additionally, the special Belgian winter situation is briefly described.

i. Dutch and German Generation Base

Figure 7 depicts German monthly generation in 2014 and the legend shows the change compared to 2013 per generation type. Nuclear and lignite baseload generation are approximately constant throughout the year, with lower feed-in in summer due to power plant revisions. Generation by hard coal and natural gas show a significant seasonal pattern. On the one hand, cogeneration with heat-side restrictions leads to higher generation in winter and on the other hand, the residual load diminishes in summer, based on low overall demand and high renewables feed-in. As can be seen from Figure 7, all types of German thermal power plants show a decrease in power generation, whereas generation from renewable energy sources show an increase.

Power Generation in Germany

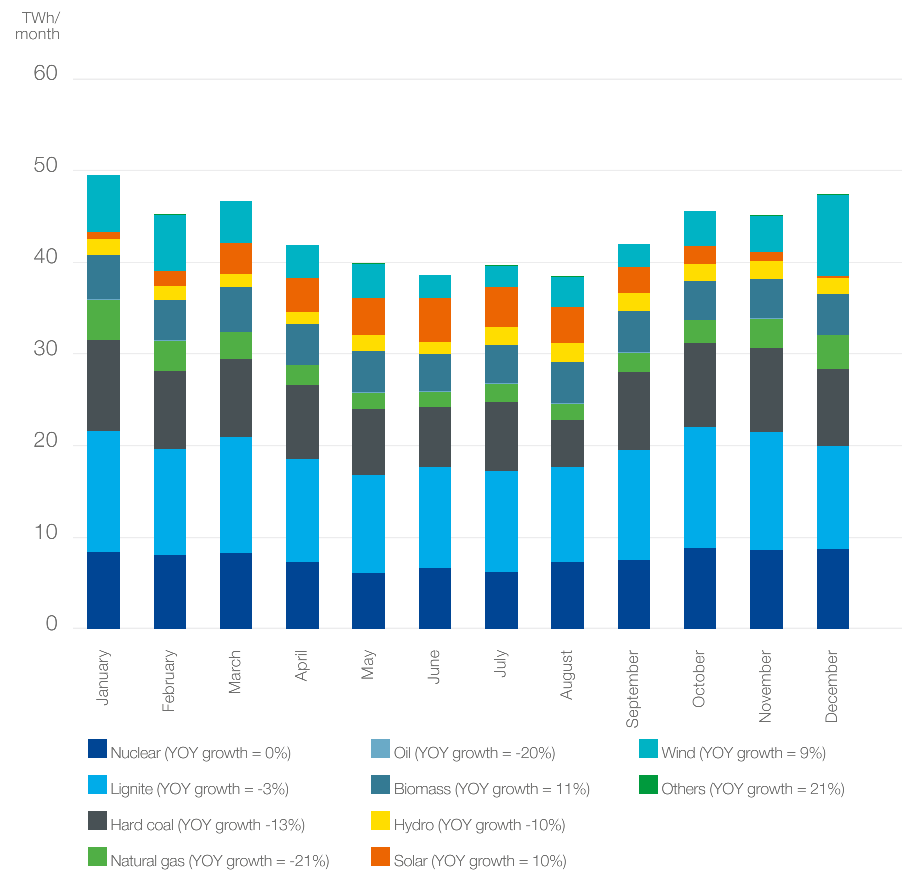

Figure 7: German monthly power generation per generation type in 2014.
Source: destatis, Fraunhofer ISE, EEX

Consumption and production

Figure 8 depicts the Dutch monthly large-scale power generation[2] in 2014 and shows the change of power generation in 2014 compared to 2013. A seasonal pattern can be observed with higher production in winter. The three new hard coal plants that came on-stream at the end of 2013 and the beginning of 2014 were not in full commercial operation in 2014. Therefore, the rise of 12% in 2014 was lower than expected. Whereas hard coal generation has increased, natural gas generation has decreased compared to 2013. Nuclear generation shows a large increase due to a longer outage of the power plant in Borssele in the fall of 2013.

Large-scale Power Generation in the Netherlands

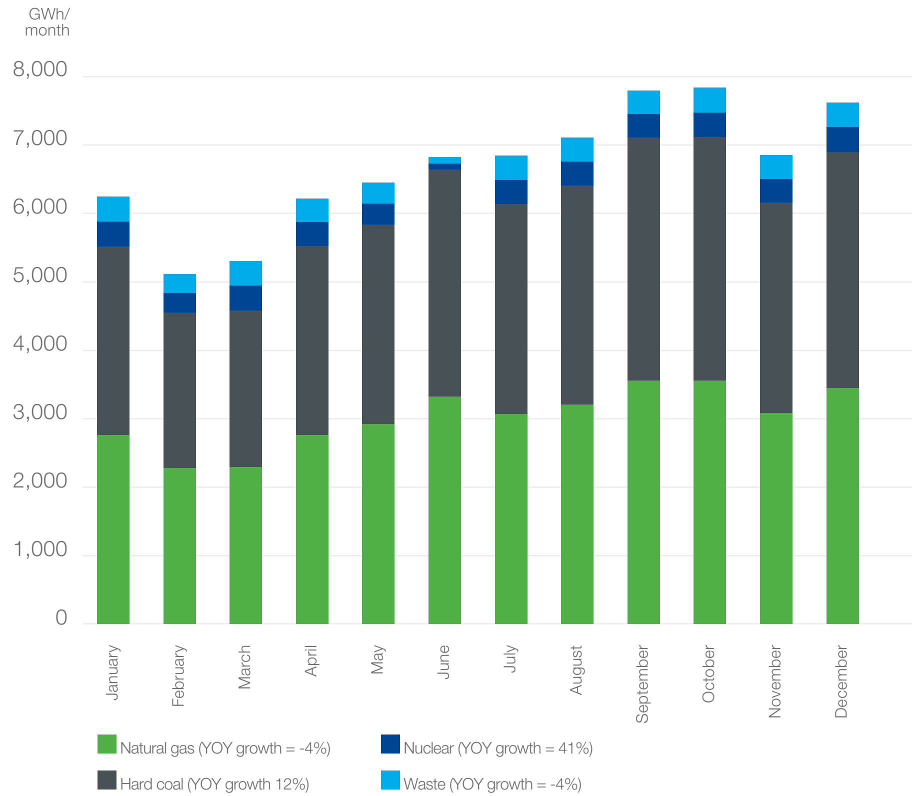

Figure 8: Dutch monthly large-scale power generation per generation type in 2014.
Source:TenneT, CBS

[2] All installations larger than 10 MW are included excluding wind turbines. However, in the Netherlands a relatively large part of total generation is decentralized production.

Consumption and production

The representation in Figures 9 and 10 help us to better understand the implications of the differences in the generation base in the Netherlands and Germany for the wholesale price in the respective countries.

On the hand, it looks at the residual load[3], this is the consumption of electricity that has to be supplied by the conventional power plants. The residual load is expressed in GW. Figures 9 and 10 show how often this residual load falls in the defined clusters. For Germany, for example, Figure 9 shows that 9% of the time the residual load is between 45 GW and 47.5 GW.

The shaded area in the graph indicates the 67% interval. For Germany this shows that most of the time the residual load was between 30.7 GW and 52.5 GW. For the Netherlands this was between 6.8 GW and 13.4 GW.

On the other hand, Figure 9 and 10 show the merit order of the conventional power plants[4]. Typically, such a merit order ranks power plants based on their marginal costs, meaning the plants with lower marginal costs such as nuclear plants and lignite can be found on the left-hand side of the curve and peak units with high marginal costs can be found on the right-hand side.

The merit order indicates which unit can be expected to be the price-setting unit at a given level of residual load. In the Netherlands, for example, if the residual load is between 0.5 GW and 7 GW we should expect a hard coal-fired plant to be the price-setting unit.

Now, if we look at the two curves combined, and focus on the shaded 67% interval, we see that most of the time the price-setting unit in Germany will be a hard coal plant, whereas in the Netherlands we will find a gas-fired plant to be price-setting.

This being said, it should also be noted that a lignite-fired plant in Germany and hard coal-fired plant in the Netherlands will be the price-setting unit in a considerable number of hours. This means flexibility will be required from those plants as they cannot be operated as pure baseload plants.

This is a theoretical approach, and more factors, such as start-up costs, and operational time constraints come into play when determining real market prices. Nevertheless, the main message is very relevant for explaining the structural price difference between the two countries: it results from fuel.

3 Residual load equals total electricity demand minus generation from photovoltaics, wind turbines, biomass plants, run-over-the-river and cogeneration, and is adjusted for scheduled import and export. Pumped storage plants are not taken into account.

4 The merit order curve reflects the marginal generation costs of the referring power plants resulting from dispatch models. The curve is based on published numbers of installed capacities. However, the fuel prices and plant efficiencies are based on model assumptions using IAEW power plant database.

Consumption and production

German Merit Order and Residual Load Distribution

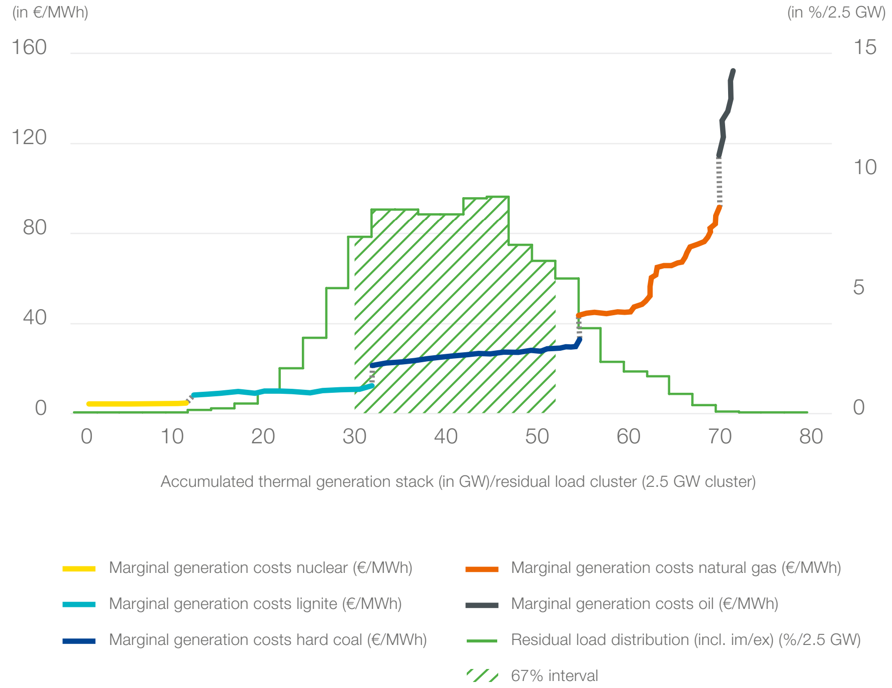

Figure 9: German merit order and residual load distribution in 2014.
Source: ENTSO-E, EEX, Bundesnetzagentur, IAEW

Dutch Merit Order and Residual Load Distribution

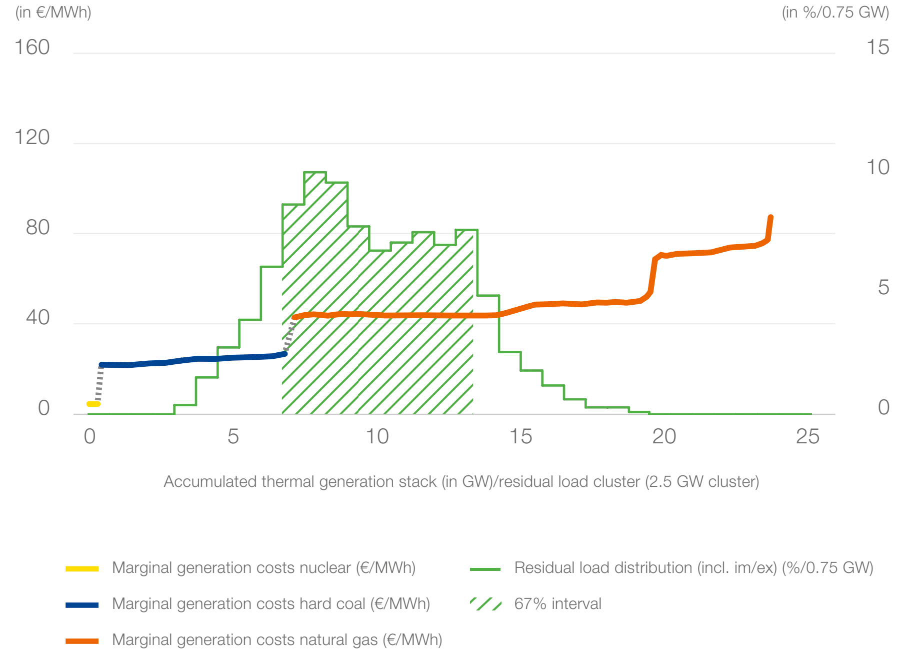

Figure 10: Dutch merit order and residual load distribution in 2014.
Source: TenneT, ENTSO-E, EEX, IAEW

Consumption and production

ii. Fuel prices

In order to explain the developments described, fuel prices as well as prices for CO_2 certificates are investigated in more detail. Figure 11 shows the corresponding graphs for the prices of natural gas (TTF), hard coal (API#2) and CO_2 emission allowances (EUA).

Prices for Natural Gas, Hard Coal and CO_2 Certificates

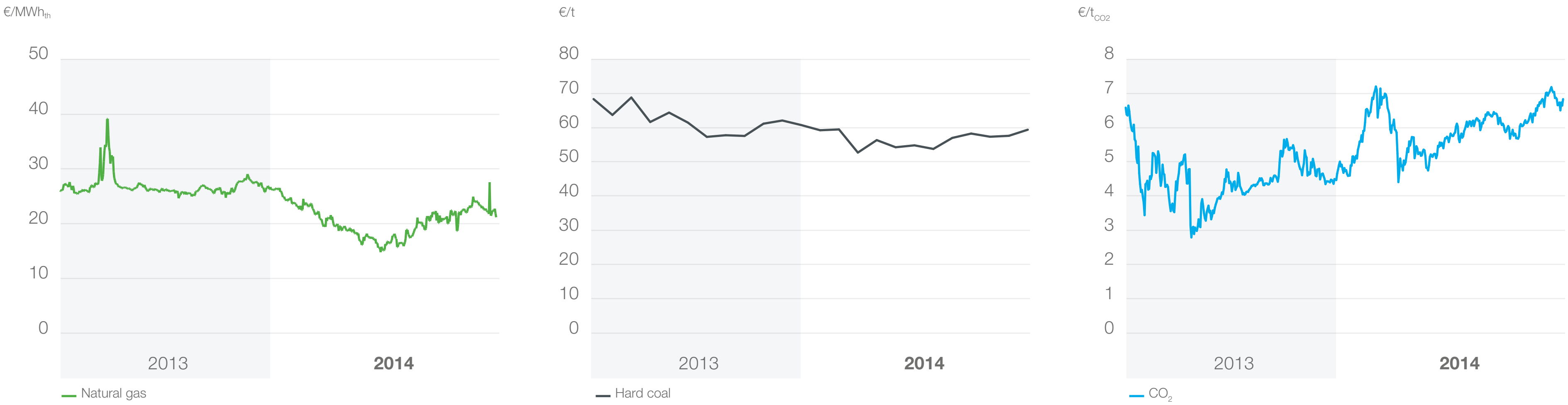

Figure 11: Daily Day-ahead gas prices from EEX TTF Index, monthly hard coal prices from API#2 ASK (CIF ARA) and daily CO_2 future price for years 2013/2014 traded through 2013 /2014.
Source: Energate, EEX

Consumption and production

In 2014 the price of natural gas went from 26.8 €/MWh$_{th}$ in January to below 15 €/MWh$_{th}$ in July and up to 27.6 €/MWh$_{th}$ in December again, showing high correlation with the electricity wholesale prices, particularly in the Netherlands. This was strengthened by the rise of prices for emission allowances from as low as 4.4 €/t in March to nearly 7 €/t in December. Prices for hard coal are levelling at around 55 €/t throughout the year, but still climbing from 53 €/t in the first half to 57 €/t in the second half of 2014.

