Agora Energiewende

A WORD ON

FLEXIBILITY

The German Energiewende in practice: how the electricity market manages flexibility challenges when the shares of wind and PV are high

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IMPRINT

A word on flexibility

The German Energiewende in practice: how the electricity market manages flexibility challenges when the shares of wind and PV are high

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WHAT YOU WILL LEARN

Why solar and wind power cannot provide steady power production

more on page 09

Bad weather is not necessarily bad news but just normal when it comes to wind and sun. There are days without much sunshine (let alone the nights) and there are hours with barely any or no wind. There are also days with plenty of wind and sunshine. The good news is: thanks to modern meteorology and weather forecasting, we quite exactly know where and how much the wind is blowing and the sun is shining, and can adapt the power supply system to the forecast electricity production from wind and PV to balance demand and supply for power at every time.

Why this is not a problem (because there are a lot of flexible gap fillers available)

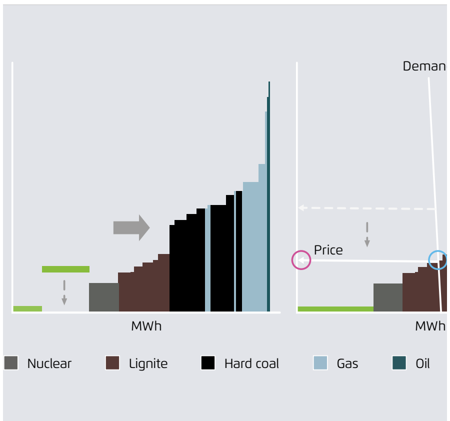
more on page 25

You have probably heard that fossil power plants are bad for the climate. To be more precise, it is burning coal, gas and oil which is bad for the climate. So the real task is to burn less coal, oil and gas and to do that only when there are no other options available – thus, when there is not enough wind and sun. This means, for example, that old coal power plants have to operate more flexibly – not in a simple "on/off" mode, and not in a "24/7" mode. Not at all impossible. The power plant in the picture in the German town of Ibbenbueren was commissioned in 1985 as an "on/off" mode power plant (providing full output through roughly half of the day). In recent years, its operator RWE has implemented new technology. Now it is able to reduce its power production by 70% within minutes and to ramp up again in a short time.

How an open power market is organizing the gap filling efficiently

more on page 15

Power markets are there to ensure that the demand for electricity is covered by the cheapest power plants available. Of course, that relies on a satisfying level of competition among generators and suppliers. Electricity market platforms collect the bids of producers, sort them from cheapest to most expensive and intersect them with bids to buy electricity. This principle minimises the cost required to meet demand. Wind and solar power can also be sold on these platforms. Since they have generation costs of close to zero (wind blows and sun shines for free, and they do not emit CO_2), they come first for serving electricity demand. After the markets close, real-time differences between supply and demand (due to sudden power plant outages, for example) are settled by the system operators who deploy balancing reserves (usually contracted in advance) that offset the differences.



Why this is not only theory but proven daily practise

more on page 12

In some parts of Germany, the average share of renewables within the grid is already over 50%, sometimes even more than 100%. Grid operators have learned to manage the fluctuating power supply very well. In the picture, you can see the control room of 50Hertz, the transmission grid operator for the eastern part of Germany.

That even some extraordinary situations have been managed properly

more on page 17

When a solar eclipse occurred over Germany in 2015, solar power production dropped and increased very rapidly – faster than ever before in history. Due to very precise predictions, there was no harm done to the power supply system at any time nor was it necessary to use the safety nets that had been built to prepare for the worst. From the perspective of electricity users, it was just a normal day. From the perspective of electricity producers, it was a glimpse of the future – with higher shares of renewables, we will see comparable variations in electricity supply more often. And now we know how to deal with them.


fotolia.de/lg0rZh

Why there are better means to provide flexibility than energy storage

more on page 17

No question: it is a very nice idea to store power when it is available in high volumes and to use it again when supply is limited. Electrical storage can provide this service. But when is the right time to start deploying storage? In the beginning of every massive roll-out of renewables, there will be excess electricity only on a few days per year – if at all (in Germany, there has not been a single day with excess power from renewables). Compared to the cost of the storage facility, those single-day storage events will, for interconnected power systems, be very expensive. Much more expensive than just dumping the excess energy or using it for less costly purposes – like exporting it to your neighbouring countries (power lines are cheaper than storage) or allowing your industry to take a little bit of extra power on some days.

CONTENT

Introduction

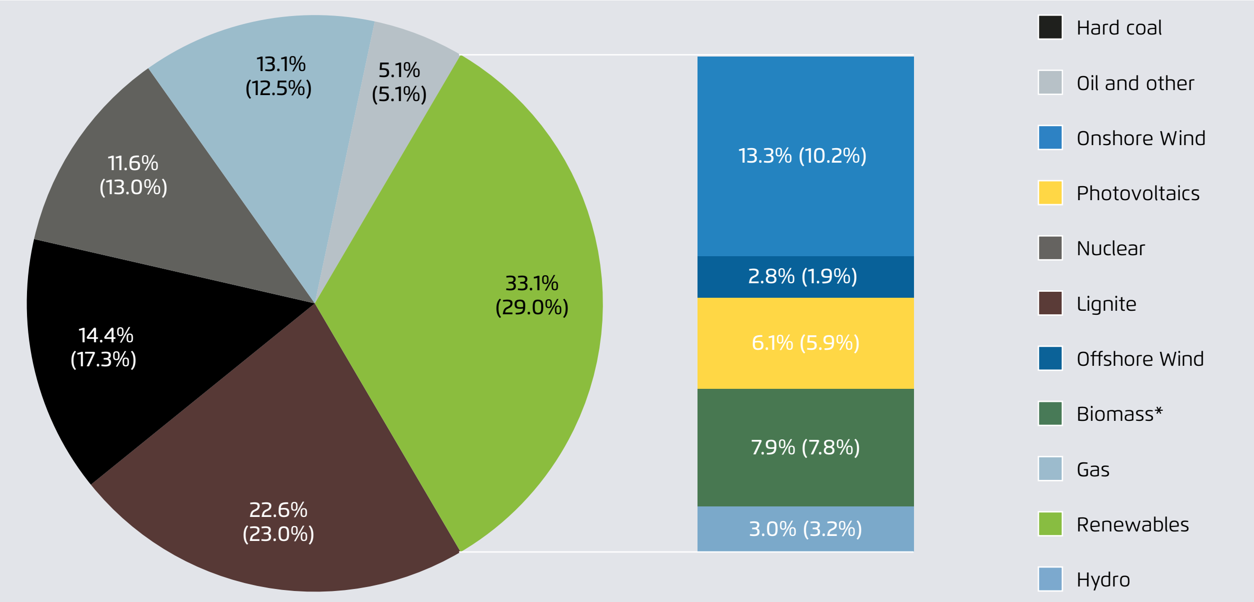
In 2017, renewable energy made up 33.1% of the German power mix. Of that, almost 67% was generated by wind power and solar photovoltaics (PV). Because wind power and PV are intermittent energy sources, their dominance has introduced a new paradigm for power systems: Flexibility.

The need for power systems to respond more flexibly as the share of wind and PV increases is illustrated in Figure 2. Flexibility is already an issue in Germany's electrical system today. Dispatchable conventional power plants have to ramp up and down more frequently and more quickly, often operating at partial loads, and have to be turned on and off with greater regularity. As the figure shows, the need for flexibility is more pronounced in times of high wind and PV feed-in: with renewables constituting 33.1% of power generation in 2017, the share of RES-E has been as high as 88% and the share of wind and PV alone can be as high as 75%. A key question therefore is: Can the German power system remain reliable while keeping its costs reasonable when need for flexibility is high? We provide some answers to this question below.

To manage the so-called flexibility challenge, wholesale power markets allow market participants to sell and buy electricity as prices rise and fall, ensuring an equilibrium between supply and demand. This paper explains how the German power system manages flexibility requirements with wholesale markets. The next chapter explains the basic functioning and structure of these markets. It is followed by selected case studies of days when shares of variable renewables (vRES) fluctuate greatly. The paper concludes with more general observations regarding the successful management of flexibility requirements using power markets.

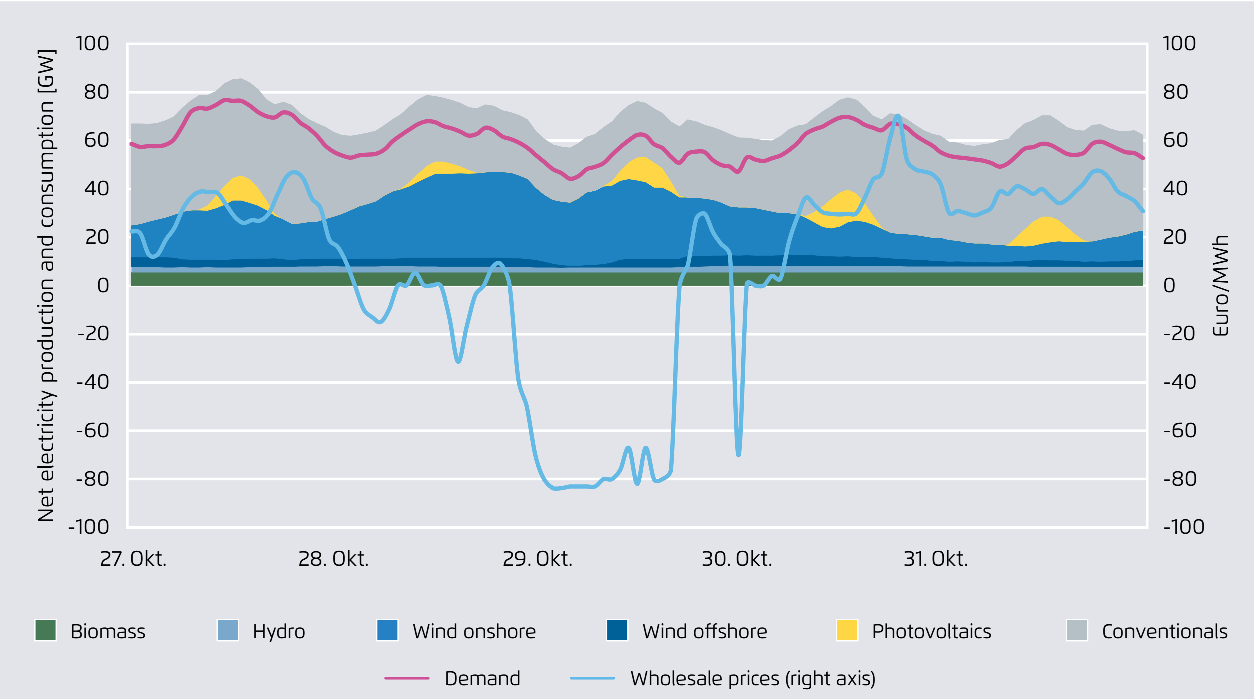
Wind turbines do deliver more and more power at cost lower than from conventional plants. Modern meteorolgy allows to predict power productions from wind parks very preceisly. That allows the power system to adapt on the variable power output.

The German power generation mix in 2017. Figure 1



*includes biodegradable household waste
AG Energiebilanzen 2017a

Power generation and consumption in Germany, 27 to 31 October 2017. Figure 2



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Power market basics

The organisation of the German power market is largely based on policy set by the European Union and its member states to create an internal market for electricity in Europe. Specific market design proposals have emerged from an electricity target model that is based on competition among market participants and cross-border electricity trading.[1] Typically, market price zones – areas where the wholesale price is the same throughout – are national in size (see Figure 3). Geography and prize-zone configuration in central, western and northern Europe. Source: OFGEM (2014)).[2] Trade across price zones takes place through what is known as market coupling, a

1 For more details regarding the European power market framework, see http://ec.europa.eu/energy/en/topics/markets-and-consumers.

2 Exceptions to the "one price zone per country" layout are Italy and the Nordic countries Norway, Sweden and Denmark, each of which have several price zones within its national borders. Austria, Germany and Luxembourg form a single price zone.

Geography and prize-zone configuration in central, western and northern Europe. Figure 3

OFGEM (2014)

cross-border market-clearing algorithm that optimises imports and exports.

