Bundesnetzagentur Bundeskartellamt

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Report
Monitoring report 2018

Monitoring Report 2018

in accordance with
section 63(3) in conjunction with section 35 of the Energy Industry Act (EnWG)
and section 48(3) in conjunction with section 53(3) of the Competition Act (GWB)
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Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen

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German Energy Industry Act section 63(3)
Reporting

(3) Once a year, the Bundesnetzagentur shall publish a report on its activities and in agreement with the Bundeskartellamt, to the extent that aspects of competition are concerned, on the results of its monitoring activities, and shall submit the report to the European Commission and the Agency for the Cooperation of Energy Regulators (ACER). The report shall include the report by the Bundeskartellamt on the results of its monitoring activities under section 48(3) in conjunction with section 53(3) of the Competition Act as prepared in agreement with the Bundesnetzagentur to the extent that aspects of regulation of the distribution networks are concerned. The report shall include general instructions issued by the Federal Ministry of Economic Affairs and Energy in accordance with section 61.

German Competition Act section 53(3)
Activity report and monitoring reports

(3) At least every two years, as part of its monitoring activities pursuant to section 48(3) sentence 1, the Bundeskartellamt shall prepare a report on the competitive conditions in the electricity generation market.

Monitoring Report data origin

Unless otherwise indicated, the figures in this report have been taken from the data collected during the monitoring survey carried out annually by the Bundesnetzagentur and the Bundeskartellamt. Undertakings that are active on the electricity or gas market in Germany provide data for the survey on all aspects of the value added chain (generation, network operation, metering operations, trade, marketing etc). Further data on trade is supplied by the electricity and gas stock exchanges, and by energy brokers. All the data is checked for plausibility and validated by the Bundesnetzagentur and the Bundeskartellamt. In 2018, some 6,500 undertakings overall supplied data to the two authorities. Thus the degree of coverage in each market segment, as reflected by the level of response, was well over 95% and in many areas it reached 100%. Any discrepancies between this and other data are the result of different data sources, definitions and survey periods.

Foreword

The electricity and gas markets in Germany and Europe are going through fundamental changes. A greater level of competition, whilst ensuring a sustainable and secure energy supply, is particularly intended to serve the best interests of consumers. Whether these goals are being reached is assessed in a timely and thorough manner in the annual monitoring report presented by the Bundesnetzagentur and the Bundeskartellamt. This year the focus is being placed even more strongly than before on the consumer: presenting energy issues from the consumer's perspective enables the final user to gain a better insight.

The ongoing energy transition is still a defining feature of the electricity markets. Gross electricity consumption in 2017 remained at a more or less consistent level when compared with the previous year; although the share of electricity from renewable energy sources in gross electricity consumption rose more than 36%. Overall, though, the amount of net electricity generated was the same as the previous year. There was an increase in generating capacity again in 2017, which can be attributed to further growth in capacity from renewable energy sources. The market integration of renewables is currently very high; about 78% is marketed in direct competition by the electricity producers.

The positive trend, when viewed in terms of competition, of declining market concentration in conventional electricity generation continued unabated in 2017. Firstly, the combined market share of the largest electricity producers was down again on previous years and, secondly, the sale of Vattenfall's brown coal business to LEAG has led to a noticeable de-concentration effect. Following on from this, the spin-off of electricity producer Uniper from the E.ON Group and its sale to the Finnish company Fortum in 2018 suggests that the trend is likely to continue.

For the first time since 2011, the electricity wholesale price annual average has risen again. This was accompanied, however, by a decline in liquidity on the wholesale markets. On 1 October 2018, the previous single bidding zone consisting of Germany and Austria was divided in view of the current physical realities. The bidding zone split was already influencing the liquidity of long-term products on the wholesale markets as early as 2017. For instance, early on before the split, market players were able to procure new products from the EEX intended solely for the German market area, with the result that, ever since, the trading volume has clearly shifted to products for the German bidding zone. On the gas markets, following a significant rise in wholesale gas prices after an earlier increase in 2016, liquidity in wholesale trading in natural gas in 2017 once again reached more or less the level of 2015.

The retail markets for electricity and gas also reflected a positive trend in 2017 towards more competition, giving rise to a greater range of choices and price advantages for final customers. The accumulated market share of the largest electricity suppliers for standard load profile and interval-metered customers was down again on the previous year and, the same as for the degree of market concentration in the two largest gas retail markets, was clearly below the statutory presumption threshold of a dominant market position.

The electricity prices recorded at the reporting date of 1 April 2018 show that prices for household customers have once again remained steady on the previous year, whereas prices for commercial customers have fallen slightly on average and those for industrial customers have risen compared with the previous year. At the same time, the electricity price component controlled by the supplier has risen for the first time since 2011.

The network charge, the renewable energy surcharge and the surcharge provided for by the Combined Heat and Power Act all decreased in 2018; consequently the price increase as at 1 April 2018 was moderate on average. Gas prices for household and commercial customers fell again as at 1 April 2018 in comparison with the previous year, hence the downwards trend in gas prices for end users is continuing in these areas. In contrast, end user prices for industrial customers have risen slightly.

Another positive factor from a competition point of view is that, on the electricity and gas markets, those supplying about a third of household customers are not the local default supplier. When consumers change a supplier, price comparison sites are now playing an ever-increasing role and at present, as part of a sector inquiry, the activities of such sites are under close examination by the recently set up decision division for consumer protection at the Bundeskartellamt. Of note in 2017 is that the supplier switching rate for electricity customers for both household and non-household supply only increased slightly and that for gas customers in both areas the rate even fell for the first time in many years. Nevertheless, for household customers it is still worth switching from a default contract to another type of contract.

As before, the conversion of the German L-gas network to H-gas supply has had a direct impact on consumers. Household customers, for example, have seen their gas heating adapted to suit. This conversion work continued successfully in 2017 in larger network areas, such as Westnetz, Avacon and wesernetz Bremen. The network operators used the experience they had gained in collecting and converting the devices affected to ensure as smooth a conversion process as possible.

The Bundeskartellamt and the Bundesnetzagentur have continued their close collaboration on this report. The Bundeskartellamt has focused on the competitive aspects of the electricity and gas value added chains, including delivery to non-household customers, whilst the Bundesnetzagentur has directed its attention towards the networks, security of supply and delivery to household customers. The market coverage and the validity of the data collected continue to be excellent thanks to the commitment of the undertakings surveyed.

Together we will continue to follow the development of the electricity and gas markets in Germany closely and will play a role in shaping this process within our respective areas of activity. The information in this report shows that the markets are on the right path as regards competition, but that there is still a need for action so that competitive conditions in the fields of gas and electricity continue to develop positively and the consumer can benefit even more from changes in the markets.

Jochen Homann
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Telekommunikation, Post und Eisenbahnen

Andreas Mundt
President of the Bundeskartellamt

Key findings

Generation

At 601.4 TWh, Germany's net electricity generation in 2017 corresponded to the 2016 level (601.4 TWh). Generation from non-renewable energy sources decreased disproportionately by 24.7 TWh. After only a slight increase in renewable electricity generation in 2016, there was a substantial increase of 24.6 TWh in 2017, with renewable electricity generation being equivalent to 36% of gross electricity consumption.

The generation landscape was characterised in 2017 by further growth in installed renewable energy capacity. At the end of 2017, installed renewable capacity had increased year-on-year by approximately 8.3 GW. Altogether, total generating capacity rose from 211.9 GW in 2016 to 217.6 GW in 2017, with 105.1 GW of non-renewable and 112.5 GW of renewable capacity.

The market power of the largest conventional electricity producers (electricity not eligible for payments under the Renewable Energy Sources Act – EEG) has decreased significantly over the last years. The cumulative market share of the five largest electricity producers in the German-Austrian market has decreased from 69.4% in 2016 to 67.5% in 2017. If the cumulative market share of the five largest undertakings were viewed only for the German market for the first-time sale of electricity, in line with the current split of the previously joint bidding zone, this would be 75.5% compared with 76.5% in 2016. Thus also this market definition shows a decline in market concentration.

Development of renewable energy generation

The growth in renewable energy capacity of 8.3 GW (sum of renewable energy installations with and without payments under the EEG) is due in particular to the continued expansion of onshore wind capacity. Onshore wind recorded a year-on-year increase of 5.0 GW, solar energy 1.7 GW, and offshore wind 1.3 GW.

Compared with 2016, onshore wind generation significantly increased by 20.0 TWh or 30.1%, on account of the higher wind levels in 2017. The amount of electricity generated through solar recorded a slight year-on-year increase of 0.9 TWh or 2.7%. Offshore wind generation was also up, showing an increase of 5.3 TWh or 44%. Total renewable electricity generation was thus 24.6 TWh or 13.7% higher than in 2016. Renewable electricity generation was equivalent to 36% of gross electricity consumption (579.9 TWh) in 2017. Payments to renewable installation operators under the Renewable Energy Sources Act averaged 13.9 ct/kWh in 2017.

Since 2017 competitive auctions have been introduced to determine the level of payments for new renewable energy and combined heat and power (CHP) installations, and a total of 24 auctions have been held (six for solar photovoltaic installations, seven for onshore wind installations, two for offshore wind projects, three for CHP installations, two for innovative CHP systems and two for biomass plants). Additionally, in 2018, for the first time, two joint auctions combining onshore wind and solar installations were held, and two auctions were launched for innovative CHP systems.

Electricity supply interruptions

In 2017, the average interruption in supply per connected final consumer was 15.14 minutes and thus below the ten-year average from 2006 to 2016 of 15.59 minutes. The quality of supply thus remained at a consistently high level in 2017.

Redispatch and feed-in management

In 2017 the need for redispatching increased. The total reductions in feed-in of conventional electricity sources due to redispatching amounted to 10,200 GWh in 2017, while the increases in feed-in by market power plants and grid reserve power plants added up to 10,239 GWh (in total 20,439 GWh). The reductions in feed-in from power plants as a result of redispatching measures thus corresponded to 2.6% of total non-renewable generation fed into the grid. Cost for redispatching measures with market and grid reserve power plants went up to €901m in 2017. The increase in redispatching measures essentially occurred in the first quarter of 2017, when a combination of various circumstances put an exceptionally severe strain on electricity networks, despite low wind power feed-in. Upon the full commissioning of the “Thuringia power bridge” on 14 September 2017 redispatching measures went down again in the fourth quarter of 2017.

With a total of 5,518 GWh the amount of renewable energy curtailed as a result of feed-in management measures recorded a new high in 2017. The amount of electricity curtailed was up just over 47% year-on-year (3,743 GWh in 2016). This corresponds to 2.9% of the total amount of electricity generated[1] by renewable energy installations eligible for payments under the Renewable Energy Sources Act (including direct selling) compared with 2.3% in 2016. The total estimated claims from installation operators rose to €610m in 2017. One reason for the increase in feed-in management measures and related costs is the connection of new offshore wind farms in 2016 and 2017. This reflects the clear need for grid expansion in the Emsland to transport the electricity generated by the offshore wind farms.

Electricity network charges

Having been broadly stable in the period between 2013 and 2015, the network charges for household customers showed an increase in 2016 and 2017. In 2018 the average network charge for household customers went down again by 0.13 ct/kWh or just under 2% to 7.17 ct/kWh.

Wholesale electricity markets

The liquidity of the wholesale electricity markets in 2017 recorded a considerable decline. One reason for this was the introduction of congestion management at the German-Austrian border as of 1 October 2018, thus effectively splitting the joint German-Austrian market area (referred to as bidding zone split).[2] Market participants had a chance to prepare for this development at an early stage purchasing new products specifically launched by EEX for the German market area, so-called Phelix DE futures. By the end of 2017, the liquidity and trading volume had clearly shifted from Phelix DE/AT futures to Phelix DE futures.

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[1] This does not include the amount of electricity curtailed through feed-in management.

[2] This bidding zone will be dissolved from 1 October 2018, so that in future there will be a bidding zone for Austria and a separate bidding zone for Germany and Luxembourg. This is what the Bundesnetzagentur and the Austrian regulatory authority E Control agreed on 15 May 2017. Cf https://www.bmwi.de/Redaktion/DE/Pressemitteilungen/2017/20170515-bnetza-e-control-einigen-sich.html (accessed on 13 September 2018).

Volumes in on-exchange futures trading and volumes traded via broker platforms decreased, while there were different trends regarding spot market trading volumes. The volume of day-ahead trading decreased slightly, while the volume of intraday trading increased by approximately 15%.

For the first time since 2011 average wholesale prices for electricity increased in 2017. Spot market prices were up about 18% year-on-year, and futures were quoted approximately 22% higher. The volume of OTC clearing of Phelix DE/AT futures on EEX went down significantly in 2017.

Retail electricity markets

The retail markets are continuing to develop positively. The Bundeskartellamt assumes that there is no longer any single dominant undertaking in either of the two largest electricity retail markets. The cumulative market shares of the four largest undertakings showed a further year-on-year decrease, down to around 25% in the national market for supplying interval-metered customers and 33% in the national market for non interval metered customers on special contracts.

About 31% of all household customers are now served by a supplier other than their local default supplier, thus for the first time making this share exceed the share of default supply customers. In 2017, once again, more than 4.7m household customers switched supplier. There was also a continued increase in the number of undertakings operating in the market. Household customers can choose between an average of 124 different suppliers.

The supplier switching rate for non-household customers has been fairly constant since 2009. The rate for non household customers with an annual consumption of more than 10 MWh reached a new high of 13.0% in 2017, compared with 12.7% in 2016.

The average total price (excluding VAT and possible reductions) for industrial customers with an annual consumption of 24 GWh was 15.30 ct/kWh, up 0.40 ct/kWh on the previous year; the increase is mainly accounted for by the price components controlled by the supplier. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh in April 2018 was 21.56 ct/kWh, representing a decrease on the previous year of 0.14 ct/kWh.

As at 1 April 2018, the average price for household customers had remained broadly unchanged, amounting to 29.88 ct/kWh, compared with 29.86 ct/kWh in 2017. This average value is calculated by weighting the individual prices across all contract models according to their consumption for an annual consumption of between 2,500 kWh and 5,000 kWh, producing a reliable average for the electricity price for household customers. As at 1 April 2018 the price component controlled by the supplier (energy procurement, supply and margin) accounts for about 6.74 ct/kWh or 22.6% of the total price, and has thus increased for the first time since 2011. This increase can be related in particular to the increasing wholesale prices in 2017, which are now gradually passed on to household customers. By contrast, average network charges fell in 2018 for the first time since 2011 but still remain at a high level, accounting for 22.9% of the total price. The same applies to the renewable energy surcharge, which also decreased but still accounts for 22.7% of the total price. Together with the reduction of the surcharge payable under the CHP Act this is having a dampening effect on rising prices in 2018.

Electric heating

Electric heating prices were slightly higher than in 2017. The arithmetic mean of the gross total price for night storage heating customers as at 1 April 2018 was 21.08 ct/kWh, slightly up on the previous year's level of 20.94 ct/kWh. The arithmetic mean of the total price for heat pump electricity was 21.71 ct/kWh, slightly up on 2017. In general, prices for heat pump electricity are approximately 0.63 ct/kWh higher than for night storage heating.

There has been a steady increase in switching activity among electric heating customers, albeit at a low level, following many years with hardly any customers switching. This increase in the switching rate indicates a higher degree of competition. Yet at the same time, the switching rates are still far below those for household electricity and non-household customers. The supplier switching rate for 2017 was around 4%. There is a steady increase in the share of electricity provided for heating purposes and electric heating meter points provided by a supplier other than the local default supplier, now standing at around 12%.

Electricity imports and exports

Electricity exports again exceeded imports in 2017. The trading volume showed a total year-on-year increase of 15.2%. With an export balance of 55.8 TWh Germany is one of Europe’s large exporters of electricity.

Gas imports and exports

The volume of gas imported into Germany rose by some 35 TWh or around 2% from 1,641 TWh in 2016 to 1,676 TWh in 2017. Gas exports decreased in 2017. While the volume of gas exported was at 770.4 TWh in 2016, in 2017 it was at 743.5 TWh, down some 27 TWh or 3.5%.

The main sources of gas imports to Germany remain Russia and Norway. The main recipients of Germany's exports were the Czech Republic, the Netherlands and Switzerland.

Gas supply interruptions

In 2017, the average interruption in supply per connected final consumer was 0.99 minutes per year. The reliability of gas supply remains at a constantly high level.

Market area conversion

The conversion of German L-gas networks to H-gas started well in 2015 with the conversion of smaller network areas. Since 2017 larger network operators such as Westnetz, Avacon and wesernetz Bremen have also been undergoing the conversion process.

Gas storage facilities

The market for the operation of underground natural gas storage facilities is still relatively highly concentrated, although concentration has eased over the past few years. The cumulative market share of the three largest storage facility operators stood at around 68.2% at the end of 2017, remaining the same as in the previous year.

On 31 December 2017 the total maximum usable volume of working gas in these storage facilities was 280.1 TWh. Of this, 132.22 TWh was accounted for by cavern storage, 125.86 TWh by pore storage facilities and 22.01 TWh by other storage facilities. As at 1 November 2017 the storage level of gas storage facilities was at over 87%.

Wholesale natural gas markets

Overall, the liquidity of the wholesale natural gas markets decreased significantly in 2017. The volume traded on the spot market rose by some 5% year-on-year, but the futures trading volume fell by about 34% to levels slightly below those of 2015. There was a decrease of about 20% in volumes of bilateral wholesale trading via broker platforms in 2017.

Unlike 2016, 2017 was marked by, in part, significantly higher wholesale gas prices. The various price indices (daily reference prices, cross-border prices, as calculated by the Federal Office for Economic Affairs and Export Control) show a year-on-year increase between 12% and 24%.

Retail gas markets

The levels of concentration in the two largest gas retail markets continue to be well below the statutory thresholds for presuming market dominance. In 2017, cumulative sales for the four largest companies to customers with standard load profile (SLP) were about 87 TWh and about 138 TWh for interval-metered customers. The cumulative market share of the four largest companies (CR4) in 2017 was around 23% for SLP customers (2016: 25%) and about 30% for interval-metered customers (2016: 28%).

The retail gas markets are continuing to develop positively. Over 1.5m household customers switched gas supplier in 2017; yet the number of customers switching gas supplier stagnated at the previous year's level or even recorded a slight decline.

After switching rates for non-household customers had remained virtually constant between 11% and 13% for several years, 2017 saw a decline to 8.9%. In 2017, total consumption affected by supplier switches was about 15% lower than in the previous year.

At 891,000, the total number of customers changing contract continued to develop positively in 2017. Overall, the percentage of household customers who have a contract with a supplier other than the local default supplier continues to decline, reaching 19% in 2017. There was also another significant increase in the number of undertakings operating in the market. Household customers can choose on average between 98 different suppliers. At the same time, the number of gas disconnections decreased. In 2017, a total of almost 38,000 customers were disconnected, representing a year-on-year decrease of around 1.5%.

Varying developments were recorded for gas prices for non-household (industrial and commercial) customers as at 1 April 2018 compared with the previous year. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") of 2.82 ct/kWh is 0.13 ct/kWh or around 5% higher than the previous year's figure of 2.69 ct/kWh. By contrast, the arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") of 4.40 ct/kWh is 0.1 ct/kWh or around 2% lower than last year's price.

Gas prices for household customers as at 1 April 2018 once again showed a year-on-year decrease, but it was not as marked as in previous years. One of the reasons for the fall in prices was the drop in procurement costs, reflected in the price component "energy procurement, supply and margin". The volume-weighted average across all groups of household customers with average consumption was down 1.3% or 0.08 ct/kWh to 6.07 ct/kWh (including VAT), compared with 2017. Taxes, levies and network charges make up around 50% of the total gas price in Germany.

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I Electricity market

A Developments in the electricity markets

1. Summary

1.1 Generation and security of supply

At 601.4 TWh, Germany's net electricity generation in 2017 corresponded to the 2016 level (601.4 TWh). Generation from non-renewable energy sources decreased by 24.7 TWh. There was a 6.3% year-on-year increase in net electricity generation from gas-fired power plants and of 2.5% from pumped storage stations, while net electricity generation from conventional sources declined. Nuclear generation was down 7.8 TWh or 9.9% on 2016. Generation by hard coal-fired power plants fell by 19.8 TWh or 19.2%. Generation by lignite-fired plants was 2.0 TWh or 1.4% lower.

After only a slight increase in renewable electricity generation in 2016, there was a substantial increase of 13.7% to a total of 204.8 TWh in 2017, compared with 180.2 TWh in 2016, corresponding to a share of 36% of gross electricity consumption.

The generation landscape was characterised in 2017 by a further increase in installed renewable energy capacity. Altogether, growth in renewable capacity amounted to 8.3 GW, compared with a year-on-year increase of 6.5 GW in 2016[3]. The highest growth in generating capacity was recorded for onshore wind (up 5.0 GW), offshore wind (up 1.3 GW) and solar energy (up 1.7 GW). Non-renewable generating capacity (nuclear, lignite, hard coal, natural gas, mineral oil products, pumped storage and other non-renewable energy sources) decreased in 2017 by 2.5 GW. Total (net) installed generating capacity increased to 217.6 GW at the end of 2017, with 105.1 GW of non-renewable and 112.5 GW of renewable capacity.

The total installed capacity of installations eligible for payments under the Renewable Energy Sources Act (EGG) in Germany stood at 107.8 GW at the end of 2017, compared with 99.5 GW a year earlier. This represents an increase of around 8.3 GW or 8.3%. A total of 187.4 TWh of electricity from renewable energy installations received payments in 2017, up 16.1% compared with 161.5 TWh in 2016. Due to the increase in electricity generation from EEG subsidised installations, payments under the Renewable Energy Sources rose to a total of €26.0bn, up 7% on 2016. In 2017, the average payable to installation operators under the Renewable Energy Sources Act[4] was 13.9 ct/kWh. In 2016, for the first time, the majority of the payments – 52.3% – were made to installation operators eligible for market premiums. This trend continued in 2017, with 43.3% of payments made under the feed-in tariff scheme and 56.7% as market premiums.

Following the amendment to the Renewable Energy Sources Act at the end of 2016/beginning of 2017, the level of payment for around 80% of new renewable capacity is now determined through competitive auctions for the different sources of energy. Installations must bid successfully in the auctions to receive payments under the Act.

[3] The 2016 figure from the 2017 monitoring has been updated.

[4] The average is calculated by dividing the total sum paid under the Renewable Energy Sources Act in a year by the total amount of renewable electricity fed in during that year.

The auctions for solar photovoltaic installations have so far been marked by a high level of competition. Up to the June 2018 auction the average volume-weighted award price fell in each successive auction from 9.17 ct/kWh to 4.59 ct/kWh, while it went slightly up again to 4.69 ct/kWh in the last auction.

The auctions held for onshore wind energy (together comprising a total volume of 2,800 MW) were significantly oversubscribed. Citizens' energy companies showed a particularly strong presence in these auctions. Unlike in the previous year's auctions, the results of the four auctions completed in 2018, without applying special rules to citizens' energy companies, were marked by reduced competitive intensity, higher award prices and far lower participation by citizens' energy companies. The second auction in May 2018 was, for the first time, slightly undersubscribed, while the last one in October was clearly undersubscribed, with the bids submitted covering only 59% of the volume offered. In the last three auctions in 2018 all the qualified bids were successful.

The lowest average volume-weighted award price of 3.82 ct/kWh was paid in the third auction, and the highest of 6.26 ct/kWh in the fourth and last auction in 2018.

In the auctions held in April 2017 and April 2018 to determine payments for offshore wind energy, ten bids for projects with a total capacity of 3,100 MW were accepted. The prices awarded ranged from 0.00 ct/kWh to 9.83 ct/kWh.

The auctions for new and existing biomass plants held in September 2017 and September 2018 were both undersubscribed, with the bids submitted covering 33% and 39%, respectively, of the volume offered. The average volume-weighted award price of all the bids accepted was 14.30 ct/kWh for the 2017 auction and 14.73 ct/kWh for the 2018 auction.

In April and October 2018, the Bundesnetzagentur conducted the first joint auctions for onshore wind and solar power installations. For the first auction in April 2018 some 54 bids were received, of which 18 were for onshore wind and 36 for solar power installations. All 32 bids accepted, totalling 210 MW, were for solar power installations only.