Fuel and CO_2 certificate prices are directly associated to the marginal costs of thermal power plants and therefore related to possible contribution margins. Figure 12 shows the monthly average clean dark spread and clean spark spread[5] in Germany and the Netherlands during 2013 and 2014. The spread of both natural gas and hard coal show a downward trend.

Based on higher prices, the overall income situation for power producers in the Netherlands is better. Assuming baseload generation, only Dutch hard coal power plants can make steadily positive contribution margins. This coincides with three large new coal-fired power plants coming on-stream, raising the contribution of hard coal to the Dutch generation mix.

Dutch clean spark spreads and German clean dark spreads were levelling at around zero, so they can only be positive contribution margins on part of the hours, but not on continuous feed-in. The German clean spark spread shows the lowest margins, so natural gas power plants in the German market area can be operated with positive margins in only a very small number of hours.

[5] The clean dark spread and clean spark spread are defined by the wholesale price minus the generation costs (spark for natural gas and dark for hard coal) incl. costs for CO_2 certificates (described by the term “clean”).

Consumption and production

Development of Clean Spark Spread and Clean Dark Spread in the Netherlands and Germany

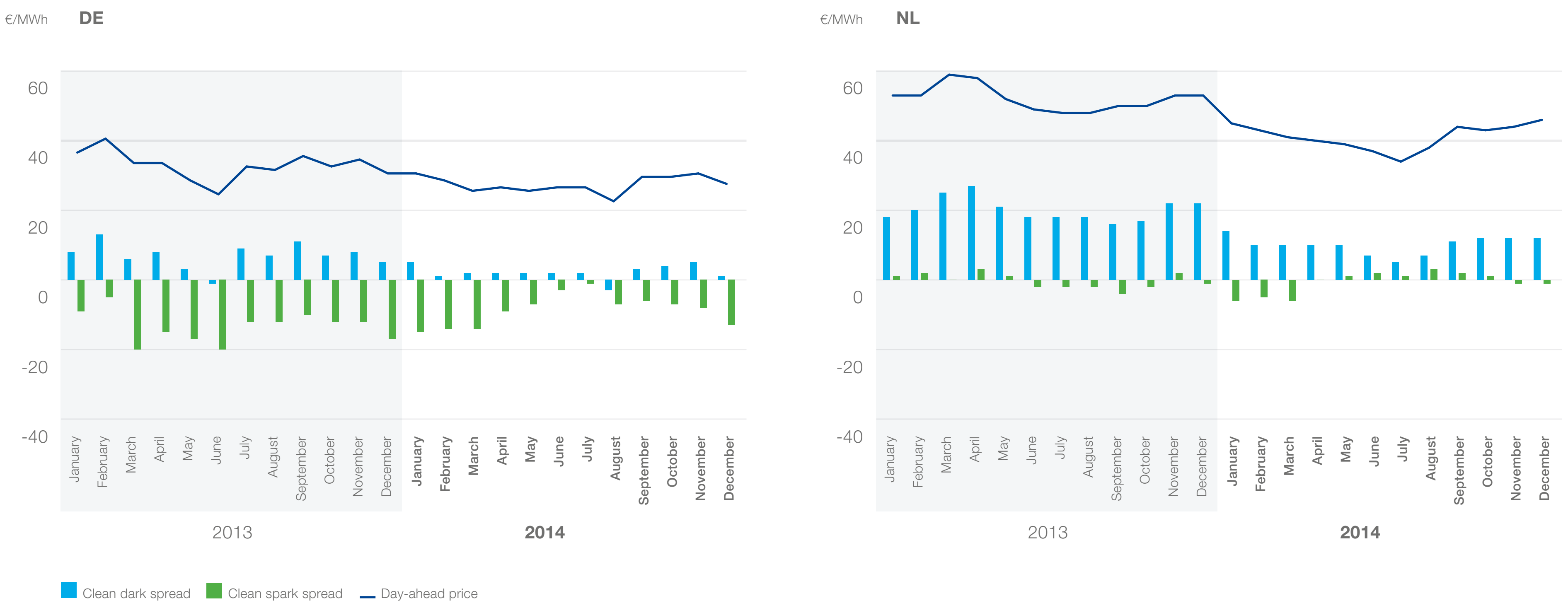

Figure 12: Monthly average clean dark spread and clean spark spread in Germany and the Netherlands. Source: EPEX Spot, energate, IAEW

Consumption and production

The persisting poor margins have led to a wave of mothballing of mainly gas-fired power plants in both Germany and the Netherlands.

Nevertheless, as indicated by the merit order curves above thermal power plants and cross-border exchange play a crucial role regarding providing flexibility in order to compensate the fluctuation of the load and the intermittent must-run generation. In this regard the following section investigates the flexibility provided.

iii. Flexibility

Variation in consumption and renewable production require flexibility that is delivered by conventional generation. Figure 13 shows the mean and volatility of hourly gradients of the German hard coal schedule in 2013 and 2014. Strikingly, these hard coal-fired plants provided higher positive gradients with higher variation in 2014, especially during morning hours from 04:00 hours till 07:00 hours. Also negative gradients during the night from 21:00 hours till 01:00 hours were higher than in 2013. These higher gradients during ramping hours mean that the flexibility contribution of hard coal is increasing in Germany.

The hourly gradients of the German natural gas schedule and Dutch coal and natural gas generation were also examined[6]. In 2014 the flexibility contribution of natural gas power plants in both Germany and the Netherlands was less than in 2013. The hourly gradients of Dutch hard coal-fired plants showed a strong change in pattern. However, most of this change is due to the three new hard coal plants that came on-stream and were testing and commissioning in 2014.

[6] The analysis for Netherlands was based on realised generation, whereas in Germany it was based on schedules. Realised generation can differ from expected generation for instance due to unplanned outages, redispatch and reserve activation.

Consumption and production

German Hard Coal Schedules – Hourly Gradients

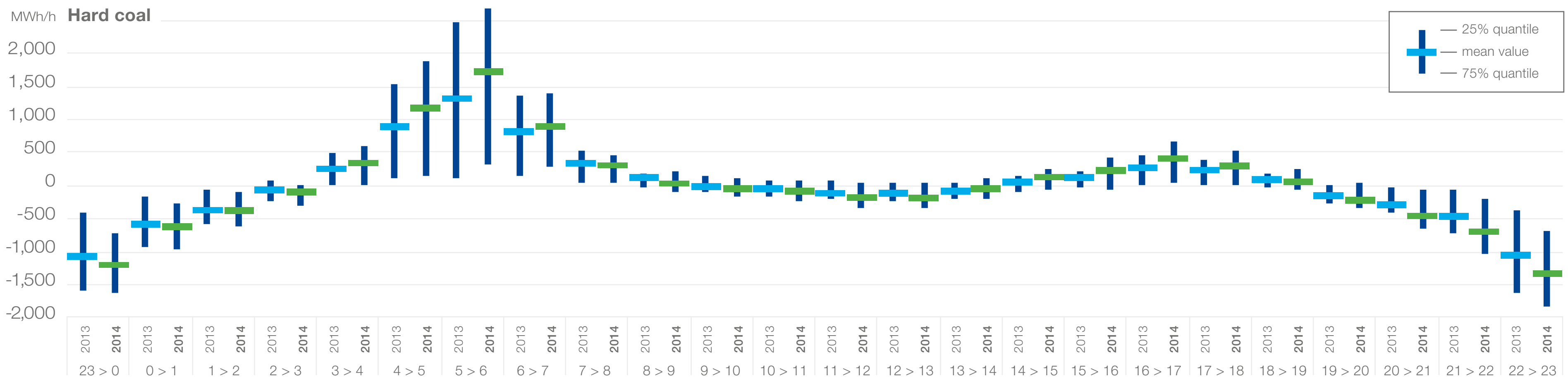

Figure 13: Hourly gradients ($P_t – P_{t-1}$) of German hard coal power plant schedule in 2013 and 2014. Source: EEX[7]

[7] Data does not cover all generation units, since power plant operators are not obligated to publish information.

Consumption and production

To shift away from averages, we take a look at the particular case of Easter Sunday in Germany which can be seen in Figure 14. Low demand because of the holiday combined with a high feed-in of wind and solar power resulted in the lowest residual load in 2014. The above-mentioned provision of flexibility by hard coal power plants is observable in this situation. Furthermore, due to the low Day-ahead market prices even lignite and nuclear plants' generation was lowered gradually, thus providing some flexibility on Easter Sunday.

Consumption and production

German Day-ahead Schedule and Day-ahead Price during Easter

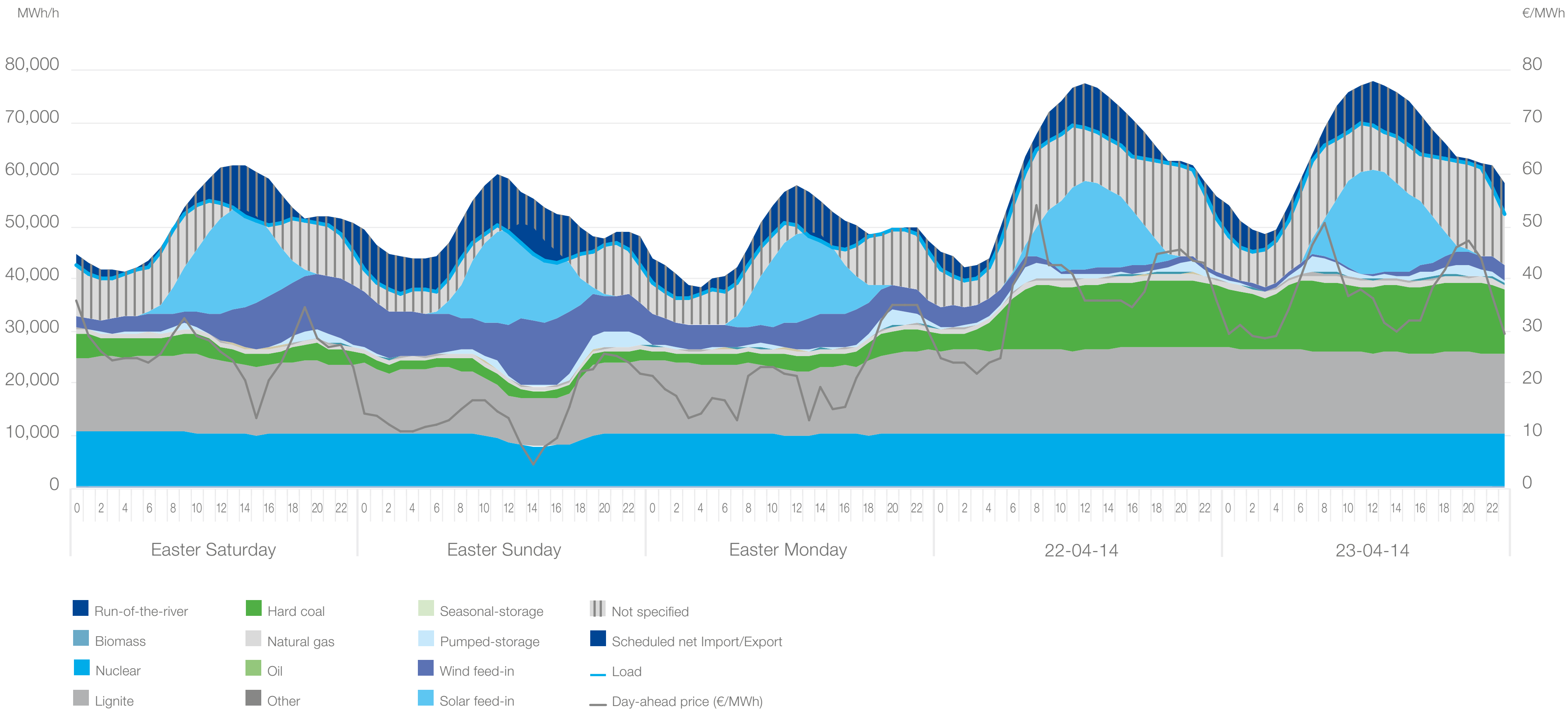

Figure 14: Generation schedule and Day-ahead price during Easter 2014 in Germany. Source: EEX, ENTSO-E, IAEW

Consumption and production

Furthermore, it should be noted that in this case not only the generation stack was providing flexibility to the market but also imports and exports from adjacent market areas. The export increased significantly especially in the hours with high feed-in by photovoltaics. Figure 15 demonstrates the provision of flexibility by imports and exports. It shows the residual load which has to be satisfied by the hydro and thermal generation stack with (green solid line) and without (blue solid line) the imports and exports. Without import and export, the bandwidth in which the generation stack would have had to operate would have increased by more than 9 GW over these five days.