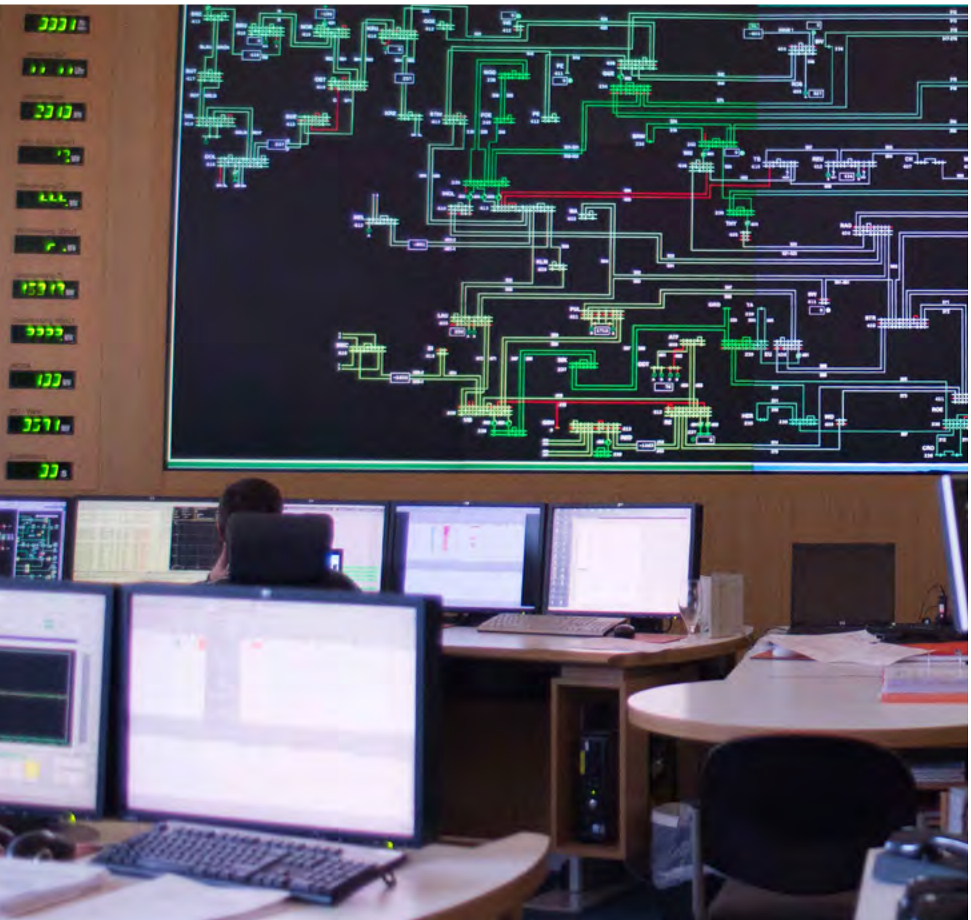
The zonal market configuration assumes a "copper plate", meaning that electricity can flow freely within each zone. But intra-zonal grid congestion often occurs and electricity cannot flow freely within a zone. When this happens, transmission system operators (TSOs) have to perform redispatch actions to bring the "zonal market" in line with physical realities of the power system (such as transmission capacity; see Box 1).[3]

Market actors trade expected supply and demand either on power exchanges or bilaterally. Figure 4 shows the sequence of market-based transactions on the German power market. Trading on the long-term forward and futures markets starts some years before actual delivery, the main purpose being to manage the risk of (uncertain future) wholesale prices. Roughly half of the actual power consumption is traded on the day-ahead market. Here, an auction takes place every day at 12AM, where electricity is traded for each hour of the following day. Each hour is characterised by a specific wholesale price that is typically lower in times of low demand and/or high renewables generation (see next section). After the day-ahead market, trading continues on the intraday market, where hourly and 15-minute products are traded until 30 minutes before delivery.

The intraday market is particularly important for integrating wind and solar, as it allows for trades responding to updated generation forecasts.[4] Depending on updated wind forecasts, intraday prices are generally higher or lower than day-ahead prices.

3 In 2015, German TSOs gave redispatch instructions to conventional power plants amounting to 17 TWh (Source: Bundesnetzagentur (2016): 3. Quartalsbericht 2015 zu Netz- und Systemsicherheitsmaßnahmen. Viertes Quartal 2015 sowie Gesamtjahresbetrachtung 2015). In comparison, German power demand in 2015 amounted to 597 TWh.

4 Some 6% of German gross electricity demand was traded on the intraday market in 2015. Source: EPEX Spot (2016)



From this control room, the power supply in East Germany is managed. On average, more than 50 percent of electricity from renewable energies flows through the grids. On some days it is almost 100 percent. The employees take care that there is a reliable supply.

Box 1: Power market dispatch, congestion management, redispatch and curtailment

In the European Union, electricity is mainly traded through decentralised power markets or trough bilateral transactions. Trade takes place for delivery on an hourly or sub-hourly basis. The market outcome of all buy and sell bids determines the allocation of resources in the system, i.e. the dispatch of supply and demand-side technologies.

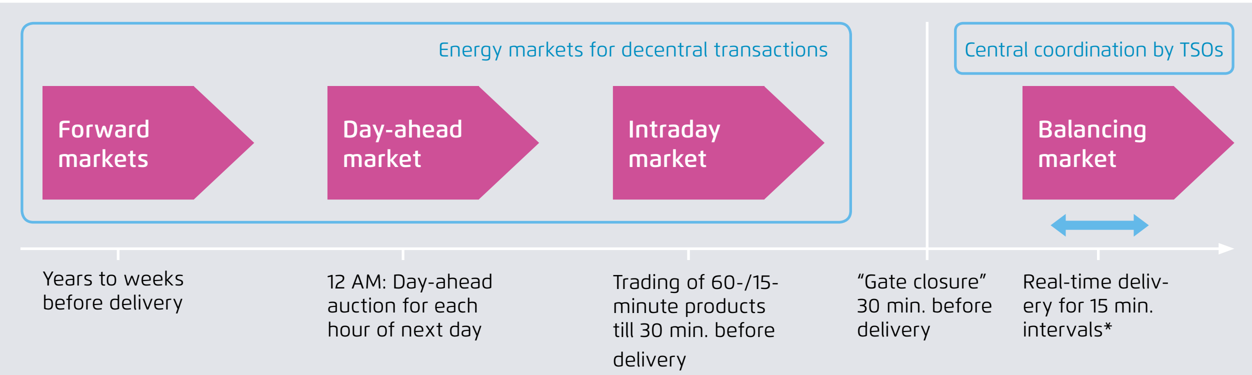
Congestion management involves the adjustment of power-market-based dispatch to respect network limits. Here, one distinguishes between preventive measures and real-time adjustment. Congestion management is typically organised by the transmission system operators (TSOs) either through market-based arrangements or through command-and-control schemes through orders to either conventional power plants (redispatch) or renewables (curtailment). In essence, congestion management is meant to align the dispatch from wholesale market clearing (which, depending on the price zone structure, may not reflect network constraints) with the network's physical realities (see CE Delft and Microeconomix (2016)).

Congestion management instructions for conventional power plants are typically described as "redispatch": Redispatching is when the TSO changes the wholesale market-based dispatch schedule of power plants. "Curtailment" is when the TSO reduces output from renewables, from wind power in particular. Redispatch reduces and increases generation, whereas curtailment only reduces generation.

For instance, in the event of a day-ahead overestimation of renewable production or underestimation of demand, additional power will be demanded on the intraday market, and intraday prices will be higher than day-ahead prices (or vice versa). Figure 5 illustrates the difference between the intraday and day-ahead prices (the so-called intraday spread) and the day-ahead wind power forecast error for a period of seven days. The intraday spread shows a strong correlation with the day-ahead wind forecast error, corrective trades on the intraday market.[5]

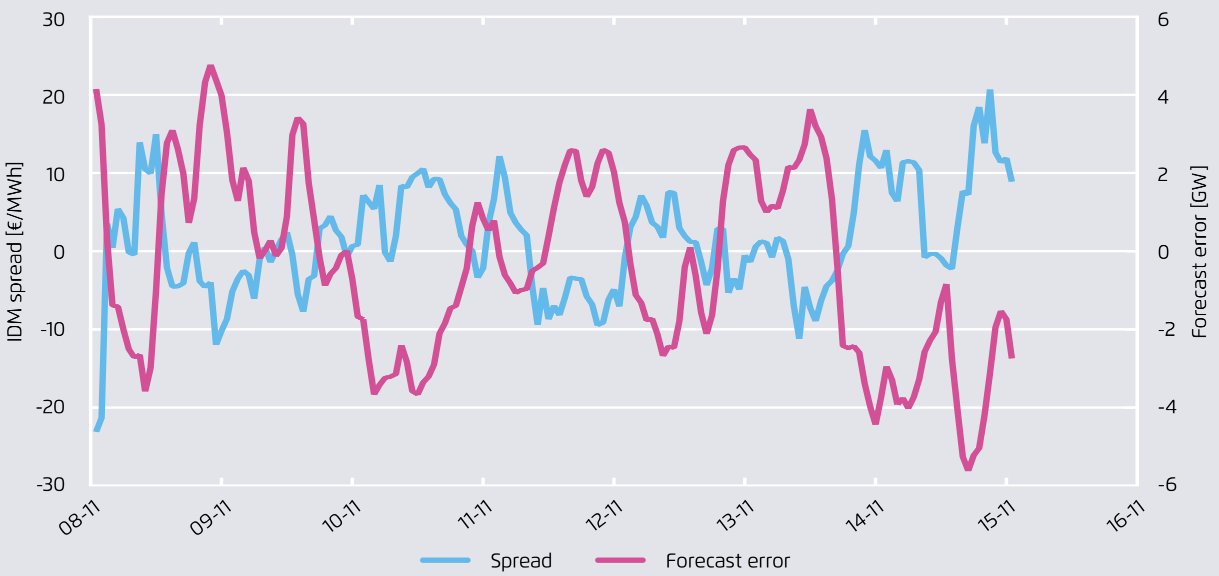
5 See CE Delft and Microeconomix (2016): Refining Short-Term Electricity Markets to Enhance Flexibility. Study on behalf of Agora Energiewende.

Sequence of market-based transactions in the German power market. Figure 4



* Imbalance penalties incentivise market actors to adhere to the physical realities of market trades.
own illustration

IDM spread (defined as intraday minus day-ahead price) vs. day-ahead wind forecast error (defined as actual wind generation minus day-ahead forecast) in Germany in November 2015. Figure 5



CE Delft and Microeconomix (2016)

30 minutes before delivery, the power markets close for trading. Afterwards, TSOs use centralised balancing markets to perform real-time balancing that manage deviations between previous trades and actual outturn (see Box 2).

How are prices formed on energy markets? We can illustrate using the example of a day-ahead market auction. In this case, generators, suppliers/retailers and large consumers trade in megawatt hours – specific amounts of energy for a specific hour of the following day. The electricity price in the day-ahead market is determined by sorting generation bids from cheapest to most expensive and intersecting them with demand bids. This mechanism, the so-called merit-order principle, ensures that power plants with

Box 2: Balancing markets

Real-time imbalances between supply and demand (due, say, to sudden power plant outages or unexpected demand increases) result in frequency deviations from the nominal frequency of 50.0 Hz. Different types of balancing reserves (usually contracted in advance by the TSOs) respond to these frequency deviations and offset the imbalance. The three main types of balancing reserves are: primary reserves (also called frequency containment reserves), secondary reserves (also called frequency restoration reserves) and tertiary reserves (also called replacement reserves). As Figure 6 shows, these reserve types differ in their activation time (from seconds to minutes) and activation duration (from seconds to <60 minutes).[6]

6 Note that in countries with liquid intraday markets and short gate closure times, such as Germany, balancing reserves are rarely deployed for timespans approaching one hour.