In 2017, the average interruption in supply per connected final consumer was 15.14 minutes and thus below the ten-year average from 2006 to 2016 of 15.59 minutes. The quality of supply thus remained at a consistently high level in 2017.

1.2 Cross-border trading

Electricity exports again exceeded imports in 2017. The trading volume showed a total year-on-year increase of 15.2%. Germany thus forms the hub for electricity exchange in Europe and plays a key role within the central interconnected system. The average available transmission capacity to neighbouring countries was 1.3% higher in 2017 than in 2016.

Total cross-border traded volumes in 2017 accounted for 90 TWh. With an export balance of 55.8 TWh Germany is one of Europe's large exporters of electricity, with exports amounting to €1,726m.

1.3 Networks

1.3.1 Grid expansion

Based on the third quarterly report for 2018, some 1,200 km of the total of about 1,800 km of power lines listed in the Power Grid Expansion Act (EnLAG) have been approved, with around 800 km of these – about 45% of the total – completed. The TSOs anticipate that some 70% of the line kilometres listed in the Act will be completed by 2020. So far, none of the underground cable pilot lines have been put into full operation. Operational testing is in progress for the first 380 kV underground cable pilot project in Raesfeld.

Alongside monitoring the projects in the Power Grid Expansion Act, the Bundesnetzagentur publishes quarterly updates on the status of the expansion projects listed in the Federal Requirements Plan Act (BBPlG). The projects currently listed in the Federal Requirements Plan Act as at the third quarter of 2018 comprise lines with a total length of about 5,900 km. According to the network development plan, around 3,050 km of these lines will serve to reinforce the system. The total length of the lines in Germany will largely depend on the route of the north-south corridors and will become apparent over the course of the procedure. In total, around 600 km have been approved and about 150 km have been completed. Thus the planning procedures that were initiated following the decision to build the DC lines using underground cables are on schedule for 2025.

1.3.2 Investments

In 2017, investments in and expenditure on network infrastructure by the network operators amounted to around €9,727m, compared with €10,418m in 2016 (both values under commercial law[5]). The investments and expenditure incurred by the distribution system operators (DSOs) in 2017 amounted to €6,629m, while the four German transmission system operators (TSOs) spent €3,096m. The TSOs' investments in new builds, upgrades and expansion projects fell slightly from €2,298m in 2016 to €1,972m in 2017, while the DSOs' investments in new builds, upgrades and expansion projects increased slightly from €1,812m in 2016 to €1,829m in 2017. At a total of €1,627m, the DSOs' investments in maintenance and renewal are considerably higher than those of the TSOs, totalling €213m in 2017. The investment time series were updated retrospectively to include TSOs' offshore investments up to 2008. There was a slight increase in the number of DSOs carrying out measures to enhance, reinforce or expand their networks as at 1 April 2018.

1.3.3 Network and system security and system stability

Redispatching measures serve to maintain network and system security. In 2017, the reductions in feed-in from conventional power plants as a result of redispatching measures corresponded to 2.6% of total non-renewable generation fed into the grid. In absolute terms, total reductions in feed-in amounted to 10,200 GWh, increases in feed-in from operational plants to 8,256 GWh and increases in feed-in due to the use

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[5] Investments and expenditure are defined in the glossary. The values under commercial law do not correspond to the implicit values included in the system operators' revenue cap in accordance with the provisions of the Incentive Regulation Ordinance (ARegV). A comparative calculation of the values under commercial law with the values from incentive regulation will be able to be made following the introduction of an index-based investment monitoring pursuant to section 33(5) ARegV. Medium to long-term trends can be derived from the evaluations on the basis of the survey of commercial values. The introduction of an index-based investment monitoring pursuant to section 33(5) ARegV is currently being prepared by the Bundesnetzagentur taking account of the effort required for companies to transmit data.

of grid reserve power plants to 2,129 GWh[6]. Overall, a total of 20,439 GWh[7] of reductions and increases in feed-in was requested for the relief of line congestion.

This reflects a considerable increase in the need for redispatching measures compared with previous years, which was mainly due to exceptional circumstances between the beginning of January and the beginning of February 2017. The severe strain on electricity networks during this period was the result of various factors, such as the unusual load flows in Germany, with large flows of electricity mainly to the south-west, the cold period throughout Europe in combination with high loads and low generation from wind and solar power installations, accompanied by the non-availability of power stations.

Throughout the year, network congestion increased significantly, primarily in the Emsland. Power lines in the Emsland running from Dörpen to Hanekenfähr are used in particular to transport electricity from offshore wind farms in the North Sea. The strain on the previously heavily congested Remptendorf-Redwitz network element, however, has eased since the full commissioning of the "Thuringia power bridge" network expansion project on 14 September 2017. Measured in time, congestion on the "Remptendorf-Redwitz" line went down to only 18 hours in the fourth quarter of 2017, compared with 945 hours a year earlier.

The high demand for redispatching in 2017 is also reflected in the TSOs' estimated costs of the relevant measures. According to these estimates, redispatching costs were up around €169m from €222.6m in 2016 to about €391.6m in 2017, with another €29.2m to be added for counter trading measures and another €479.9m for providing and using grid reserve power plants.

The amount of energy curtailed as a result of feed-in management measures, i.e. the curtailing of installations receiving payments under the EEG or the CHP Act, also recorded a new high in 2017, totalling 5,518 GWh. This reflects a year-on-year increase of just over 47%, compared with 3,743 GWh in 2016. This corresponds to 2.9% of the total amount of electricity generated[8] by renewable energy installations eligible for payments under the Renewable Energy Sources Act (including direct selling) compared with 2.3% in 2016. The amount of compensation claims paid to installation operators in 2017 was €574m, down around €69m on 2016 (€643m). The total estimated claims from installation operators, however, rose to €610m in 2017. The discrepancy between the figures is due to the fact that the compensation paid in 2017 does not reflect the compensation for energy curtailments in 2017. The compensation paid in 2017 may include amounts payable for curtailments in previous years and claims from 2017 may not be reflected properly, as the billing period does not correspond to the period when the measures were taken.

In 2017, as in previous years, feed-in management measures primarily involved onshore wind power plants, accounting for 80.8% of the total amount of curtailed energy, down from 93,5% in 2016. Offshore wind power plants, which were first affected by feed-in management measures in 2015, accounted for about 826 GW or 15% of the total amount of curtailed energy in 2017, up from around 32 GW or 0.9% in 2016.

The main reason for the increased feed-in management measures in 2017 was the curtailment of offshore wind power plants in addition to the wind situation and the growth of renewable capacity. Given the

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[6] This total value on the use of grid reserve power plants also includes test starts and test runs.

[7] This total value on the requests for using grid reserve power plants to manage congestion does not include test starts and test runs.

[8] This does not include the amount of electricity curtailed through feed-in management.

increased need for feed-in management measures and assuming that there will be a further steady increase in renewables, the measures required for network optimisation, reinforcement and expansion must be implemented without delay. Once again, this applies to the networks in the Dörpen region, which are also affected by redispatching measures; as regards feed-in management measures, the substation level between high voltage and extra-high voltage in Schleswig-Holstein deserves particular consideration.

In 2017, a total of three distribution system operators took adjustment measures, resulting in feed-in adjustments of about 34.5 GWh.

In total, the costs for network and system security[9] amounted to about €1,510.7m in 2017, up around €369.4m on the 2015 peak of €1,141.3m.

1.3.4 Network charges

The volume-weighted network charges (including meter operation charges) for household customers went down by 0.13 ct/kWh or just under 2%.

- household customers, annual consumption 2,500-5,000 kWh: volume weighted 7.17 ct/kWh

One reason for the fall in average network charges in 2018 is the Network Charges Modernisation Act, which was adopted by the German Bundestag on 30 June 2017 and helps amend the mechanism of avoided network charges. The lower forecast data for avoided network charges are a first indicator of the Act's impact. Regardless of the implementation of the Network Charges Modernisation Act, the Bundesnetzagentur still sees a need to continue the reform of the avoided network charges regime to minimise misguided incentives and windfall profits.

For household customers the arithmetic mean charges are up on a year earlier[10]. The network charges (including meter operation charges) for commercial customers increased by 1% (2016: 6.19 ct/kWh) and those for industrial customers by 4% (2016: 2.26 ct/kWh). The charges as at 1 April 2018 for the three consumption groups were as follows:

- commercial customers, annual consumption 50 MWh: arithmetic mean 6.27 ct/kWh

- industrial customers, annual consumption 24 GWh, without a reduction under section 19(2) of the Electricity Network Charges Ordinance (StromNEV): arithmetic mean 2.36 ct/kWh

There are large regional differences in the network charges. A comparison of the network charges in Germany for the three consumption groups, based on all the DSOs' published price lists (charges excluding metering operation), shows the following: The network charges for household customers range from 2.5 ct/kWh to 25.4 ct/kWh, with only very few customers paying this maximum charge. The range of network charges for commercial customers is similar to that for household customers, with charges ranging from 2.2 ct/kWh to

[9] The operators use feed-in management, redispatching, grid reserve power plants and countertrading to maintain network and system security.

[10] It should be noted that the arithmetic mean reflects neither the wide spread of the network charges nor the heterogeneity of the network operators for these three consumption groups.

24.6 ct/kWh. The network charges for industrial customers (without possible reductions) range from around 0.6 ct/kWh to 5.8 ct/kWh.

1.4 System services

The net costs for system services in a broader sense increased by €518.2m from about €1,464.9m in 2016 to €1,983.1m in 2017. A large part of the costs is accounted for by the costs of reserving and using grid reserve power plants at around €479.9m (2016: €285.7m), national and cross-border redispatching at just under €291.6m (2016: €222.6m), the estimated claims for compensation for feed-in management measures at €609.9m (2016: €372.7m), procuring primary, secondary and tertiary control reserves at €145.5m (2016: €198.1m), and energy to compensate for losses at about €280.4m (2016: €304.8m).

The structure of the system service costs changed in 2017 from 2016. The total net costs for balancing energy fell by €52.6m. One reason for this fall is the further slight decrease in the volumes of the three types of balancing reserve procured. An increase of around €693m was mainly recorded for the costs for network and system security measures.

1.5 Wholesale

Well-functioning wholesale markets are vital to competition in the electricity sector. Spot and futures markets are crucial for meeting suppliers' short and longer term electricity requirements. Electricity exchanges play a key role alongside bilateral wholesale trading (over-the-counter trading, or OTC). They create a reliable trading forum and at the same time provide key price signals for market players in other areas of the electricity industry.

The liquidity of the wholesale electricity markets in 2017 recorded a considerable decline. One reason for this was the introduction of congestion management at the German-Austrian border as of 1 October 2018, thus effectively splitting the joint German-Austrian market area (referred to as bidding zone split).[11] Market participants had a chance to prepare for this development at an early stage purchasing new products specifically launched by EEX for the German market area, so-called Phelix DE futures. By the end of 2017, the liquidity and trading volume had clearly shifted from Phelix DE/AT futures to Phelix DE futures.

While in July the share of Phelix-DE accounted for only 24% of the total Phelix-DE and Phelix DE/AT futures, it exceeded Phelix-DE/AT between October and November. By December 2017 Phelix-DE had significantly gained in importance, accounting for as much as 62% of the total futures for Germany.

Volumes in on-exchange futures trading and volumes traded via broker platforms decreased, while there were different trends regarding spot market trading volumes. The volume of day-ahead trading on EPEX SPOT in 2017 was around 233 TWh, slightly down on the previous year's volume of 235 TWh, while the volume of intraday trading increased by approximately 15% to 47 TWh. The volume of day-ahead trading on EXAA remained stable at around 8 TWh in 2017. The on-exchange trading volumes of Phelix futures increased

[11] This bidding zone will be dissolved from 1 October 2018, so that in future there will be a bidding zone for Austria and a separate bidding zone for Germany and Luxembourg. This is what the Bundesnetzagentur and the Austrian regulatory authority E Control agreed on 15 May 2017. Cf https://www.bmwi.de/Redaktion/DE/Pressemitteilungen/2017/20170515-bnetza-e-control-einigen-sich.html (accessed on 13 September 2018)

significantly again, following considerable growth in the previous years: volumes decreased in 2017 by 46% from 1,466 TWh to over 786 TWh.

For the first time since 2011 average spot market prices increased in 2017. The Phelix day base average on EPEX SPOT rose by about 18% from €28.98/MWh to €34.20/MWh. At €38.06/MWh, the Phelix day peak was also nearly 19% above the previous year's level of €32.01/MWh. The gap between the Phelix day base and the Phelix day peak was around €3.86/MWh in 2017; thus the day peak was some 11% above the day base.

The annual averages of the Phelix-DE/AT future prices rose again compared with a year earlier. At €32.38/MWh, the average Phelix base year future price was €5.81/MWh or around 22% higher than the previous year's average price of €26.58/MWh. The price of the Phelix peak front year future averaged €40.51/MWh over the year. This was exactly €7/MWh or around 21% up on the figure from previous year's average of €33.51/MWh. The volume of OTC clearing of Phelix DE/AT futures on EEX went down significantly in 2017.

Since the introduction of the Phelix-DE future on 25 April 2017 the base year future as well as the peak year future prices have more or less adjusted to the level of the "old" Phelix-DE/AT, only showing a difference of around €0.05/MWh.

1.6 Retail

1.6.1 Contract structure and competition

On the retail market there was another increase in the number of electricity suppliers available to retail customers. In 2017, final consumers could choose on average between 143 suppliers in each network area (not taking account of corporate groups). The average number of suppliers for household customers was 124.

The number of household customers switching supplier has increased steadily since 2006. In 2017 the number of customers switching electricity supplier stabilised at a high level of around 4.7m, compared with 4.6m in 2016. On the whole, the switching rate for household customers was at 11.8%, slightly up from 11.4% in 2016, and the rate for non household customers with an annual consumption of more than 10 MWh stood at 13.0%, up from 12.7% in 2016. In addition, around 2.6m household customers switched contracts with the same supplier.

In 2017, a relative majority of household customers – 41.2% compared with 40.9% in 2016 – were on non-default contracts with their local default supplier. The percentage of household customers on default contracts stood at 27.6%, representing another year-on-year decrease from 30.6% in 2016. About 31% of all household customers are now served by a supplier other than their local default supplier compared with 28.6% in 2016, and this share is continuously growing. Overall, around 69% of all households are still served by their default supplier (under either default or other contracts). Thus the strong position that default suppliers still have in their respective service areas slightly weakened year-on-year.

1.6.2 Disconnections

There was a decrease in 2017 in the number of electricity customers whose supply was disconnected. The number of household customers whose supply was disconnected by the network operator at the local default supplier's request rose by 11,773 to 330,242. Additionally, 13,623 disconnections were carried out on behalf of a supplier other than the local default supplier. Based on information from the network operators, there was a total of 343,865 disconnections. Suppliers issued around 4.8m disconnection notices to household customers, which reflects a significant year-on-year increase. Of these, about 1.1m were subsequently passed on to the relevant network operator with a request for disconnection.

1.6.3 Price level

Data was collected from the suppliers operating in Germany on the prices for household customers as at 1 April 2018. The average price (including VAT) had remained broadly unchanged, amounting to 29.88 ct/kWh, compared with 29.86 ct/kWh in 2017. This average value is calculated by weighting the individual prices across all contract models according to their consumption for an annual consumption of between 2,500 kWh and 5,000 kWh, producing a reliable average for the electricity price of household customers.

In 2018 the price component controlled by the supplier (energy procurement, supply and margin) accounts for about 22.6% of the total price, and has thus increased for the first time since 2011. This increase can be related in particular to the increasing wholesale prices in 2017, which are now gradually passed on to household customers. By contrast, average network charges fell again in 2018 for the first time since 2011, but still remain at a high level accounting for 22.9% of the total price. The same applies to the renewable energy surcharge, which also decreased but still accounts for 22.7% of the total price. Together with the reduction of the surcharge payable under the CHP Act, this is having a dampening effect on rising prices in 2018.

The average price for household customers on default contracts with an annual consumption of between 2,500 kWh and 5,000 kWh increased by about 1.7% to 31.47 ct/kWh from 30.94 ct/kWh in 2017. The average price for non-default contracts with the default supplier remained largely constant, amounting to 29.63 ct/kWh, compared with 29.61 ct/kWh in 2017, while prices for customers on a contract with a supplier other than the local default supplier went down to 28.80 ct/kWh in 2018, from 29.12 ct/kWh in 2017.

As a rule, customers on default contracts can make savings by switching contract and even more by switching supplier, saving up to 1.84 ct/kWh and 2.67 ct/kWh respectively.[12] Household customers with an annual consumption of 3,500 kWh could consequently cut their energy costs by around €64 (change of contract) or €93 (change of supplier) per year. Special bonuses offered by suppliers, including one-off bonus payments, are an added incentive for customers to switch. One-off bonus payments for customers switching to special contracts with their local default supplier average €55, and those for customers switching to a non-default supplier €63.

Varying developments were recorded for electricity prices for non-household customers as at 1 April 2018 compared with the previous year. The average total price (excluding VAT and possible reductions) for industrial customers with an annual consumption of 24 GWh was 15.30 ct/kWh, up 0.40 ct/kWh on the previous year; the increase is mainly accounted for by the price components controlled by the supplier. By contrast, the average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh was 21.56 ct/kWh, representing a decrease on the previous year of 0.14 ct/kWh.

[12] Savings based on an annual consumption of between 2,500 kWh and 5,000 kWh.

1.6.4 Surcharges

Part of the price is due to surcharges, which make up around 25% of the total of the average price mentioned above. Network operators estimated that they would pass on nearly €26.08bn in surcharges to network users in 2018. In order of volume, surcharges include: the renewable energy surcharge (€23.8bn), the surcharge under section 19 of the Electricity Network Charges Ordinance (€1.07bn), the surcharge payable under the Combined Heat and Power Act (€0.97bn), the offshore liability surcharge as per section 17f of the Energy Industry Act (€0.19bn) and the interruptible loads surcharge (€0.05bn). The renewable energy surcharge thus continues to make up over 90% of total surcharges.

1.7 Digital metering

The entry into force of the Metering Act (MsbG) in September 2016 triggered significant changes in metering. The Act requires the comprehensive rollout of modern metering equipment and smart metering systems. Whereas in the past household customers were mainly equipped with analogue Ferraris meters, modern metering systems consist of digital meters that are connected to a communication unit (smart meter gateway) via an interface. Modern metering systems do not transmit any data. They are referred to as smart metering systems when they are connected to a smart meter gateway, enabling them to transmit the data recorded by the meter.

Since the beginning of 2017, the first modern metering systems have been available in the market and have been installed by the first metering operators on a large scale. It has still not been possible to start the rollout of smart metering systems in 2017, since no BSI-certified smart meter gateways were yet available in the market. However, in light of the statutory requirements set out in the Act and advances in metering technology, a large scale rollout of modern metering equipment and smart metering systems is expected in the coming years.

2. Network overview

2.1 Network balance

The network balance provides an overview of supply and demand in the German electricity grid in 2017. Total electricity supply was 628.0 TWh, comprising a net total of electricity generated of 601.4 TWh (including 10.2 TWh from pumped storage) and cross-border flows[13] from abroad amounting to 26.7 TWh. Total electricity consumption was about 631 TWh, with 485.4 TWh from the general supply networks, comprising 472.6 TWh for final consumers and 12.9 TWh for pumped storage stations. The amount of energy consumed by pumped storage stations is higher than the amount generated because of the electricity needed for the pumping process (the electricity consumed by the power station itself.) The net total of electricity generated but not fed into the general supply networks (industrial, commercial and domestic own use) was 40.8 TWh. It may be assumed that the actual value for self-generation is higher, because only data for plants of 10 MW or more are reported to the Bundesnetzagentur. Distribution and transmission losses amounted to 27.5 TWh and physical flows to other countries 77.3 TWh. The sum of the individual entries for demand is around 631 TWh. The difference between this and the total supply of 628.1 TWh is 2.9 TWh or 0.46%. Supply and demand are

[13] The physical flows, and not the trade flows, are decisive for the network balance. Trade flows (73 TWh of exports and 17 TWh of imports) are different from physical flows in the interconnected alternating current system.

therefore almost completely balanced. The difference of 2.9 TWh is due to the complex structure of the data survey involving a large number of different market players.

Network balance 2017

	TSOs	DSOs	Total
Total net nominal generating capacity as at 31 December 2017 (GW)			**217.6**
Facilities using non-renewable energy sources			104.1
Facilities using renewable energy sources			112.5
Generation facilities eligible for payments under the Renewable Energy Sources Act			107.8
Total net generation (including electricity not fed into general supply networks) (TWh)			**601.4**
Facilities using non-renewable energy sources			396.5
Pumped storage			10.2
Facilities using renewable energy sources			204.8
Generation facilities eligible for payments under the Renewable Energy Sources Act			187.4
Net amount of electricity not fed into general supply networks 2016 (TWh)[1]			40.8
Losses (TWh)	**9.9**	**17.6**	**27.5**
Extra high voltage	7.9	0.0	7.9
High voltage (including EHV/HV)	2.0	3.3	5.3
Medium voltage (including HV/MV)	0.0	5.7	5.7
Low voltage (including MV/LV)	0.0	8.6	8.6
Cross-border flows (physical flows) (TWh)			
Imports			77.3
Exports			26.7
Consumption (TWh)[2]	**40.3**	**445.2**	**485.5**
Industrial, commercial and other non-household customers	28.1	324.4	352.5
Household customers	0.0	120.1	120.1
Pumped storage	12.2	0.7	12.9

[1] Own use by industrial, commercial and domestic users, excluding consumption by Deutsche Bahn AG for traction purposes
[2] Including consumption by Deutsche Bahn AG for traction purposes

Table 1: 2017 network balance based on data from TSOs, DSOs and power plant operators

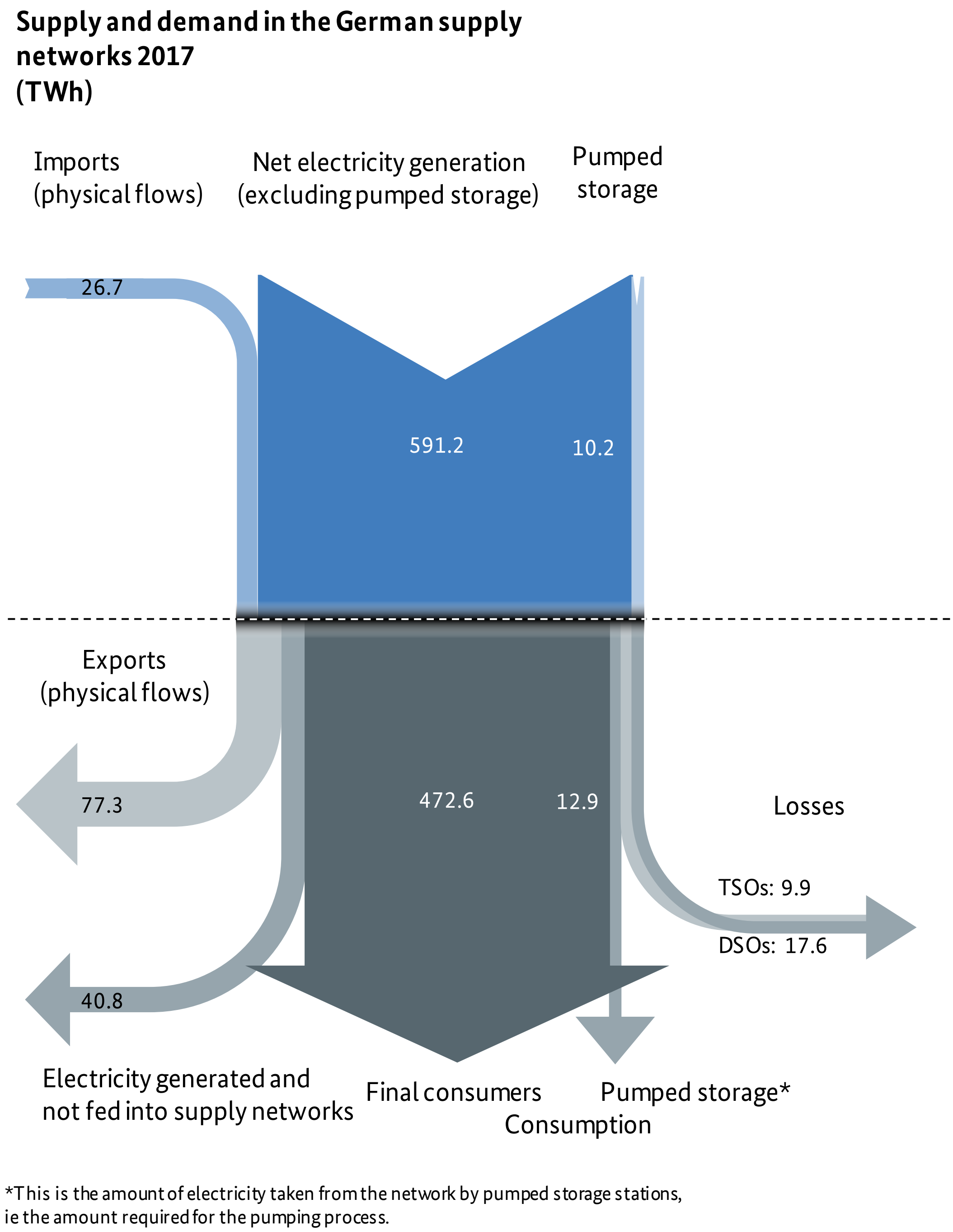

Figure 1: Supply and demand in the electricity supply system, 2017

2.2 Electricity consumption

A gross electricity consumption reported for the monitoring survey of 579.9 TWh can be derived from the network balance presented in 2.1. This gross consumption comprises the sum of gross electricity generation[14] (630.5 TWh) and cross-border flows into Germany (26.7 TWh) less the cross-border flows out of Germany

[14] The actual figure is higher, because the electricity consumed by the power station itself and electricity volumes from self-generation plants with an installed capacity of 10 MW or higher are included in the monitoring.