German Residual Load with and without Imports and Exports during Easter

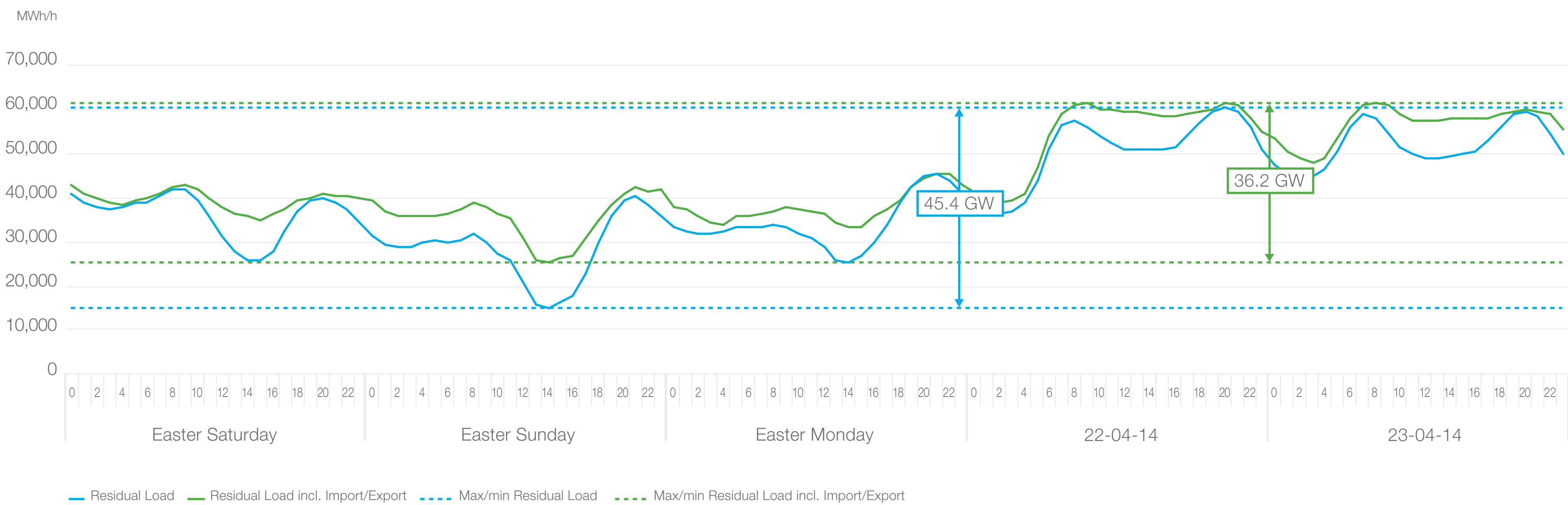

Figure 15: Residual load with and without imports and exports during Easter 2014 in Germany. Source: EEX, ENTSO-E, IAEW

Consumption and production

The observed provision of flexibility by imports and exports for this particular situation with occasional high feed-in by renewables can be extrapolated to a more general conclusion with the help of Figure 16. Representing the average hourly solar feed-in and the average net export-import saldo for 2013 and 2014, the graph shows an increase of the exports on average in times of a high solar feed-in. The increase of solar feed-in and the higher net exports of Germany seem to be correlated. This means the neighbouring countries of Germany provide flexibility to the German market on the one hand, but on the other hand profit from a higher supply in Germany, resulting in the previously mentioned price damping effect around noon in Germany.

German Net Export and Solar Feed-in

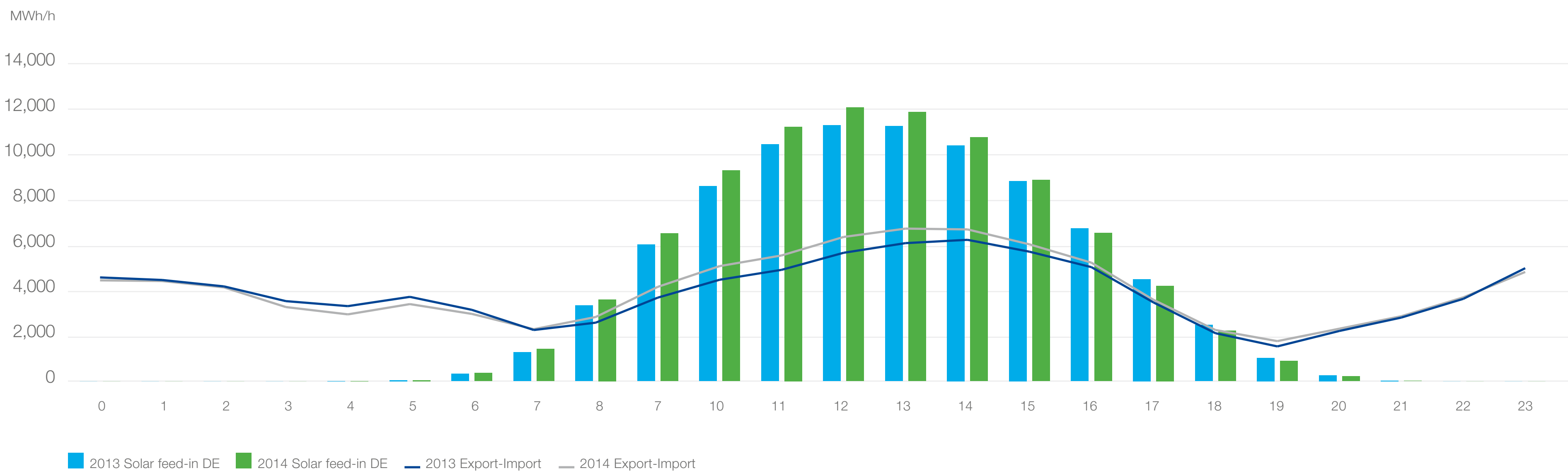

Figure 16: Yearly average of net export (export-import) of commercial flows and solar feed-in for each hour of the day in Germany. Source: ENTSO-E, EEX

Consumption and production

Besides the provision of flexibility through the market induced by price incentives, the German TSOs contract additional capacity for safety reasons based on the legal framework Reservekraftwerksverordnung (ResKV).

After the Moratorium for nuclear power plants in Germany in 2011 and the political decision to phase out nuclear generation by 2022, running conventional capacity is expected to decrease. Due to the reported low level of prices and spreads in the German market area, no short-term investment incentive for new thermal generation capacities can be expected. By contrast, a substantial amount of conventional generation capacity was shut down or mothballed in 2013 and 2014[8].

Moreover, under special winter conditions secure grid operation can be threatened. This can occur when high wind feed-in in the north of Germany coincides with high demand in the south of Germany, especially on days that there is little production from solar energy in the south.

Some of the lines needed to fulfil the transportation of electrical energy from the north to the south still have to be completed. To ensure the security of the grid in the short term, the TSOs are allowed to contract additional backup generation units for the winter.

It has to be mentioned that this should not be confused with an introduction of a capacity market because the contracted power plants under the ResKV are only allowed to be activated in the case of network security concerns through redispatch actions by the TSOs. Furthermore, the actual legal framework ResKV is limited to the end of 2017.

This additional capacity is procured outside of the wholesale market and can be located inside or outside of Germany. Figure 17 depicts the development of this needed capacity for the last two winters and the upcoming two winters. The increasing total amount of capacity is based on the system analysis conducted by the German TSOs and approved by the German regulating authority Bundesnetzagentur (BNetzA).

[8] Market Review 2014 H1 – Electricity market insights – First half 2014.

Consumption and production

Development of Reserve Capacity in Germany

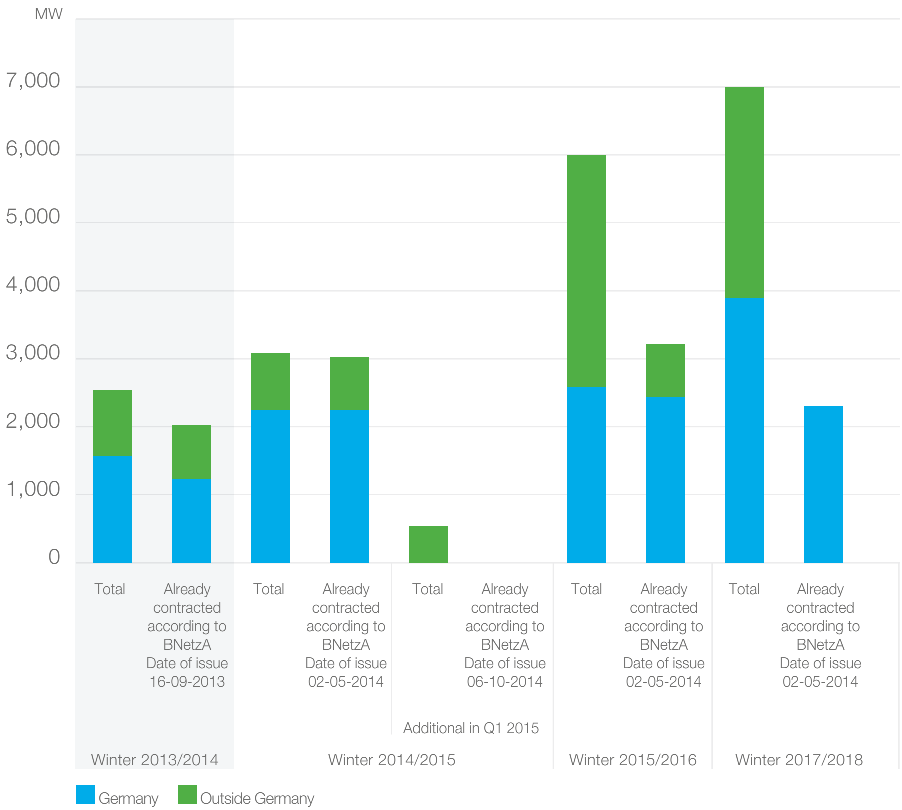

Figure 17: Reserve capacity (demand and contracted) under Reservekraftwerksverordnung.
Source: Bundesnetzagentur, TenneT

In summary, despite the cross-border flexibility, usually most of the flexibility is provided by the national generation stack. Their non-availabilities have a major impact on the European electricity prices as well as on network security, as the following example shows.

iv. Belgian winter situation

In 2014, regular planned and a number of unplanned outages of nuclear power plants occurred in the Belgian market area. Unplanned, persisting outages occurred in the generation units Doel 3 and Tihange 2 after a fracture toughness test in spring of 2014 revealed unexpected results. Both reactors were immediately shut down.

The maximum of the power generation capacity which was not available due to planned and unplanned outages of the nuclear fleet occurred in December 2014 and reached only 4,100 MW (cf. Figure 18). This critical lack of generation capacities in combination with potential peak demand in electricity in the case of a cold spell threatened the grid security and security of supply during the winter. One way to deal with this is to build up a strategic reserve. In order to avoid involuntary disconnections of load at hours with peak demand, the strategic reserve can be deployed. The strategic reserve ensures additionally 745 MW from gas-fired power plants and 100 MW from the industry, which undertook to reduce consumption when needed. The reserve can be activated between 1st November and 30th March and will be reviewed every year[9].

[9] Source: http://www.elia.be/en/about-elia/questions-about-the-risk-of-shortage-in-Belgium#11

Consumption and production

On top of these internal Belgian measures, several studies regarding the upcoming winter have been performed together with the Transmission System Operators (TSOs) and coordination centres of the CWE region to assess the situation. These studies showed scenarios where there is a need for a coordinated approach to cope with hours where the demand for electricity cannot be guaranteed despite the activation of the strategic reserves. For these scenarios the TSOs in the region (Elia, RTE and TenneT) jointly prepared a procedure consisting of a set of extraordinary measures to be exceptionally applied in the case of adequacy risks detected in Belgium. The measures consist of the coordination of transmission capacity values on several borders within the CWE region in order to guarantee sufficient levels of import capacity for the Belgian market. Sufficient levels of import capacity are important for the Belgian market in order to cope with a situation of extreme scarcity and to avoid involuntary disconnections of load in Belgium.

Outages of Nuclear Power Plants in Belgium

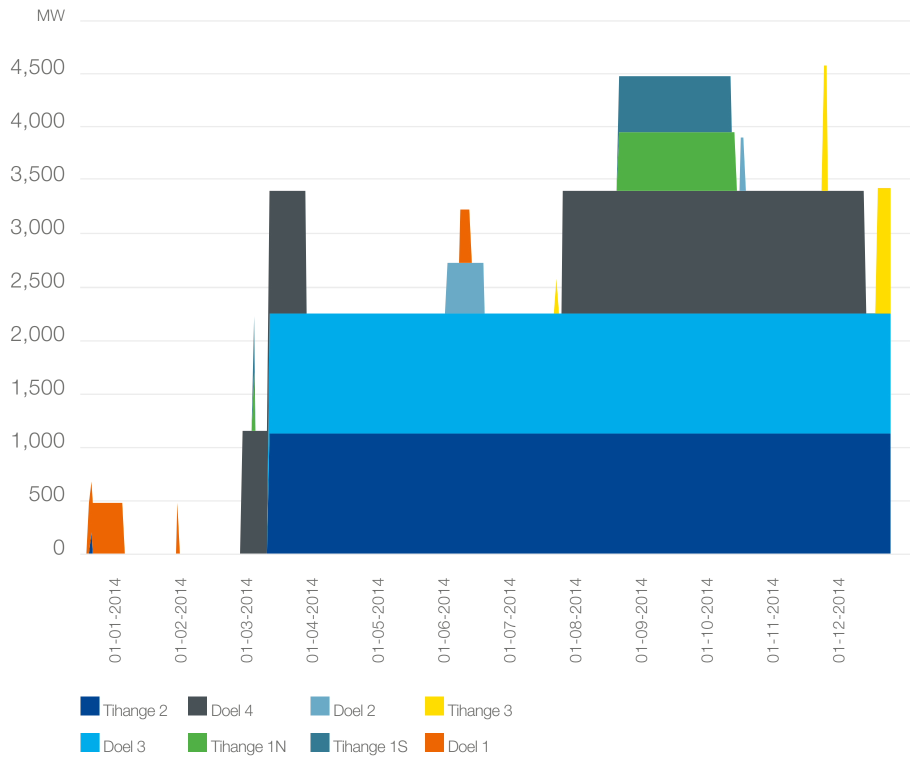

Figure 18: Planned and unplanned outages of nuclear power plants in Belgium in 2014. Source: ELIA

Consumption and production

The lack of generation capacities not only threatens the security of supply, but also has significant impact on the Belgian and the adjacent market areas. The unplanned outages of Doel 3 and Tihange 2 occurred on 26th March, overlapping with the planned outage of Doel 4.

Following these outages the high price convergence between Belgium and France in the first two months of 2014 decreased significantly (cf. chapter 2) and the Belgian price converged with the Dutch price. The price convergence between Belgium and France stayed at a low level over the summer with a minimum of price convergence in only 7% of the hours in August and nearly full imports from France, reflecting the unplanned additional outage of Doel 4 (cf. chapter 5).

v. Renewable electricity generation

In section iii indications are given that the needed flexibility in Germany is rising due to a significant share of the volatile feed-in by renewables. Furthermore, the described price development especially in Germany is directly linked to this issue.

The feed-in by renewables contributed to the decrease of the average German base price by more than 12% from 37.77 €/MWh in 2013 to 32.76 €/MWh in 2014. Renewable feed-in had a share of approximately 25.8% in the German gross electricity generation in 2014, exceeding the previous year's value by 1.7 percentage points (cf. Figure 19).