Types of balancing reserves in response to real-time imbalances of supply and demand. Figure 6

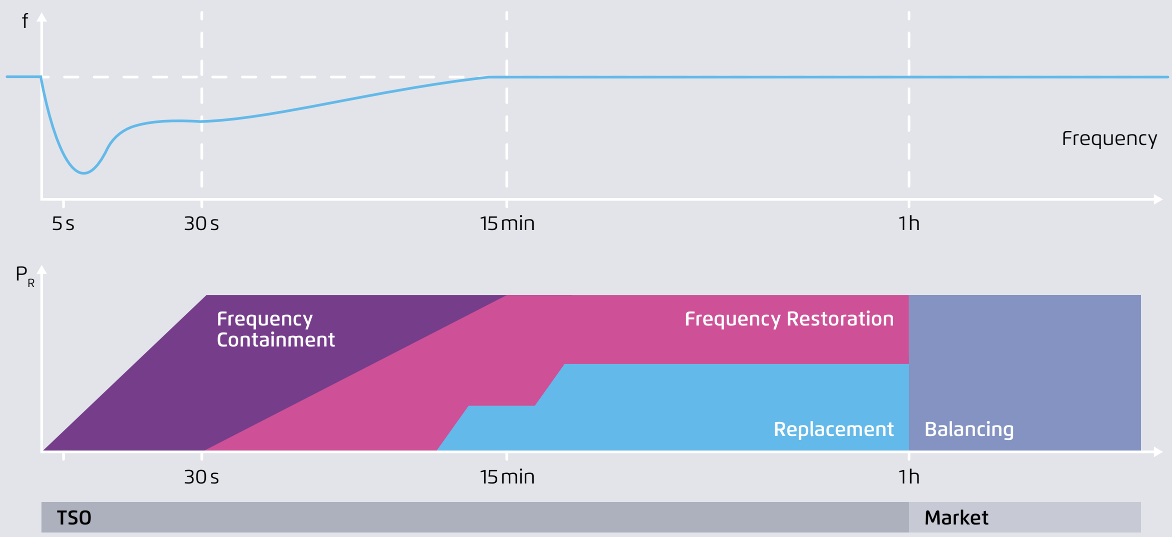


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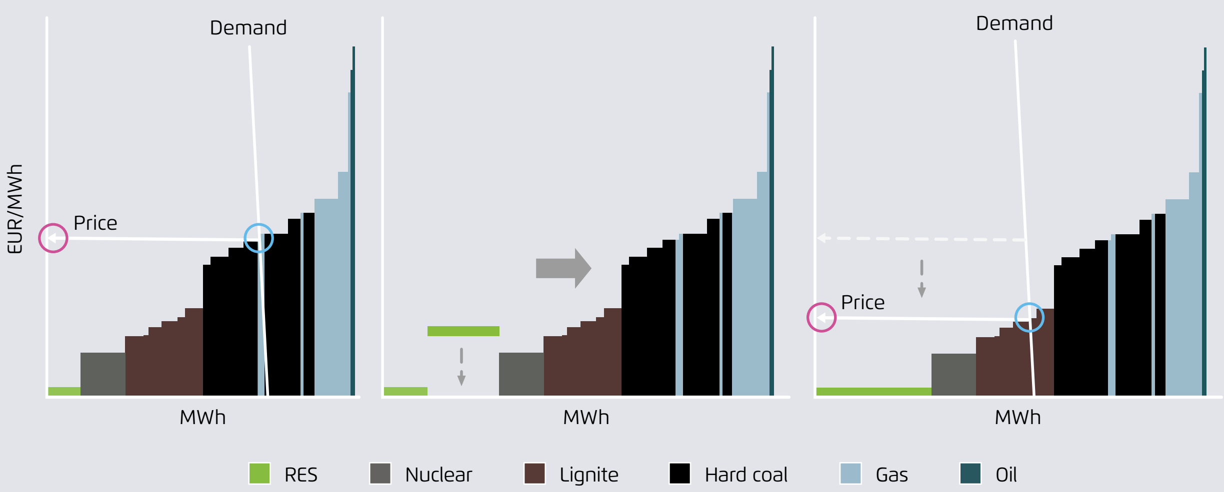
Illustration of wholesale power market and merit-order of generation technologies as a function of their generation costs* Figure 7



* Schematic illustration: Costs of fossil-fuelled plants depend on fuel and CO_2 prices → high CO_2 prices yield lower generation costs for gas fired plants than coal fired plants

Own illustration

the lowest operating costs are deployed first. As long as surplus generation is available, prices will follow the operating (or marginal) costs of the most expensive plant running in the system (typically a fossil-fuel plant whose marginal costs mainly consist of fuel and CO_2 costs). The deployment of wind power and solar PV depresses the wholesale power price. Because wind and solar have short-run generation costs close to zero (wind blows and sun shines for free and they do not emit CO_2), they come first in the merit-order (see Figure 7).[7]

Below we present several case studies that explain how flexibility requirements arising from variable renewables feed-in are managed by wholesale market-based transactions.

7 The so-called merit-order effect of renewables is described in more detail in Sensfuß, F., Ragwitz, M., Genoese, M. (2008). The merit-order effect: a detailed analysis of the price effect of renewable electricity generation on the spot market. Energy Policy 36, 3086–3094.

Case studies

Solar eclipse 2015

On 20 March 2015, Germany experienced a partial solar eclipse. From 9:30AM to 12:00AM, the moon dimmed the light as it moved between earth and sun.[8] For one hour it became darker and over the next hour it became brighter again.

At that point in time, some 39 GW of solar PV were installed in Germany. As 20 March was a clear day, the eclipse affected solar power generation to a fair degree. During the first half of the eclipse, PV output dropped by 5 GW for 65 minutes, whereas in the second half it increased by 13 GW over 75 minutes before reaching its noon generation peak of 21 GW (see Figure 8).[9]

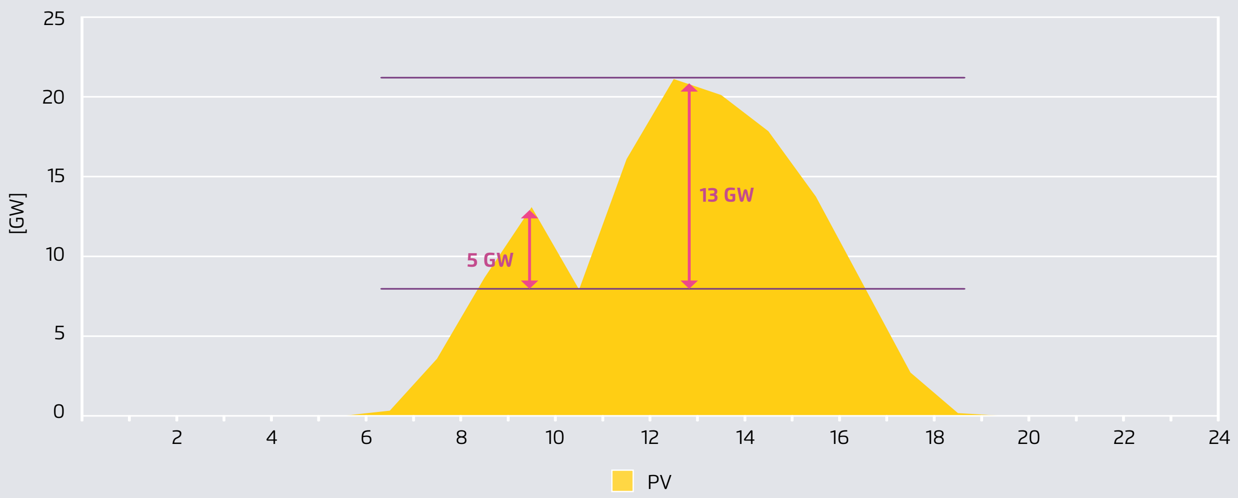
To manage the impact of the solar eclipse, transmission system operators across Europe coordinated system operations before and during the event. For example, more balancing reserves were procured in Germany (to be able to potentially deploy more balancing energy), members of staff received special training and the number of staff in the system operation units was increased. But as we will see below, the flexibility challenge caused by the solar eclipse was

8 Up to 82% of the sun was covered by the moon (50Hertz et al, 2015).

9 These ramps are unusual today, but by 2030 in Germany they will occur frequently, with some 50% of electricity being produced by renewables. By comparison, the largest hourly generation increase of PV in Germany in 2015 amounted to 8.2 GW and the largest hourly output reduction of PV amounted to -7.7 GW, roughly half the size of the output changes during the solar eclipse.

During the solar eclipse in 2015, the power production of solar power plants dropped sharply in a short time and then increased again. We've learned that power systems can deal well with such situations.

Electricity production of solar PV on 20 March 2015. Figure 8



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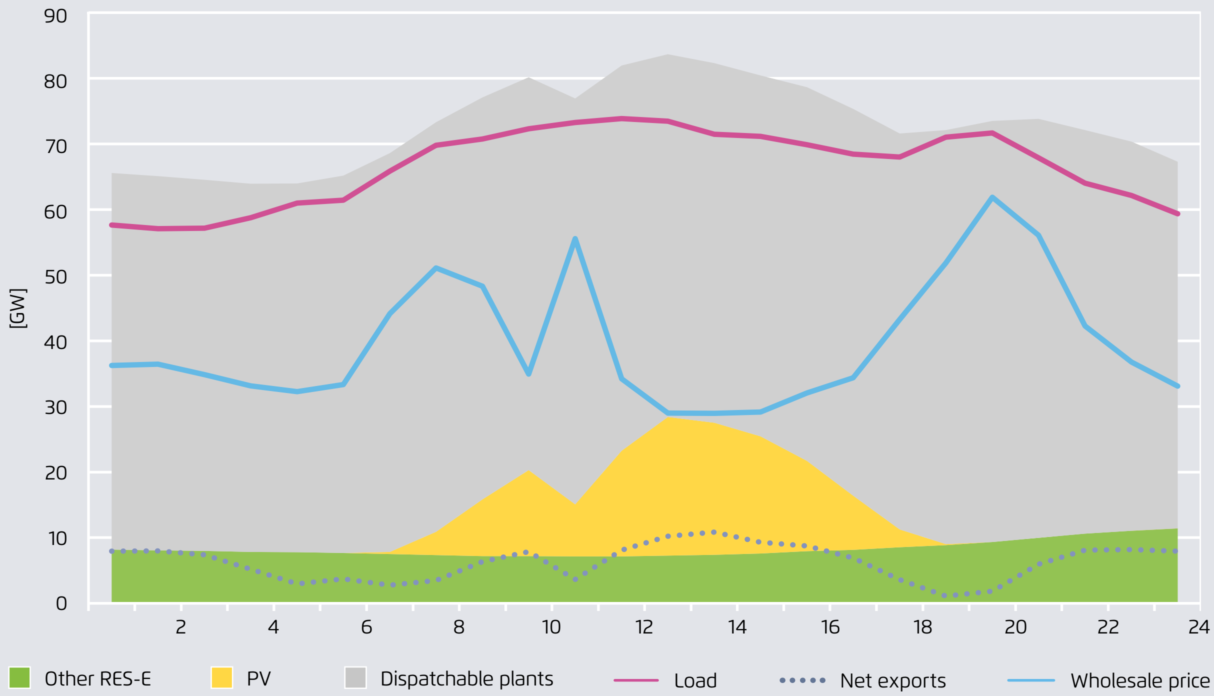
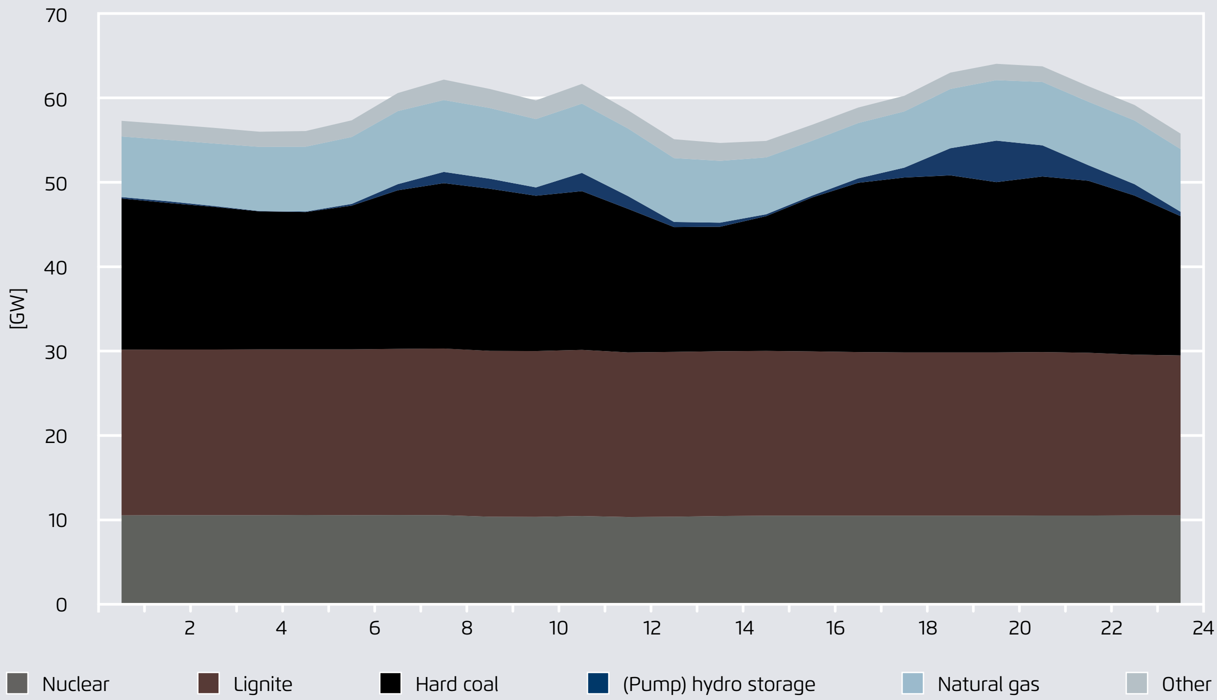
mostly managed by market actor trading on the day-ahead and intraday energy markets. Figure 9 shows that as PV generation dropped due to the solar eclipse in hour 11, prices in the day-ahead auction increased for hour 11. This is an expected market response because less PV generation at zero marginal costs was available during that time. As a response to rising prices, hard-coal plants increased their production during hour 11, as did (pumped-) storage hydropower plants. Nuclear and lignite generated at full load