(77.3 TWh). Gross generation is higher than net generation because it includes the electricity consumed by the power station itself.

It is also possible to calculate the electricity consumption of final customers in Germany. At 513.4 TWh, this figure is well below the gross value, because it does not include the electricity consumed by the power station itself electricity taken from the grid into pumped storage or network losses. The majority of this figure is made up of consumption by final consumers, which has dropped to about 472.6 TWh from 475.5 TWh in 2016. Then there is the net electricity generation that is not fed into the grid and is used directly by final consumers, which according to the monitoring is 40.8 TWh.[15]

Table 2 shows the consumption of electricity in 2017 by final consumers in the network areas of the TSOs and DSOs participating in the survey. It can be seen that although the number of non-household customers with an annual consumption of more than 2 GWh is relatively small, these customers account for nearly half of the total consumption in Germany. Consumption by these large consumers was stable compared with the previous year. Smaller non-household customers (annual consumption >10 MWh and ≤2 GWh) accounted for 26.4% of total consumption in 2017, about 2% down on a year earlier. The largest customer group in terms of numbers comprises final consumers with an annual consumption of up to 10 MWh. These are almost all household customers. They represented about 25.4% of the total volume in 2017.

Their total electricity consumption was around the same as in 2016. The average household customer (defined as having consumption <10 MWh) consumed about 2,542 kWh in 2017, according to data from DSOs. The highest household customer consumption was in the band between 2,500 kWh and 5,000 kWh and totalled about 44.1 TWh, according to data from electricity suppliers. The average consumption for this representative case was about 3,345 kWh.

Final consumption by customer category

Category	TSOs (TWh)	DSOs (TWh)	TSOs + DSOs (TWh)	Percentage of total (%)
≤ 10 MWh/year	0.0	120.1	120.1	25.4
10 MWh/year - 2 GWh/year	0.1	124.9	124.9	26.4
> 2 GWh/year	28.0	199.5	227.5	48.1
Total	28.1	444.5	472.6	100.0

Table 2: Final consumption by customer category based on data from TSOs and DSOs

[15] Here, too, the actual value will be higher because this figure only includes electricity from self-generation plants with an installed capacity of 10 MW or higher.

2.3 Network structure data

The four TSOs with responsibility for control areas[16] took part in the 2018 Monitoring Report data survey. The TSOs' total circuit length (overhead lines and underground cables) as at 31 December 2017 was 37,489 km (see Table 3).

This represents an increase of 892 km on 2016. The total number of meter points in the four TSOs' network areas was 577, almost all of which were interval-metered, ie average consumption was recorded at least every quarter of an hour. The offtake of the 155 final consumers connected to the TSOs' networks totalled 28.1 TWh as at 31 December 2017, representing a year-on-year decrease of around 1.6 TWh.

Network structure figures 2017

	TSOs	DSOs	Total
Network operators (number)	4	815	833
Total circuit length (km)	37,489	1,807,895	1,845,385
Extra high voltage	37,098	168	37,267
High voltage	391	94,089	94,480
Medium voltage		520,010	520,010
Low voltage		1,193,628	1,193,628
Total final consumers (meter points)	577	50,467,615	50,468,192
Industrial, commercial and other non-household customers	577	3,225,937	3,226,514
Household customers		47,241,678	47,241,678

Table 3: 2017 network structure figures based on data from TSOs and DSOs

As at 7 November 2018, a total of 890 electricity DSOs were registered with the Bundesnetzagentur, 815 of whom were included up to 25 June 2018 in the data analysis for the Bundesnetzagentur's 2018 monitoring report.[17] According to these 815 DSOs, the offtake of the DSOs' networks was about 444.5 TWh in 2017, a decrease of around 4 TWh on the previous year.

[16] Data reported for TenneT GmbH's offshore holding companies are included in the monitoring under TenneT.

[17] The figures for total circuit length and final consumers are not directly comparable with the figures from previous years because of the changes in the number of DSOs participating in the monitoring survey.

TSOs and DSOs in Germany

	2011	2012	2013	2014	2015	2016	2017	2018
TSOs with responsibility for control areas	4	4	4	4	4	4	4	4
Total DSOs	869	883	883	884	880	875	878	890
DSOs with fewer than 100,000 connected customers	793	807	812	812	803	798	797	809

Table 4: Number of TSOs and DSOs in Germany: 2009 to 2018

The DSOs' total circuit length (overhead lines and underground cables) at all network levels as at 31 December 2017 was around 1,807,896 km. As shown in Figure 2, the majority of the DSOs included in the data analysis (628 or 77%) have networks with a short to medium circuit length (lines and cables) of up to 1,000 km. These DSOs serve 7.4m or 15% of all meter points in Germany. 184 DSOs have networks with a total circuit length of more than 1,000 km. These network operators supply 43.1 meter points, about 85% of the total.

DSOs by circuit length (number and percentage)

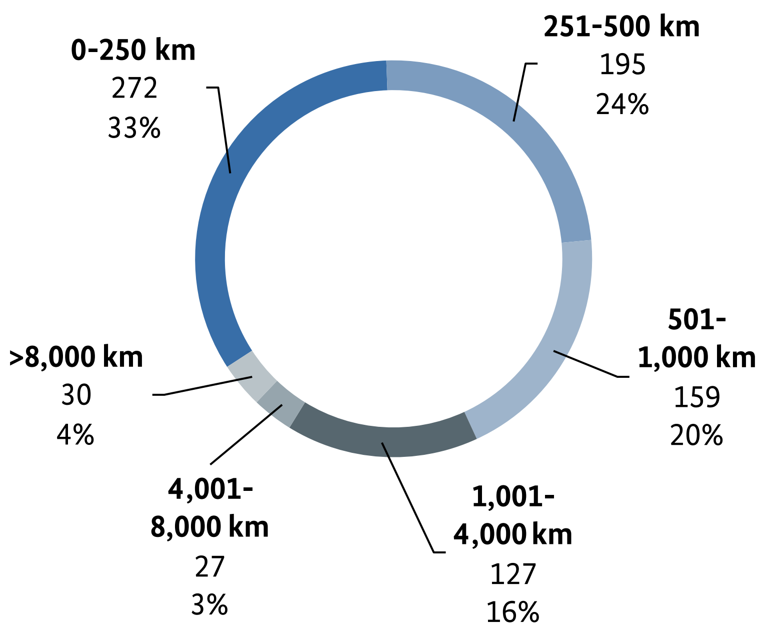

Figure 2: Number and percentage of DSOs by circuit length based on data from DSOs

There were hardly any changes in the DSOs' structure, which continues to be primarily regional. The total number of reported meter points of final consumers in the DSOs' network areas was 50,467,615, of which about 47,241,678 were for household customers as defined in section 3 para 22 EnWG and 395,245 were interval meters.

As in the previous year, more than three quarters of the DSOs surveyed supply up to 30,000 meter points, while around 10% of all DSOs supply more than 100,000 meter points. The latter supply about 76% of all meter points (38.2m). Figure 3 shows a breakdown of DSOs by the number of meter points supplied.

DSOs by number of meter points supplied

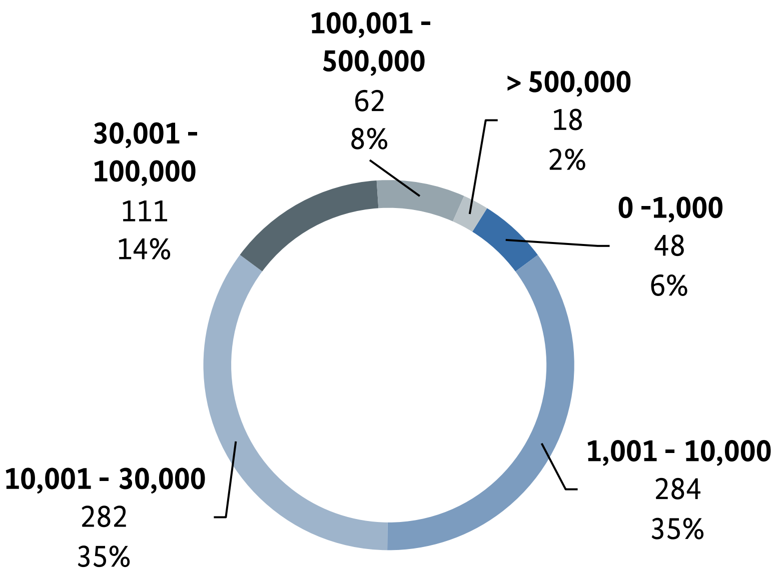

Figure 3: DSOs by number of meter points supplied based on data from DSOs

3. Market concentration

The degree of market concentration is determined by the market share distribution of the players on the market concerned. Market shares are a useful reference point for estimating market power because they represent the extent to which demand in the relevant market was actually satisfied by one company during the reference period[18].

An extensive analysis of market power is currently not carried out in the course of energy monitoring. According to the practice of the Bundeskartellamt, such an analysis would include a residual supply analysis with regard to electricity generation.[19] In future, the Bundeskartellamt will carry out such an analysis in a report on the competition conditions in the electricity generation sector in accordance with Section 53 of the German Competition Act, GWB, as amended by the Electricity Market Act[20]. The report will be based on data

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[18] Cf. Bundeskartellamt, Guidance on Substantive Merger Control, para. 25.

[19] Cf. Bundeskartellamt, Sector Inquiry into the Electricity Generation and Wholesale Markets, 2011, p.96 ff.

[20] Section 2 of the Act on the Further Development of the Electricity Market, Federal Law Gazette. 2016, 1786, 1811. Cf. also legislative intent, Bundestag printed paper 18/7317, 134.

collected by the Market Transparency Unit for Electricity/Gas. Until then this report will be based on indicators which are less complex to identify.

The Herfindahl-Hirschman Index or the sum of the market shares of the three, four or five competitors with the largest market shares (known as “concentration ratios”, CR3 – CR4 – CR5) are typically used to represent the market share distribution. The larger the market share covered by only a few competitors, the higher the market concentration.

In the previous reporting year – and as a result of the historically evolved structure of the power markets – the points of reference for the analysis of power generation, first-time sale of electricity and end customer supply were the five strongest power producers RWE AG, E.ON SE[21], EnBW AG, Vattenfall GmbH and LEAG GmbH. At the same time these far surpassed other producers with regard to power generation capacities and electricity volumes fed into the grid (CR 5).

Changes on the supplier side in 2016 brought about by the sale of Vattenfall’s lignite business in Lusatia to LEAG caused a considerable shift in market shares in power generation and the first-time sale of electricity. The market leader RWE has now been joined by four other power producers with market shares between five and 15% which themselves have a significant market share lead over the other power producers.

The report examines the market concentration on the economically significant market for the first-time sale of electricity (power generation) and on the two largest retail markets for electricity. The market shares on the retail markets are estimated using the "dominance method”. The market shares on the market for the first-time sale of electricity are calculated on the basis of competition law principles, which produces more accurate results (for details of the differences between the two calculation methods see the box below).

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[21] In 2016 E.ON outsourced large parts of its former core business – conventional power generation (excluding nuclear power plants), energy wholesale trading and gas production – to its new subsidiary Uniper AG, in which Fortum acquired a majority shareholding in 2018. In 2017 E.ON was the largest direct shareholder of Uniper with a share of around 47%; the remaining 53% of Uniper shares were in free float (institutional investors, private investors). In 2017 the calculation of the market shares was based on the rules applying to company groups because E.ON was still the largest shareholder of Uniper and can be expected to exercise over 50% of Uniper voting rights in light of the actual presence at shareholder meetings. This is due to the fact that around 11% of the shares are held by private investors who, as past experience has shown, are less likely to attend shareholder meetings. There is also likely to be a high level of agreement among E.ON and Uniper shareholders because E.ON shareholders became Uniper shareholders with the same proportion of shares on 12 September 2016.

Calculation of group market shares under competition law vs. calculation of market shares using the "dominance method"

For the calculation of market shares one first has to define which companies (legal entities) are to be considered as affiliated companies and consequently as a corporate group. This implies that there is no (substantial) competition between the individual companies of a group.

German competition law uses the concept of "affiliated” companies (Section 36 (2) of the German Competition Act, GWB). The concept aims to establish whether a dependent or controlling relationship exists between companies. The turnover or sales of each controlled company are fully attributed to the company group; the sales of a company that is not controlled are not added to the company group's sales quantities (not even on a pro-rata basis). A typical example of a controlling relationship is a scenario in which the majority of the voting rights in an affiliated company are held by another company. Controlling relationships may also arise for other reasons, for example, personal ties or a controlling agreement. If several companies act together in such a way that they can jointly exercise a controlling influence over another company (e.g. because of a shareholder agreement or consortium agreement), each of them is considered a controlling company. Investigating and assessing which companies belong to a certain group under these principles can sometimes be rather time-consuming.

For this reason, group membership is predominantly assessed in the course of energy monitoring by applying the considerably simpler "dominance method". The sole aim of this method is to establish whether one shareholder holds at least 50% of the shares in a company. If a single shareholder holds more than 50% of a company’s shares, that company's sales will be fully attributed to this shareholder. If two shareholders each hold 50% of a company’s shares, they will each be attributed 50% of the sales. If there is only one shareholder holding 50% of the shares with all other shareholders holding shares of less than 50%, half of the sales will be attributed to the largest shareholder; the remaining shares will not be attributed to any of the remaining shareholders. If no shareholder holds a share of 50% or more, the company’s sales will not be attributed to any shareholder (in this case, the company will be the parent company).

In the case of majority shareholding, the two calculation methods usually produce the same results. However, a controlling relationship can also occur under a minority shareholding and would not be identified as such by the dominance method. A calculation of market shares using the dominance method therefore tends to underestimate the market shares of the strongest company groups, particularly when there are strong joint ventures active in the market.

3.1 Power generation and first-time sale of electricity

The Bundeskartellamt defines a relevant product market for the generation of electricity which is not remunerated under the Renewable Energy Sources Act (EEC) (hereafter also “conventional power”) and the first-time sale of electricity (market for the first-time sale of electricity). In its case practice, the Bundeskartellamt has most recently applied the following criteria for the calculation of market shares[22]:

The market shares are assessed according to feed-in quantities (not capacities). Electricity remunerated according to the fixed remuneration system under the Renewable Energy Sources Act (EEG) or according to historically sometimes optional direct marketing was most recently included in the residual supply analysis but not in the calculation of the market shares on the market for the first-time sale of electricity.[23] Electricity from renewable energy resources is generated and fed into the grid regardless of the demand situation and electricity wholesale prices. Renewable electricity plant operators are not exposed to competition from the other “conventional” electricity suppliers. In the case of drawing rights, the corresponding amounts or capacities are attributed not to the power plant owner but to the owner of the drawing rights, provided he decides on the use of the power plant and bears the risks and rewards of marketing the electricity.[24] Only electricity volumes that are fed into the general supply grid will be taken into consideration. In other words electricity fed into closed distribution networks, electricity for own consumption and traction current are not included in the market for the first-time sale of electricity.

In geographical terms the Bundeskartellamt defines the market for Germany and Austria as a single market. The main reasons for this are that throughout 2017 no NTC value was recorded at the interconnections between the two countries and, in particular, that there was a common price zone for the German-Austrian electricity wholesale trade. Such conditions currently do not exist in other neighbouring countries.[25] The consequences of congestion management from 1 October 2018 at the German-Austrian border for the geographical market definition will only be reflected in the next energy monitoring report.

In the course of this year’s energy monitoring, data was collected on the electricity capacities (including drawing rights) and volumes generated by the five strongest companies – RWE, E.ON/Uniper, EnBW, Vattenfall and LEAG – based on the above definitions. Data on the overall market was extracted from monitoring questionnaires completed by producers and network operators. In addition, the Austrian energy regulator E-Control has provided aggregate data for Austria.

The results of the survey on power generation volumes are shown in the table below, which also includes data from the previous year for comparison.

[22] Cf. Bundeskartellamt, Decision of 8 December 2011, B8-94/11, RWE/Stadtwerke Unna, para. 22 ff.

[23] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, p. 73 f.

[24] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, p. 93 f.

[25] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, p. 81 ff.

Electricity volumes generated by the five largest electricity producers

	Germany + Austria 2016		Germany + Austria 2017		Germany 2016		Germany 2017	
	TWh	Market share	TWh	Market share	TWh	Market share	TWh	Market share
RWE	134.0	30.7%	119.2	29.0%	130.8	33.5%	117.0	29.9%
Vattenfall[1]	66.8	15.3%	24.1	5.9%	66.8	17.1%	24.1	6.2%
EnBW	47.3	10.8%	43.6	10.6%	47.3	12.1%	43.6	11.2%
E.ON/Uniper	37.2	8.5%	31.8	7.8%	36.9	9.4%	31.5	8.7%
LEAG[2]	17.3	4.0%	58.2	14.2%	17.3	4.4%	58.2	14.9%
CR 5	302.6	69.4%	276.9	**67.5%**	299.1	76.5%	274.4	**75.5%**
Other producers	133.5	30.6%	133.6	32.5%	92.0	23.5%	89.1	24.5%
Total net electricity generation	436.1	100%	410.5	100%	391.1	100%	363.5	100%

[1] Including Vattenfall's lignite business in Lusatia in the first three quarters of 2016
[2] Including LEAG's lignite business in Lusatia in the last quarter of 2016

Table 5: Electricity volumes generated by the five largest German electricity producers based on the definition of the market for the first-time sale of electricity (i.e. excluding EEG electricity, traction current, electricity for own consumption)

The aggregate market share of the five strongest companies on the market for the first-time sale of electricity in the German/Austrian market area was around 67.5% in 2017 (69.4% in 2016). Based on the above definition the total net electricity generation which was not entitled to payments under the EEG fell by 25.7 TWh to 410.5 TWh. The reason for this was that in 2017 electricity generation from renewable energies entitled to payments under the EEG reached a new record level of around 187 TWh, consequently replacing conventional electricity generation. RWE's market share fell by 1.7% compared to 2016.[26] The decline in market share of EnBW and E.ON / Uniper was less significant at 0.2 and 0.6% respectively. Vattenfall's market share declined significantly from 15.3% to 5.9%. The analysis of this significant change in market share has to take account of

[26] In last year's questionnaire when asked to state the volume of electricity generated by plants in which it had a share of less than 100%, RWE inadvertently quoted the total electricity volume and not the proportional volume generated by those plants. As correcting the information would have been very complex, it was decided not to re-evaluate the data. At a rough estimate RWE indeed had an approx. 1% lower market share in 2016.

the divestment of the Lusatia lignite business in 2016 and that the feed-in volumes of the lignite business were included in the calculation for the first three quarters of 2016. Conversely, the calculation of LEAG's market share in 2016 included only the feed-in volumes of the last quarter. As a result LEAG's market share in 2017 compared with 2016 rose by around 10% to approx. 14.2%. Although still far behind the market leader RWE, LEAG is now the second largest electricity producer in Germany.

While the feed-in volumes from renewable energy resources have risen significantly, conventionally produced electricity and the volume of the market for the first-time sale of electricity as defined above decreased over the same period. This decline is most clearly visible in the context of the domestic German market area without Austria. Here the volume of conventionally produced electricity has fallen from 391.1 TWh to 363.5 TWh – a decline of around 7%. As the feed-in volumes from renewable energy resources reached a new record level of approx. 187 TWh in 2017 and now account for more than one-third of total electricity generation, conventionally produced electricity has reached its lowest level ever.

Shares of the five strongest suppliers on the market for the first-time sale of electricity

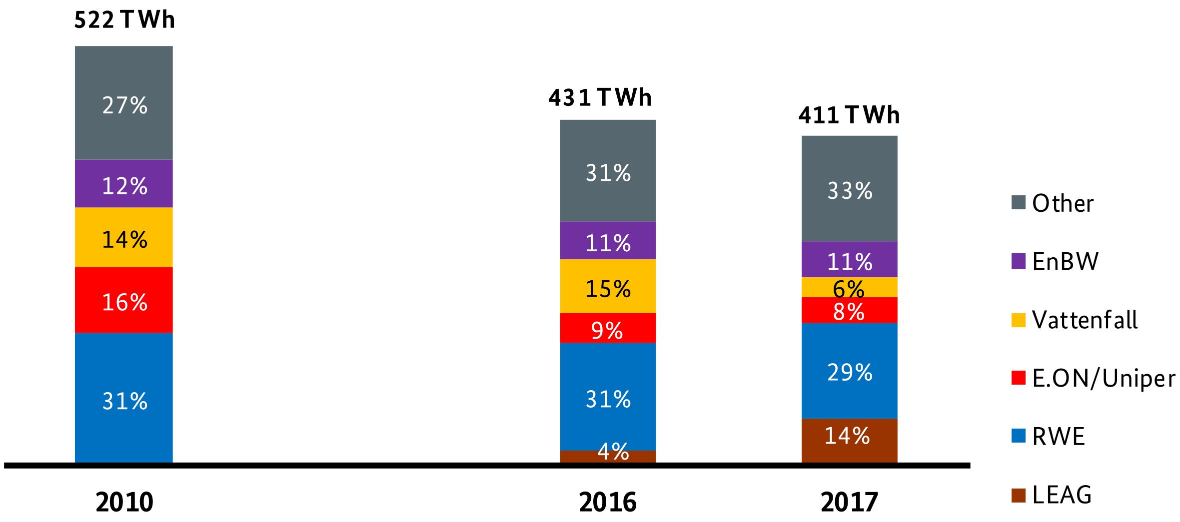


Figure 4: Share of the five strongest companies on the market for the first-time sale of electricity

The five suppliers' share of the German/Austrian generation capacities available for use on the market for the first-time sale of electricity (i.e. excluding EEG capacities, traction current, closed power plants or plants not feeding into the general supply grid) was 55.5%, down slightly from 56.6% in the previous year. The total amount of power generation capacity available fell by 3.5 GW year-on-year to 111.1 GW. The reduction in capacity of the CR5 amounts to 3.3 GW of the total decline of 3.5 GW. The reduction in the capacity of the CR5 is chiefly attributable to RWE – i.a. due to transfer of the blocks of the Frimmersdorf power plant to security standby status and the shutdown of blocks A and B of Voerde power station.[27] The capacities

[27] Also see footnote 26.

attributable to EnBW also declined by 0.6 GW while those attributable to Vattenfall also declined by 0.2 GW. The degree of market concentration has consequently decreased.