Development of Renewable Feed-in in Germany

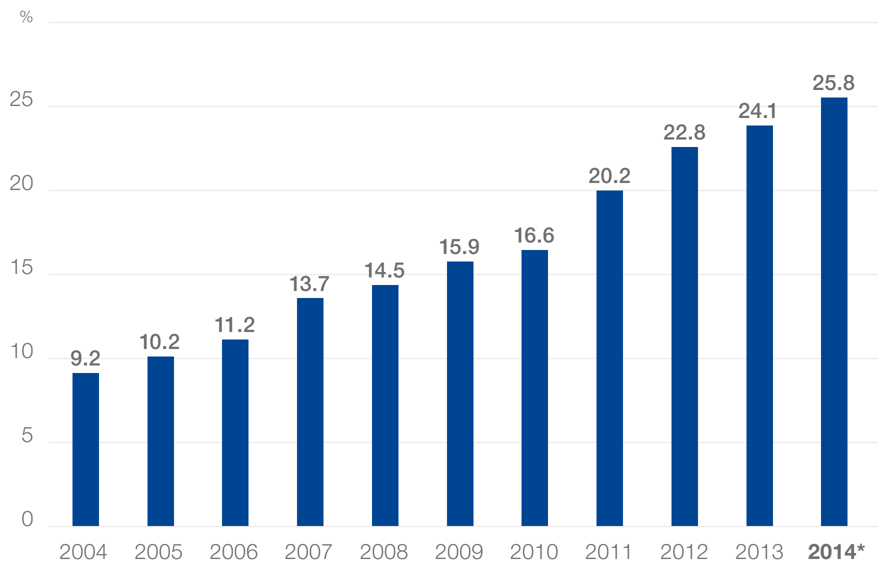

Figure 19: Share of renewable energy feed-in in German gross electricity generation 2004 – 2014. Source: Statista. *Preliminary values.

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German Renewable Feed-in per Generation Type

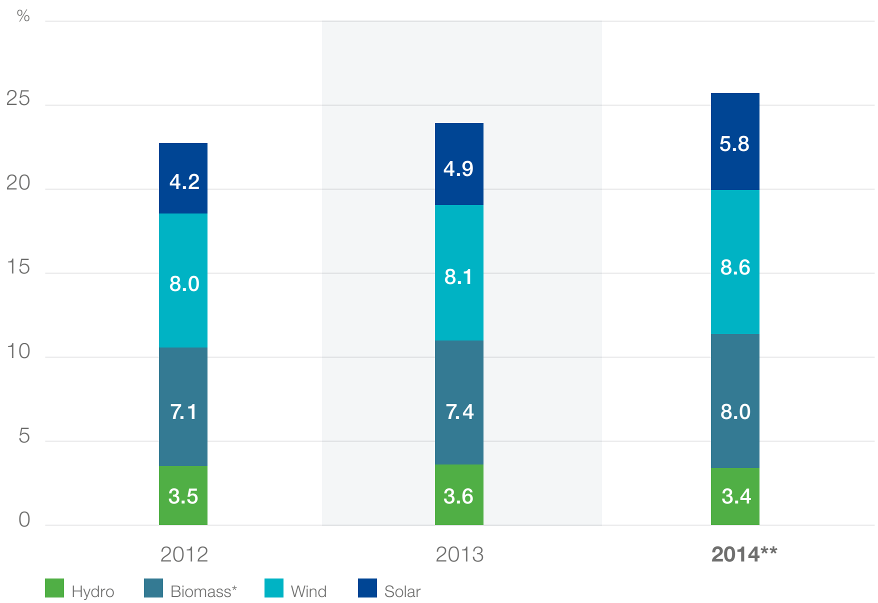

Figure 20: Share of renewable energy feed-in in gross electricity generation per generation type in Germany. Source: Destatis. *Biomass including biological share of waste. **Preliminary values.

Figure 20 breaks down the relative share of the German gross electricity generation on a technology basis for the last three years. The increasing share of renewables feed-in is especially the result of an increase of solar energy by 0.9 percentage points reflecting the installation of 1.9 GW new generation capacities in 2014[10]. Moreover, 4,750 MW new onshore wind turbines were installed[11]. Weather conditions for solar energy were favourable whereas wind conditions were favourable mainly in the first half of 2014 and in December.

In the Dutch market area, the share of renewables in gross electricity generation (11.4%) is less than half the share in Germany (cf. Figure 21). In the Netherlands, wind energy predominantly causes the intermittent feed-in. Currently, the impact of photovoltaic units on the system is still small in the Netherlands. However, the installed capacity has grown rapidly for three consecutive years and reached 1 GW in 2014. If it continues at the same growth rate in 2015, the impact will become a reality.

[10] Source: Anlagenregister Bundesnetzagentur.
[11] Source: Windguard GmbH: Status des Windenergieausbaus an Land in Deutschland.

Consumption and production

Power production from biomass has decreased, which can be explained by the repeal of a subsidy for renewable electricity (MEP-subsidy)[12].

Dutch Renewable Feed-in per Generation Type

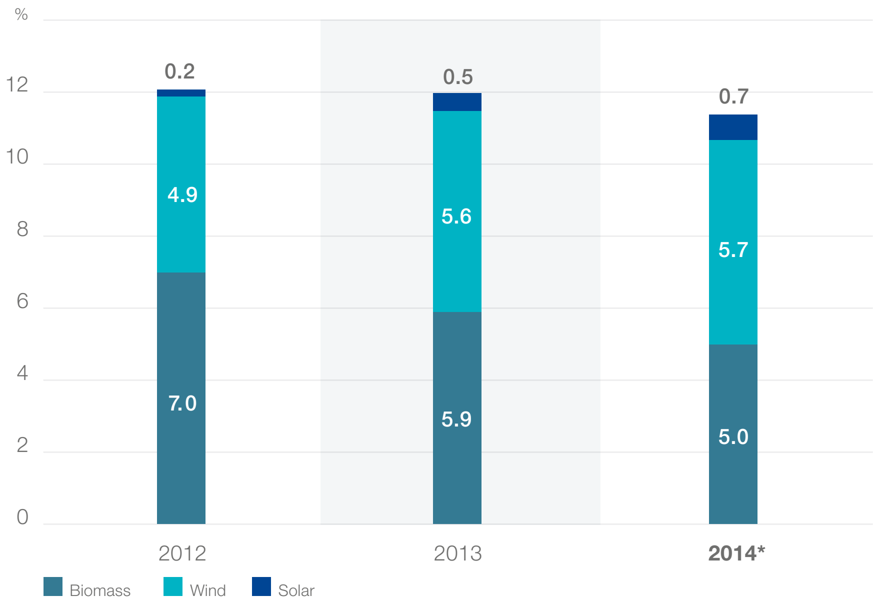

Figure 21: Share of renewable energy feed-in in gross electricity generation per generation type in the Netherlands. Source: Statistics Netherlands. *Preliminary values.

The effect of wind and solar energy on the German price level can be seen in Figure 22, which depicts the monthly average feed-in and the average German Day-ahead market prices over the last three years. Months with higher feed-in tend to have lower prices as high production of solar and wind energy shift the supply curve to the right, leading to a change in the price-setting power plant, or even the price-setting technology (the 'merit order effect').

This effect is particularly visible in December 2014, in which the average feed-in of wind turbines reached a high of nearly 12 GW. Consequently, the average Day-ahead market prices significantly decreased compared to November 2014.

Furthermore, seasonal patterns of the two intermittent sources are visible, which seem complementary on a monthly, energetic base. A high feed-in of solar power in the summer is followed by a high feed-in of wind turbines in winter. Despite the energetic complement of wind and solar power, the daily pattern for the feed-in by solar units has to be considered (cf. Figure 16) as mentioned in chapter 3, and explaining the resulting damping effects on the market prices at noon in Germany.

[12] Source: Compendium voor de Leefomgeving.

Consumption and production

German Monthly Average Solar and Wind Feed-in

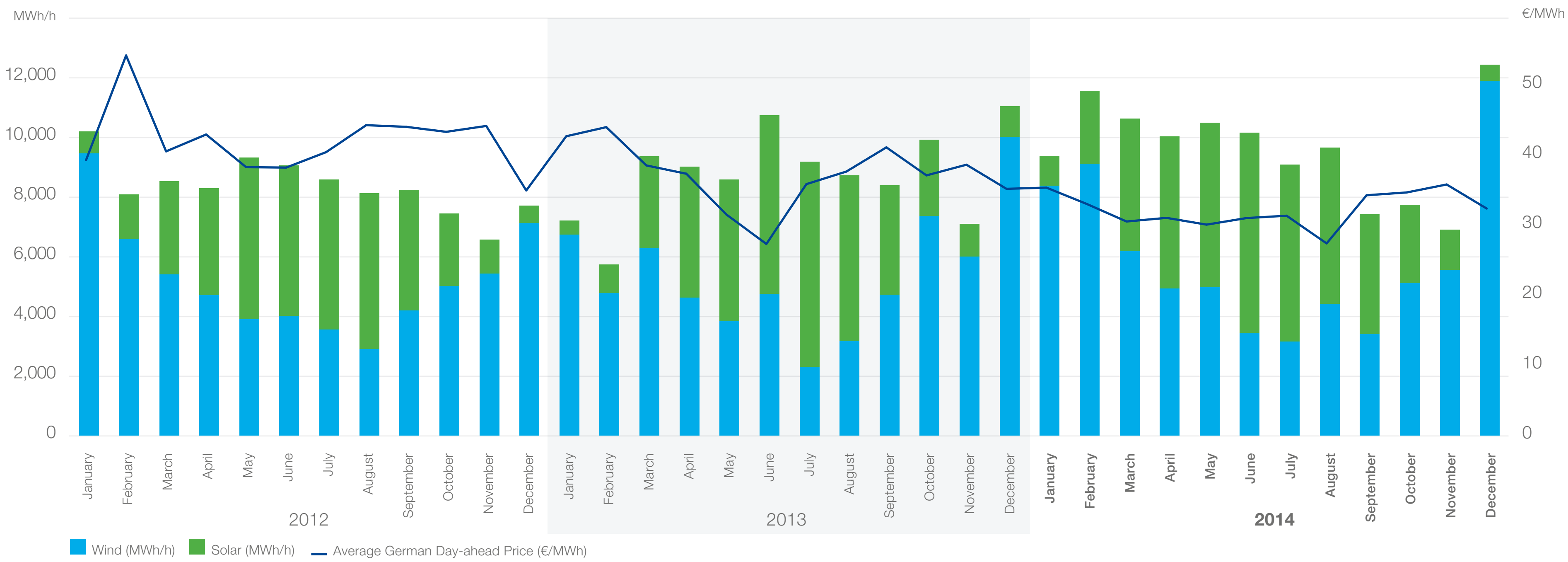

Figure 22: German monthly average wind and solar feed-in and Day-ahead price. Source: EEX

Due to the lower share of renewables in the Dutch generation system such effects are not visible in this market area. In Figure 23 the average monthly wind and solar feed-in and the average Dutch Day-ahead market price is plotted for the last three years. Neither in February nor December 2014 is an effect on the wholesale price visible despite the relatively high feed-in by wind turbines. This can be explained by the generation stack. As described in section i, the merit order of the Dutch market area consists almost exclusively of natural gas and hard coal-fired plants.

Consumption and production

The feed-in of the wind turbines in the Netherlands cannot yet cause such a merit order effect that hard coal plants become the predominant price-setting plants. Furthermore, as reported for the German market area, the wind feed-in mainly occurs energetically in the winter months with a higher demand in the winter months (cf. chapter 3). For solar feed-in, a relatively large increase can be observed over the years.

Dutch Monthly Average Solar and Wind Feed-in

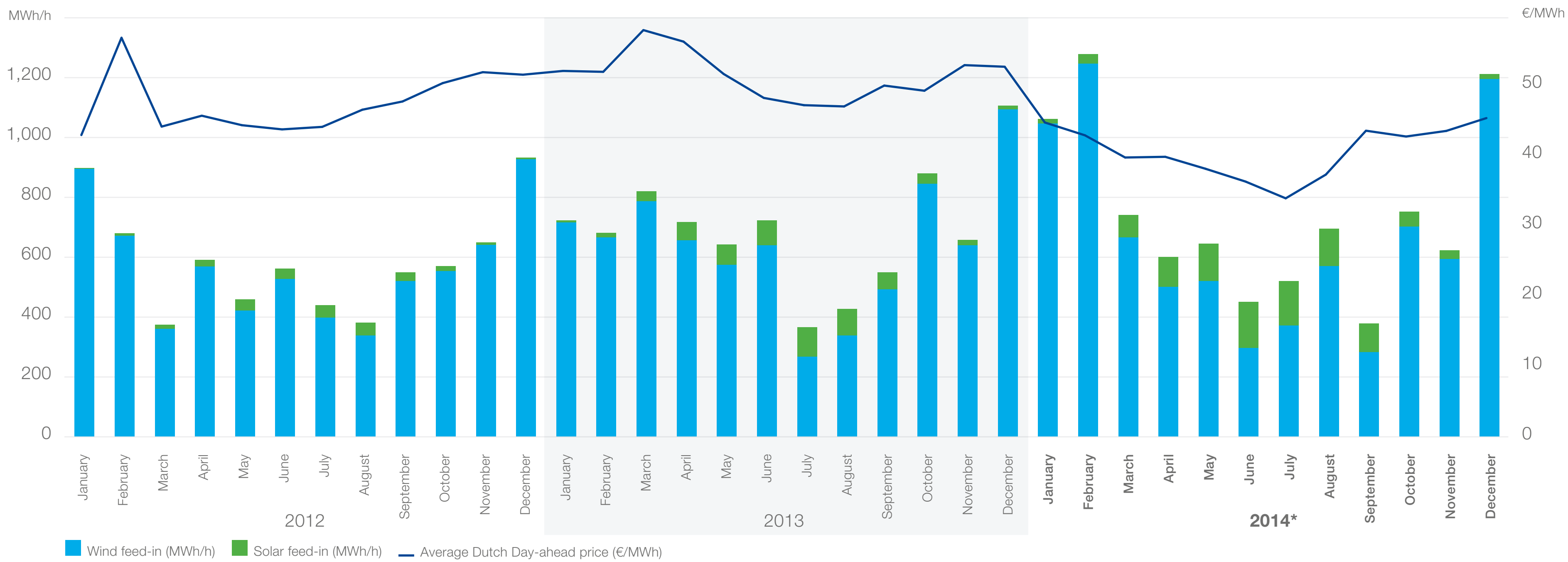

Figure 23: Dutch monthly average wind and solar feed-in and Day-ahead price. Source: CBS, EnTranCe[13]. *Preliminary values.

[13] For the estimation of monthly solar generation data from EnTranCe were used. Source: http://www.en-tran-ce.org/

Consumption and production

The main reason for the different share of renewables in the two market areas is the long-standing high investment incentive in Germany for renewables. Large shares of the renewable feed-in in Germany are subsidised for a certain time span[14] by the German Renewable Energy Act (EEG) with a fixed feed-in premium, the so called Festpreisvergütung. The subsidised energy is sold by the TSO at the Day-ahead market.