Price on the intraday market auction in Germany on 20 March relative to a "normal" business day in that month. Figure 10

EPEX Spot

Generation, consumption and net exports of Germany on 20 March 2015.
The lower figure shows electricity production from dispatchable power plants. Figure 9





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Comparison of activated balancing energy (top figure) and the remaining area control error (bottom figure) in the German power grid on 19 and 20 March 2015

Figure 11

Own analysis based on TSO data

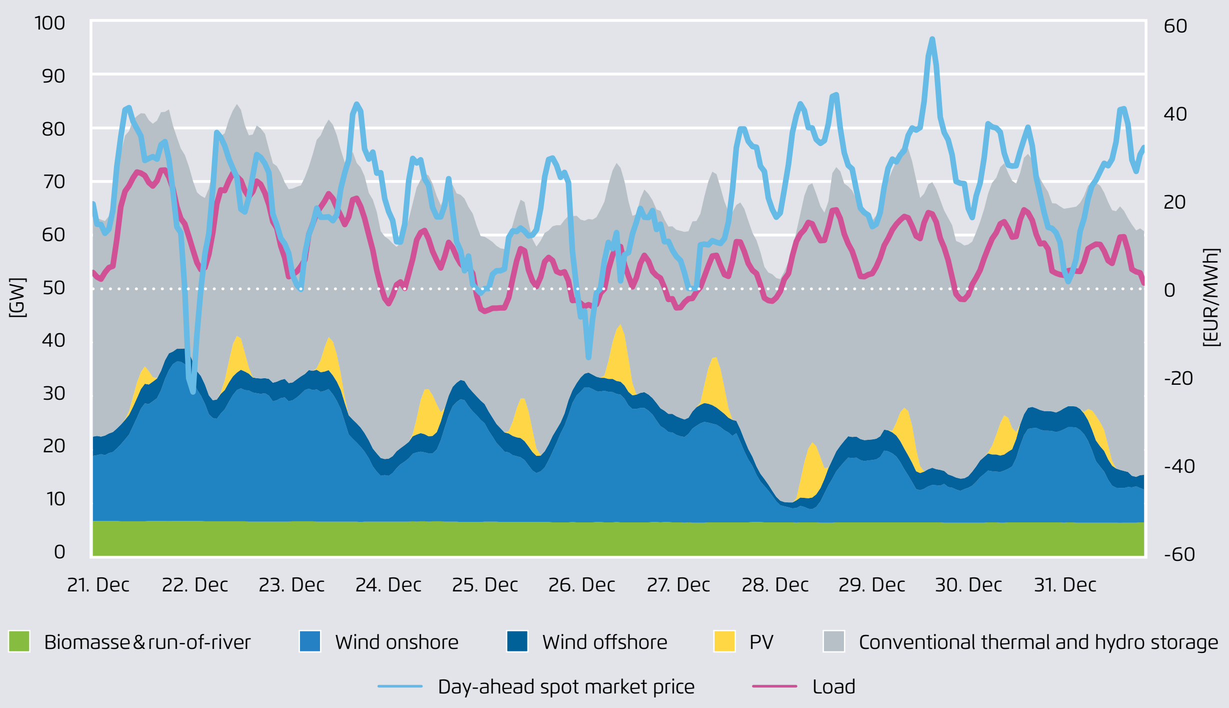
throughout the eclipse. Only a few gas plants were able to increase their production. This is because gas plants are currently more expensive to operate than hard-coal plants, and those few gas plants were dispatched on that day and those running were combined heat and power (CHP) plants with heat delivery obligations.

Another effect of the solar eclipse was a reduction in exports as PV generation declined. In fact, exports to the neighbouring countries were reduced by approx. 4 to 5 GW. As the upper graph in Figure 9 shows, net exports are a function of wholesale prices. Exports are higher when domestic prices are low (allowing available domestic capacities to cover demand abroad), but approach zero when domestic prices are high since domestic capacities are more heavily utilised and leave little export potential.

The solar eclipse is an interesting case study because it shows the key role played by intraday markets when transitioning to a power system based on wind and solar (see also Figure 4). Indeed, the solar eclipse was mainly "traded" on the intraday market, where 15-minute energy products are exchanged. Both volume and price showed significant variations relative to "normal" days replicating the sudden drop and increase of solar PV. For example, the intraday auction for the 15 minutes with the steepest PV generation drop reached some 460 EUR/MWh. 5 GW of power were traded during those 15 minutes in the intraday auction (see Figure 10).

The electricity supply remained stable during the entire eclipse. As shown above, the ramps in PV generation necessitated by the eclipse were traded on the day-ahead and intraday markets. Even though the TSOs contracted more balancing reserves as a

Electricity generation and demand in Germany, 21–31 December 2015. Figure 12



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precaution (1.5 GW more, to be exact), only little more balancing energy was required on the day of the eclipse. There were fewer upward balancing activities and some more downward balancing activities than the previous day (see Figure 11). These differences seem to be more a result of stochastic daily fluctuations than of the eclipse, as shown by the comparison of the area control error (the remaining "imbalance" after activating balancing energy) on the day of the solar eclipse with that of the preceding day (see the lower graph in Figure 11).

In conclusion, it was mainly the day-ahead and intraday markets that managed the flexibility challenge from the solar eclipse. The specific challenge was caused by a few very large ramps (up to 15 GW per hour) due to the sudden drop and increase of PV feed-in during the 2 ½ hours of the eclipse. Such ramps rarely occur in the German power system, whose maximum hourly PV ramps range from minus 8 GW to plus 8 GW. Wholesale prices acted as the main coordination mechanism by signalling pumped-storage hydropower and hard-coal plants to adjust their generation to accommodate the fluctuations in solar PV. As wholesale prices changed, so did the export balance. This highlights the potential flexibility offered by interconnected national power systems. The balancing energy markets – a flexibility source of last resort – were rarely used during the day of the solar eclipse.

Christmas holidays 2015

In this case study we look at the 2015 Christmas period, specifically the time from 21 to 31 December. During these 11 days, 5 were either public holidays or weekend days. They represent an interesting flexibility case study, as on weekends or public holidays demand is typically low while generation from renewables can nonetheless reach high levels. As we will see below, this affects the operation of conventional power plants.

Figure 12 shows that demand was particularly low from 25 to 27 December, ranging from 50 to 60 GW.[10] At the same time, strong winds passed through Germany, yielding a wind power feed-in up to 30 GW. Net load, defined here as load minus generation from renewables, dipped as low as 12.5 GW. This net load has to be covered by conventional generation, storage plants or imports. The low net load levels yielded low day-ahead market prices thanks to low demand and / or high RES-E feed-in. Indeed, there were times during the 11-day period when wholesale prices were negative. This is because a high number of inflexible conventional power plants were dispatched along with generation from renewables. Generation from conventional thermal power plants never dropped below 28 GW during the period, exceeding the net load in this hour by 15.5 GW. As a result of the high supply level from conventional power plants, power plant operators were willing to accept negative prices for their sales just to prevent shutting down their power plants (see Box 3 on negative prices).

Figure 12 shows that Germany was a net exporter throughout the period in question. When the share of domestic generation with low short-run generation costs increases, the remaining domestic capacity – still cheaper than the generation capacities in neighbouring interconnected systems – is available for export. Hence, the use of generation capacities is optimised in interconnected power systems because of import and export. Thus, cross-border electricity exchange is an important flexibility option.

10 Peak load in Germany can be as high as 85 GW.

Box 3: Negative power prices

Negative power prices mean that generators pay consumers to buy their energy. This may seem odd at first sight, but it can be explained by the economic and technological realities. Negative prices occur on the wholesale market whenever a high share of inflexible generation meets low power demand. Inflexible generation submits negative price bids and the intersection of these bids with the demand curve yields negative prices. Negative power prices are not an indication of “surplus” renewables, however. (The record share of RES-E in the German power system was 88.6%, which occurred during a single hour on 30 April 2017.) Rather, negative prices are caused by inflexible conventional power plants. Though renewable power generation is usually marketed at the negative value of the feed-in premium (or, if applicable, the feed-in tariff), inflexible conventional fossil-fuel power plants submit negative bids.

Inflexible conventional power plants are not only characterised by ramping constraints during operations. Because shut-downs and start-ups are expensive, power plant operators submit negative bids (known as opportunity cost bidding) to avoid shut-down and start-up costs. Similarly, CHP plants with heat-delivery obligations or power plants that are contracted as balancing reserves also submit negative bids on the power exchange.