If only generation capacity on the German domestic market for the first-time sale of electricity is taken into account, 92.6 GW is still available compared to 97 GW in 2016, a decline of 4.4 GW. Here again the CR5's decline in capacity of around 3.3 GW accounts for the largest share. Ultimately this scenario resulted in a slight reduction in the market concentration of the CR5 from 65.3 in 2016 to 64.9%.

Generation capacities of the five largest German electricity producers

	Germany + Austria 31.12.2016		Germany + Austria 31.12.2017		Germany 31.12.2016		Germany 31.12.2017	
	GW	Market share	GW	Market share	GW	Market share	GW	Market share
RWE	27.6	24.1%	25.2	22.7%	26.2	27.0%	23.9	25.8%
Vattenfall	8.3	7.3%	8.1	7.3%	8.3	8.6%	8.1	8.7%
EnBW	11.7	10.2%	11.1	10.0%	11.7	12.1%	11.1	12.0%
E.ON/Uniper	9.5	8.3%	9.4	8.5%	9.3	9.6%	9.3	10.0%
LEAG	7.8	6.8%	7.8	7.0%	7.8	8.0%	7.8	8.4%
CR 5	64.9	56.6%	61.6	**55.5%**	63.4	65.3%	60.1	**64.9%**
Other companies	49.7	43.4%	49.5	44.5%	33.6	34.7%	32.5	35.1%
Total capacity	114.6	100%	111.1	100%	97.0	100%	92.6	100%

Table 6: Generation capacities of the five largest German electricity producers based on the definition of the market for the first-time sale of electricity

To sum up, it can be said that, in terms of generation volume, the market for the first-time sale of electricity continues to be concentrated with a CR 5 of 67.5% (69.4% in 2016). There was a slight decline in the degree of market concentration in the German/Austrian market area.

Apart from the decline in market concentration, there are a number of other factors that have led to a downward trend in market power. Power generation capacities in Germany and Europe have invariably exceeded the demand for electricity for years. In addition, an increased share of the demand for electricity is covered with the feed-in of renewable energy.

The degree of market concentration is further qualified by the generation and first-time sale of electricity from plants that are eligible for payments under the EEG which suppresses demand on the market for the first-time sale of electricity described above because of the priority feed-in and the pricing structure. However, electricity remunerated according to the fixed remuneration system under the EEG or according to historically sometimes optional direct marketing is still not included in the calculation of the market shares on the market for the first-time sale of electricity. The reason is that the generation and feed-in of electricity from renewable energy resources is not subject to competition on the market for the generation and sale of other, largely conventional electricity.

However, this Monitoring Report contains surveys on the five producers' market shares in EEG power generation in order to provide a rough estimate of the effects on the degree of market concentration. In line with the survey on the generation and first-time sale of conventional electricity, the producers were also asked about their generation volumes and capacities of EEG electricity, which were then put in relation to the overall market data. As in the previous year, the share of the five largest companies mentioned of the German market area alone accounted for around six per cent of the generation volume in 2017. They also accounted for around 3% of capacities in 2017, as in the previous year. The improved use of transmission capacities for electricity imports as a consequence of increased market coupling can help limit the scope of action on the market for the first-time sale of electricity. These additional aspects are not reflected in the market shares illustrated but would be taken into consideration in an extensive analysis of market power, particularly, in a residual supply analysis. With regard to the future, it should ultimately also be borne in mind that the closure of existing German nuclear power plants, envisaged for 2022 at the latest, is one of the factors that will bring about further changes in the market structure.

3.2 Electricity retail markets

In the electricity retail markets the Bundeskartellamt differentiates between customers with metered load profiles and customers with standard load profiles. Metered load profile customers are generally industrial or commercial customers. Standard load profile customers are consumers with relatively low levels of consumption. They are usually household customers and smaller commercial customers. The distribution of these customers' electricity consumption over specific time intervals is based on a standard load profile.

The Bundeskartellamt most recently defined a Germany-wide market for the supply of electricity to metered load profile customers. The Bundeskartellamt has until now differentiated between three product markets for the supply of standard load profile customers:

(i) supply with electric heating (network-based definition),

(ii) default supply (network-based definition),

(iii) supply on the basis of special contracts (without electric heating, definition as a national market)[28].

Since the EnWG no longer uses the term “special contract customers” in this sense, the relevant contracts are referred to as “special contracts” only in the context of market definition under competition law. For the purpose of the Monitoring Report, these contracts will otherwise be referred to as “contract with the default supplier outside the default supply” or as “contract with a supplier who is not the local default supplier”.[29] In energy monitoring the sales volumes of individual suppliers (legal entities) are collected as national total values. In the case of standard load profile customers, a differentiation is made between electric heating, default supply and supply under a special contract. The following analysis is based on data from around 1,070 electricity providers (legal entities) (2016: round 1,150).

Based on information supplied by suppliers, in 2017 around 261 TWh of electricity were sold to metered load profile customers and around 162 TWh of electricity to standard load profile customers. 14.5 TWh of the total sales to standard load profile customers consisted of electric heating, 35.2 TWh went to standard load profile customers with default supply contracts and 113 TWh to standard load profile customers with special contracts. In 2016, 266 TWh of electricity were sold to metered load profile customers and 161 TWh to standard load profile customers. 14 TWh of the total sales to standard load profile customers consisted of electric heating and 38 TWh went to standard load profile customers with default supply contracts and 108 TWh to standard load profile customers with special contracts. In contrast to the generation and first-time sale of electricity, the changes among the large suppliers did not have a significant effect on the market shares relating to the supply of final consumers of electricity so that the current CR 4 analysis continues to be appropriate. Based on the data provided by the individual companies, it was determined which sales volumes were attributed to the four strongest companies. The sales volumes were aggregated using the “dominance method” according to the calculation method described above. This provides sufficiently accurate results for the purpose of this analysis. With regard to data on percentages, it should be borne in mind that the monitoring survey of the electricity suppliers does not cover the entire market. The quoted percentages therefore merely approximate the actual market shares.

In 2017 the four strongest companies sold a total of around 65 TWh on the German **market for the supply of electricity to metered load profile customers**. The aggregated market share of the four companies is therefore only around 25% in this sector. In the previous year, the CR 4 still sold as much as 75 TWh, which was equivalent to a share of 28%. There has been another decline in the market shares of the CR 4 on the metered load profile customer market. This figure is clearly below the statutory thresholds for the presumption of a dominant position (Section 18 (4) and (6) GWB). The Bundeskartellamt assumes that there is no longer a dominant supplier on the market for the supply of metered load profile customers.

In 2017, the cumulative sales of the four strongest companies on the German **market for the supply of standard load profile customers with special contracts** (outside the default supply and excluding electric heating) amounted to around 37 TWh – up from 36 TWh in the previous year. The aggregated market share of

[28] Cf. Bundeskartellamt, decision of 30 November 2009, file reference, B8-107/09; Integra/Thüga, para. 32 ff.

[29] The term "special contract" is used in section 1(4) of the Electricity and Gas Concession Fees Ordinance (KAV). The term continues to be important for the calculation of the concession fee and has also been the subject of abuse proceedings and sector inquiries (electric heating). The terms “default (and auxiliary) supply” and “special contract” are appropriate for the purpose of market definition in terms of competition law and will continue to be used because they are legally defined.

the CR 4 in this market was therefore around 33% – 34% in 2016. This value is clearly below the statutory thresholds for the presumption of a dominant position. The Bundeskartellamt assumes that there is no longer a dominant supplier on the German market for the supply of standard load profile customers with special contracts (excluding electric heating).

In the default supply sector the cumulative domestic sales of the CR 4 were around 14.5 TWh of the total default supply volume of standard load profile customers, which amounted to around 35.2 TWh. The share of the CR 4 was therefore around 41%. With regard to the **supply of standard profile customers with electric heating** the CR 4 maintained their relatively strong position. The cumulative sales of the CR 4 are around 8.6 TWh of the total 14.5 TWh of electric heating. As a result, the CR 4 account for around 60%.

The shares of sales to all standard load profile customers, i.e. including electric heating customers and default supply customers, can also be calculated on the basis of the monitoring data. The total values thus determined do not correspond to the Bundeskartellamt's definition of a product market but are merely meant to indicate the size of the shares of the strongest companies in a national analysis involving all standard load profile customers. The volume of electricity supplied by the four strongest companies to all standard load profile customers was around 60.4 TWh, which is equivalent to an aggregate share of around 37%. In 2016 the volume supplied by the CR 4 was still 62 TWh and the aggregate share was 38%. The share in relation to all standard load profile customers is thus higher than in the analysis based solely on standard load profile customers with special contracts. The reason for this is that in the areas of electric heating and default supply the four strongest companies – as illustrated above – tend to account for higher shares of the German sales volumes than in the area of standard load profile customers with special contracts, excluding electric heating.

Shares of the four strongest companies in the sale of electricity to metered load profile (RLM) customers and standard load profile customers (SLP)

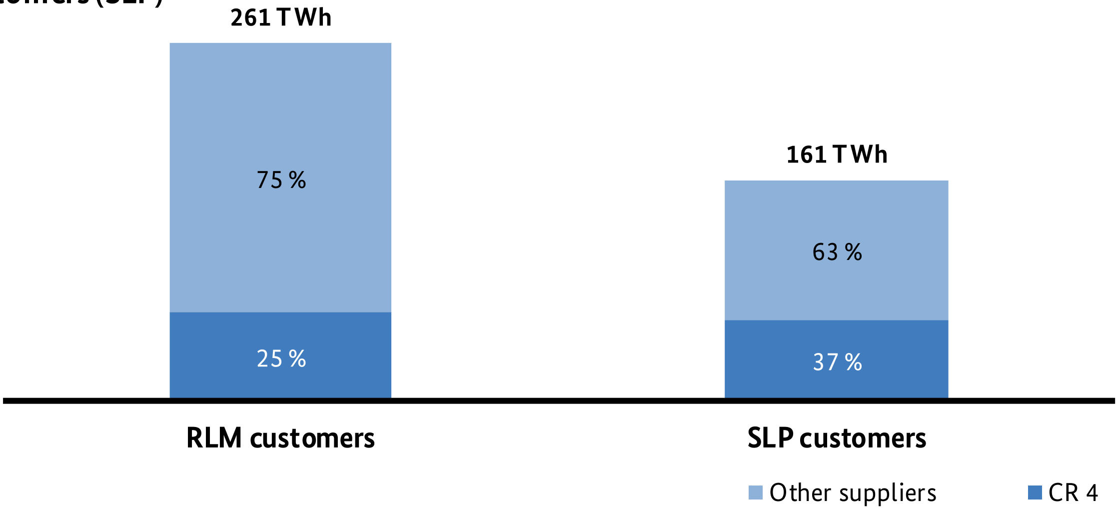


Figure 5: Share of the four strongest companies in the sale of electricity to final customers in 2017

4. Consumer advice and protection

The Bundesnetzagentur's task as the central information point for energy consumers is to provide private household customers with independent information about their rights, the dispute resolution process and market events. The energy consumer advice service has been providing information and support to consumers on general energy issues and questions as well as problems with suppliers and network operators since 2011, developing into an experienced and reliable service and first point of contact. Its staff receive and respond to consumer queries by telephone, e-mail and letter.

Overview of customer queries

In 2017, 15,861 queries and complaints were sent to the consumer advice service, a slight increase on the previous year. 8,563 queries were received by telephone, 6,805 by e-mail and 493 by post.

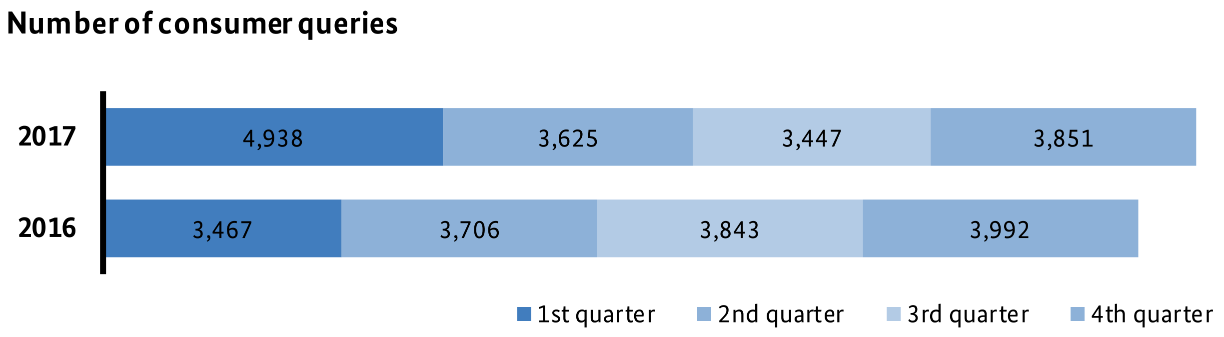


Figure 6: Number of consumer queries

Queries fell into the categories of electricity, gas and other as shown below. "Other" includes research-related questions, queries from consultancies and correspondence on matters not falling within the Bundesnetzagentur's remit.

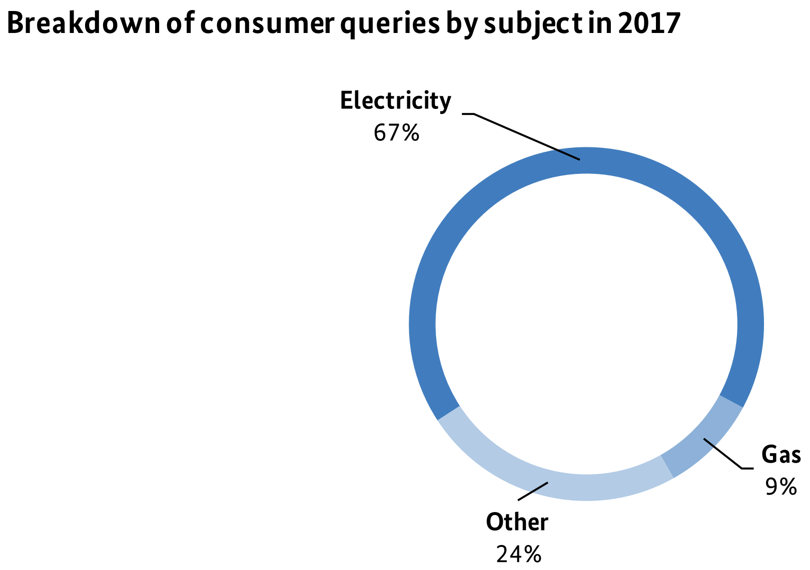


Figure 7: Breakdown of consumer queries by subject in 2017

In the past year, the energy consumer advice service has dealt with questions from consumers on all aspects of the energy market and has responded by explaining possible actions and pointing out legal remedies. Consumers were concerned about issues such as grid connection and billing problems as well as recent developments in metering. Of particular interest to consumers were problems when switching supplier, questions about fallback supply, payment in instalments and the size of such instalments, and general contractual questions like contract length, cancelling and bonuses.

B Generation

1. Installed electricity generation capacity and development of the generation sector

1.1 Net electricity generation 2017

Net electricity generation in 2017 was at the same level as in 2016 (601.4 TWh). In contrast to the previous year, electricity generation from renewable sources rose significantly in 2017 and the renewable energy capacity continued to increase (see "I.B.2 Development of renewables" on page 72 onwards). With regard to non-renewable energy sources, generation fell in 2017 by 24.7 TWh to 396.6 TWh. Electricity generated from renewable energy sources increased by 24.6 TWh (13.7%), from 180.2 TWh in 2016 to 204.8 TWh in 2017. 36.0% of gross electricity consumption[30], totalling 579.9 TWh, came from renewable sources in 2017. The chapter "I.B.2 Development of renewables" on page 72 onwards contains a detailed analysis of the annual energy supplied by installations entitled to payments under the EEG and its development.

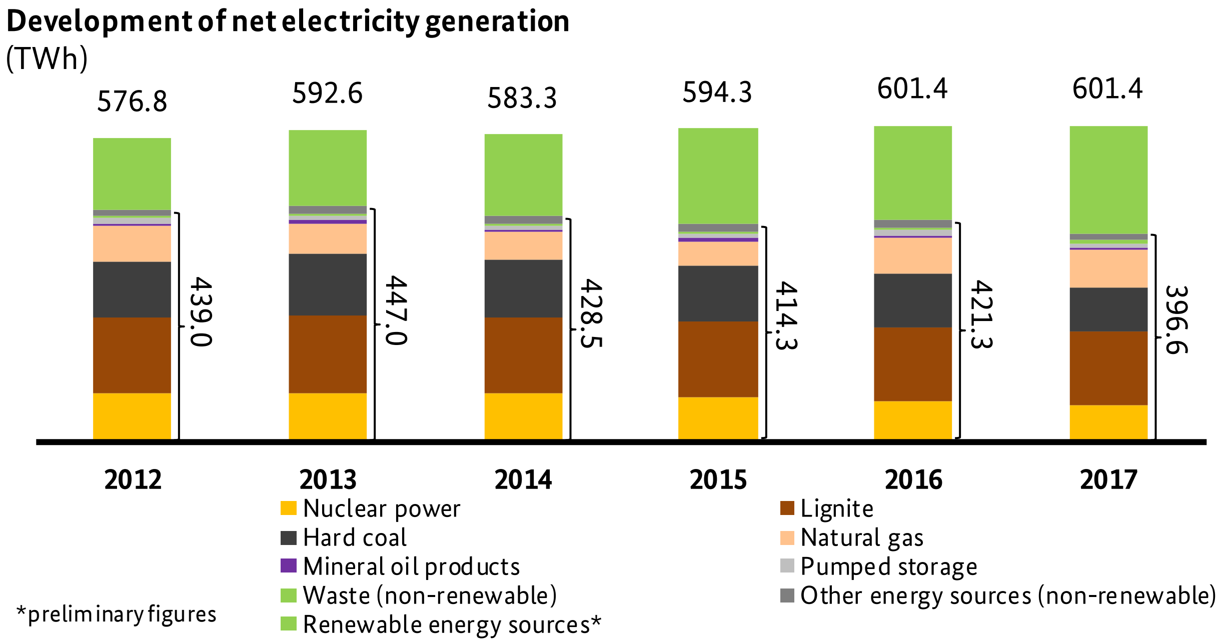


Figure 8: Development of net electricity generation (as at November 2018)

Compared to 2016 net electricity generation from non-renewable energy sources fell by 24.7 TWh (-5.9%) from 421.3 TWh to 396.6 TWh (cf. Figure 8). Feed-in from natural gas-fired power plants increased again as it did in the previous year, with 6.3% more electricity being generated than in 2016. In contrast, generation from all other non-renewable energy sources, with the exception of natural gas, pumped storage and other energy sources, declined. Generation from hard coal power plants fell by 19.8 TWh (-19.2%) to 83.5 TWh. Generation

[30] Gross electricity consumption is calculated from the gross electricity generation plus cross-border import load flows and minus cross-border export load flows. Gross electricity generation also includes the electricity consumed by power plants for their own use and is thus higher than net electricity generation.

from nuclear power plants fell by 7.8 TWh or 9.9% in 2017 to 70.5 TWh. As in the two previous years, generation from lignite-fired power plants decreased again in 2017. This decline was due to the transfer of the lignite-fired plant Buschhaus to security standby status on 1 October 2017. In total generation of lignite-fired power plants fell by 2 TWh (-1.4%) to 137.9 TWh.

Net electricity generation 2012 - 2017
(TWh)

	2012	2013	2014	2015	2016	2017
Nuclear power	94.2	92.1	91.8	85.1	78.3	70.5
Lignite	141.5	148.7	144.5	142.5	139.9	137.9
Hard coal	107.7	116.4	111.6	106.1	103.3	83.5
Natural gas	66.6	58.4	50.0	48.7	68.0	72.3
Mineral oil products	5.0	4.6	3.8	4.3	3.9	3.8
Pumped storage	8.9	9.7	9.5	10.1	9.9	10.2
Waste (non-renewable)	3.8	3.9	4.3	4.2	4.3	4.3
Other energy sources (non-renewable)	11.2	13.1	12.9	13.4	13.6	14.0
Total of non-renewable energy sources	439.0	447.0	428.5	414.3	421.3	396.6
Renewable energy sources*	137.8	145.6	154.8	180.0	180.2	204.8
Total	576.8	592.6	583.3	594.3	601.4	601.4
Renewables' share of net electricity generation	**24%**	**25%**	**27%**	**30%**	**30%**	**34%**

*preliminary figures

Table 7: Net electricity generation (as at November 2018)

There were several reasons for the increase in 2017 compared to previous years in feed-in from natural gas power plants. One cause is the change in prices of hard coal and natural gas. Falling gas prices on future and spot markets contrasted with rising hard coal prices. These differences in fuel prices make at least modern gas-fired power stations increasingly competitive with inefficient hard coal power plants. In addition, increasing fluctuation in the feed-in from renewable energies tends to result in higher load gradients. Flexible, non-volatile power plants, such as gas-fired power stations, are ideal for covering such peak demand.

1.2 CO_2 emissions from electricity generation in 2017

The Bundesnetzagentur asked operators of power plants with a net nominal capacity of at least 10 MW to supply data on CO_2 emissions from electricity generation in 2017. For CHP plants, operators only had to supply data on the share of CO2 attributable to electricity generation. Table 8 contains the results of the survey of power plant operators.

CO_2 emissions from electricity generation in 2017

	CO_2 emissions in 2016 t million	CO_2 emissions in 2017 t million	Change t million
Lignite	157.9	155.9	-2.1
Hard coal	90.1	74.6	-15.5
Natural gas	26.2	27.0	0.7
Mineral oil products	2.1	2.1	0.0
Waste	7.7	7.6	-0.1
Other energy sources[1]	17.6	18.3	0.6
Total	301.7	285.4	-16.3

[1] other energy sources (non-renewable), mine gas

Table 8: CO_2 emissions from electricity generation in 2017 (as at October 2018)

According to the data provided by the operators of power plants, total CO_2 emissions in 2017 fell by 16.3m tonnes of CO2 compared to 2016. This is in particular due to a reduction in installed capacity and less electricity being generated by hard coal-fired power plants. Power plant operators reported that lignite-fired power plants emitted 155.9m tonnes of CO_2 emissions, which made up over half of all CO_2 emissions from electricity generation (54%), and were the biggest emitters of CO_2. However, in total, lignite-fired power plants emitted slightly less CO_2 in 2017. This is primarily due to the gradual transfer of some lignite-fired power plants to security standby status. Hard coal power plants emitted 74.6m tonnes of CO_2, or 15.5m tonnes less than in 2016. Emissions of CO_2 by natural gas power plants were slightly higher than in the previous year (27.0m tonnes CO_2 in 2017 compared to 26.2m tonnes CO_2 in 2016). The remaining 27.9m tonnes of CO_2 are distributed across mineral oil-fired power plants (2.1m tonnes), waste to energy power plants (7.6m tonnes) and other energy sources (18.3m tonnes).

It should be noted that the data submissions from power plant operators do not include CO_2 emissions from generating facilities with under 10 MW of net nominal capacity.

1.3 Installed electricity generation capacity in Germany

In 2017, as in previous years, electricity generation was marked by growth in renewables. Total (net) installed generation capacity, which includes power plants that are not currently operating in the electricity market but are backup power stations or temporarily closed, rose by 5.8 GW from 211.9 GW (at the end of 2016) to 217.6 GW at the end of 2017.[31] Of this, 105.1 GW was non-renewable and 112.5 GW renewable energy capacity.

Renewables grew by 8.3 GW compared to 6.5 GW in 2016[32]. As at the end of 2017 the share of renewable energy generating capacity in Germany's total installed generating capacity was around 52%. Compared to 2011 (the year in which figures were first recorded for comparison purposes) renewable energy generating capacity increased by 46.1 GW; this is equal to an increase of the renewables' share in the total installed generation capacity of around 13%. The chapter "I.B.2 Development of renewables" on page 72 onwards contains a detailed analysis of the installed capacity of installations entitled to payments under the EEG and its development.