With reformation of the EEG beginning in 2012, additional feed-in premium systems for renewables have been introduced. The so called direct marketing – incentivizing a market oriented feed-in – is gaining importance especially for new wind turbines, as will be shown in chapter 7. However, the fixed feed-in premium is still of significant importance mainly for smaller units and solar.

Figure 24 shows the average Festpreisvergütung of all generation units in this premium model. Therefore, units being operated under the regime of the direct marketing model are excluded in this figure. Three main observations can be made:

- Firstly, the average Festpreisvergütung is fairly stable.
- Secondly, the 'average income', which represents the economic value of the electricity generated in the market, is significantly lower than the 'average EEG-Festpreisvergütung', which represents the costs. For all technologies, but especially for solar, the costs are a multiple of the value.
- Thirdly, the average income of the feed-in by renewables sold by the TSOs at the Day-ahead market has decreased since 2013 due to the drop in the average price level. A stable fixed premium and a decline of the market value results in an increasing gap per energy unit subsidised by the Festpreisvergütung.

[14] Mostly 20 years.

Consumption and production

Market Value compared to Fixed Feed-in Tariff of Renewable Energy in Germany

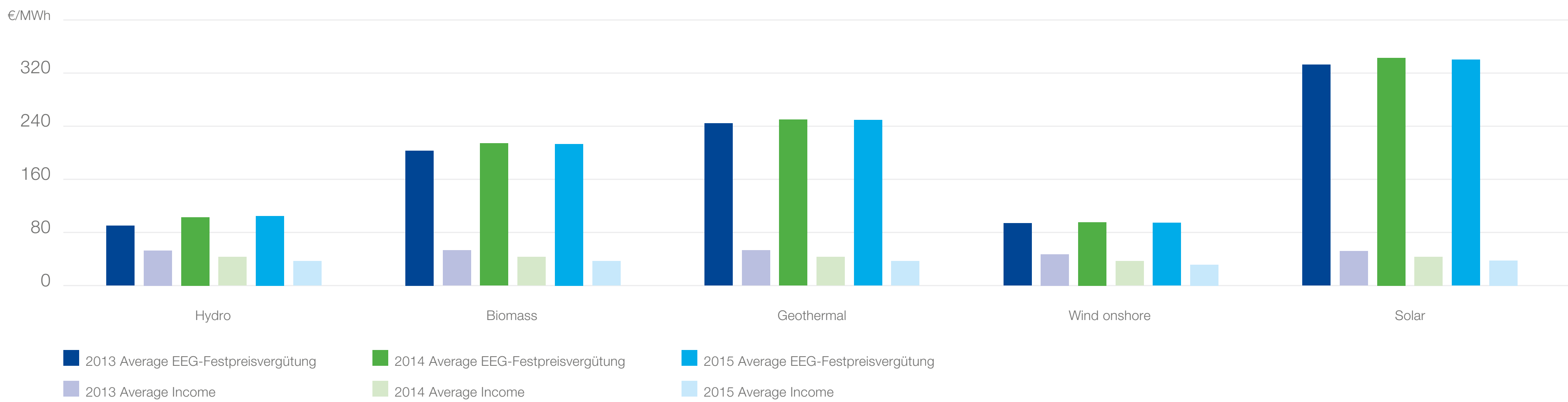

Figure 24: Average fixed feed-in tariff (EEG-Festpreisvergütung) by technology and the calculated average income of the subsidised energy sold by TSOs at the Day-ahead market. Source: netztransparenz.de

Additionally, the direct marketing of renewables is rewarded by the so-called market premium and has to be added to the overall costs for renewables. The gap between these premiums paid and income from the sold energy at the Day-ahead market by the TSO is nationalised to the community through the so-called EEG-Umlage, which is added to the end customer's electricity price. Furthermore, Figure 25 shows the development of the German EEG-Umlage for the years 2010 to 2015. For the first time since the introduction of the remuneration, the value has dropped – although it has to be mentioned that this is mainly caused by significantly reduced additional costs due to liquidation of surpluses in the settlement account.

Consumption and production

Development of Renewable Energy Surcharge in Germany

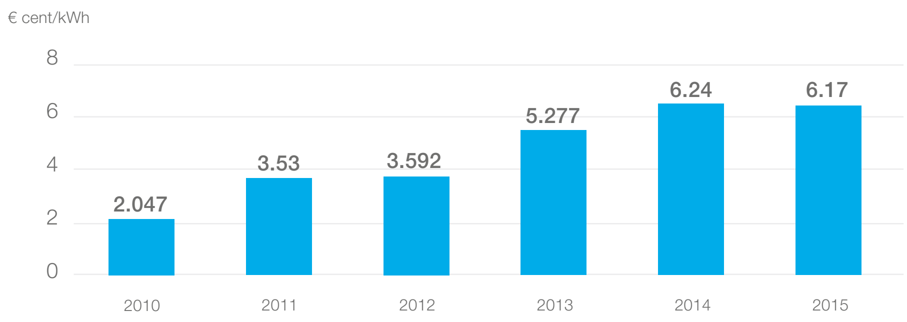

Figure 25: Development of the renewable energy surcharge (EEG-Umlage) in Germany.
Source: netztransparenz.de

As previously discussed, thermal and renewable generation offer the major share in supply of electric energy and flexibility in the Netherlands and Germany. Their availability, especially of baseload generation such as nuclear power plants, are important for both low wholesale prices and network security. Hard coal-fired generation provides more flexibility in Germany, while gas-fired generation provides less flexibility. Due to the incentives provided by the German government, the share of renewables is increasing, making it one of the drivers of the decreasing price level in the German market area. Furthermore, the high share of intermittent volatile feed-in by wind turbines and photovoltaic units can have a substantial impact on the price volatility. Developments in price volatility are described in the following chapter.

Price volatility

This chapter describes the variations of electricity prices over time in different European market areas from different angles. It can be observed that the Dutch prices are less volatile than German prices. Furthermore, price volatility has decreased in the Netherlands, whereas it has increased in Germany.

Not only the absolute level of the market prices are of interest, but also the volatility of the prices. Price volatility is, at the same time, an indicator of both the need for flexibility in a system and its ability or inability to deliver such flexibility.

As described earlier, intermittent feed-in at almost zero marginal costs have a lowering effect on the average price. However, due to the fluctuating nature of the feed-in, it can be expected that the prices will also become more volatile. So we will now analyse the volatility of the Day-ahead market prices by looking at both the Dutch and German market areas in the years 2010 and 2014.

In Figure 26 the average daily market prices for 2010 and 2014 for the Netherlands and Germany are shown relative to 100% in order to eliminate differences due to changing prices levels. Additionally, the 5% and 95% quantiles of the hourly averages are indicated by the grey and blue areas in both of the graphs.

Different aspects can be observed in the price data of both countries. At first, the change in the daily pattern of the German market area from 2010 to 2014 is obvious. The former peak at noontime is significantly flattened due to the increased feed-in of photovoltaic units. Instead, price peaks in the morning and the evening relative to the base price can be observed, showing the increasing technical challenge for the remaining generation stack to follow the residual load.

The quantiles, in which 90% of the yearly values lie, have significantly widened from 2010 to 2014, showing the increased volatility of the prices throughout almost the whole day due to the higher fluctuating energy sources. Reduced volatility is to be observed only in the morning hours around 07:00 hours. This is caused by a higher number of power plants running in partial load, providing steady prices over the year at this time of day.

A different picture is drawn in the Dutch market area. The shape of the daily averages does not show as significant shifts as the German ones, although the prices in 2014 seem to level more narrowly around the base price represented by the 100% line. This first indication for decreased volatility is verified when looking at the 5% and 95% quantiles of the hourly price curves. It is obvious that the blue area representing the values of the year 2014 is not as wide as the grey area representing the values of 2010 except for a few hours. Hence, it can be deduced that the Dutch prices are less volatile nowadays than four years previously.

Additionally, when looking at the two graphs together, the Dutch market seems to be less volatile than the German one, based on the area covered by the quantiles.

Price volatility

Volatility of Day-ahead Market Prices in Germany and the Netherlands

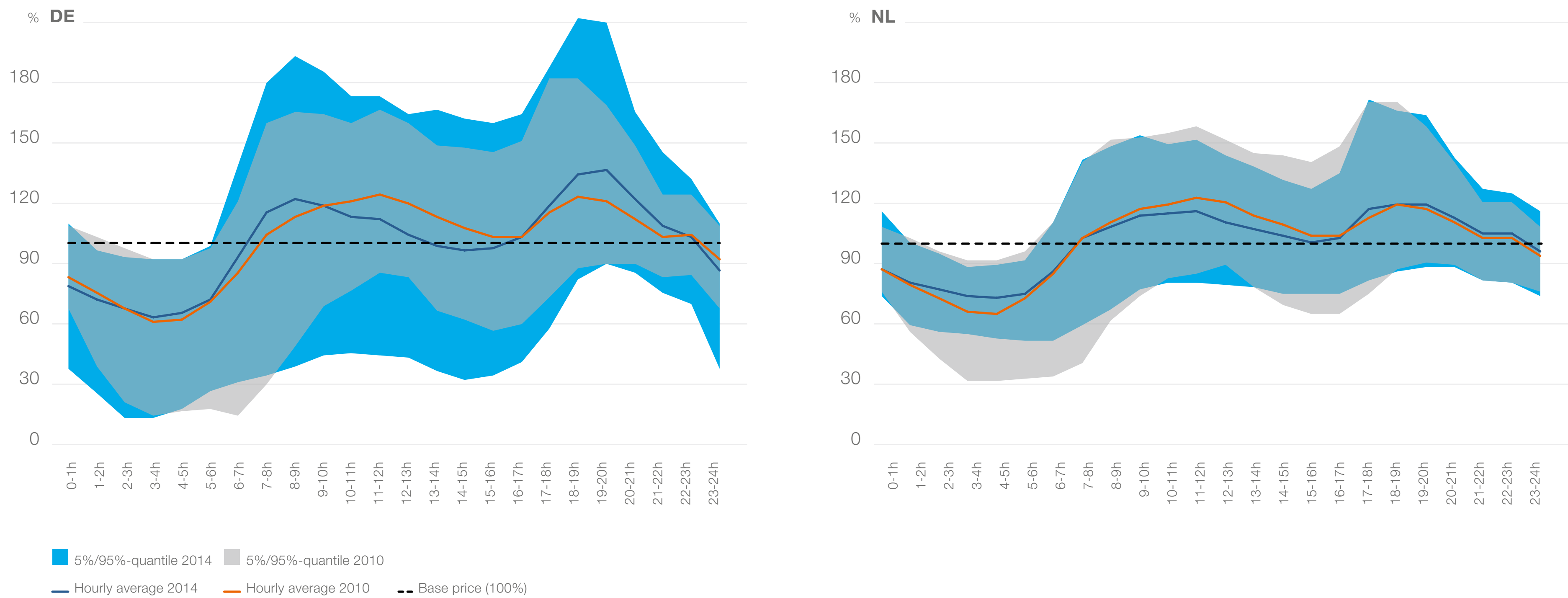

Figure 26: Yearly average of hourly Day-ahead wholesale prices for each hour of the day and their 5%/95% quantiles in Germany (left) and the Netherlands (right) in 2010 and 2014. Source: EPEX Spot

Price volatility

To prove this assumption, the average base prices of the major European market areas as well as the corresponding standard deviation is shown in Figure 27. Although the prices in the Netherlands lie significantly above the German prices, the standard deviation is lower, confirming that prices in the Dutch market area are less volatile.

This effect is the result of the significantly lower fluctuating feed-in accompanying an even more flexible conventional generation stack mainly based on natural gas-fired power plants. Also the high level of interconnection capacity relative to the market size plays an important role, with BritNed effectively capping the price and NorNed putting a floor on the Dutch prices.

Moreover, it is to be noted that less volatile prices are typically observed in the Nordic market areas such as Sweden, Denmark and Norway, caused by the price-equaling effect of – especially Norwegian – hydropower throughout the year.

European Average Wholesale Prices and Standard Deviations

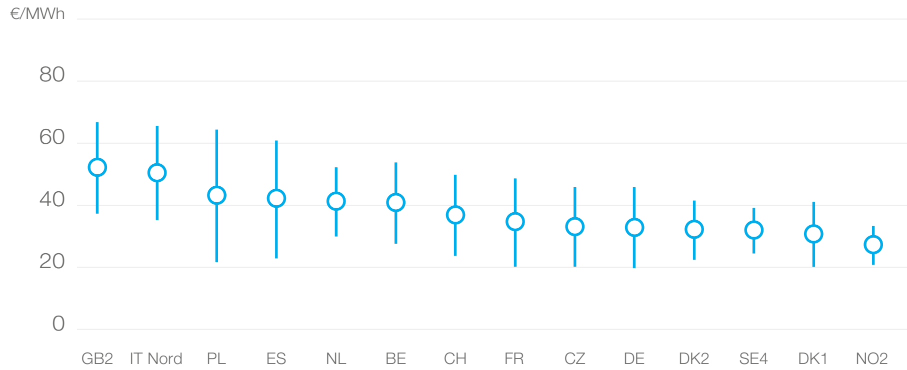

Figure 27: Yearly average of hourly Day-ahead wholesale prices and their standard deviation of major European market areas in 2014. Source: Energate, APX, EEX, Nordpool, POLPX, OTE, GME, OMIP

Price volatility

Standard deviations measure the price volatility from hour to hour. Additionally, peak and off-peak prices are considered to specify the expected highest and lowest price periods. Based on the transition towards high renewable generation shares, current market product definitions of peak and off-peak[1] can lead to misconceptions. Figure 28 visualises both the peak and off-peak prices based on the product definitions as well as the highest and lowest prices for an equivalent number of hours in the Netherlands and Germany in 2014.

Average Peak and Off-Peak Prices versus Quantiles

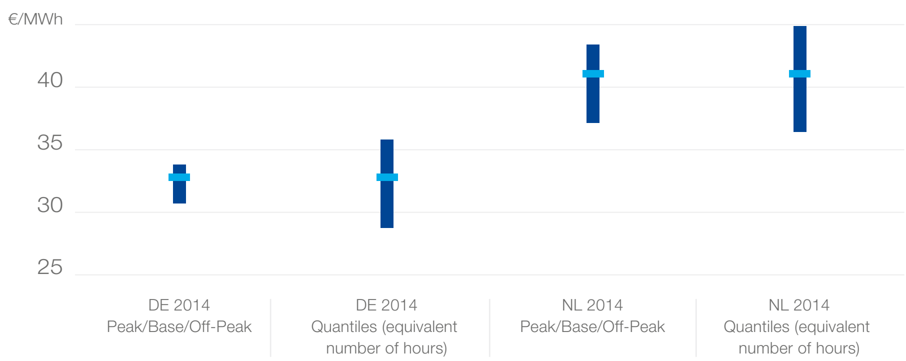

Figure 28: Average prices of peak and offpeak products as traded on the power exchanges and average prices of the hours with the highest and lowest prices (equivalent number of hours) for the Netherlands and Germany. Source: Energate

The figure shows that peak and off-peak products no longer reflect the high and low prices. Peak prices are below the highest prices and off-peak prices are above the lowest prices in the Netherlands and Germany. The renewable supply leads to higher prices, e.g. before 08:00 hours and after 20:00 hours, as well as to lower prices during day time. In Germany the two measures are deviating both by around 2 €/MWh. The effect is significantly lower when looking at the Dutch market, causing only differences up to 1.5 €/MWh at a higher base price. This development might give rise to a demand for alternative products traded at the power exchanges. Products that are more designed to reflect the expected production pattern could facilitate demand to respond based on price signals well in advance of the Day-ahead market.