Negative prices indicate a lack of flexibility. But their presence provides flexibility incentives for both the supply side (power plant operators invest in better and more flexible technologies) and the demand side (load shifting from hours with higher demand to hours with lower demand), lowering the likelihood of negative prices. Negative prices also propel market design adjustments such as the re-design of balancing markets to reduce the share of must-run plants for balancing power (see Box 4), the enabling of balancing power from renewables or the restructuring of network tariffs.[11]

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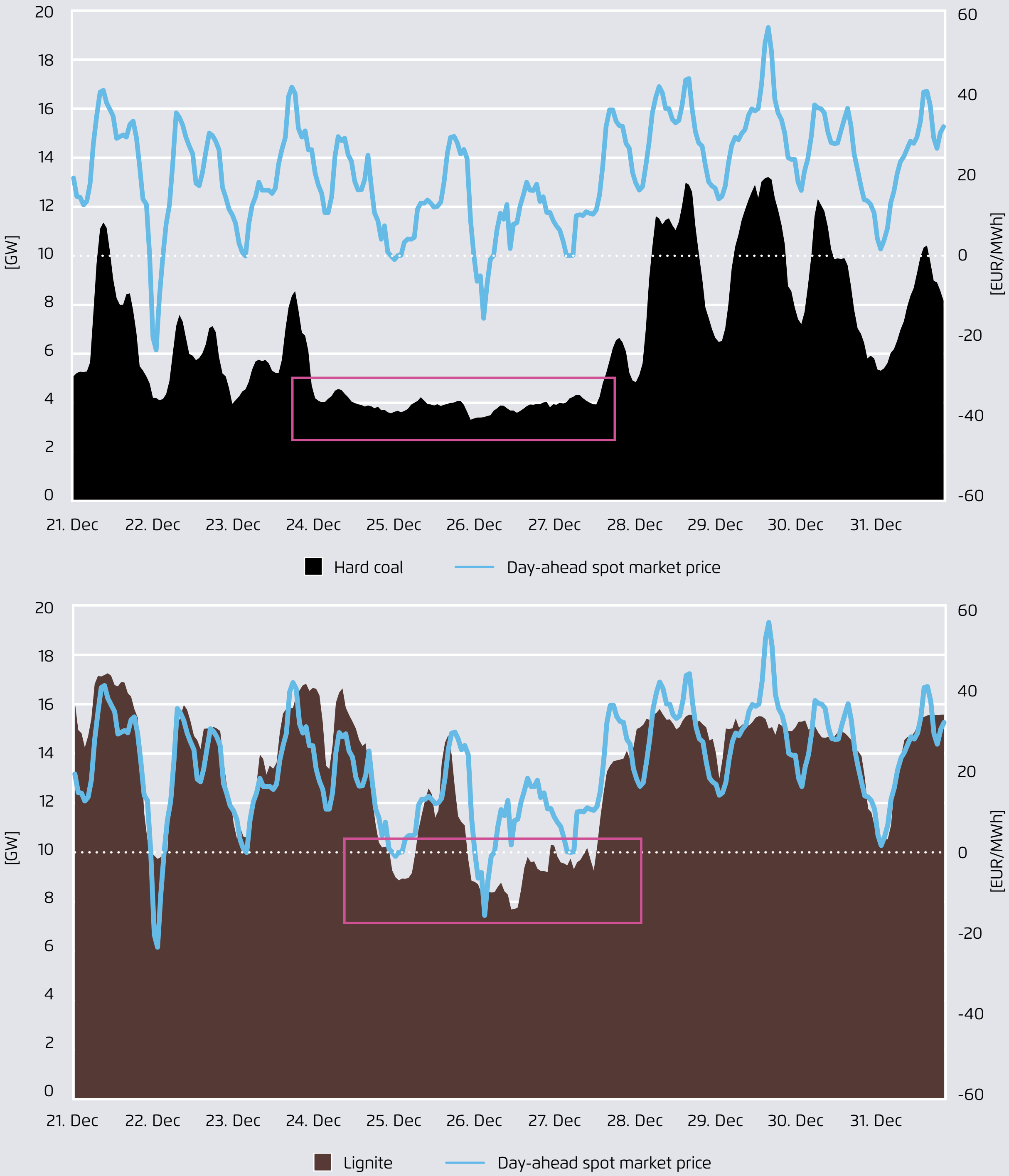
11 For more details, see Agora Energiewende (2014): Negative Strompreise: Ursachen und Wirkungen. Study performed by Energy Brainpool on behalf of Agora Energiewende; and Clean Energy Wire (2016): Factsheet: How does power trading work and how do negative prices occur?

Electricity generation from hard-coal (top figure) and lignite plants (bottom figure) and day-ahead market prices, 21–31 Dec 2015. During this period, the minimum generation level of hard-coal plants amounted to 4 GW, whereas that of lignite plants amounted to 8 to 10 GW (as indicated by the highlights).

Figure 13



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Up to 30 GW of conventional power plants are always in operation in Germany, irrespective of the wholesale price level.[12] As explained in Box 3, this can yield negative wholesale prices. This minimum generation level consists of 8 GW "must run" capacities, which are required for system and grid services and some 20 GW due to inflexible conventional capacities (see Box 4).

Figure 13 shows the response of hard-coal and lignite power plants to market prices. Hard-coal plants reacted to market prices and performed load following by ramping up and down by 8 GW within a day. The minimum generation of German hard-coal plants is around 4 GW in the winter months, as can be seen in the figure. This level still occurs even at low (< 15 EUR/MWh) or negative power prices (both lower than the short-run generation costs of hard-coal plants).

What was quite unusual during the 2015 Christmas period was that lignite plants responded fairly flexibly as wholesale prices fluctuated, reducing generation to between 8 to 10 GW. At output levels between 10 to 18 GW, lignite plants varied their output mainly based on power price. Above a certain price level, lignite plants produced at close to full capacity (when generation costs are lower than market prices), whereas below a certain price level, they produced a constant 8 to 10 GW (due to technological constraints as well as to avoid the costs of quick shut-downs and start-ups).

12 See Consentec (2016): Konventionelle Mindesterzeugung – Einordnung, aktueller Stand und perspektivische Behandlung (commissioned by the German TSOs). We will address the issue of must-run generation in more detail below. We note for now that a high share of conventional power plants in operation irrespective of the net load situation indicates inflexibility within the power system.

This coal-fired power plant in North Rhine-Westphalia from the 1980th was originally a medium-load power plant – it produced electricity during the week, and had been turned off on weekends. In recent years, the operator has extensively modernized the plant: Today it can adapt its power output very flexibly to the demand.

Box 4: Must-run and inflexible conventional generation in the German power system

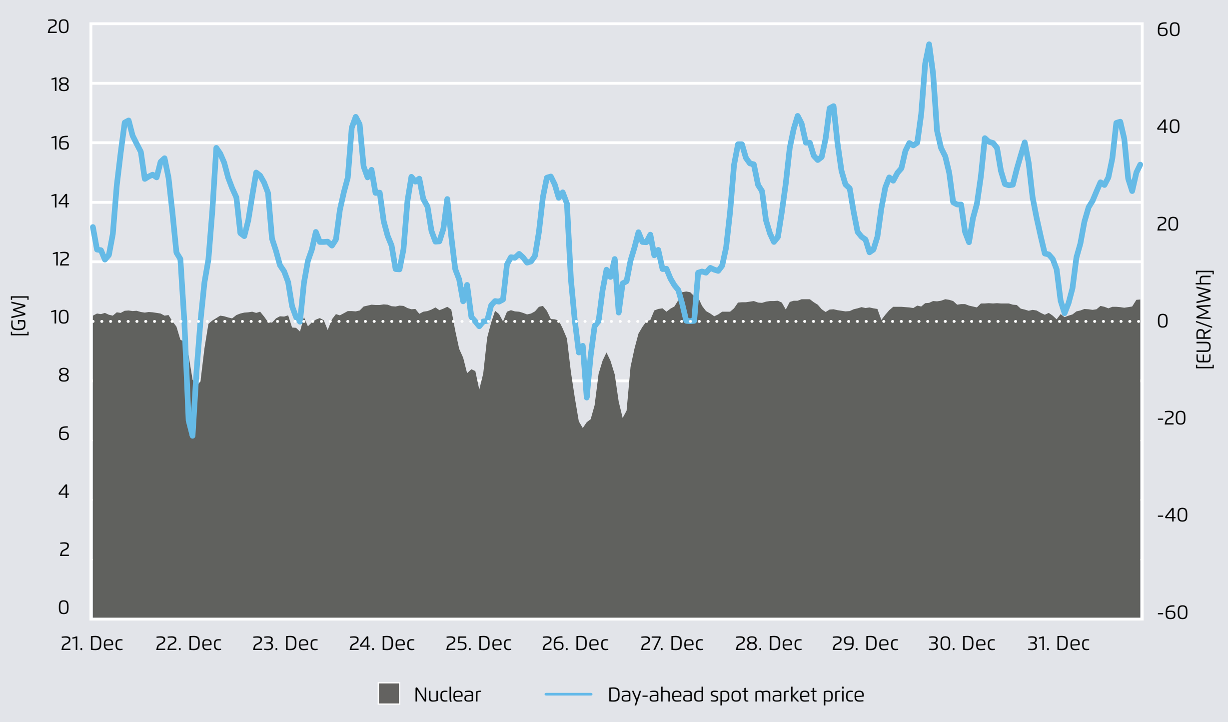
Conventional power plants in Germany are always producing 25 to 30 GW of power, irrespective of the wholesale price level (leading to the negative prices discussed in Box 3). Among this minimum output, one distinguishes must-run generation from inflexible generation.

Must-run generation is required "around the clock" to provide system services, such as balancing and contributing to secure grid operations: 0.5 to 2.5 GW are required for redispatch (to handle congestions in the domestic grid – see Box 1), 3.5 to 5.5 GW for providing balancing energy and 1.5 to 2.5 GW for backing up balancing capacities.

By far the largest share of conventional minimum generation – some 20 GW – stems from inflexible power plants. This comprises plants whose energy is used for on-site power demands or combined heat-and-power plants (CHP) with heat delivery obligations. An important contributor is the so-called minimum load of power plants, the minimum output level of a power plant once it is online, which can amount to 15 to 40% of its installed capacity.

75% of the inflexible generation stems from nuclear and lignite plants. For more details on minimum conventional generation in the German power system, see Consentec (2016).

Electricity generation from nuclear plants and market prices, 21–31 Dec 2015. Figure 14



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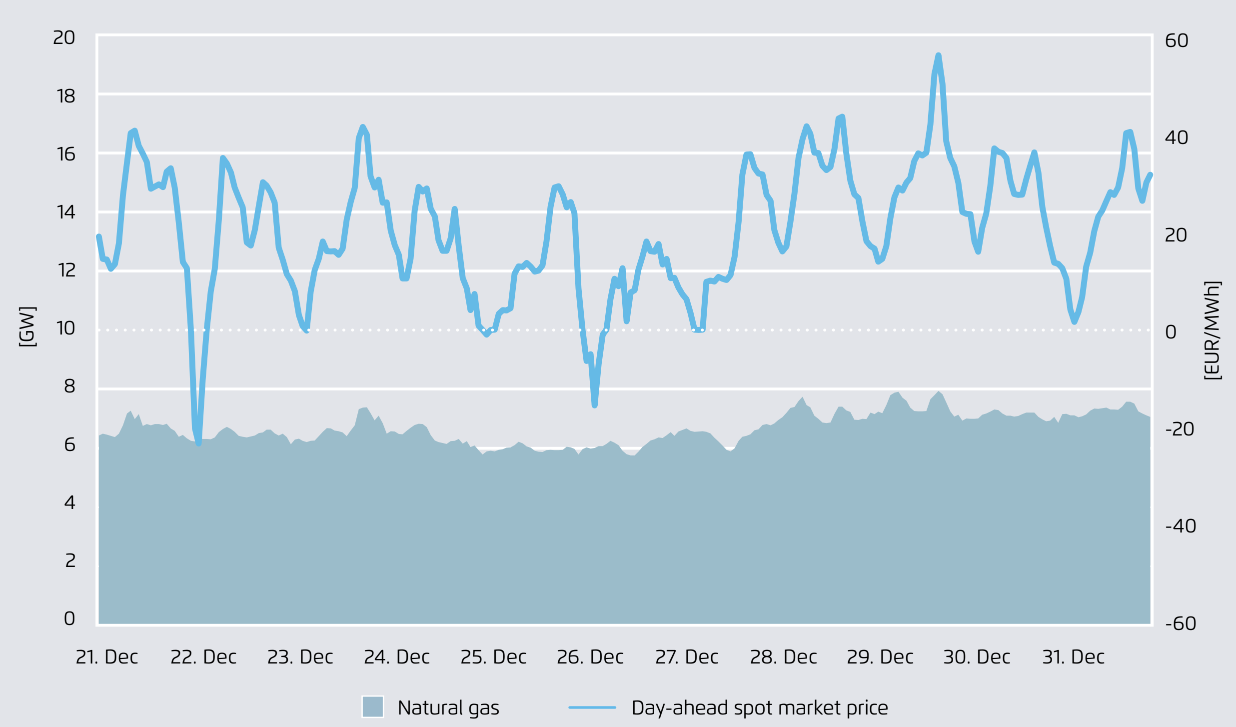
Nuclear power plants mainly run at a steady level, as shown by Figure 14. They are the conventional power plants with the lowest short-run generation costs, which explains why they typically produce in a "baseload" mode. Only when power market prices near zero (below their generation costs) do they reduce generation slightly, but their output never dips below 10 GW.

In today's economic environment of low coal and CO_2 prices and high gas prices, gas-fired power plants are the conventional generation technology with the highest marginal costs. As a result, they are rarely dispatched – with one exception. Some 6 to 7 GW of combined heat-and-power (CHP) plants run "24-7" to meet heat delivery obligations. As Figure 15 shows, gas generation barely responds to price fluctuations although it is the fossil-fuel-fired technology with the highest flexibility in theory.