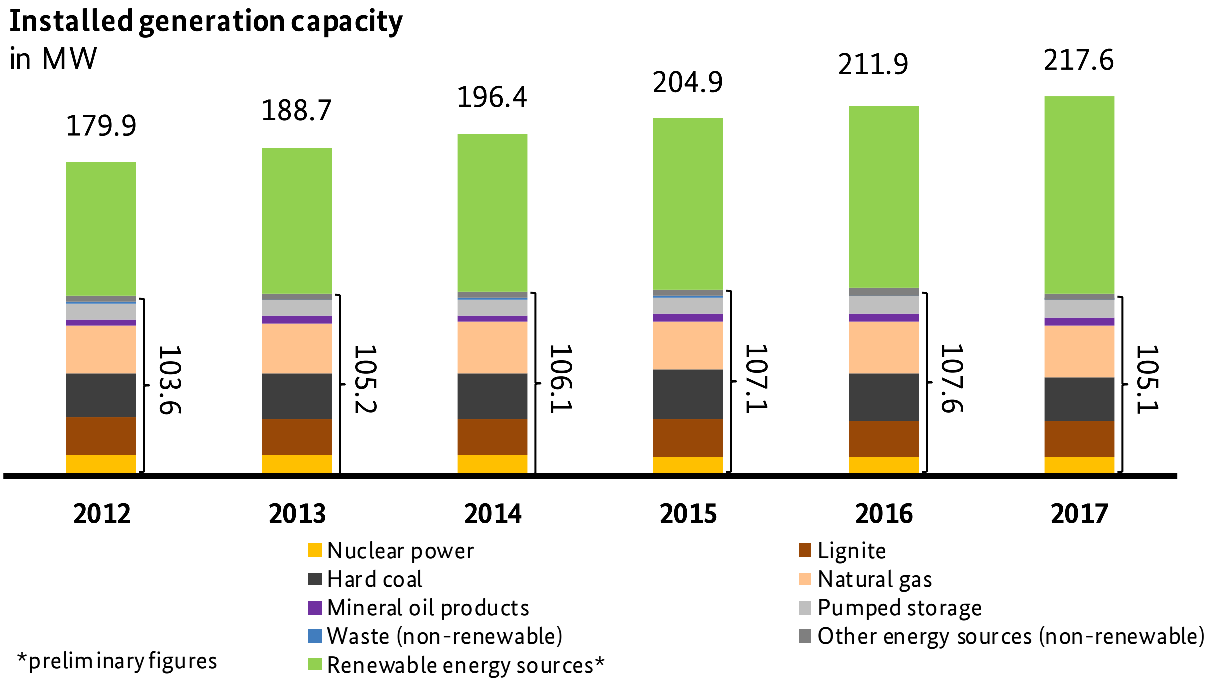


Figure 9: Development of installed electrical generating capacity (nominal net capacity) as at 31 December 2017.

Installed capacity from non-renewable sources decreased in 2017 by 2.5 GW, as shown in Table 9. As in the previous year, several hard coal power plants in particular were closed (including power plants in Voerde and Herne). Between 2012 and 2016, the hard coal generating capacity had still increased, largely due to the commissioning of power plants planned prior to the phasing out of nuclear energy.

[31] The total installed generating capacity figures include (pumped storage and hydro) capacity of 4.6 GW in Luxembourg, Switzerland and Austria feeding into the German grid.

[32] The figures taken from Monitoring 2017 have been updated for 2016.

Installed generation capacity, 2012 - 2017
(GW)

	2012	2013	2014	2015	2016	2017
Nuclear power	12.1	12.1	12.1	10.8	10.8	10.8
Lignite	21.3	21.2	21.1	21.4	21.3	21.2
Hard coal	25.2	26.0	26.2	28.7	27.4	25.1
Natural gas	27.4	28.4	29.0	28.4	29.7	29.9
Mineral oil products	4.1	4.1	4.2	4.2	4.6	4.3
Pumped storage	9.2	9.2	9.2	9.4	9.5	9.5
Waste (non-renewable)	0.9	0.9	0.9	0.9	0.9	0.9
Other energy sources (non-renewable)	3.5	3.3	3.4	3.4	3.5	3.4
Renewable energy sources*	76.3	83.5	90.3	97.7	104.2	112.5
Total of non-renewable energy sources	103.6	105.2	106.1	107.1	107.6	105.1
Total	179.9	188.7	196.4	204.9	211.9	217.6
Renewables' share of total electricity generation	**42%**	**44%**	**46%**	**48%**	**49%**	**52%**

*preliminary figures

Table 9: Installed generation capacity (net nominal capacity)

There have been slight changes in the capacity of non-renewable sources since the end of 2017 resulting from closure and commissioning within the twelve-month period. There are no more current monthly or quarterly data available for installations which are entitled to payments under the EEG; Figure 10 consequently shows the figures for these installations on 31 December 2017. This share is correspondingly underrepresented as further growth can be expected particularly in this field since the beginning of the year. Total (net) installed generation capacity is currently 215.6 GW. Of this amount, 103.1 GW was sourced from non-renewables. The closure of the nuclear power plant Gundremmingen Block B and closures of hard coal, mineral oil and natural gas power plants reduced capacities compared to 2017 by 2.0 GW (as at November 2018).[33] A detailed breakdown of the installed capacity by individual renewable energy sources can be found in the section "I.B.2 Development of renewables" on page 72 onwards.

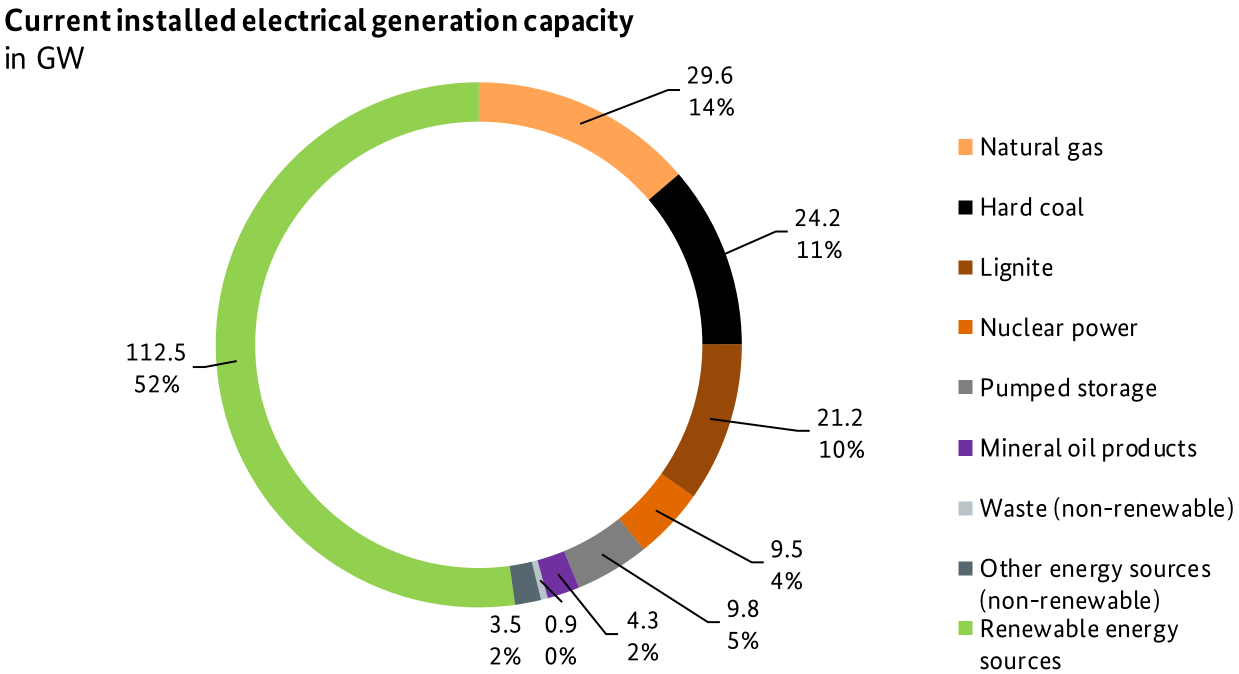


Figure 10: Currently installed electrical generating capacity (net nominal capacity as at October 2018; EEG as at 31 December 2017)

The following table shows closures of power plant capacity. The table shows that from 2012 and up to 1 October 2018 a total capacity of 26,230 MW has been closed, 15,015 MW finally. Total closed power plant capacity falls in three categories: notified closures, closures without notification and security standby.

[33] Changes during the twelve-month period with regard to the contribution of foreign power plants which feed into the German control area are not yet included in the current values.

Closures of power plant capacity since 2012

Year		2012	2013	2014	2015	2016	2017	2018*	Total on 1 Oct. 18
Further closures during the year (MW)		3,655	1,266	4,494	4,408	3,200	6,919	2,339	26,230
Further notified closures during the year (MW)		977	415	4,412	4,400	2,052	5,057	1,239	18,501
of which final closure	Capacity (MW)		60	2,349	2,643	912	2,747	1,239	9,950
	Average age in years at time of closure		45	45	40	40	44	34	
of which temporarily closed	Capacity in MW	355	355	206	661	301	78		1,955
	Average age in years at time	39	40	39	39	33	26		
of which reserve capacity	Capacity (MW)	622		1,857	1,096	839	2,232		6,596
	Average age in years at time of closure	32		42	47	27	38		
Further non-notified closures during the year in MW**		2,678	851	82	8	796	1,300	41	5,756
of which final closure	Capacity (MW)	1,995	851	74	8	796	1,300	41	5,065
	Average age in years at time of closure	43	42	39	19	18	30	25	
of which temporarily closed	Capacity (MW)	683		8					691
	Average age in years at time of closure	46		43					
Further capacity on security standby***	Capacity (MW)					352	562	1,059	1,973
	Average age in years at time of closure					31	49	41	

* temporary values

** The figures for 2017 also include a nuclear power plant with a capacity of 1,284 MW and for 2016 a hard coal power plant with a capacity of 765 MW which was not commissioned. The figures for 2012 and 2013 also include closures of power plants > 10MW which were not notified before the Reserve Power Plant Ordinance (ResKV) came into force.

*** The power plants on security standby will be finally closed after four years and are currently outside of the electricity market.

Table 10: Closures of power plant capacity (as at October 2018)

The first section of the table shows how much power plant capacity has been notified for closure and in which year, capacity which has been finally closed and the backup power station capacity which is categorised as systemically relevant. The table shows the additional capacity in each year and the average age of the power plants.

The second section refers to temporary and final closures of power plant without notification. The high capacity of finally closed power plants in 2017 is partly explained by the closure of the Gundremmingen Unit B nuclear power plant with its 1,284 MW. The figures for 2012 and 2013 also include closures of power plants >10 MW which were not notified before the Reserve Power Plant Ordinance (ResKV) came into force.

The last section of the table refers to lignite-fired power plant security standby according to annual capacity and average age. As at 1 October 2018, there was 1,973 MW of security standby capacity.

1.4 Power plant capacity by federal state

Figure 11 shows the location of installed generation capacity, including power plants which are not currently operating in the electricity market, broken down by renewable and non-renewable energy sources, in each of the federal states. The Figure does not include generating capacity in Luxembourg, Switzerland and Austria feeding into the German grid. With regard to non-renewable energy sources, only plants with a capacity of 10 MW or more are shown. The Bundesnetzagentur does not have any detailed data on smaller installations with a capacity of less than 10 MW not entitled to payments under the EEG and therefore cannot allocate this capacity (totalling 4.9 GW) to specific states.

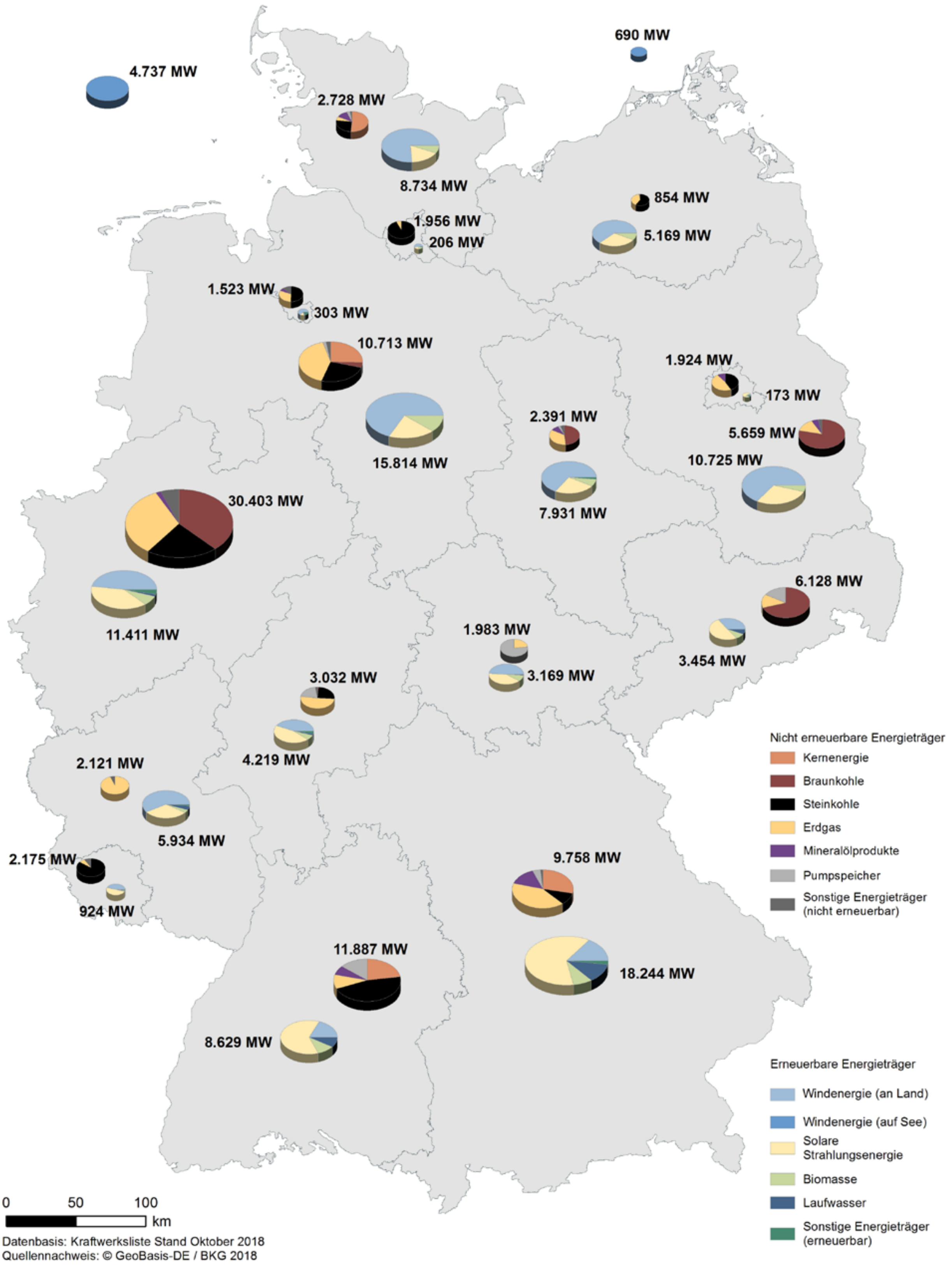


Figure 11: Generating capacity by energy source in each federal state – as at October 2018

Generating capacity by energy source and federal state, including temporarily closed, plants providing reserve capacity and plants on security standby*
(MW)

Federal state	Non-renewable energy sources							Renewable energy sources						
	Lignite	Hard coal	Natural gas	Nuclear power	Pumped storage	Mineral oil products	Others	Biomass	Run-of-river hydro	Offshore wind	Onshore wind	Solar	Others	Total
BW	0	5,529	1,012	2,712	1,873	702	59	888	653	0	1,486	5,518	84	**20,516**
BY	0	847	4,137	2,698	543	1,384	149	1,626	1,919	0	2,482	11,883	334	**28,001**
BE	0	777	911	0	0	218	18	45	0	0	12	98	18	**2,097**
BB	4,409	0	733	0	0	334	183	447	4	0	6,810	3,379	85	**16,385**
HB	0	772	459	0	0	86	206	12	10	0	190	42	48	**1,825**
HH	0	1,794	150	0	0	0	12	40	0	0	111	42	12	**2,161**
HE	34	753	1,511	0	625	25	84	260	62	0	1,845	1,940	112	**7,251**
MV	0	514	319	0	0	0	21	353	3	0	3,131	1,661	21	**6,023**
NI	352	2,933	4,111	2,696	220	56	344	1,524	58	0	10,435	3,737	59	**26,527**
NW	10,908	7,737	8,746	0	303	538	2,171	802	156	0	5,479	4,638	335	**41,814**
RP	0	13	1,959	0	0	0	149	164	228	0	3,384	2,089	69	**8,055**
SL	0	1,822	155	0	0	0	199	20	11	0	429	450	14	**3,099**
SN	4,325	0	693	0	1,085	17	8	280	215	0	1,215	1,728	16	**9,582**
ST	1,153	0	810	0	80	213	135	450	28	0	5,104	2,242	108	**10,322**
SH	0	680	129	1,410	119	321	70	503	5	0	6,626	1,572	28	**11,462**
TH	0	0	468	0	1,509	0	6	252	33	0	1,551	1,322	11	**5,153**
North Sea	0	0	0	0	0	0	0	0	0	4,737	0	0	0	**4,737**
Baltic Sea	0	0	0	0	0	0	0	0	0	690	0	0	0	**690**
Total	**21,181**	**24,171**	**26,304**	**9,516**	**6,357**	**3,892**	**3,814**	**7,668**	**3,386**	**5,427**	**50,291**	**42,339**	**1,353**	**205,700**

No detailed data is available for non-EEG installations with a capacity of less than 10 MW; the total capacity of these installations (4,885 MW) is therefore not included in the table

The figures do not include generating capacity in Luxembourg, Switzerland and Austria feeding into the German grid. (5,000 MW)

* This table includes the following plant statuses: operational, seasonal mothballing, special cases, temporarily shut down, reserve capacity, security mode for backup purposes

Table 11: Generating capacity by energy source in each federal state

1.5 Combined heat and power (CHP)

Combined heat and power (CHP) is the simultaneous conversion of primary fuels into mechanical or electrical energy and useful heat in a single thermodynamic process.

The Bundesnetzagentur's list of power plants includes all German electrical installations, including CHP plants, with an electric net nominal capacity of at least 10 MW broken down precisely by plant unit. Since 1 July 2017, all CHP plants must be registered in the Bundesnetzagentur's core energy market data register (MaStR) regardless of size.

1.5.1 CHP plant capacity with a minimum capacity of 10 MW

The evaluations presented in this chapter include all CHP-capable German power generation units with a net electricity capacity of at least 10 MW. There were 487 power generation units capable of cogenerating heat and process steam on the market in 2017. 261 of these power generation units are bigger than 10 MW and smaller than 50 MW. CHP plants of this size must now participate in CHP auctions in order to qualify as modernised or new under the Combined Heat and Power Act (KWKG); see chapter "I.B.1.5.3 CHP auctions"). Figure 12 shows the number of CHP-capable power generation units per federal state. North Rhine-Westphalia is the federal state with the most installed CHP-capable power generation units.

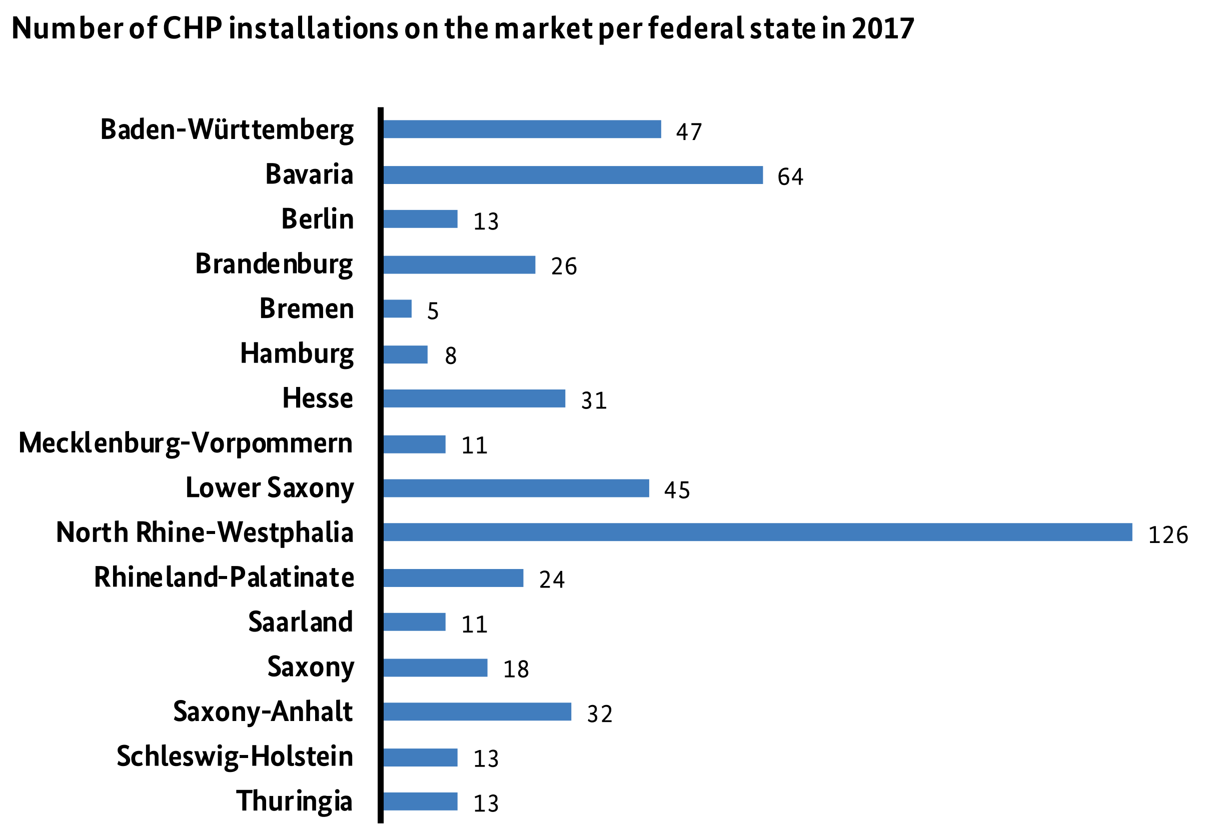


Figure 12: Number of CHP installations on the market per federal state in 2017

The installed electrical and thermal capacity of CHP plants in MW are shown separately in . CHP plants provide installed electrical capacity of 21.8 GW. A thermal capacity of 47.1 GW is installed in power generating installations. The biggest installations of each kind provide 728 MW of electrical capacity and 680 MW of thermal capacity. These two installations are not part of the same power plant.

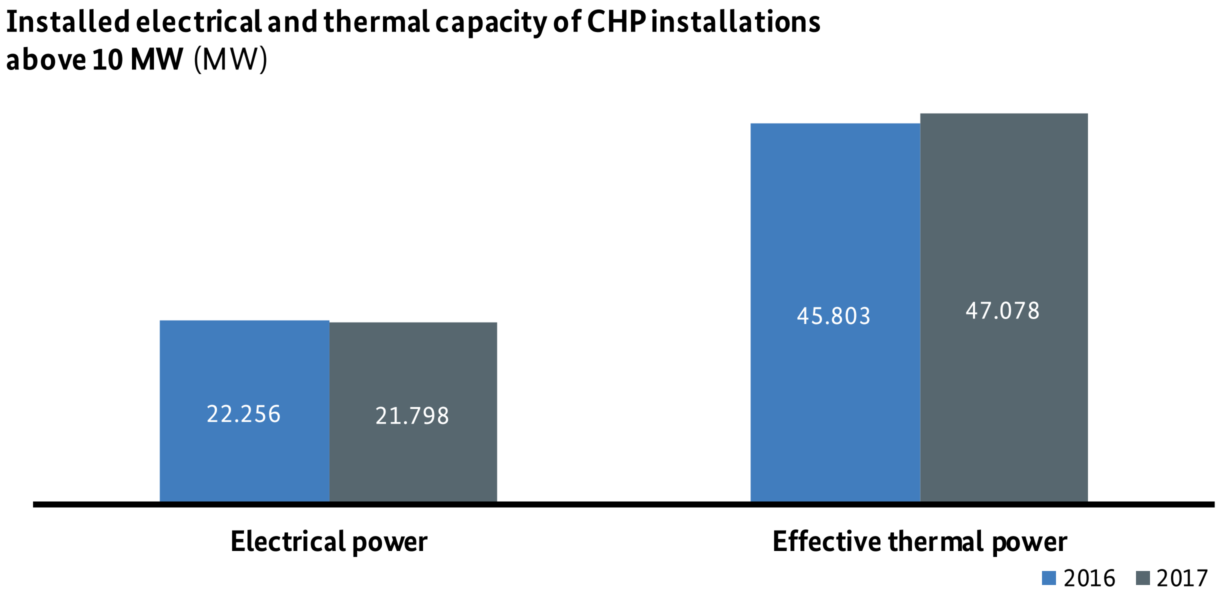


Figure 13: Installed electrical and thermal capacity of CHP installations with a minimum capacity of 10 MW

The (electrical and thermal) installed capacity is sourced as follows (Table 12). The table clearly shows that natural gas and hard coal in particular are used in CHP plants. Numerous smaller CHP plants in Germany have an installed electrical capacity of less than 10 MW and are not captured by the monitoring survey performed by the Bundesnetzagentur and are therefore not included in the capacities shown in the following table.