Like prices, volatility should converge in an integrated pan-European electricity market. In theory, uncongested market areas with price coupling would lead to equal prices and therefore similar volatility. The following section discusses the status and developments of European market integration and cross-border exchange.

[1] Peak hours are defined by the time span from 08:00 hours to 20:00 hours from Monday to Friday (assumed to be the expensive hours) and off-peak hours by the remaining hours of the week (assumed to be less expensive hours).

Market integration and interconnection flows

The integration of European electricity markets results in the efficient use of the interconnection capacity between countries. It can be observed that a mismatch exists between commercial flows resulting from trades and physical flows resulting from electric load flow.

Figure 29 shows the yearly aggregated commercial scheduled flows (Day-ahead) for the CWE region and at the German borders in 2013 and 2014. Furthermore, the colour of each arrow shows which percentage of the total capacity that was made available was used. Net Transfer Capacity (NTC) values were used to calculate these percentages[1]. The NTC is the maximum exchange between two market areas after reduction of security margins[2].

High numbers in the shares can be observed at the Dutch-German border with a rate of nearly 100%, as well as at the French-Belgian border in 2014. Also, the NorNed cable is almost fully used in the direction from Norway to the Netherlands. No particular trend of the flows can be observed, although tendencies from Germany towards other market areas are visible. Despite the high price difference between Germany and Poland, there is limited exchange of commercial flows at the Polish-German border. This is mainly driven by the low NTC values for transits from Germany to Poland given to the market.

The stressed power supply situation in Belgium (cf. 3.iv) is also visible in this depiction. Comparing the electricity imported by Belgium between 2013 and 2014, a significant increase can be noted. The utilisation of the interconnector capacities between Belgium and France rises in 2014. Furthermore, the electricity saldo of the imports and exports between the Dutch and the Belgian market area changed direction in 2014, reflecting the lack of power generation capacities in Belgium due to the outages of nuclear power plants.

[1] i.e. if there was an aggregated flow of 1,000 GWh from market area A to market area B in 2000 hours of the year and a constant NTC at 1,000 MW, the calculated share from A to B yields 1,000 GWh / (2000 h * 1,000 MW) = 50%. The share from B to A is calculated in the same way.

[2] The Net Transfer Capacity (NTC) is defined by the Total Transfer Capacity (TTC) minus the Transmission Reliability Margin (TRM). The TTC is the maximum exchange possibility between two market areas where no uncertainties for a given system scenario are present. The TTC computation incorporates certain base flows subject to a base case. Transit and loop flows are therefore already considered. The TRM quantifies future uncertainties like unintended deviations of physical flows during operation or reserve activation.

Market integration and interconnection flows

European Commercial Cross-Border Flows

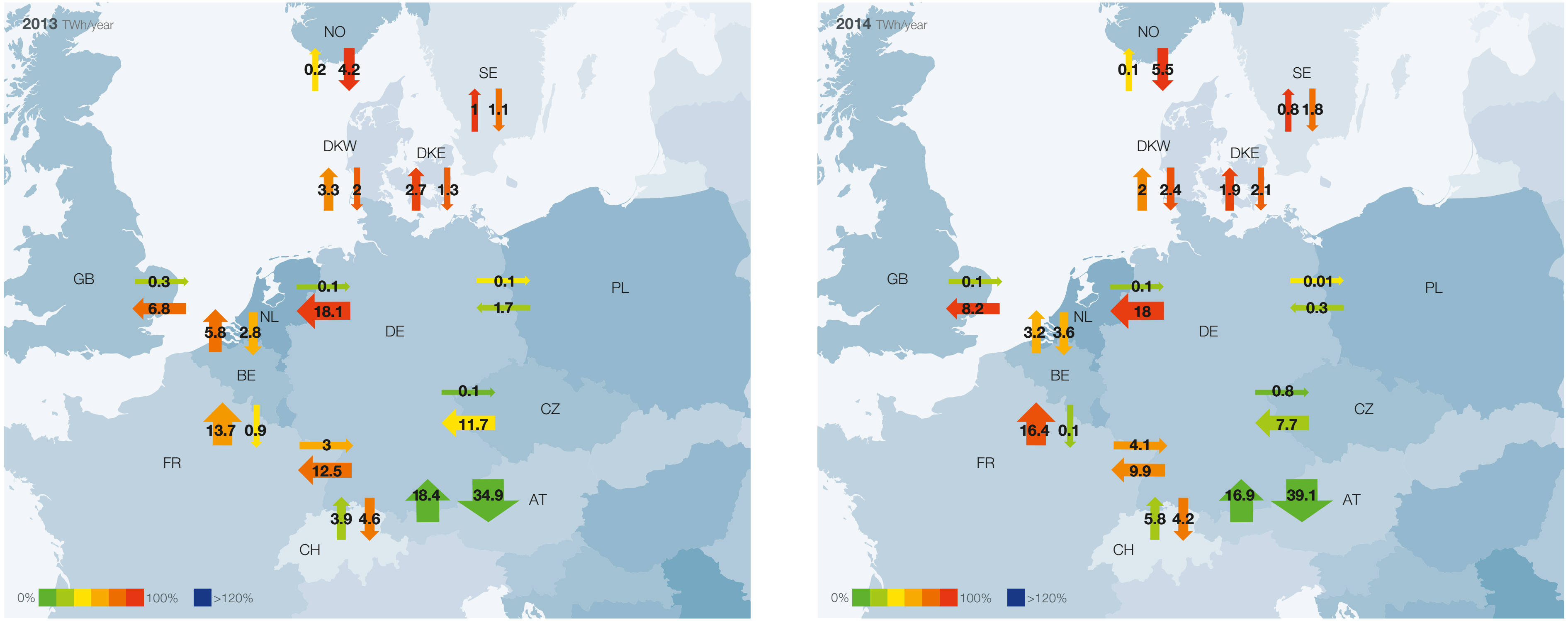

Figure 29: Annual commercial cross-border flows in CWE region and at the German borders. Source: TenneT, ENTSO-E, BritNed, Swissgrid

Market integration and interconnection flows

Now, Figure 30 shows cross-border physical flows. Arrow colours are again based on totalled NTC in hours in use. This difference between the scheduled and physical flows is due to the fact that the physical flows do not consider any economic decision but only follow the laws of physics.

As shown, the physical flows from Germany to the Netherlands, Poland and Switzerland exceed 120% of the corresponding NTCs. While predicted transit and loop flows are already considered in the corresponding TTC calculation, it seems obvious that those interconnectors are partially used to realise commercial exchanges stemming from other borders.

Physically, a larger share of the imports into Belgium come from the Netherlands, much more than what is expected on the basis of the commercial flows. Flows from Germany to Belgium physically tend to go via the Netherlands instead of via France. This partly explains why at the French-German border exchanges are opposite to the scheduled commercial flows. Furthermore, the German physical flows to Poland are far higher than the scheduled flow. Despite the high scheduled flows from the German market area to the Dutch market area, the physical flow is 35% higher. Flow Based Market Coupling, that is described in the following chapter, will bring scheduled flows and physical flows closer together.

Market integration and interconnection flows

European Physical Cross-Border Flows

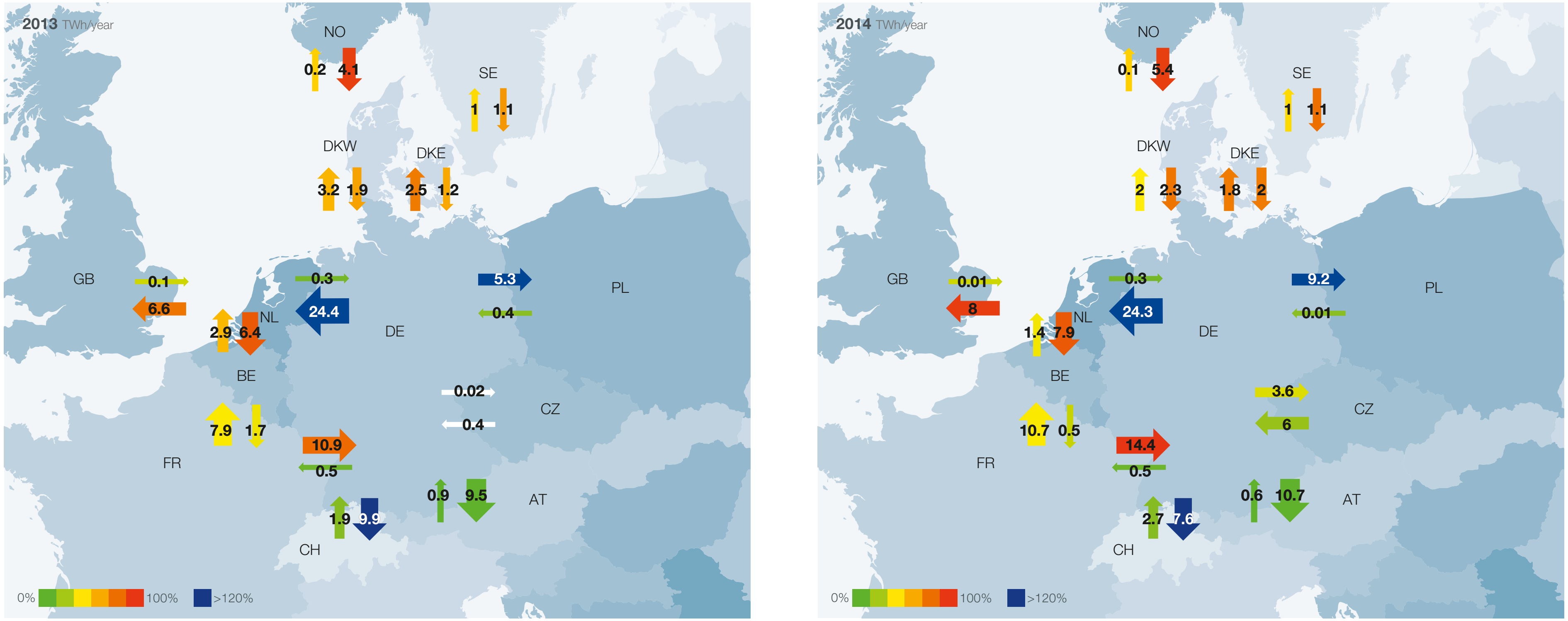

Figure 30: Annual physical cross-border flows in CWE region and at the German borders. Source: TenneT, ENTSO-E, Swissgrid

Market integration and interconnection flows

Since the German wind feed-in reached significant amounts, the NTC between Germany and the Netherlands, France and Switzerland are adjusted by the Day-ahead wind feed-in forecast with the so-called C-function, which is illustrated in Figure 31. This means less capacity is made available to the market to ensure a secure grid.

This C-function coordinates the aggregated NTC values of the borders Germany > Switzerland, Germany > Netherlands and Germany > France, depending on the forecasted wind feed-in in the German market area in order to reduce transfer flows from north to south. Figure 31 shows such an adjustment over four days.

It can be observed that the export capacities from Germany towards the other market areas are successively reduced as soon as the forecasted feed-in of wind power generation rises above 17 GW. The minimum aggregated NTC values are reached at the beginning of the second day. Even in the case of decreasing forecasts, the sum of NTCs remains on the lowest value until the forecast declines below approximately 13 GW again.

Example of the Effect of Wind Feed-in on Cross-Border Capacity

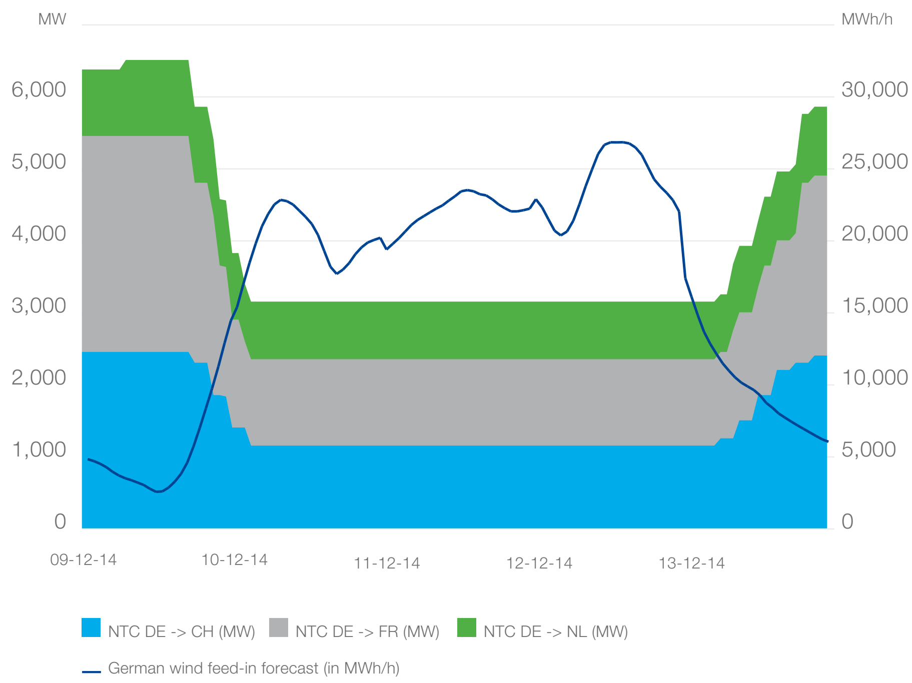

Figure 31: Hourly German wind feed-in forecast and resulting net transfer capacities on the German borders with Switzerland, France and the Netherlands for 09-12-14 - 13-12-14. Source: ENTSO-E

Market integration and interconnection flows

The described cross-border exchanges and wind-dependent transfer capacities are based on the current market coupling with fixed transfer capacities.

In this chapter we observed the high use of interconnection across Europe and the differences between commercial schedules and physical flows.
In the following chapter we will look into the possibilities of making better use of the existing transmission capacity in the CWE countries.

Flow Based

The planned introduction of Flow Based Market Coupling would further improve the efficient use to cross-border capacity. This would further enhance capabilities of cross-border capacities to provide flexibility. In 2014 price convergence between Germany and the Netherlands would have been higher using Flow Based Market Coupling. In this chapter we explain the concept of Flow Based Market Coupling and analyse its impact on prices and flows.