Contrary to gas plants and their current economics, power price increases yield increased generation from pumped-storage hydropower plants. But these plants produce a limited amount of output in Germany, with an installed capacity of 7 GW. Pumped-storage hydropower plants quickly increase production (see Figure 16) when power prices spike, delivering high ramp rates. Specifically, they generate more as a function of pronounced wholesale price spikes. This is to be expected, as pumped-storage hydropower plants have fairly high opportunity costs. The decision to generate also depends on expectations about future price levels, so as to avoid "spilling" stored water.

The Christmas 2015 case study has shown that during times of high renewables feed-in – the average hourly share of wind and solar PV that went to meeting the German power demand amounted

Electricity generation from gas plants and market prices, 21–31 Dec 2015. Figure 15



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to 32% during this period – hard-coal plants and pumped-storage hydropower stations perform load following to meet the load net of renewables. At the same time, a significant stock of inflexible thermal power plants (mainly lignite and nuclear) produced an output of around 28 GW irrespective of wholesale power prices. This stock of inflexible power plants is a stumbling block to further flexibilisation of the power system. A large part of this inflexible generation is exported in times of low or negative wholesale prices.

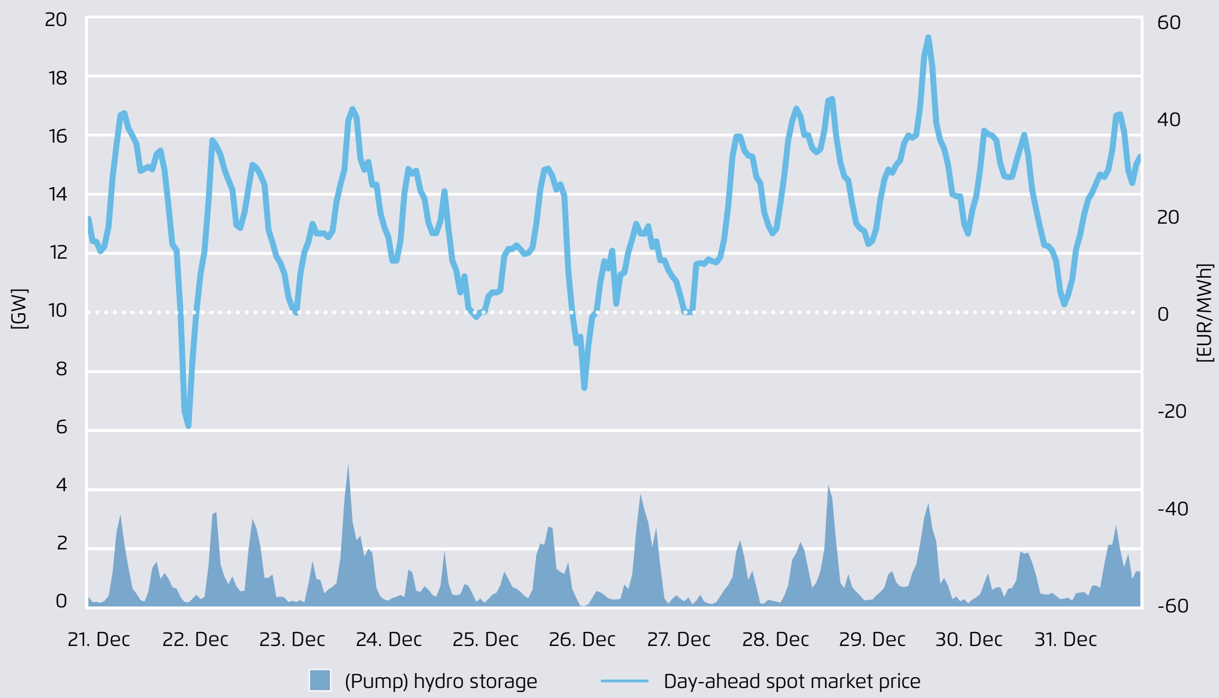
Mother's Day and Pentecost 2016

In the last case study of this paper, we look at the period from 7 to 16 May 2016. During these ten days, very high feed-in levels from renewables occurred. Electricity demand was fairly low during this period, especially on the weekends and the Pentecost public holidays. On Mother's Day, 8 May 2016, Germany had a very high RES-E share in one single hour: 86.3%.

Figure 17 shows that feed-in levels from renewables was very high during the period. PV generation reached highs ranging from 17 to 29 GW. The average hourly wind feed-in was 15 GW, with hourly values fluctuating between 3.5 and 24 GW during the 10-day period. At certain times, net load was as low as 8.5 GW. This led to negative day-ahead market

Electricity generation from pumped-storage hydropower and market prices, 21–31 Dec 2015. Note that this graph shows hourly averages. Pumped-storage hydropower plants typically operate on a quarter-hourly basis; accordingly, generation during these intervals can be larger than the values shown here.

Figure 16



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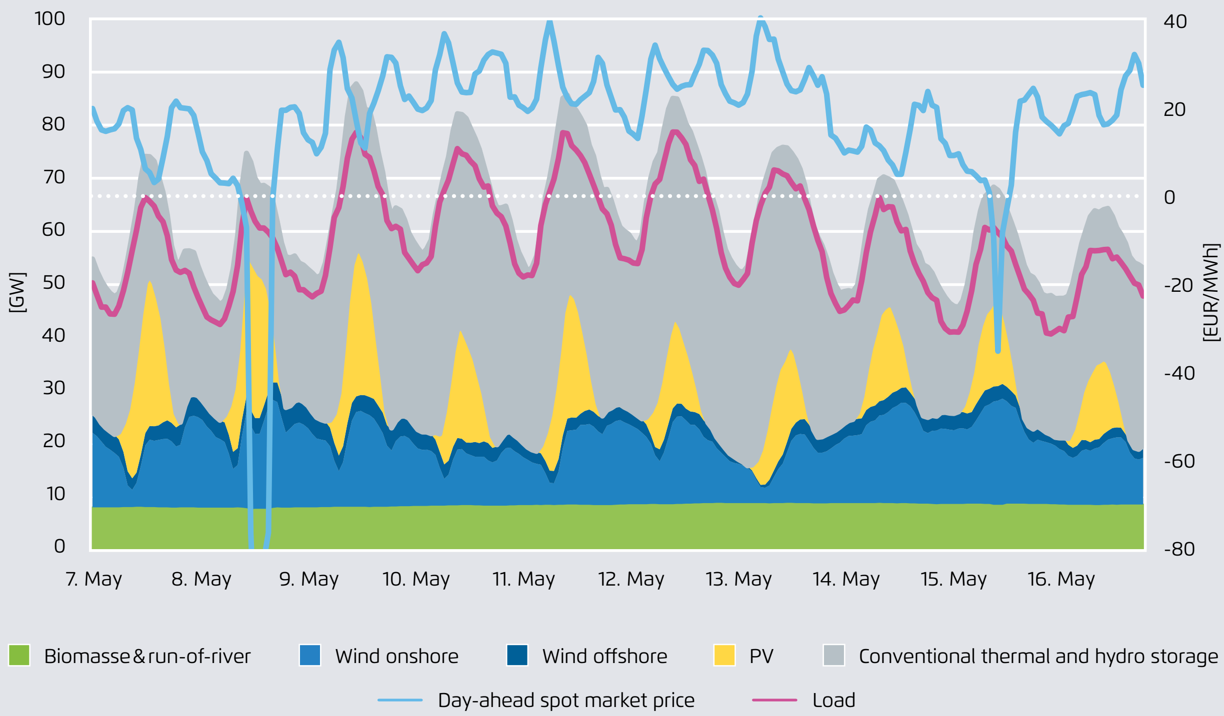
Electricity generation and demand in Germany, 7 to 16 May 2016.

Figure 17



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prices for eight hours on Sunday, 8 May (falling as low as -130 EUR/MWh) and for four hours on Sunday, 15 May. A greater amount was dispatched from conventional power plants than was required to meet domestic load. In fact, conventional power plants in Germany were producing no more less than 17 GW during hours with negative prices and a minimum net load.[13] Up to 10 GW of electricity generation was exported during these hours.

Figure 20 shows the response of hard-coal and lignite power plants to market prices during the study period. In periods of low and negative wholesale prices (< 10 EUR/MWh) – below the short-run generation costs of coal-fired power plants – average hard-coal generation was still some 3 GW. During wholesale prices in the range of 20 to 40 EUR/MWh, hard-coal plants performed load following, cycling their generation levels between 5 and 16 GW. For example, on 12 May, hard-coal generation increased from 6.4 to 14.4 GW within three hours. From 13 to 14 May, hard-coal generation decreased from 12 to 2.5 GW within five hours. During flexible operation, hard-coal-fired power plants are typically the price-setting technologies in the day-ahead market (see the merit-order principle shown in Figure 6).

Lignite plants followed the power price signal in a more dampened mode, yielding a higher share of inflexible generation – 6 GW to be precise. This has at least two reasons. First, lignite plants are less flexible than hard-coal plants. Second, the generation costs of lignite plants are typically below wholesale prices, so they tend to produce at maximum output as soon as wholesale prices are higher than generation costs. Yet the inflexible minimum generation for lignite –

13 See Boxes 3 and 4.

during the study period, it amounted to between 6 and 9 GW – produced output at wholesale price levels that are lower than the plants' variable generation costs. The latter range from 10 to 12 EUR/MWh.[14]

Nuclear power plants, the conventional generation technology with the lowest short-run generation costs, typically generate at maximum output levels whenever the power price is above their generation costs. When wholesale prices are negative, nuclear plants still produce close to full output. (During the study period, nuclear plants produced a minimum of 6 GW.) This reflects the technology's limited flexibility due to technical constraints and the high costs of switching nuclear plants on and off.

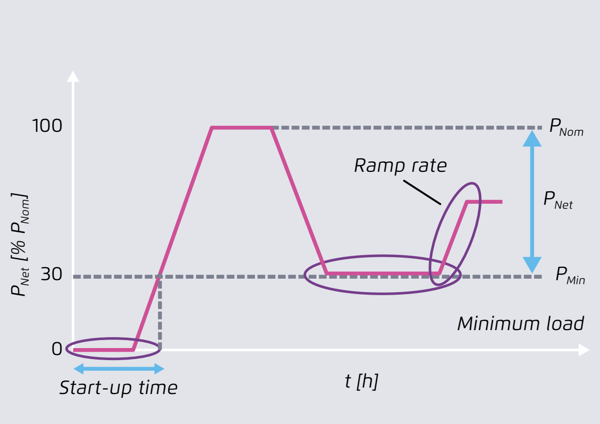
14 In 2017, total generation cost for lignite plants in Germany range from 34 to 47 EUR/MWh. See Öko-Institut (2017): Die deutsche Braunkohlenwirtschaft. Historische Entwicklungen, Ressourcen, Technik, wirtschaftliche Strukturen und Umweltauswirkungen. Study on behalf of Agora Energiewende and the European Climate Foundation.

Box 5 Flexibility in thermal power plants

Flexibility – rather than baseload generation – is the paradigm that shapes modern power systems. At the power plant level, operational flexibility is characterised by three main features: the overall bandwidth of operation (ranging between minimum and maximum load), the speed at which net power feed-in can be adjusted (ramp rate), and the time required to attain stable operation when starting up from standstill (start-up time) (see Figure 18).

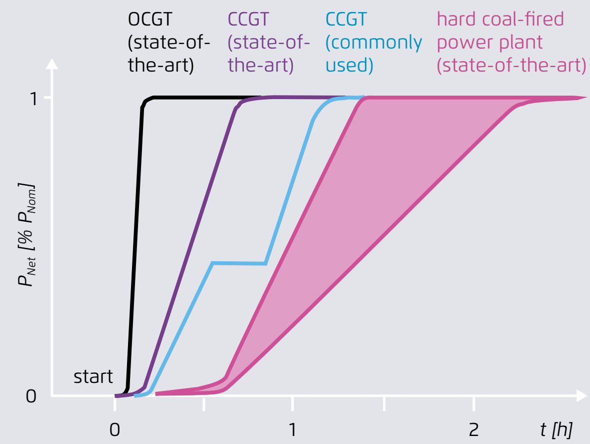
Comparing the flexibility parameters (minimum load, ramp-rate and start-up time) of most commonly used and state-of-the-art power plants for each generation technology (OCGT, CCGT, hard coal- and lignite-fired power plants), one finds that gas-fired power plants (OCGT and CCGT) have a higher operational flexibility relative to coal-fired units. As Figure 19 shows, start-up time is significantly shorter and ramp rates are higher than for hard coal- and lignite-fired power plants.