Installed electrical and thermal capacity of CHP power plants by energy source with a minimum capacity of 10 MW (MW)

	Electrical power		Effective thermal power	
	2016	2017	2016	2017
Waste	822	750	3,451	3,621
Biomass	419	449	1,723	1,866
Lignite	1,220	1,227	4,960	5,210
Natural gas	11,774	11,430	20,634	20,699
Others	1,213	1,305	3,310	3,446
Black coal	6,809	6,638	11,726	12,236
Total	22,256	21,798	45,803	47,078

Table 12: CHP plants with a minimum installed electrical and thermal capacity of 10 MW per source

The CHP-capable power generation units on which this evaluation is based produced 144.7 TWh useful heat and 70.6 TWh electricity in 2017. CHP plants generated almost as much electricity in 2017 as in 2016. Around the same volume of useful heat was also generated in 2017 as in 2016.

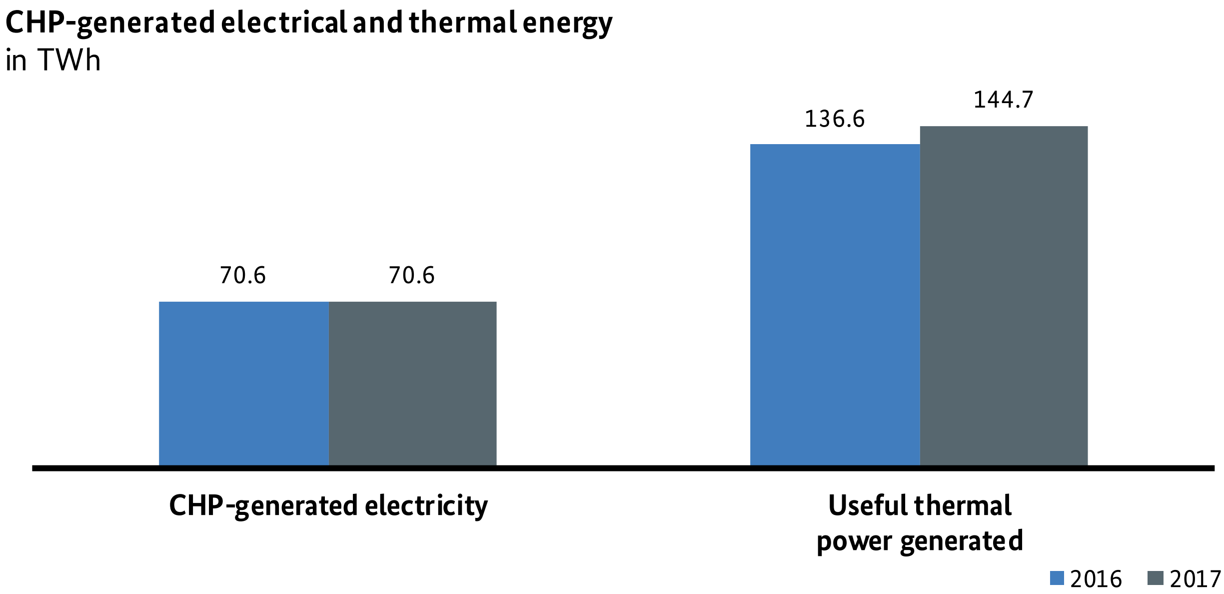


Figure 14: Electrical and thermal generation from CHP installations with a minimum capacity of 10 MW

The amount of electricity and useful heat generated by CHP plants results from an energy mix which corresponds to the installed capacity. The most important energy sources for the generation of electricity from CHP plants and useful heat volumes are natural gas and hard coal (see Table 13). Natural gas is a particularly important energy source for electricity generated from CHP plants and accounts for 63% of total generation. 41% of useful heat is generated from natural gas and 24% from hard coal.

Amount of electrical and thermal power generated by CHP power plants by energy source with a minimum capacity of 10 MW (TWh)

	Total CHP electricity generated		Useful thermal power generated	
	2016	2017	2016	2017
Waste	3.5	3.1	11.3	11.1
Biomass	2.2	2.3	9.0	8.8
Lignite	3.7	3.7	13.2	15.5
Natural gas	44.6	44.5	60.3	59.6
Others	4.0	4.3	9.4	15.3
Hard coal	12.7	12.8	33.4	34.4
Total	70.6	70.6	136.6	144.7

Table 13: Amount of electrical and thermal power generated by CHP plants with a minimum capacity of 10 MW per source

1.5.2 CHP plants newly registered in the core energy market data register from July 2017 onwards

Since 1 July 2017, under the Core Energy Market Data Register Ordinance (MaStRV), CHP plants must be registered with the Bundesnetzagentur. Besides information about the plant operator and plant location, approval information and technical master data for the installation – such as main fuel and capacity – have to be provided. The date of the commissioning, the connection network operator, the voltage level and information about the ability to control the installation remotely are requested as well.

Commissioned CHP installations
(MW)

	Net nominal capacity	Effective thermal power	Number
Before July 17	4.6	4.9	4
July 2017	9.3	13.0	180
August 2017	5.8	9.1	218
September 2017	48.4	57.6	265
October 2017	17.2	22.4	286
November 2017	81.0	106.3	334
December 2017	90.5	160.4	509
January 2018	4.9	7.0	126
February 2018	8.8	11.8	144
March 2018	16.1	18.9	154
April 2018	5.3	7.5	143
May 2018	4.9	6.6	103
June 2018	1.8	2.9	82
After June 18	1.3	1.5	7
Total	**299.9**	**430.0**	**2,555**
Outstanding approval	*1,042.5*	*1,048.5*	*60*

Source: Bundesnetzagentur's core energy market data register (MaStR)

Table 14: Commissioning of CHP installations

2,615 installations with a total net nominal capacity of 1,342 MW were registered in the first year (1 July 2017 to 30 June 2018). Of these, approximately 1,043 MW are based on outstanding approvals and approximately 300 MW on commissioning.

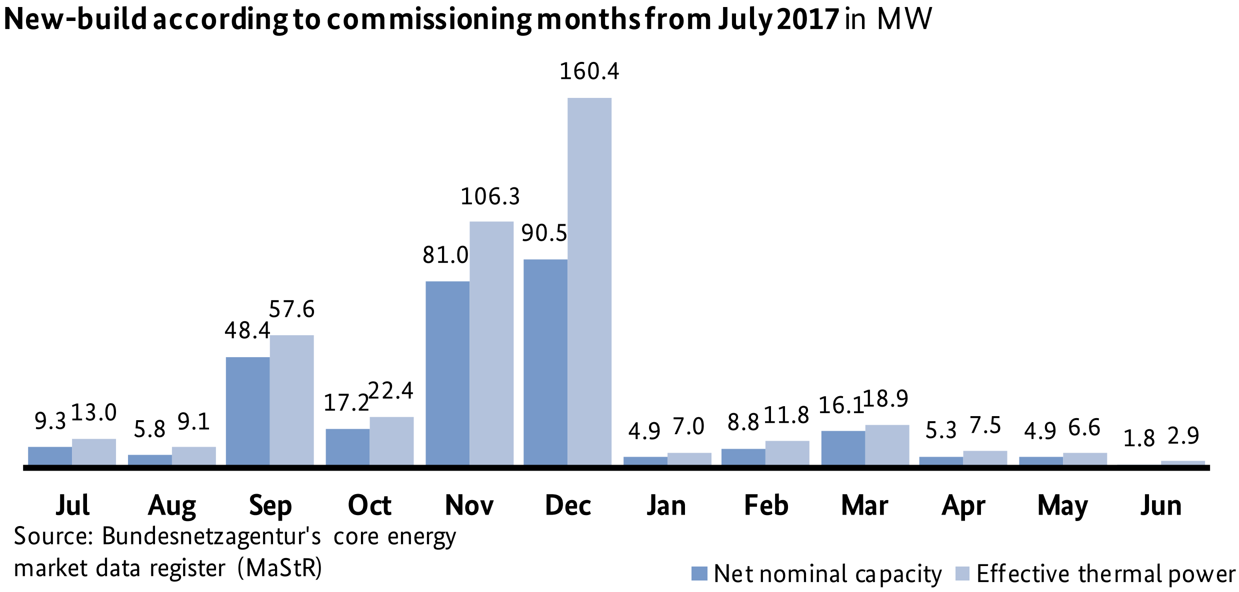


Figure 15: Capacity increase according to commissioning months

Figure 15 shows the net nominal capacity and thermal effective power per month in the first year of registration. More than half of the new capacity was commissioned in November and December 2017 (172 MW) probably as a direct result of the CHP auction round in December 2017 (cf. “I.B.1.5.3 CHP auctions").

Commissioning by federal states in 2017
(MW)

Federal state	Net nominal capacity	Effective thermal power	Number
Baden-Württemberg	59.3	842.8	520
North Rhine-Westphalia	55.7	1,200.4	453
Mecklenburg-Western Pomerania	41.5	462.8	31
Bavaria	36.1	440.8	351
Saxony	18.5	210.6	112
Hamburg	16.2	190.4	50
Lower Saxony	13.3	186.5	301
Thuringia	13.1	143.4	68
Saxony-Anhalt	10.9	130.7	53
Saarland	10.5	139.9	23
Schleswig-Holstein	6.8	93.8	111
Rhineland-Palatinate	5.3	75.4	127
Brandenburg	5.2	70.8	75
Hesse	5.2	78.8	219
Berlin	2.0	29.0	49
Bremen	0.2	4.1	12
Total	**299.9**	**4,300.1**	**2,555**

Source: Bundesnetzagentur's core energy market data register (MaStR)

Table 15: Commissioning by federal state

Most installations were commissioned in Baden-Württemberg (520) and North Rhine-Westphalia (453). In terms of net nominal capacity, almost 40% of newly-registered installations are in these two federal states.

Approvals by federal state in 2017
in MW

Federal state	Net nominal capacity	Effective thermal power	Number
Berlin	304.0	234.2	3
Schleswig-Holstein	194.9	196.2	2
North Rhine-Westphalia	174.3	168.5	9
Rhineland-Palatinate	103.3	100.8	4
Baden-Württemberg	56.6	86.9	4
Saxony-Anhalt	54.8	66.3	2
Bavaria	50.2	83.5	10
Saxony	34.1	38.1	6
Thuringia	30.6	32.0	7
Mecklenburg-Western Pomerania	10.4	10.7	3
Lower Saxony	10.3	10.8	4
Brandenburg	9.9	10.7	2
Hesse	4.7	5.0	3
Hamburg	4.4	4.9	1
Total	1,042.5	1,048.5	60

Source: Bundesnetzagentur's core energy market data register (MaStR)

Table 16: Approvals by federal state

In contrast, by far the largest proportional capacity for which approvals have been reported is in Berlin (304 MW) followed by Schleswig-Holstein (195 MW) and North Rhine-Westphalia (174 MW).

1.5.3 CHP auctions

Under the revised Combined Heat and Power Act (KWKG), which came into force at the turn of the year 2016/2017, and the related CHP Auction Ordinance payments for CHP plants with a capacity of more than 1 MW and up to and including 50 MW will only be awarded in auctions. With the introduction of auctions, the level of payments for approximately 15% of the additional capacity of CHP systems will be determined in a competitive process. Auctions will be held for conventional CHP systems as well as for innovative systems. Innovative CHP systems include a CHP installation, an innovative renewable heat source and an electric heat generator. The innovative renewable heat source may be a solar thermal installation, geothermal energy or a heat pump.

Bids are accepted on the basis of the rate specified in the respective bid ("pay as bid"). Accepted bids expire after 54 months in each case. Bidders pay penalties if installations are not commissioned within 48 months. The highest value for the bids is 7 ct/kWh for CHP installations and 12 ct/kWh for innovative CHP systems (iCHP systems).

The CHP payment will be made for CHP electricity fed into the general supply grid regardless of the plant operator's electricity and heat revenue and is thus revenue in addition to prices on the power exchange.

CHP auctions

	CHP December 2017	CHP June 2018	iCHP systems June 2018
Volume put up for auction	100 MW	93 MW	25 MW
Submitted bids	20 (225 MW)	14 (96 MW)	7 (23 MW)
Winning bids	7 (82 MW)	13 (91 MW)	5 (21 MW)
Average rate	4.05 ct/kWh	4.31 ct/kWh	10.27
Lowest bid (awarded)	3.19 ct/kWh	2.99 ct/kWh	8.47 ct/kWh
Highest bid (awarded)	4.99 ct/kWh	5.20 ct/kWh	10.94 ct/kWh
Excluded bids	None	1 (4 MW)	2 (2 MW)

Table 17: CHP auctions

1.6 Power plants outside of the electricity market

The total generating capacity of 103.1 GW from non-renewables (as at October 2018) can be divided into power plants operating within the electricity market (91.6 GW) and power plants operating outside of the electricity market (11.5 GW). Within these two categories, the following subsets can be classified with regard to power plant status:

Power plants operating in the electricity market:

- 91.2 GW: plants in operation;

- 0.4 GW: plants temporarily not in operation (e.g. owing to repairs following damage) or with restricted operation.

Plants operating outside of the electricity market:

- 6.9 GW: backup power stations (power stations systemically relevant under sections 13b(4) and 13b(5) EnWG and now only operated when requested by the TSOs)

- 2.0 GW: power plants on security standby[34]

[34] The costs for these power plants were lower than €100m in 2017. More detailed information is unobtainable as RWE Power AG classifies this information as operating and business secrets. As only two operators' plants were on security standby on 1 April 2018, these operators were able to calculate their respective competitor's costs from the total costs.

– 2.6 GW: plants temporarily closed.

The backup power plants referred to above are plants which were notified as scheduled for temporary or final closure but which may not be closed for supply security reasons (see "Operation of reserve power plants" on page 129 onwards for more information). These plants currently comprise power stations using natural gas (3.0 GW), hard coal (2.3 GW) and mineral oil products (1.6 GW).

In accordance with section 13g EnWG, the lignite-fired power plants Buschhaus, Neurath C, Niederaußem E and F, Frimmersdorf P and Q as well as Jänschwalde E and F have been gradually transferred to so-called security standby status as from 1 October 2016 (transfer of lignite-fired plant Buschhaus Block D to security standby status by 1 October 2016, 352 MW; the lignite-fired plants Frimmersdorf P and Q by 1 October 2017, 562 MW; and the lignite-fired plants Neideraußem E and F and Jänschwalde F by 1 October 2018, 1,059 MW). In addition to ensuring security of supply, security standby serves primarily to reduce carbon dioxide emissions in the electricity sector. The power plant units remain on security standby for four years. During this period, these power stations are not permitted to produce electricity other than for security standby purposes. After four years, the plants must be permanently closed. A return to the electricity market is not permitted.

The plants temporarily closed are power stations using natural gas (2.2 GW), lignite (0.3 GW) and mineral oil products (0.2 GW).

Figure 16 shows the location of power plants operating outside of the electricity market. The map shows power plants which have been notified as scheduled either for temporary ("reserve power plants") or final closure but which may not be closed for supply security reasons. The EnWG distinguishes between temporary and final closure: In contrast to final closures, temporary closures can be reversed within a period of one year.

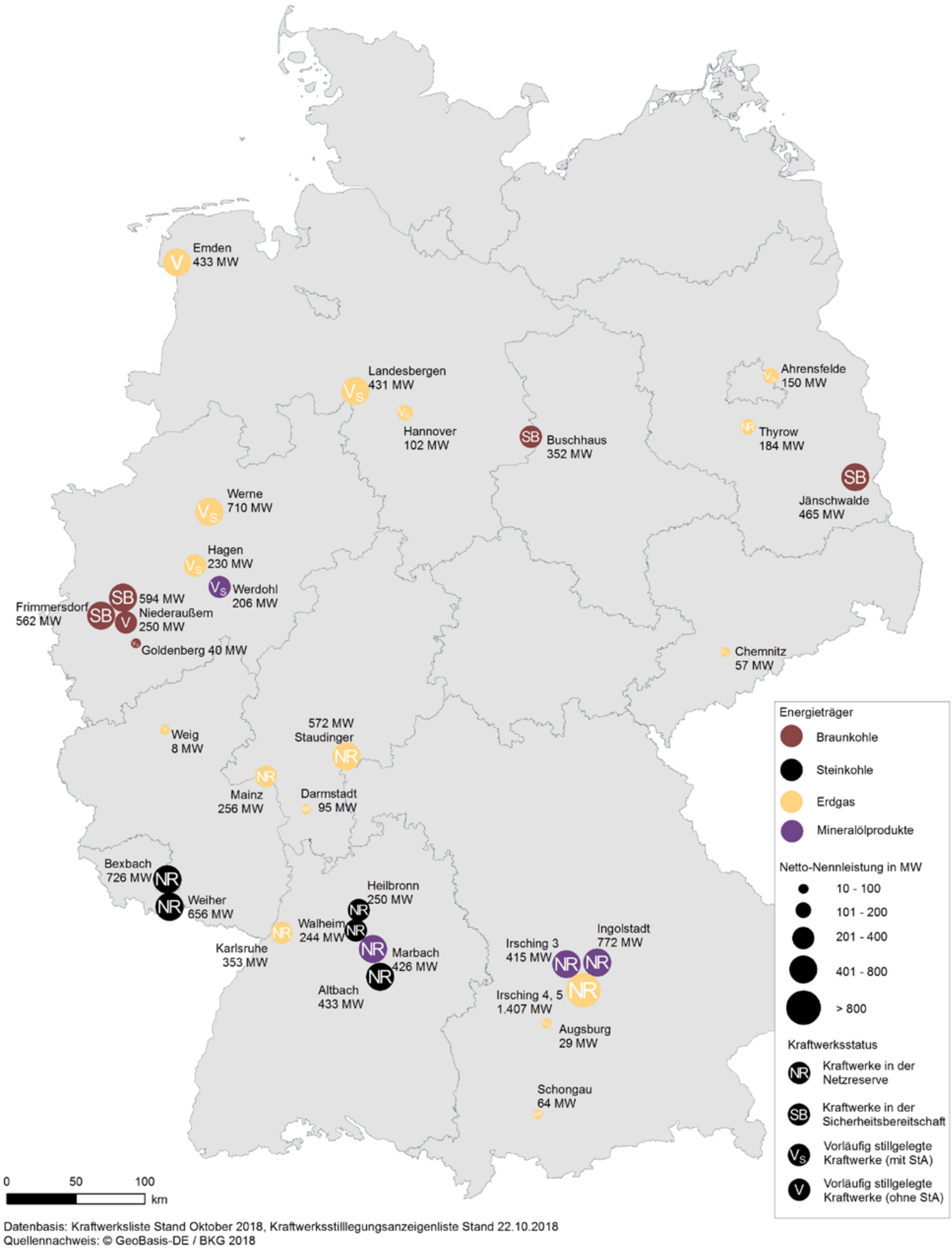


Figure 16: Power plants outside of the electricity market (net nominal capacity, as at October 2018)

1.7 Development of the generation capacity of non-renewable energy sources

1.7.1 Construction of conventional power plants

In addition to information on existing power plants, the Bundesnetzagentur also requests monitoring data on the future development of power plant capacity. The following section first examines the construction of new power plants. Chapter "I.B.1.7.2 Power plant closures" on page 69 then complements the assessment of the future development of the generation system with the power plant closures. . The analysis of the future generation system is limited to non-renewable energy sources. The analysis of newly constructed power plant capacity only considers power generating modules currently in trial operation or under construction with a minimum net nominal capacity of 10 MW up to the year 2021. In such cases, the probability of projects being implemented is considered to be sufficiently high.

Generation capacity totalling 2,079 MW is currently in trial operation or under construction and will likely be completed by 2021 (see Figure 17). The conventional power plant projects in Germany relate to hard coal (1,052 MW), natural gas (954 MW and other energy sources (73 MW).

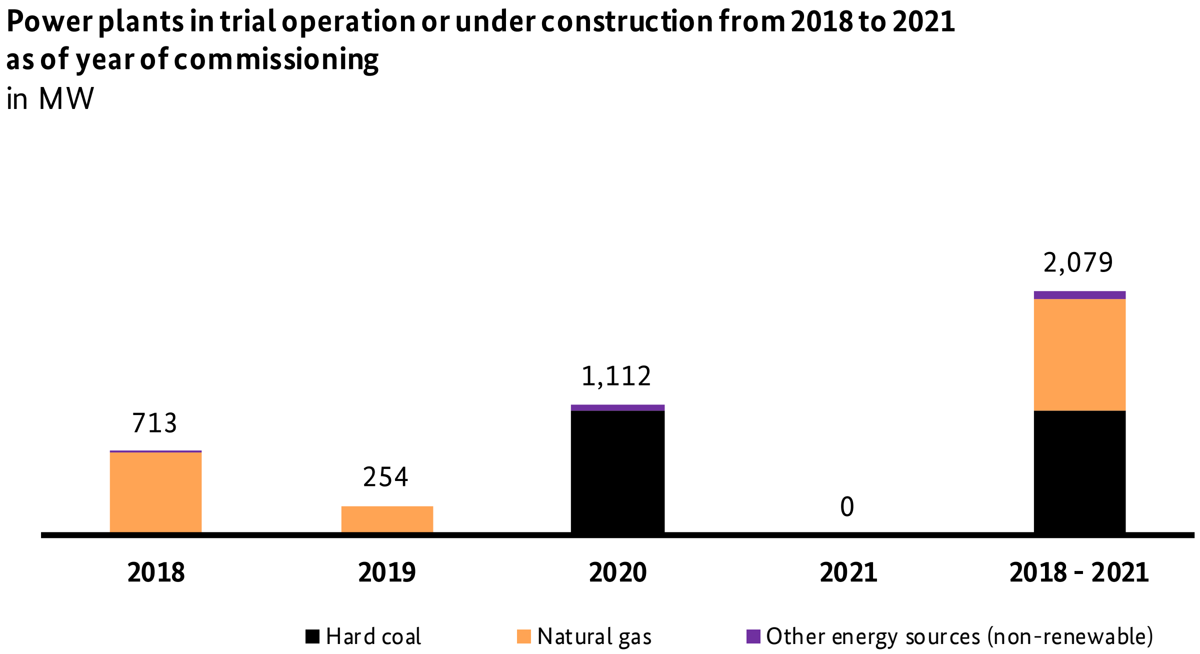


Figure 17: Power plants in trial operation or under construction from 2018 to 2021 by year of commissioning (national planning data for net nominal capacity 2018 to 2021, as at October 2018)

1.7.2 Power plant closures

The future development of the generation system can be described by the construction and the planned closures of power plants. Just as with the power plant constructions, the analysis of power plant closures only considers those power plants with a sufficiently high probability of closure. These include power plants which have been notified to the Bundesnetzagentur as scheduled for final or provisional plant closure. It also takes into account the statutorily required shutdown of nuclear power plants.

Figure 18 shows the locations of the expected new power generating units or units to be closed with a minimum capacity of 10 MW for the period until 2021. The total number of plants which have been notified as scheduled for closure does not include systemically important power plants, as the closure of such plants is prohibited. Also excluded are the closures scheduled after 2021 of the nuclear power plants Neckarwestheim 2, Emsland and Isar 2, (with a total capacity of 4,056 MW) as well as the München Nord 2 hard coal power plant (with a capacity of 333 MW).