After the launch of the Market Coupling based on the Available Transmission Capacities (ATC) at the end of 2010, the parties in the CWE region focused on the implementation of a Flow Based (FB) capacity calculation and update the Market Coupling to allocate the capacity. An important pillar is the parallel run of the FB methodology in order to gain experience and fine-tune this approach. The results of this parallel run are public to allow market parties to be well prepared.

Due to the exceptional situation on the Belgian market in the winter (cf. section 3.iv) the original date to go live with Flow Based Market Coupling at the end of November 2014 was postponed to 2015. Before investigating sample results of the parallel run, the concept of Flow Based Market Coupling will be introduced briefly.

With the help of a simplified example of three market areas in which market area A is connected to B and C, the main difference between the ATC and FB approach is illustrated in Figure 32. The x-axis represents the commercial exchange from market area A to C, and the y-axis represents the commercial exchange from A to B. The market clearing has to consider limits in the power exchange between different market areas. There are several physical constraints for the flows between the market areas due to critical network elements. This can be e.g. caused by a limited thermal load capacity. In the case of the ATC methodology, the TSOs have to split their capacities across their borders. This is executed on a local basis. In the shown example, one possible choice is represented by the blue rectangle. In comparison to the grey area, representing the FB security of supply domain, the ATC rectangle is more restrictive. The increasing scope of possible solutions is enabled through a common optimisation, which includes the order books and the physical constraints of the interconnectors, in which the influences from all resulting exchanges of all participating market areas are explicitly taken into account. The objective function of this maximisation problem is the overall social welfare. In theory, the higher integrated FB approach enables an overall equal or higher social welfare compared to ATC. Through this dynamic approach, cross-border capacities can be shifted to the border where they have the most impact on the social welfare, thereby providing flexibility where mostly needed[1].

The difference between the Flow Based and the ATC Concept

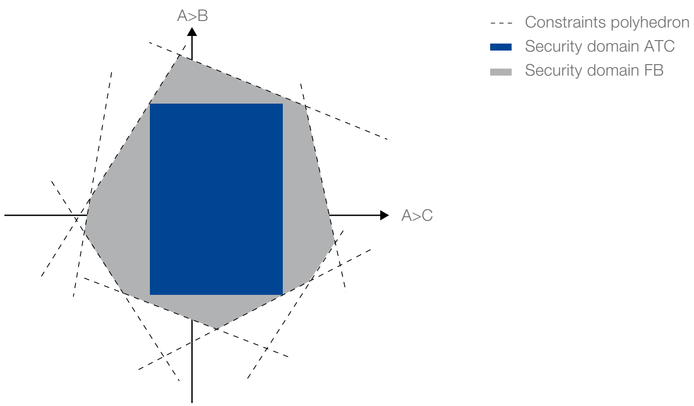

Figure 32: Illustration of the difference between the Flow Based and the ATC concept.

[1] Source: CWE Enhanced Flow Based MC feasibility report.

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Flow Based

Within the CWE FB project, two alternative market coupling modes were considered. The FB 'plain' and the FB 'intuitive' (FBI). The FBI adds additional constraints to the optimisation, when needed, to forbid exchanges from a high price market area to a low priced one, even if this would gain additional welfare[2]. After consultation with the market parties and regulators, it has been decided to use the FBI method to go live with. After a certain period after go-live there will be an evaluation of this decision.

This brief theoretical explanation of FB is now illustrated with the help of a sample short time span showing results of the FBI parallel run. This will be followed by more insights into the FBI parallel run for the German and Dutch market areas. It should be noted that the figures from this parallel run are a best estimate of the FB project of what the market results would look like in case the FB methodology would already have been applied. The results of the FB methodology once it actually is in operation might differ from these parallel run results.

In Figure 33 the hourly price difference between the FBI and the ATC methodology is plotted for the CWE countries for a week in 2014. Therefore, a positive value describes a higher price in the case of the FBI approach. In France and Belgium, no general tendency of the price difference between the approaches can be extracted in this situation. There are hours in which the higher price occurs in the FBI approach and there are others in which this approach determines a lower price. A more general but contrary tendency is observable for the German and Dutch market areas. In the Dutch market area the determined prices in the case of a FBI approach are lower in most hours than in the ATC case. In Germany, the opposite is observable so that in a higher share of the hours a higher price is determined by the FBI approach.

Example of Impact of Flow Based on Wholesale Prices

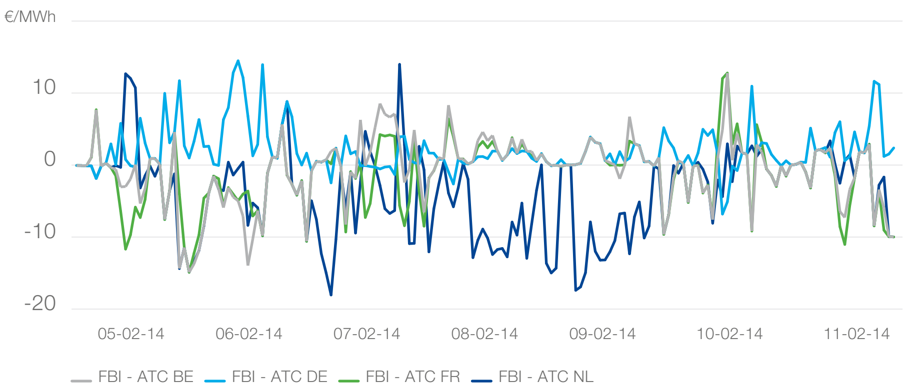

Figure 33: Hourly difference between the FBI prices (based on parallel run) and the actual prices (based on current ATC approach) in CWE countries for 05-02-14 - 11-02-14. Source: TenneT

The change in the market clearing prices in the case of the FBI approach is due to the more efficient use of the cross-border capacities. This can be illustrated with the help of Figure 34, in which the change of the net positions of the CWE market areas is depicted, where the net positions represent the balance of the imports and exports of a market area. A positive value reflects a higher export in the case of the FBI approach than in case of the ATC approach. It is observable that German exports increase in the case of the FBI approach in almost every hour of the exemplary time period. In contrast, the Dutch market area is able to import more, which results in the previously described rising prices in Germany and decreasing prices in the Netherlands.

[2] Source: Annex 16.13 Intuitiveness Analysis for the FB/FB(I).

Flow Based

Example of Impact of Flow Based on Cross-Border Trade

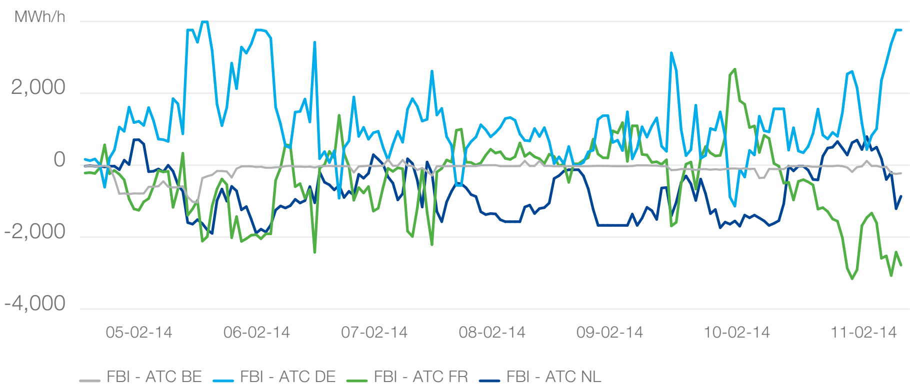

Figure 34: Hourly difference between FBI net positions (based on parallel run) and the actual net positions (based on current ATC approach) in CWE countries for 05-02-14 - 11-02-14.
Source: TenneT

The difference in the resulting prices and the net positions of the different approaches affects the overall social welfare of the participating market areas consisting of the consumer and producer surplus as well as the congestion rent collected by the TSOs.

Extrapolating the insights of the prices and net positions in the sample situation to the social welfare, in most of the cases the producer surplus in Germany is expected to rise and the consumer surplus to fall. Again, the opposite is true for the Dutch market area. Figure 35, showing the change of the social welfare in the considered time span, confirms this expectation. Moreover, the small changes in the consumer and producer surplus in the French and Belgian market areas can be explained by the appearance of higher and lower prices in the case of the FBI compared to the ATC approach, which are netted in this representation. Including all participating market areas in the social welfare calculation, there is an increase of social welfare, although changes in consumer and producer surplus in each direction can occur in the different market areas. The highest additional consumer surplus is gained in the Dutch market area in contrast to the highest additional producer surplus in Germany. The results of the parallel FBI run indicate that the total social welfare in the CWE countries increases by €1.6 million in these seven days.

Example of Impact of Flow Based on Social Welfare

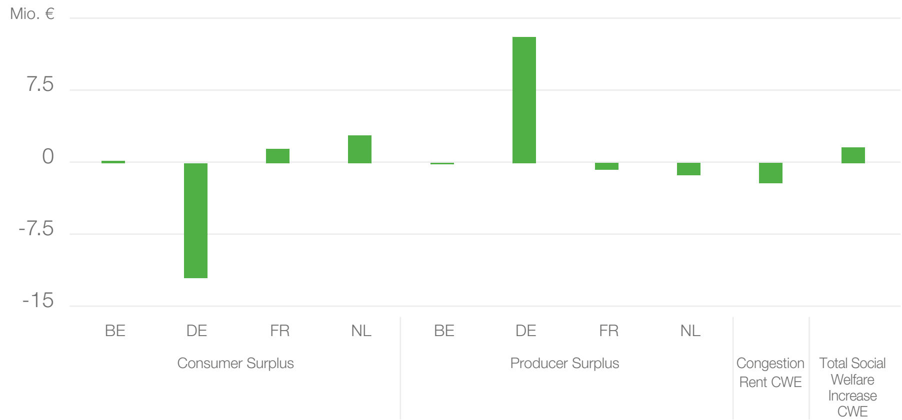

Figure 35: Breakdown of difference in CWE social welfare resulting from FBI (based on parallel run) and the actual CWE social welfare (based on current ATC approach) for 05-02-14 - 11-02-14.
Source: TenneT

The change in the determined prices in the case of the FB approach can lead to higher price convergence between market areas. Therefore, the prices determined by the two methodologies are investigated in more detail for the whole FBI parallel run in 2014, focusing on the Dutch and German market areas.

Flow Based

Figure 36 depicts the hourly difference between the Dutch and the German Day-ahead market price in the case of the ATC methodology and the outcome of the FBI parallel run. The ATC approach leads to a price convergence in 29% of the hours of these two market areas, whereas FBI reaches 44%. Furthermore, it can be pointed out that in most of the times the FBI methodology leads to a decreasing price gap between the two market areas.

Impact of Flow Based on Hourly Price Difference between the Netherlands and Germany

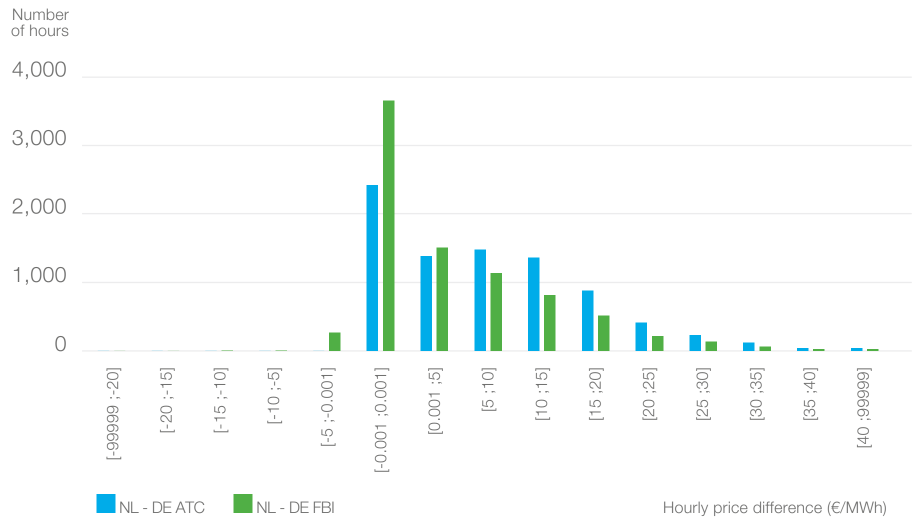

Figure 36: Hourly price difference between the Netherlands and Germany divided over clusters of price difference for FBI parallel run and ATC for 2014. Source: TenneT

Flow Based

Figure 37 shows the impact of FBI on the level of price convergence between the Netherlands and Germany per month[3]. With the exception of July 2014, the level of full price convergence would have been higher in every month. In some months the increase would have been even more than 20%.

Impact of Flow Based on Price Convergence between the Netherlands and Germany

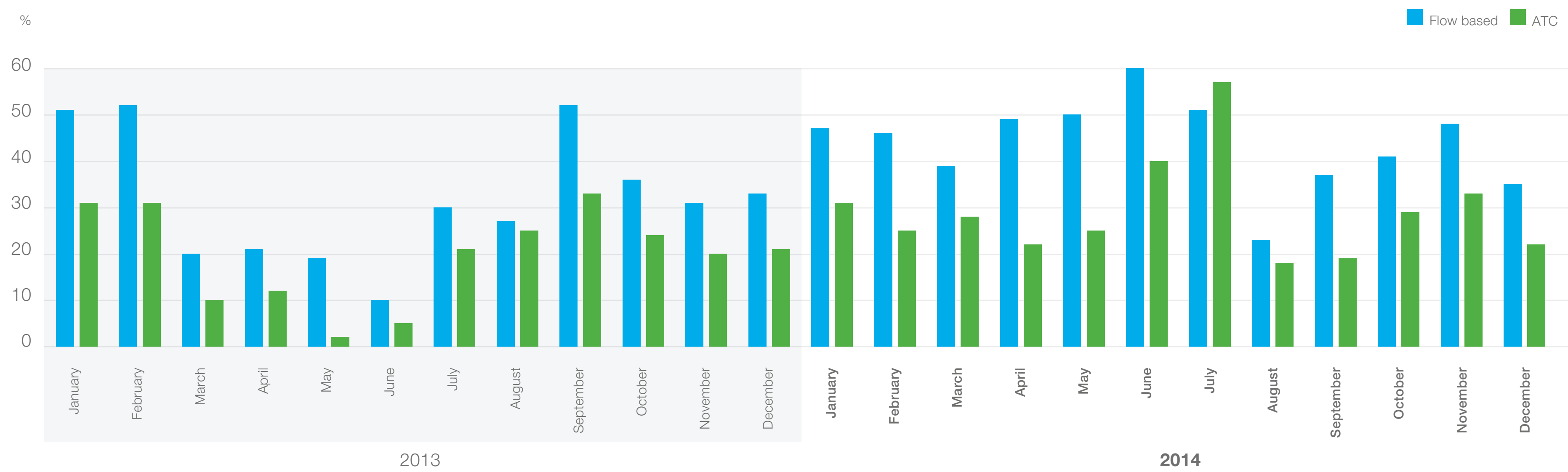

Figure 37: Share of hours with full price converge between the Netherlands and Germany for ATC and FBI parallel run. Source: TenneT

The results of the parallel run of the FBI methodology show an overall increase of social welfare. This is the result of a more sophisticated capacity calculation and allocation, allowing further optimisation of the European unit dispatch and European market integration.