Qualitative representation of key flexibility parameters of a power plant. Figure 18



Fichtner (2017)

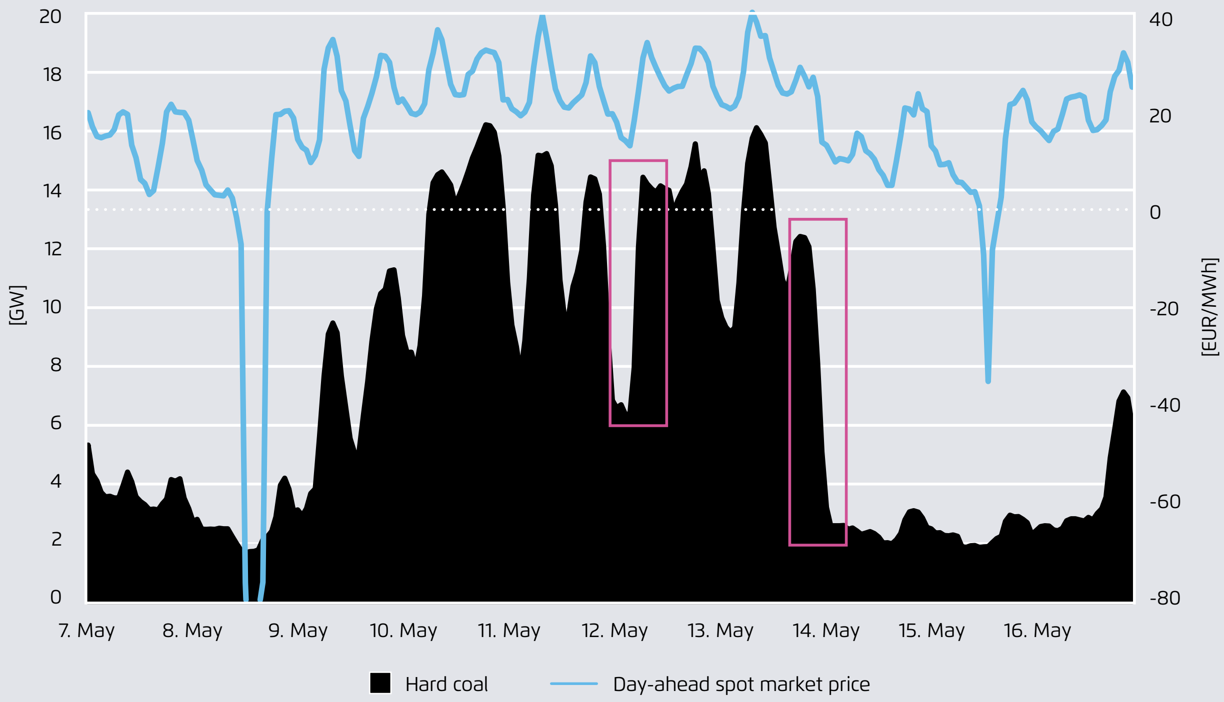
Ramp rates and start-up times of different power plant technologies. Figure 19

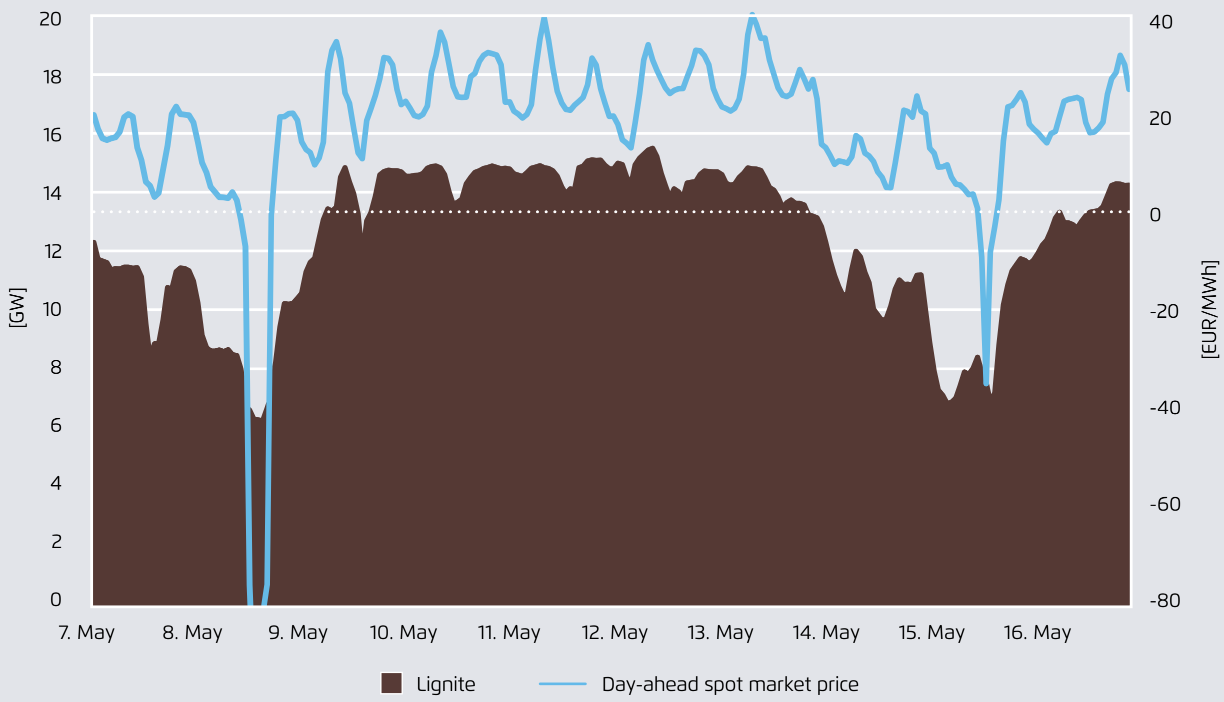


Fichtner (2016) based on VD, (2012)

Electricity generation from hard-coal (top figure) and lignite plants (bottom figure) and day-ahead market prices, 7 to 16 May 2016. The hard-coal fleet ramped up and down by up to 3 GW per hour as shown in the figure.

Figure 20





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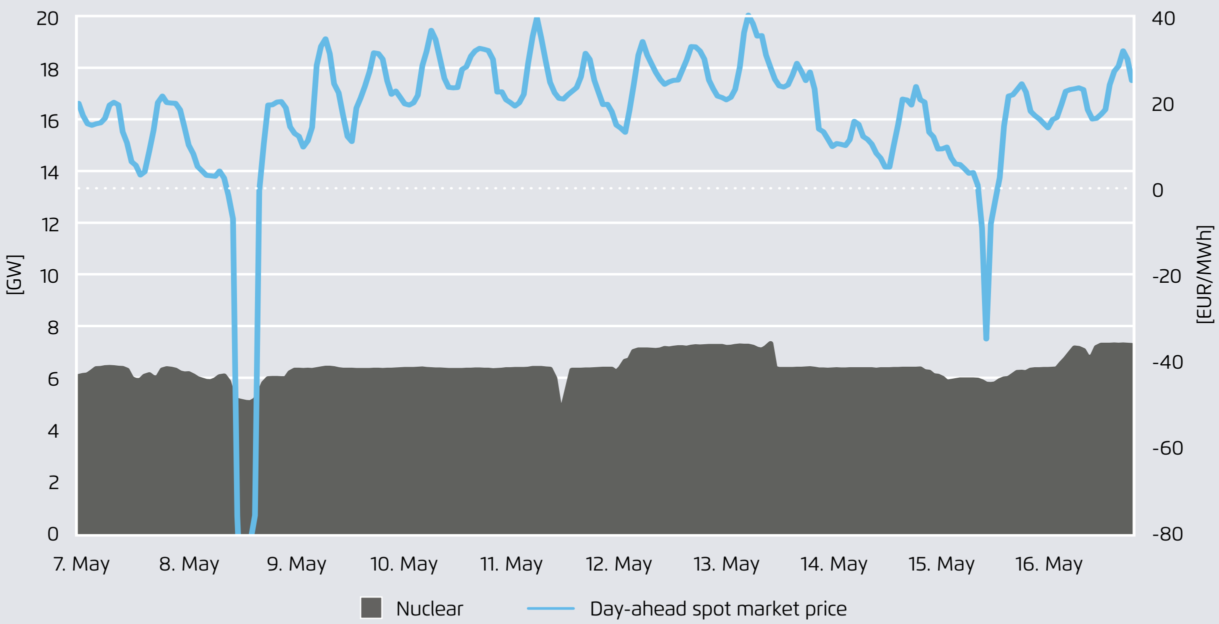
Electricity generation from nuclear plants and market prices, 7 to 16 May 2016. Figure 21



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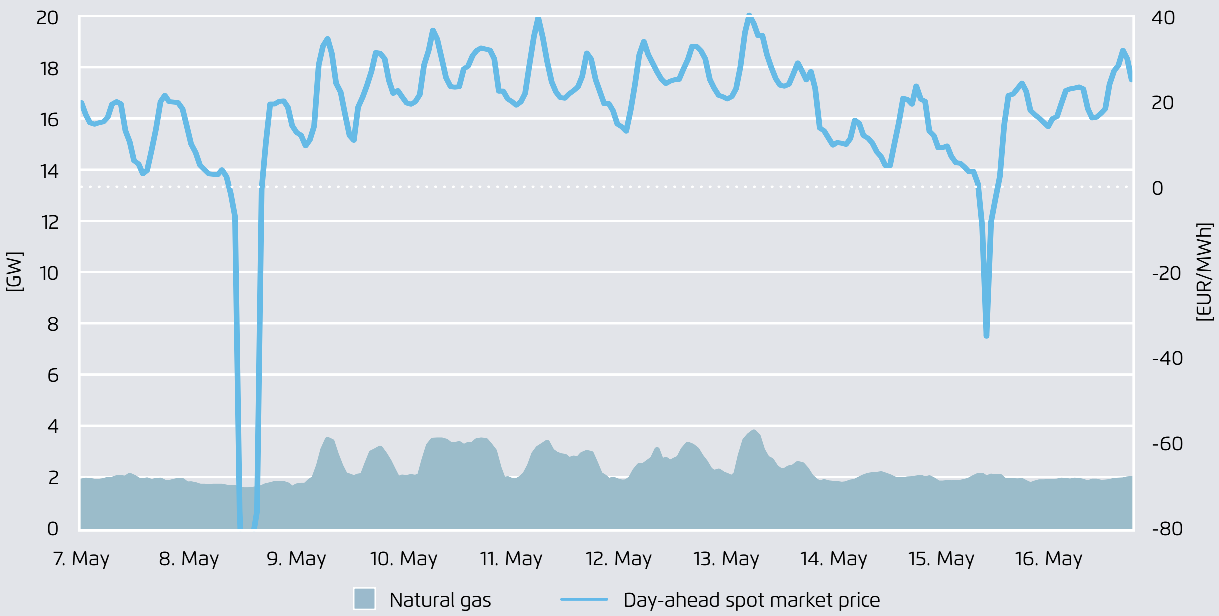
Electricity generation from gas plants and market prices, 7 to 16 May 2016. Figure 22