In Germany as a whole, the capacity of planned closures – consisting of plants notified as scheduled for final closure (2,256 MW) and nuclear power plants scheduled for statutory closure (5,460 MW) – until 2021 exceeds the capacity of newly constructed power generating units (2,079 MW) by 5,637 MW. A reduction of existing surplus capacities is therefore expected. From security of supply perspective, a differentiated analysis of northern and southern Germany is also of interest. The analysis uses the Main river line as an approximate dividing line between northern and southern Germany. South of the Main, 172 MW of power plant capacity is currently under construction. By contrast, a capacity of 2,713 MW is marked for final closure in southern Germany by 2021. Some 2,690 MW of this capacity is attributable to the Philippsburg 2 (scheduled for closure in 2019) and Gundremmingen Block C (closure in 2021) nuclear power plants alone. This equates to a deficit of -2,541 MW in southern Germany by 2021. North of the Main river as well, planned plant closures exceed the capacity of newly constructed power plant units. The total capacity of 1,907 MW of power generating units in trial operation or under construction (including Datteln 4) contrasts with the planned closure of a total capacity of 5,003 MW, of which 2,770 MW is accounted for by the Brokdorf and Grohnde nuclear power plants (2021). This corresponds to a deficit of -3,096 MW by 2021.

In addition to the final closures, the Bundesnetzagentur was also notified of provisional closures of a total capacity of 984 MW.

In addition, pursuant to section 13b(1) EnWG, the lignite-fired power plants Jänschwalde E and Neurath C, with a total capacity of 757 MW, will be transferred to a "security standby status". After four years on "security standby", these plants must be ultimately closed.

In addition to the above-mentioned formal notifications of planned final or temporary closures, the Bundesnetzagentur was also informed of further planned closures of power generating units through its monitoring activities. The final closure of a total additional capacity of 852 MW is thus expected by 2021. This concerns specifically hard coal fired power plants with a capacity of 760 MW, a natural gas fired power plant with a capacity of 11 MW, other energy sources with a capacity of 67 MW and the partial closure of lignite-fired power plant capacity of 14 MW. All these power plants are located north of the Main river line.

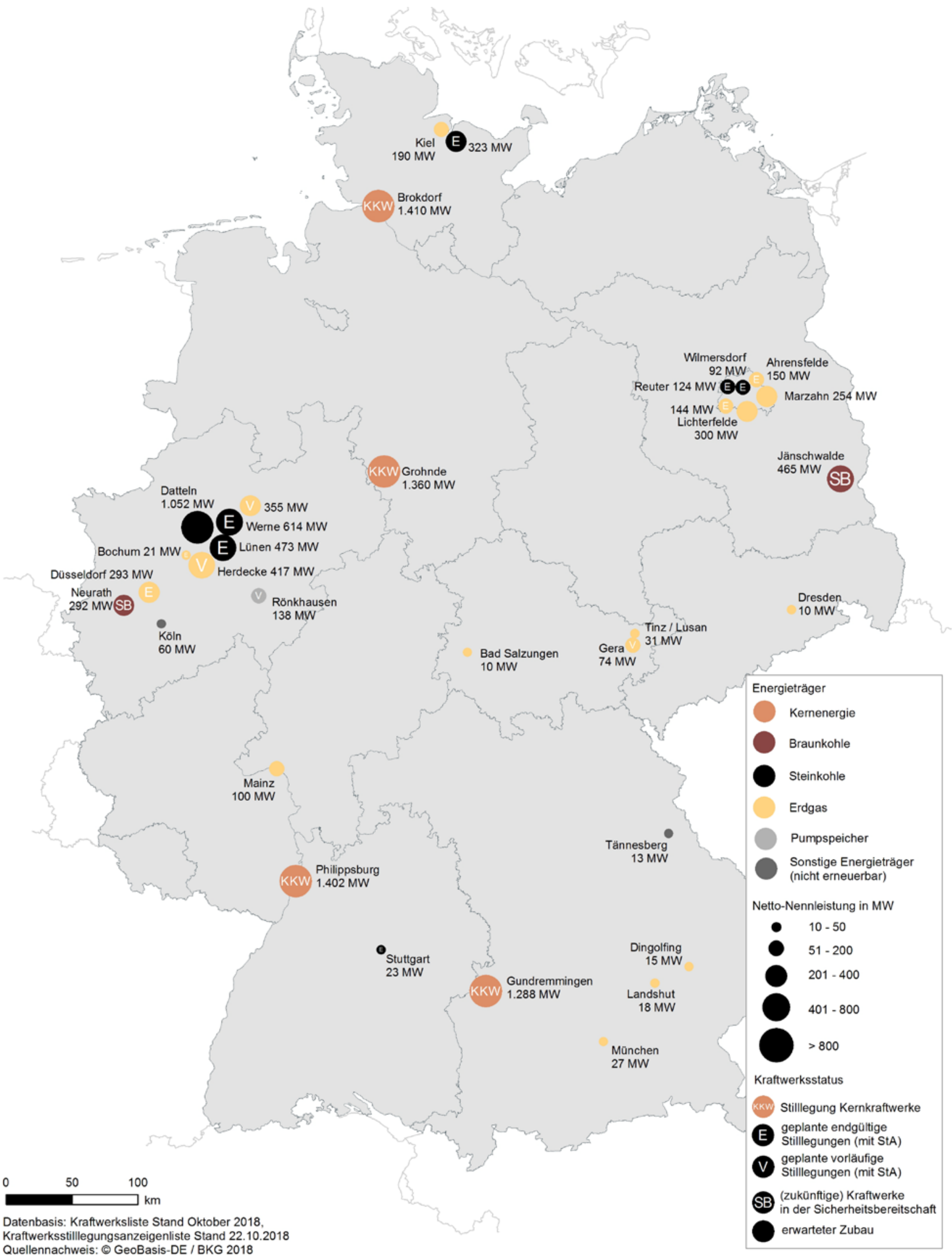
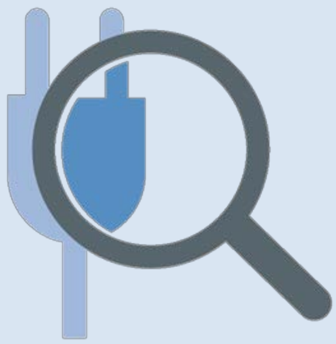


Figure 18: Locations with an expected increase or decrease in power generation capacity to 2021 – as of October 2018

The capacity of power plants scheduled for final or statutory closure by the year 2021 thus totals 8,568 MW. Some 2,713 MW of this is located in southern Germany. The overall national balance of increase or decrease of power generation capacity by 2021 is thus -6,489 MW. This balance of power plant constructions and closures is calculated on the basis of power generation units in trial operation or under construction minus formal notifications of final plant closures pursuant to section 13b(1) EnWG, nuclear power plant closures and final closures identified through the monitoring process. The overall balance for southern Germany in the same period is -2,541 MW.



The intensive expansion of renewable energies makes it possible to phase out nuclear power and reduce CO_2 emissions in Germany. New conventional generation capacities have arisen over the last two years primarily in flexible natural gas power plants.

The change in the electricity generation mix calls for further grid expansion, in particular to transport the wind-generated electricity from the north of the country to the south of Germany.

In order to secure the supply of electricity in Germany, the Bundesnetzagentur is assessing which power plants can be closed or must continue to operate to stabilise the electricity network.

2. Development of renewables

2.1 Development of renewable energies (entitled to payments under the EEG)

Not all renewable energy generating facilities are entitled to payments under the EEG. A distinction must therefore be made between renewable energy generating facilities with and without entitlement to payments. The majority of installed renewable energy capacity falls under the EEG payment regime (market premium or feed-in tariff). 107.8 GW of the 112.5 GW of capacity installed at the end of 2017 is eligible for EEG payments. This chapter consequently examines the renewable energies entitled to payments in more detail.

The 4.8 GW of renewable energy capacity not entitled to payments is primarily accounted for by the energy sources run-of-river power (2.4 GW), dammed water (1.5 GW) and waste (0.9 GW). For the energy source waste, only the biogenic share of the waste generation is considered a non-eligible renewable energy source. The remaining 0.9 GW of energy capacity for the energy source waste is assigned to the non-renewable energy sector. A total of 18.3 TWh of electricity was generated from renewable energies in 2017. The majority of that energy was generated in run-of-river and dammed water power plants (13.6 TWh in total) and in waste-fired power plants (4.3 TWh).

The key figures presented in this section are collected by the Bundesnetzagentur to fulfil its monitoring function in the nationwide EEG compensation scheme process. To this end, selected data is provided on an annual basis from the year-end accounts of TSOs (by 31 July), energy utilities and DSOs (by 31 May). Since

August 2014, the Bundesnetzagentur's installations register is used as an additional source of information to evaluate the installed capacity of EEG installations.

In the publication "EEG in Numbers 2017", the Bundesnetzagentur provides market stakeholders with evaluations that go beyond the key figures presented here. In particular, this publication contains evaluations for specific energy sources, federal states and grid connection levels.[35]

Plant operators must register themselves and their installations in the core energy market data register in order to receive payments under the EEG (https://www.marktstammdatenregister.de/). Consumers who are already operators of an electricity-generating installation are also required to register their installation in the core energy market data register even if they are already entered in another Bundesnetzagentur register.

2.1.1 Installed capacity

As at 31 December 2017, the total installed capacity of installations receiving payment in accordance with the EEG was approximately 107.8 GW. Around 8.3 GW of total additional capacity entitled to payments was installed in 2017, representing an increase of around 8.3%.

[35] https://www.bundesnetzagentur.de/eeg-daten

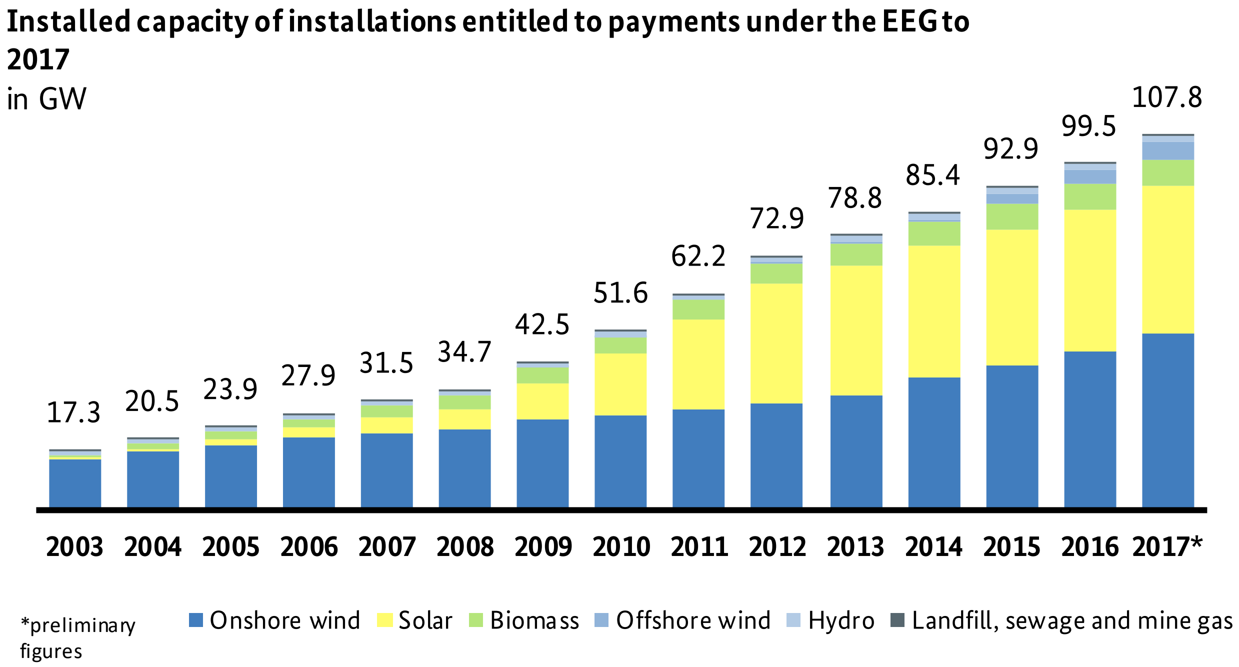


Figure 19: Installed capacity of installations entitled to payments under the EEG up to 2017

A sharp rise in the net capacity of offshore and onshore wind power installations was again recorded in 2017. Offshore wind power installations with a capacity of 1.3 GW were newly installed (2016: approximately 0.8 GW), which represents an increase of 30.7%. The net new build of onshore wind installation capacity (5.0 GW) was greater than in the prior year (2016: 4.0 GW). The 1.7 GW increase of photovoltaic installation capacity was, as in the three previous years, less than the development corridor defined in the EEG (2.5 GW). However, while an average of 1.3 GW was added in the three previous years, there was again a slight increase (1.7 GW) in the capacity of photovoltaic installations. The 0.3 GW growth in biomass installations was slightly higher than in the previous year (2016: 0.2 GW).

The development corridor for onshore wind installations in the years 2017 to 2019 is for an overall increase of 2.8 GW, while an overall increase of 2.5 GW is planned for solar power. With an overall increase of 5.0 GW (gross total), onshore wind significantly exceeded the planned development corridor, while the increase of 1.7 GW for solar power (gross total) fell below the planned corridor. In the case of biomass, an increase of installed capacity of 0.15 GW (gross total) is planned for the years 2017 to 2019; this increase, however, applies only to the commissioning of new installations rather than the expansion of existing facilities. The installed capacity of offshore wind installations is set to rise to a total of 6.5 GW by 2020 and 15 GW by 2030. In the year 2017, installations with an installed capacity of 1.3 GW had been commissioned, so that by 31 December 2017 a total of 5.4 GW had been installed, which already accounts for 83% of the growth target.

Installed capacity of installations entitled to payments under the EEG by energy source

	Total 31 December 2016	Total 31 December 2017*	Increase / Decrease in 2017	Increase / Decrease compared to 2016
	in MW	in MW	in MW	in %
Hydro	1,579.7	1,586.3	6.6	0.4%
Gases[1]	496.9	506.1	9.2	1.9%
Biomass	7,258.8	7,568.4	309.6	4.3%
Geothermal	37.8	37.8	0.0	0.0%
Onshore wind	45,282.9	50,291.5	5,008.6	11.1%
Offshore wind	4,152.0	5,427.1	1,275.1	30.7%
Solar	40,679.4	42,339.1	1,659.7	4.1%
Total	99,487.4	107,756.2	8,268.8	8.3%

[1] Landfill, sewage and mine gas

*preliminary figures

Table 18: Installed capacity of installations entitled to payments under the EEG by energy source (on 31 December)

Some 72,277 new facilities were installed in 2017. Photovoltaic installations accounted for 97% of new installations, onshore wind installations for 0.2% and biomass installations for 0.2%. The growth rates of EEG installations entitled to payments are shown in Table 19.

Development of the number of installations entitled to payments under the EEG

	2011	2012	2013	2014	2015	2016	2017*
Hydro	6,825	6,974	6,864	6,947	7,078	7,041	7,074
Gases[1]	680	684	622	627	630	612	653
Biomass	12,697	13,371	13,485	14,024	14,113	14,186	14,328
Geothermal	4	6	7	8	9	10	11
Onshore wind	20,204	21,339	21,819	23,593	24,696	26,057	27,555
Offshore wind	49	65	113	241	789	945	1,166
Solar	1,154,968	1,328,293	1,449,413	1,521,365	1,572,922	1,622,405	1,692,746
Total	1,195,427	1,370,732	1,492,323	1,566,805	1,620,237	1,671,256	1,743,533

[1] Landfill, sewage and mine gas

*preliminary figures

Table 19: Development of the number of installations entitled to payments under the EEG

Table 20 shows the growth rates of EEG installations entitled to payments by energy source.

Growth rates of installations by energy source

	Total 31 December 2016 Number	Total 31 December 2017* Number	Increase / Decrease in 2017 Number	Increase / Decrease compared to 2016 in %
Hydro	7,041	7,074	33	0.5%
Gases[1]	612	653	41	6.7%
Biomass	14,186	14,328	142	1.0%
Geothermal	10	11	1	10.0%
Onshore wind	26,057	27,555	1,498	5.7%
Offshore wind	945	1166	221	23.4%
Solar	1,622,405	1,692,746	70,341	4.3%
Total	1,671,256	1,743,533	72,277	4.3%

[1] Landfill, sewage and mine gas

*preliminary figures

Table 20: Growth rates of installations entitled to payments under the EEG by energy source (on 31 December)

2.1.2 Annual feed-in of electricity

In 2017 the total annual feed-in of electricity from installations entitled to payments under the EEG was 187.4 TWh. Total annual feed-in of electricity has increased significantly by 16.1% compared to the previous year (161.5 TWh). This increase is partly explained by the fact that 2017 was a stronger wind year than 2016, as shown in Figure 20. The largest share of annual electricity feed-in of 86.3 TWh (46%) was generated by onshore wind installations, followed by biomass installations with a share of 41.0 TWh (22%) and photovoltaic installations with a share of 35.4 TWh (19%).

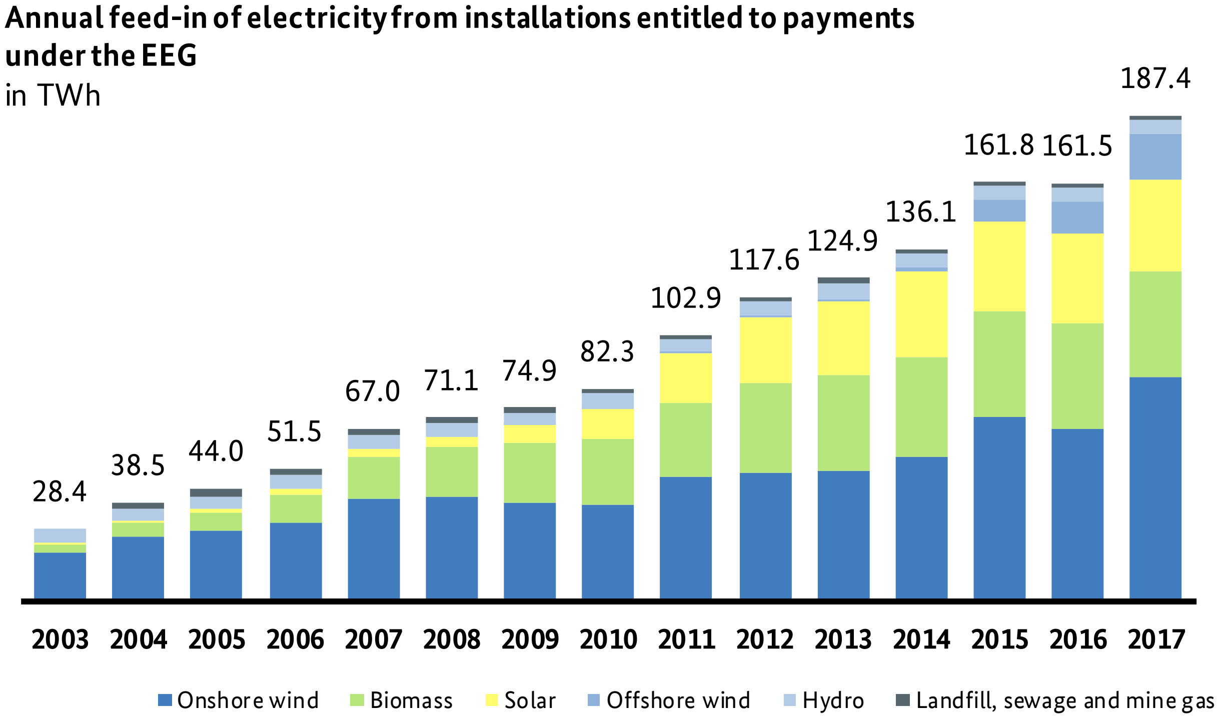


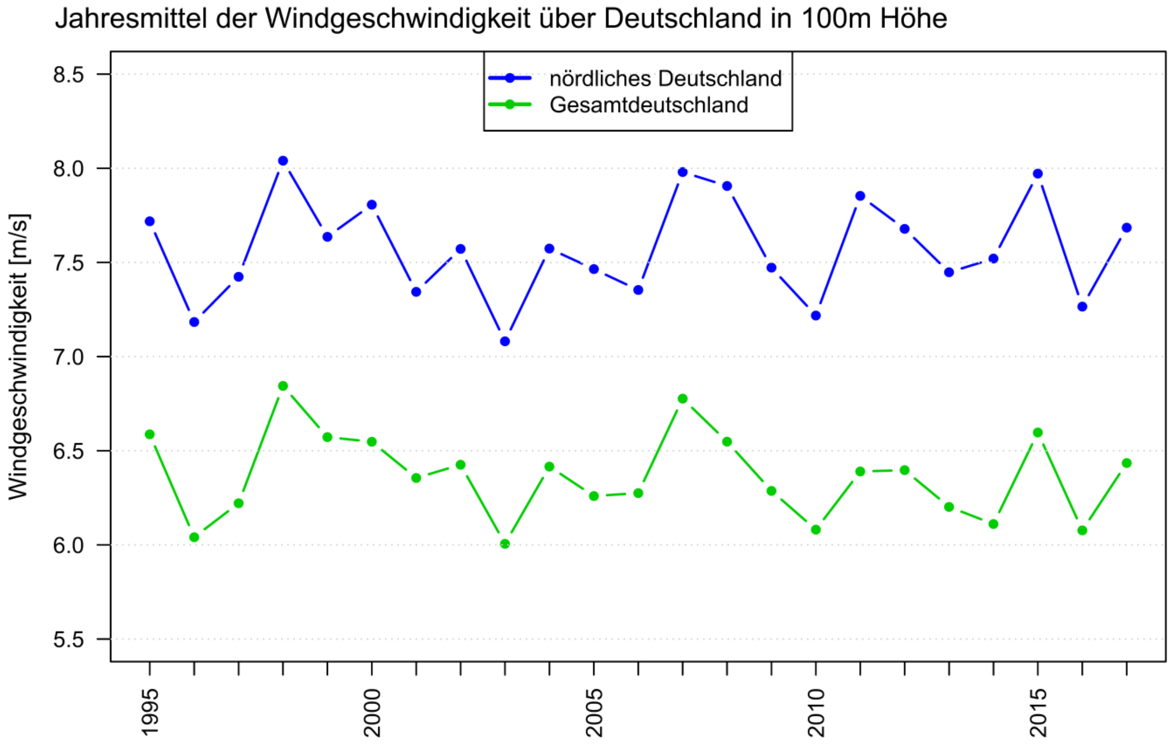
Figure 20: Development of annual feed-in of electricity from installations entitled to payments under the EEG

Annual feed-in of electricity from EEG installations entitled to payments by energy source

	Total 31 December 2016 in GWh	Total 31 December 2017 in GWh	Increase / Decrease compared to 2016 in %
Hydro	5,949	5,777	-2.9
Gases[1]	1,434	1,319	-8.0
Biomass	41,016	41,056	0.1
Geothermal	175	163	-6.9
Onshore wind	66,324	86,293	30.1
Offshore wind	12,092	17,414	44.0
Solar	34,490	35,428	2.7
Total	161,479	187,448	16.1

[1] Landfill, sewage and mine gas

Table 21: Annual feed-in of electricity from EEG installations entitled to payments by energy source (on 31 December)



Jahresmittel der Windgeschwindigkeit in 100m Höhe über Deutschland, sowie dem nördlichen Bereich Deutschlands. Die Daten basieren auf der globalen atmosphärischen Reanalyse "ERA−Interim" des europäischen Copernicus Klimadienstes (C3S) und stellen den Mittelwert über folgende Bereiche dar: Deutschland: ca. 6°O − 15°O, ca. 48°N − 55°N; nördliches Deutschland: ca. 6°O − 15°O, ca. 52°N − 55°N (Quelle: Deutscher Wetterdienst, Nationale Klimaüberwachung, basierend auf C3S/ERA−Interim: Dee et al. (2011)).