The change in the consumer and producer surplus can be different in each participating country and shifts of social welfare per country is to be expected. Furthermore, the changes in capacity allocation impact the prices of the participating market areas and the level of price convergence.

[3] In this figure price convergence levels under ATC approach may differ from actual price convergence levels, as only days for which the FB parallel run process was representative are

Balancing

With the upcoming European legislation regarding electricity balancing, balancing market design is receiving a great deal of scrutiny, especially in Germany, where this should be seen in the context of the *Energiewende*.

Coordinated balancing and harmonisation

In 2014 significant steps were made to complete the Network Code on Electricity Balancing, which is an important piece of upcoming legislation. A recommendation of the European Agency for the Corporation of energy Regulators (ACER) on the ENTSO-E[1] draft of this Network Code is expected in May 2015, after which it will enter the comitology process in which the European Commission will decide on the final draft, after considering inputs from Member States. In addition to a focus on important settlement principles, one of the main features of this Network Code is the establishment of Coordinated Balancing Areas (CoBAs), in which market participants can sell balancing energy to TSOs across the border. This will be done in a TSO-TSO model, in which balancing energy bids are placed on common merit order lists so market participants will still only communicate with their local TSO.

A prerequisite for the establishment of such CoBAs is a sufficient amount of harmonisation of the balancing market designs of the TSOs involved. In order to manage this, the draft Network Code advocates the use of marginal pricing and short gate closure times for balancing energy.

Marginal imbalance pricing

On 31 October 2014, BMWi published the Green Paper, *Ein Strommarkt für die Energiewende*. One of the topics it elaborates on is the introduction of marginal pricing for imbalance. Utilising a marginal pricing system for imbalance could complement a marginal pricing system for balancing energy. It could help to prevent arbitrage between balancing energy and imbalance prices and to help maintain financial neutrality for the TSO.

Figure 38 shows the deviation of imbalance prices in 2014 from Day-ahead prices as a function of the activated amount of balancing energy for both Germany and the Netherlands. A defining aspect of the current average pricing model is the local price peak around zero imbalance that we see in the German graph, which is a striking difference with the imbalance price delta of approximately zero for small imbalance volumes in the Dutch system and may provide questionable incentives to market participants with regard to their imbalances.

The German price peak can be explained by a larger probability of counter activations around zero imbalance on the one hand, in which the TSO activates both upwards and downwards reserves, and the small amount of imbalance volumes on the other, causing relatively high costs to be divided by relatively small imbalances to reach a high average price. A marginal pricing system is an effective way to improve the incentives around zero.

[1] ENTSO-E stands for European Network of Transmission System Operators for Electricity.

Balancing

Net Imbalance and Balance Incentives for Germany and the Netherlands

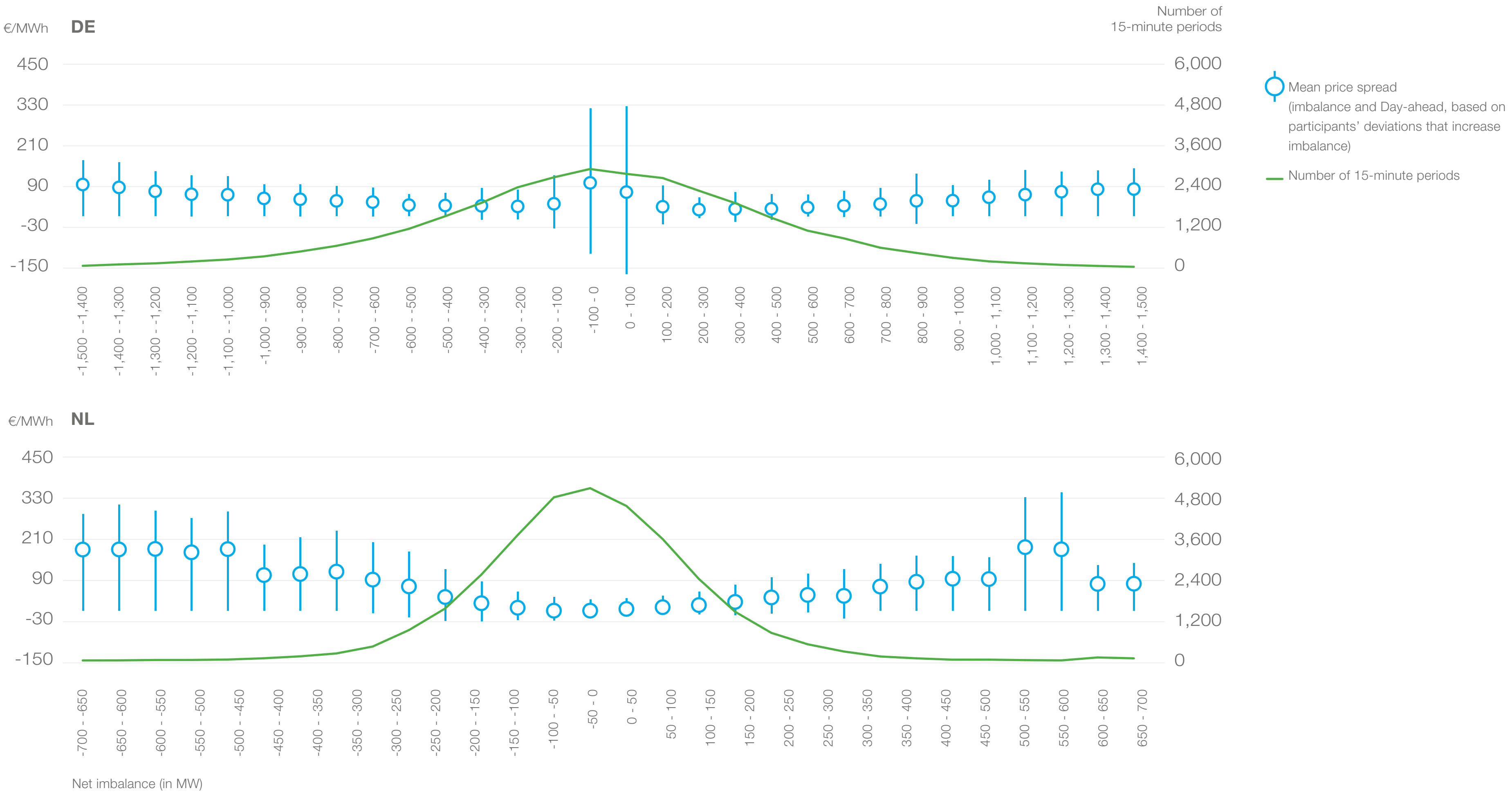

Figure 38: Net imbalance cluster (in MW) and difference between the imbalance price and the Day-ahead price in the Netherlands and Germany. Source: regelleistung.net, Energate, TenneT

Balancing

Energiewende and direct marketing

As mentioned above, the *Energiewende* is one of the drivers behind a possible balancing market review in Germany. Some changes have already been introduced on the same grounds. One important alteration came in 2012 with the introduction of direct marketing for renewables. Until then, renewable generation was exempted from carrying balance responsibility for their imbalances, and were fully sheltered from risks on the energy markets.

After three years of direct marketing, we can say that it has proven to be a great success, especially for wind production. Figure 39 shows the development of the installed capacities participating in the direct marketing over the past years.

Development of Direct Marketing of Wind and Solar Generation

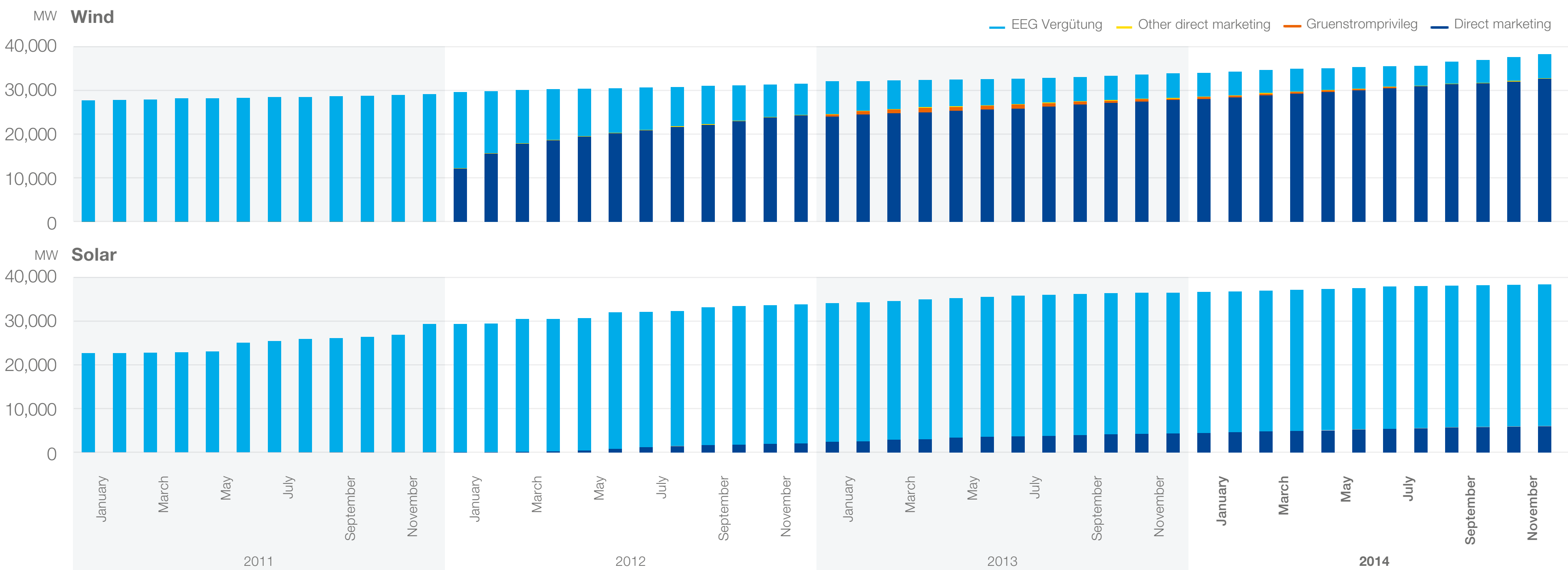

Figure 39: Monthly direct marketing share of wind and solar generation in Germany[2]. Source: Anlagenregister Bundestnetzagentur, EEX, Netztransparenz.de

[2] Other direct marketing is in comparison with EEG Vergütung and Direct marketing negligible and therefore hardly visible in this graph.

Balancing

Up until recently, direct marketing was only one of the options for German producers of renewable electricity. With the EEG 2014, however, which came into effect on 1 August 2014, direct marketing has become mandatory for new renewable energy plants with a capacity of over 0.5 MW. Mandatory direct marketing is also foreseen for plants with capacities of over 0.25 MW (from 2016), and of over 0.1 MW (from 2017). These changes slowly place balance responsibility back in the hands of the market.

When producers of renewable energy are exposed to imbalance risks, like any other market participant, as is the case in the Netherlands and increasingly also in Germany, it becomes more important for them to improve the quality of their forecasts and mitigate the consequences of intermittency. This could prove beneficial for the energy balance in the system.

Main findings

In 2014 we observed falling wholesale prices in the first half of the year followed by a price increase in the second half in the CWE countries. Since the prices in the Netherlands have decreased more than those in Germany, the price differences between the countries decreased. Wholesale prices have decreased in almost all European countries in comparison to 2013. However, large price differences across Europe remain despite market integration.

Price convergence between the Netherlands and Germany increased from 19% in 2013 to 29% in 2014. The level was especially high in summer as a result of a decrease in the natural gas price in the first half of the year. Price convergence between the Netherlands and Belgium increased sharply following the outages of nuclear power plants in Belgium.

The consumption of electricity in the CWE region has decreased in the last few years, despite economic growth in Germany – a development that adds further pressure on the electricity prices.

The price decrease in the Netherlands is explained by the lower average level of the gas price, as gas power plants are price-setting in most cases. Whereas Dutch hard coal power plants still show a low but positive contribution margin, the margins for coal production level around zero for German producers. Regarding gas generation, margins are lower compared to coal with negative margins in Germany. This constant decrease of margins for gas generation has resulted in the mothballing of gas-fired power plants in the Netherlands and Germany. This development has eroded the role of natural gas for commercial power generation in Germany. Coal power plants are more often used to provide flexibility in the ramping hours.

Renewable electricity production has increased in Germany in the last year, which is a further explanation for the decrease in wholesale price. Wind energy production in the Netherlands has shown a slight increase in 2014. The relative increase of solar energy was high but its absolute contribution remains low.

Price volatility has decreased in the Netherlands, whereas it increased in Germany in the period 2010-2014. Dutch prices appear to be less volatile than German prices, which can be explained by the lower fluctuating feed-in and a more flexible conventional generation stack in the Netherlands. Also the high level of interconnection capacity in relation to the Dutch market size contributes to a stable price level.

When comparing both commercial and physical flows in Europe, we observe a mismatch between commercial flows resulting from trades and physical flows resulting from electric load flow. As a result, the cross-border capacity that can be made available to the market has to be reduced in particular hours, for example in periods with high wind power generation in Germany, to ensure secure grid operation.

The amount of cross-border capacity that can be made available can be increased by targeted grid expansion but also by the implementation of Flow Based Market Coupling. This Flow Based Market Coupling is expected to be implemented in 2015. Based on the parallel run results from 2014, we can expect an increase in price convergence between the Netherlands and Germany and a positive effect on social welfare for the whole CWE region.

Colophon

This Market Review is a publication of TenneT

Contact
Address for visitors
TenneT Holding B.V. and TenneT TSO B.V.
Utrechtseweg 310, Arnhem, the Netherlands
T: 0031 (0)26 - 373 11 11

Postal address
P.O. Box 718
6800 AS Arnhem, the Netherlands

Corporate Communications Department
T: 0031 (0)26 - 373 26 00
E: communication@tennet.eu
W: www.tennet.eu

Project management
Erik van der Hoofd (TenneT)

Scientific Supervision
Prof. Albert Moser (IAEW)

Project team

TenneT
René Müller
Tobias Frohmajer
Esther Bos
Anne Martin van de Wal
Maaike Post

IAEW
Andreas Schäfer
Mihail Ketov
Denis vom Stein

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