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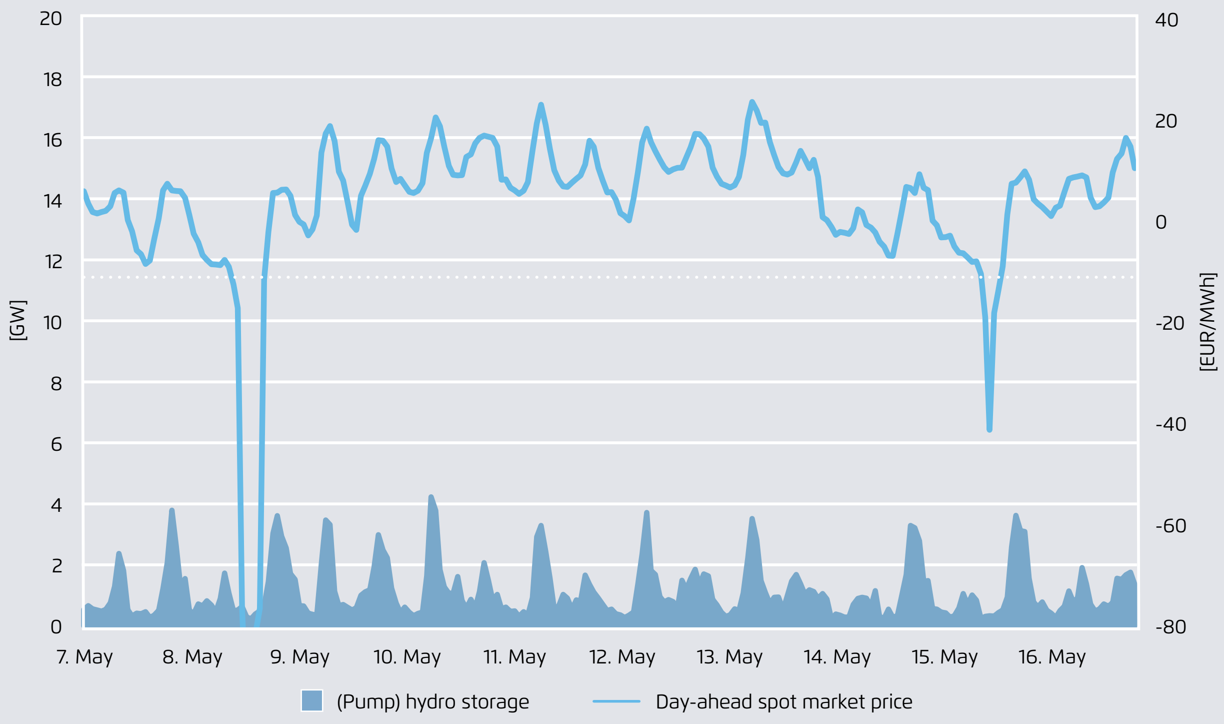
In contrast to nuclear power plants, gas-fired power are very flexible from a technological point of view. But they are rarely dispatched because their generation costs are higher than those of coal-fired plants. In the spring, only some 2 to 3 GW of combined heat-and-power (CHP) plants are dispatched "24-7" to meet heat delivery obligations. Figure 22 shows that they respond to wholesale power price fluctuations only when prices approach 40 EUR/MWh, a figure approaching their short-run generation costs.

Figure 23 shows the response of pumped-storage hydropower plants to market prices. They are the most flexible power plant technology, quickly increasing production when power prices spike.

The Mother's Day and Pentecost study shows that during times of high feed-in from renewables – the average hourly share of wind and solar PV that went to meeting the German power demand amounted to 38% during this period – hard-coal plants and pumped-storage hydropower stations perform load following to meet the load net of renewables. The running hard-coal generation ramped up 3 GW per hour.

During this time, a significant stock of inflexible thermal power plants (mainly lignite and nuclear) produced an output of around 15 GW irrespective of wholesale power prices. This contributed to negative wholesale prices, which dipped as low as -130 EUR/MWh.

Electricity generation from pumped-storage hydropower and market prices from 7 to 16 May 2016. Figure 23



Agorameter. Note that this graph shows hourly averages. Pumped-storage hydropower plants typically operate on a quarter-hourly basis; accordingly, generation during these intervals can be larger than the values shown here.

Using the power market to manage the flexibility challenge: Main takeaways from German case studies

Wind power and solar PV represent the future backbone of Germany's future power system. Already in 2016, they generated 22.2% of Germany's electricity. An important reason for this is that, even when including integration costs, they will soon be cheaper than any other new technology.[15]

To cost-effectively integrate progressively higher shares of variable renewable electricity, power supply and demand must respond flexibly to wind and PV energy. Flexibility is the new paradigm for the German power system.

A set of wholesale power markets can manage flexibility needs arising from renewable energy's variable generation. Prices provide key incentives for plant operators to adjust output and for customers to adjust consumption. A strong, value-based and undistorted price signal can enable flexibility efficiently by optimising the dispatch of supply- and demand-side resources, lowering total system costs.

The above case studies have shown how flexibility requirements arising from variable renewables feed-in are managed by wholesale-market transactions. In Germany, the day-ahead and intraday markets are the main tools for accommodating fluctuations of wind and solar generation. Over time, the intraday market will assume an even more important role. Currently, it allows the trading of 15-minute products up to 30 minutes before delivery. This enables quick market-based responses to updated generation forecasts for wind and PV.

15 See Agora Energiewende (2015): The Integration Cost of Wind and Solar Power. An Overview of the Debate on the Effects of Adding Wind and Solar Photovoltaic into Power Systems.

The solar eclipse case study showed that the high ramps during the 2 ½ hours of the eclipse (as high as 15 GW per hour) were compensated by hydro storage and hard-coal plants, which adjusted their generation as a function of wholesale prices. The export balance also changed with wholesale prices. This highlights the flexibility potential offered by interconnected national power systems.

Real-time balancing markets, though their market volume remains limited, are an important "market of last resort". TSOs are responsible for balancing the system, offsetting any deviations between wholesale market trades and actual outturns. They also take into account requirements for secure grid operations (which the German wholesale day-ahead and intraday markets do not consider).

Another important enabler of flexibility in addition to domestic trade is cross-border trade. For example, wind power feed-in is decorrelated over large geographical areas, so that surpluses in one area can be exported to areas with little feed-in from renewables.[16] Wind power also gives access to cross-border flexibility options, which lowers the costs of flexibility. Indeed, cross-border exchange is beneficial for all systems because it lowers prices for importing countries, providing access to the cheapest flexibility option in the region and maximises reliability as a larger pool of resources for system balancing is available. The solar eclipse is an interesting case study –

16 In the case of EU-wide aggregation, hourly wind onshore ramps can be reduced by around 50% relative to the national baseline. For more details, see Fraunhofer IWES (2015): The European Power System in 2030: Flexibility Challenges and Integration Benefits. An Analysis with a Focus on the Pentalateral Energy Forum Region. Analysis on behalf of Agora Energiewende.

one in which changing export patterns represent a "buffer" for flexibility requirements from sudden fluctuations in renewable generation.

Looking forward, markets alone will be unable to create sufficient flexibility if the incumbent generation mix remains inflexible. This is why the structure of the conventional power plant park needs less base-load capacity and more mid-merit and peak-load resources.[17]

The Mother's Day and Pentecost study has shown that mostly hard-coal plants and pumped-storage hydropower perform load following to meet the load net of renewables when fluctuations occur. At the same time, a significant stock of inflexible thermal power plants (mainly lignite and nuclear) produced during those days irrespective of the wholesale power price. This has contributed to negative wholesale prices, which at the time fell as low as -130 EUR/MWh.

Indeed, the biggest stumbling block today to a flexible power system in Germany is the high share of inflexible generation in conventional plants. As we have seen in the case studies above, some 25 to 30 GW of conventional power plants are always producing, irrespective of the wholesale price level, even when prices are negative (see Box 4). A large part of this inflexible generation is exported in times of low wholesale prices.

Out of these 25 to 30 GW, almost 20 GW from inflexible plants are produced "around the clock". This is mainly due to economic or technical constraints (combined heat and power plants with heat delivery obligations, the technical minimum load of inflexible power plants, associated start-up and shut-down constraints, on-site power consumption). 75% of the 20 GW stems from nuclear and lignite plants. These plants also generate at negative electricity prices because of technical constraints and costs, which occur with shut-downs and start-ups.[18]

Enhanced power system flexibility can be achieved at significantly lower system costs when the share of inflexible conventional power plants decreases while the share of flexible resources increases. Put differently: a cost-effective transition requires that the increase in wind and solar PV is accompanied by a system shift to a qualitatively different, more flexible capacity mix.[19] This comprises the increased use of demand-side flexibility (demand response) and, with progressively higher shares of wind and PV, new storage and coupling in the electricity, heating and transport sectors ("P2X").

The above-mentioned flexibility options, the cross-border integration of power systems and a flexible set of power markets can work together to manage flexibility needs. As we have seen in this paper, wholesale power markets are the main economic enabler of flexibility in the German power system, steering the dispatch of supply-side,- & demand-side and storage resources.

17 The needs of German baseload plants will decrease by 50% through 2030 provided renewable targets are reached (see Fraunhofer IWES 2015).

18 Policy measures that actively remove inflexible high-carbon capacity from the German power system are required for both emission reduction and low-cost system operation. See Agora Energiewende (2016): Eleven Principles for a Consensus on Coal: Concept for a Stepwise Decarbonisation of the German Power Sector; and Agora Energiewende (2016): The Power Market Pentagon: A Pragmatic Power Market Design for Europe's Energy Transition.

19 A scenario with 45% renewables, a higher share of flexible resources and a lower share of inflexible resources delivers the same amount of energy at the same reliability but with over 40% less investment expenditures relative to a scenario with 45% renewables and a higher share of inflexible resources. For more details, see RAP (2014): Power Market Operations and System Reliability: A Contribution to the Market Design Debate in the Pentalateral Energy Forum. Study on behalf of Agora Energiewende; and IEA (2014): The Power of Transformation.

GLOSSARY

Ancillary services
System services that help the transmission system operator (TSO) operate the power system continuously within the required parameters (such as frequency and voltage range) and recover energy balance after significant unplanned changes in supply and demand.

Balancing market
A centralised market operated by the transmission system operator (TSO) where the TSO corrects current or expected imbalances between supply and demand. The delivery of the balancing energy takes place in real time, that is, after wholesale energy markets have closed (gate closure).

Baseload
The operating mode of a power plant producing for most hours or for all hours of a year.

Combined heat and power (CHP) plants
Power plants that simultaneous produce heat and electrical energy. In most cases, CHP plants are thermal power plants in which waste heat is used for residential heat (typically after being fed into a district heating system).

Congestion management
Congestion management comprises all measures taken by the TSO to eliminate overloading in the electricity network. It typically comprises the redispatch of conventional power plants and the curtailment of renewables.

Curtailment
Reduction in the output of renewable power plants relative to planned generation in accordance with TSO instructions.

Day-ahead market
An energy market where an auction takes place on the preceding day (typically at noon) for the delivery of electricity on the next day (typically for each hour of the following day).

Demand response
Consumer loads that can be reduced or increased at various times of the day for certain hours.

Dispatch
Unit commitment of power system resources (supply, demand response, storage) and their output adjustment in line with changes in demand.

Inflexible generation
Power from plants subject to technical or economic constraints that prevent rapid adjustment of generation levels.

Intraday market
An energy market in which electricity is traded for delivery on the same day. Typically, intraday markets trade hourly, half-hourly and 15-minute products. Trading concludes up to 30 minutes before delivery so as to offset short-term fluctuations in supply and demand.

Merit-order principle
The merit-order principle is a basic principle for power market operations. It ensures that power plants with the lowest operating costs are deployed first, followed by those with higher operating costs. On the power market, generation bids are sorted from cheapest to most expensive and crossed with demand bids, which are sorted from highest to lowest willingness to pay.

Must-run generation
Generation capacities that have to be online at all times to perform system services such as balancing.

Net load
Power demand not already served by renewables.

Redispatch
Instructions from the TSO to adjust the wholesale market-based dispatch of power plants for the purpose of preventing or fixing grid overloads (known as preventive or curative redispatch).

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About Agora Energiewende

Agora Energiewende develops evidence-based and politically viable strategies for ensuring the success of the clean energy transition in Germany, Europe and the rest of the world. As a think tank and policy laboratory we aim to share knowledge with stakeholders in the worlds of politics, business and academia while enabling a productive exchange of ideas. Our scientifically rigorous research highlights practical policy solutions while eschewing an ideological agenda. As a non-profit foundation primarily financed through philanthropic donations, we are not beholden to narrow corporate or political interests, but rather to our commitment to confronting climate change.

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