Figure 21: Annual average wind speed at 100m elevation for all of Germany as well as for northern Germany

Maximum feed-in of electricity from wind power installations and photovoltaic installations

The maximum feed-in from wind power installations and photovoltaic installations only increased slightly compared with previous years. In 2017, the maximum feed-in from wind power installations and photovoltaic installations of 54.8 GW was recorded on 7 June 2017. Almost two thirds of this peak feed-in was due to feed-in from wind power installations. On this day, photovoltaic installations fed up to 19.1 GW into the grid. This coincided with a medium level of feed-in of 35.7 GW from wind power installations. Figure 22 shows the maximum feed-in from wind power installations and photovoltaic installations between 2012 and 2017.

In 2017 the maximum feed-in from photovoltaic installations alone of 27.7 GW was recorded on 27 May 2017. The year’s highest feed-in values for wind power installations (onshore and offshore) were recorded in October 2017. The peak capacity of 43.5 GW achieved on 28 October 2017 was due primarily to the gale force winds deep low pressure system HERWART. Several peak values were also observed at the end of the year as a result of various storm systems. Figure 23 shows the development of feed-in from wind power installations in 2017.

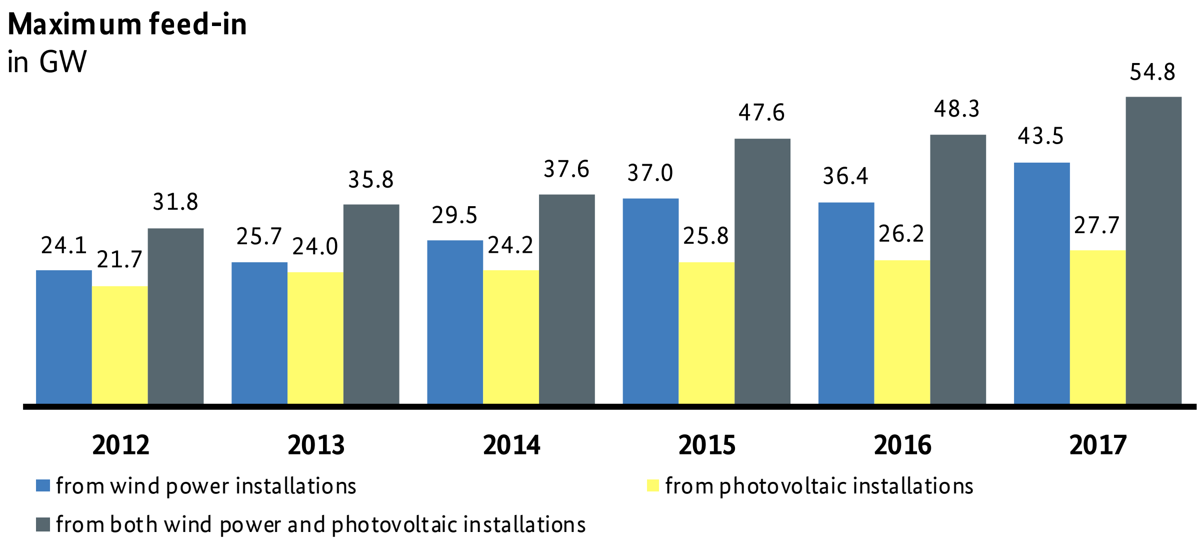


Figure 22: Maximum feed-in

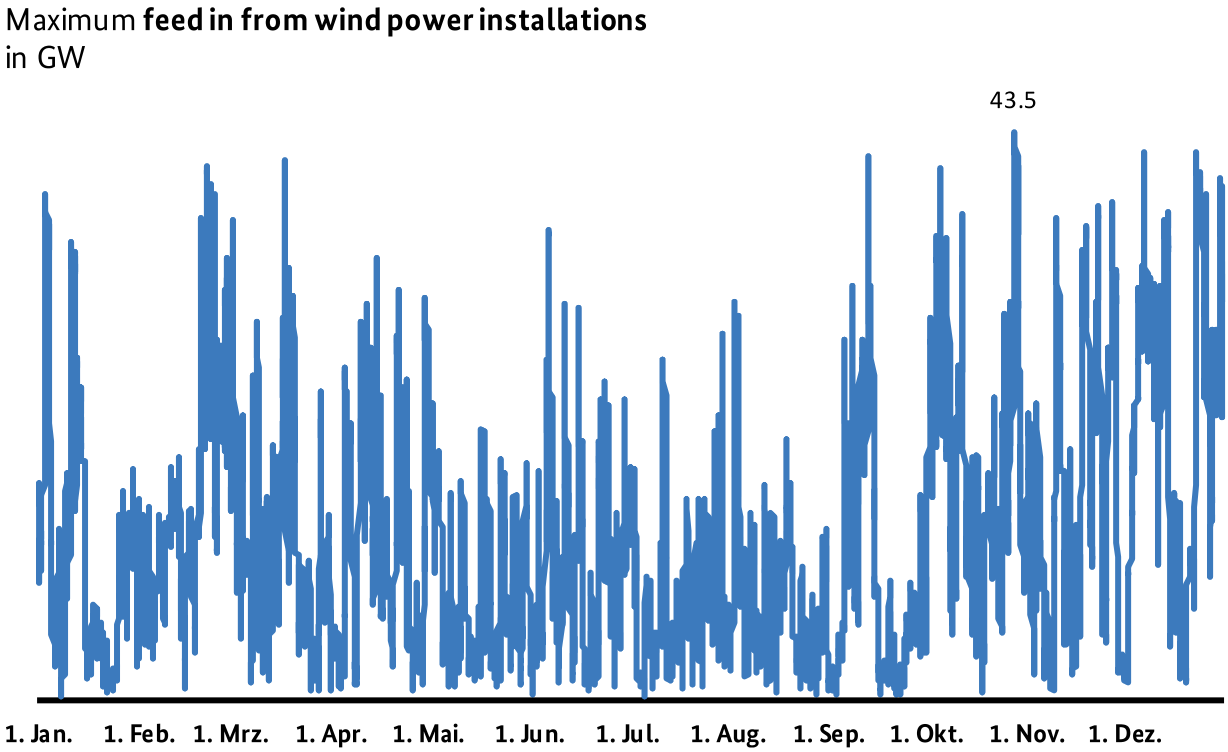


Figure 23: Maximum feed-in from wind power installations in 2017

2.1.3 Form of selling

Under the EEG 2012, installation operators were able for the first time to choose between three different forms of direct selling as an alternative to fixed feed-in tariffs (section 33b EEG 2012): claiming a market premium (as an EEG-based payment in addition to market profits), reducing the EEG surcharge through energy utilities (green electricity privilege), or other forms of direct selling (sales of EEG electricity without additional payment under the EEG). Subsequent amendments to the EEG all stipulate direct selling or the market premium as standard forms of selling. Only existing or new installations with a capacity of up to

100 kW can still opt for fixed feed-in tariffs. Other forms of direct selling, ie selling without payment under the EEG, also remain possible.

From 2013 more than half of annual electricity feed-in has been sold directly, and in 2015 a total of 69.4% of annual feed-in was sold through direct channels. In 2017 only 22% of annual feed-in was paid a fixed feed-in tariff (cf Figure 24).

Table 22 shows that almost three quarters of annual feed-in of electricity was remunerated under the EEG in the form of the market premium. This is already the case for 100% of offshore wind power installations (and at 95%, the number of onshore wind power installations receiving market premiums is also approaching the 100% mark. In 2016 the figure was still 93.5%). At 25%, the proportion of electricity from photovoltaic installations paid a market premium (2016: 22.6%) is still relatively low but growing continually.

In 2017 the main energy source for direct selling was onshore wind power, which accounted for a share of 56.5% (2016: 52.8%). The share of electricity fed in by offshore wind power installations also increased to 12% (2016: 10.3%).

Annual feed-in of electricity from installations with a fixed feed-in tariff or direct selling
%

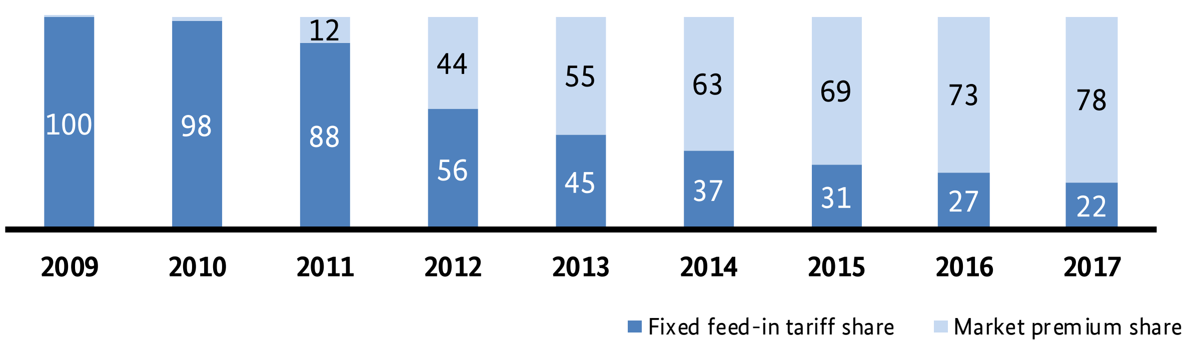


Figure 24: Annual feed-in of electricity from installations entitled to payments under the EEG by feed-in tariff or market premium

Annual feed-in of electricity from installations with a fixed feed-in tariff and market premium

	All installations GWh	Installations with feed-in tariff GWh	Installations with market premium GWh	Share of installations with market premium in total annual feed-in %
Hydro	5,777	2,479	3,298	57
Gases[1]	1,319	309	1,010	77
Biomass	41,056	8,673	32,382	79
Geothermal	163	4	158	98
Onshore wind	86,293	4,157	82,136	95
Offshore wind	17,414	0	17,414	100
Solar	35,428	26,507	8,921	25
Total	187,448	42,129	145,319	78

[1] Landfill, sewage and mine gas

Table 22: Annual feed-in of electricity from installations with a fixed feed-in tariff or market premium

Breakdown, by energy source, of annual feed-in from installations with market premium for 2017
%

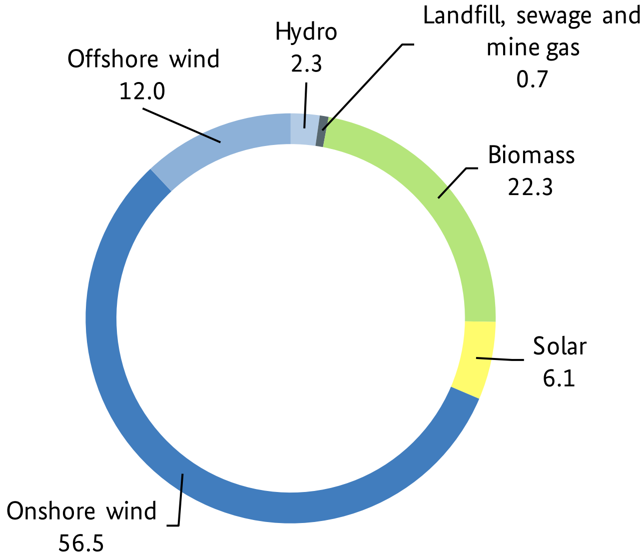
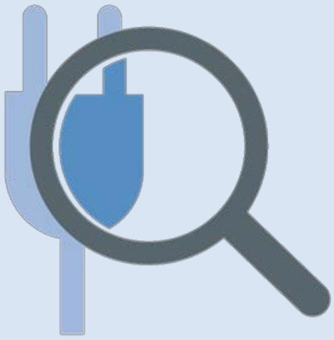


Figure 25: Breakdown, by energy source, of annual feed-in from installations with market premium



Operators of newly installed renewable energy installations with a capacity of up to 100 kW (ie installations of the kind typically installed on house roofs) are still entitled to statutory feed-in remuneration, ie payments under the EEG for the produced electricity without having to worry about selling the electricity. All operators of installations with a capacity more than 100 kW must sell the electricity produced by the installation themselves or via a service provider. They also have responsibility for balancing.

The majority (78%) of the renewable electricity generated in Germany in 2017 was sold directly either by the operator or a service provider.

2.2 Changes in payments under the EEG

2.2.1 Overall changes in payments under the EEG

Payments for renewable energy fed into the public electricity network are made by the operators to whose network the generating installations are connected in accordance with technology-specific rates (values to be applied) as defined in the EEG. The payments are made from the year in which the installation is commissioned and for a subsequent period of 20 years.

In 2017 a total of €26bn was paid to installation operators by the operators to whose networks the installations are connected. This includes, on the one hand, payments to installation operators who sell their electricity through transmission system operators (feed-in tariff). On the other hand, this amount also includes premium payments to installation operators who market their electricity themselves ("market premium"). For the first time, in 2016 the majority of payments went to installation operators entitled to the market premium (52.3%). This trend continued in 2017 (feed-in tariff: 43.3%, market premium: 56.7%).

Photovoltaic installations (€10.2bn), biomass installations (€6.8bn) and onshore wind power installations (€5.7bn) accounted for significant shares of these payments.

Payments by energy source

	Total 31 December 2016 € million	Total 31 December 2017 € million	Increase / Decrease compared to 2016 %
Hydro	467	440	-6
Gases[1]	72	60	-17
Biomass[2]	6,902	6,772	-2
Geothermal	39	35	-10
Onshore wind	4,693	5,720	22
Offshore wind	1,948	2,770	42
Solar	10,226	10,236	0
Total	24,346	26,033	7

[1] Landfill, sewage and mine gas

[2] Including support for flexibility

Table 23: Payments under the EEG by energy source (as at 31 December)

Table 23 shows that compared with previous years overall payments in 2017 increased only slightly. This is in particular due to the constant annual feed-in from these installations (cf Table 21 and page 77). Payments only increased significantly for offshore and onshore wind, largely owing to the significant expansion of these energy sources.

Operators of renewable energy installations received an average of 13.9 ct/kWh in payments under the EEG[36] in 2017. Payments for the different energy sources varied significantly, however. For example, operators of photovoltaic installations received an average of 28.9 ct/kWh in 2016 while operators of onshore wind installations received an average of 6.6 ct/kWh. These average values include both existing installations, which receive high payments under the EEG, and new installations, which receive much lower payments under the EEG. Installation operators have also received additional revenue since 2012 from direct marketing on power exchanges. These revenues are not included in the payments shown. Figure 26 shows the average payments under the EEG compared with the previous year.

[36] Average payments under the EEG are arrived at by dividing total payments under the EEG by the total annual feed-in for the relevant year.

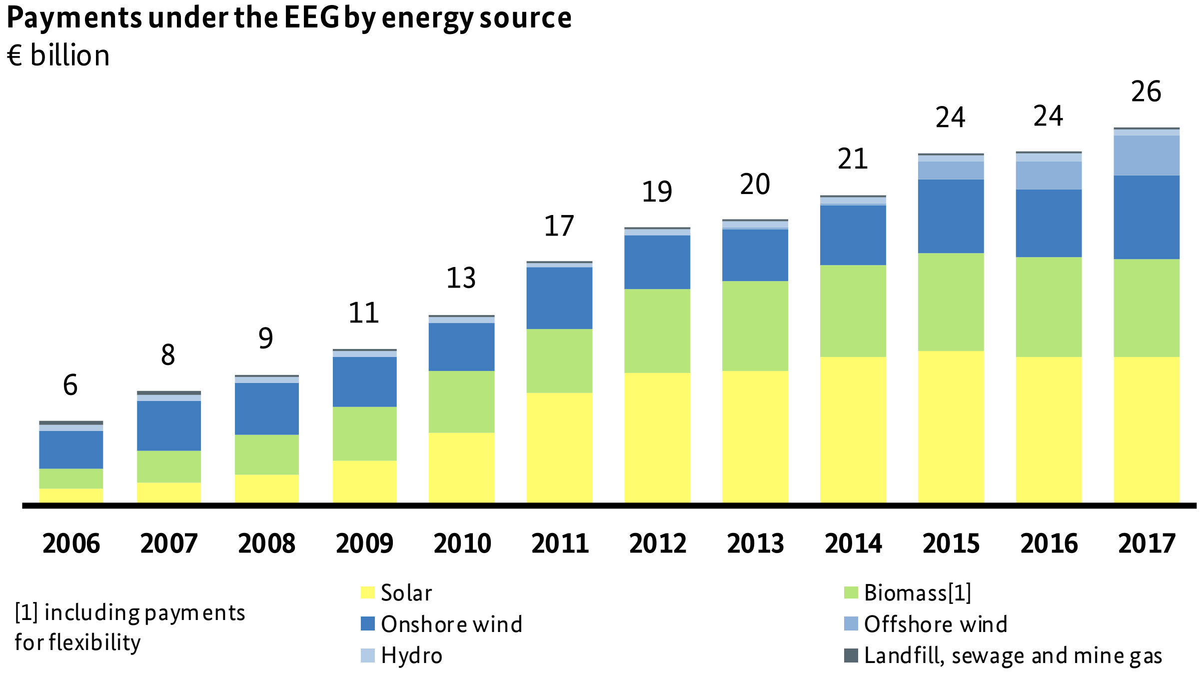


Figure 26: Changes in payments under the EEG according to energy sources

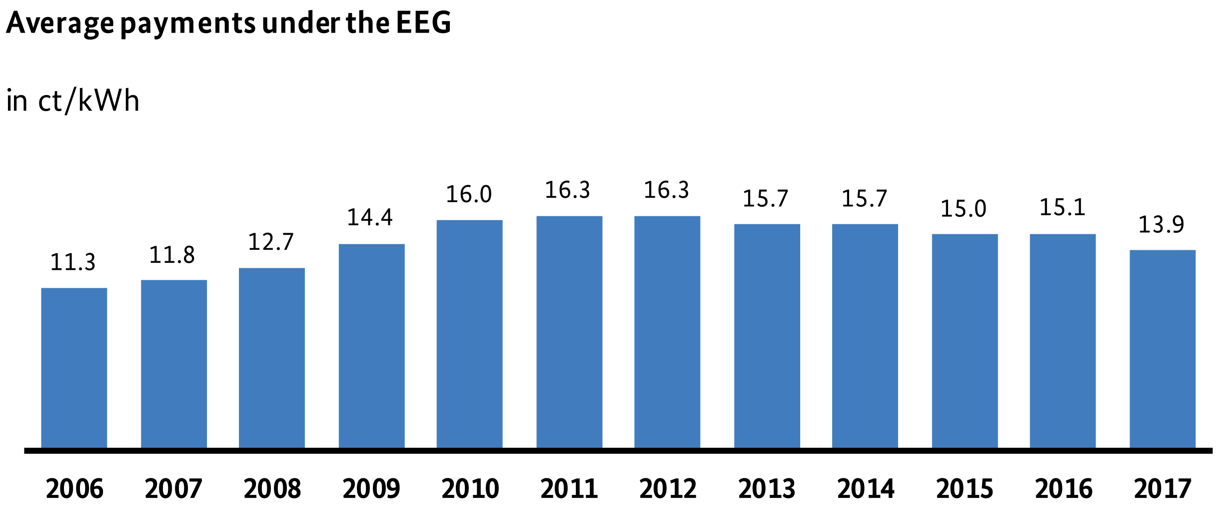


Figure 27: Changes in average payments under the EEG

2.2.2 Changes in the EEG surcharge

Payments under the EEG are for the most part refinanced through the EEG surcharge. Accordingly, the increase in payments under the EEG leads to an increase in the EEG surcharge over time. In previous years a portion of this increase has been attributable to the decline in wholesale prices for electricity and market profits for renewable electricity. Figure 28 shows that the EEG surcharge has been comparatively stable at between 6.2 and 6.9 ct/kWh since 2014. In the two previous years it rose much more steeply from 3.6 to 6.24 CT/kWh. The falling payments for new installations in particular have slowed the rate of increase substantially in recent years. The increase in wholesale prices for electricity since 2017 will even result in a reduction in the EEG surcharge in 2018 and 2019.

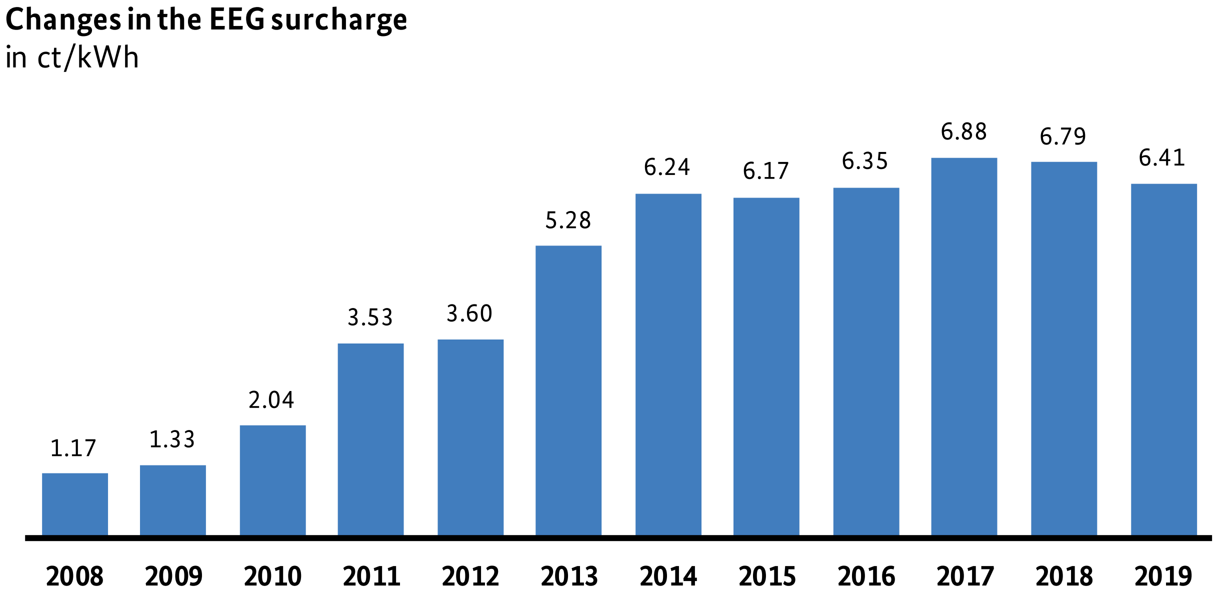


Figure 28: Changes in the EEG surcharge

The EEG surcharge finances green electricity payments to the operators of photovoltaic, wind power, hydropower or biogas and biomass installations. The surcharge is paid for by all electricity customers, with certain commercial and industry customers receiving a discount. The four transmission system operators determine the surcharge for the following year by 15 October each year on the basis of projected revenue and expenditure.

The payments made to operators of renewable energy installations play a key role in the calculation of the surcharge. The transmission system operators sell all the renewable electricity entitled to a fixed feed-in tariff (approximately 22%), which is mainly generated by smaller and existing installations, on the power exchange. The largest share of renewable electricity (78%) is sold directly by installation operators or via direct sellers on the market, eg the power exchange. In both cases the revenue from the market profits is not sufficient to cover the actual payments made or payment entitlements.

This difference is passed on to electricity consumers by the renewable energy surcharge.

2.2.3 Lowering of the values to be applied (reference values for calculating the payment entitlement)

Automatic cost reduction mechanisms were introduced in the EEG 2014 to reflect the cost reductions brought about by technological advancements. Thus, as from September 2014, the values to be applied for solar power are reduced by a set percentage each month. For onshore wind power, the values to be applied have been reduced on a quarterly basis as from January 2016. There is an additional adjustment (reduction or increase) of the values to be applied that depends on the actual capacity expansion in a pre-defined reference period. If the planned expansion corridor is exceeded, the degression rate used for calculation purposes is automatically increased, thus lowering the values to be applied. If, by contrast, expansion fails to meet the statutory expectations, the values to be applied remain the same or even rise. Calculations are based on the data recorded in the core energy market data register.

Lowering of the values to be applied

Energy source	Relevant reference period for calculating actual reduction	Growth corridor (MW)	Actual growth in reference period in MW	Applied reduction	Reduction cycle	Period of validity of reduction
Solar	Sep 2013 - Aug 2014	2,400 - 2,600 (gross)	2,398	0.25%	monthly	Q3 2014
	Dec 2013 - Nov 2014		1,953	0.25%		Q1 2015
	Mar 2014 - Feb 2015		1,811	0.25%		Q2 2015
	Jun 2014 - May 2015		1,581	0.25%		Q3 2015
	Sep 2014 - Aug 2015		1,437	0.0%		Q4 2015
	Dec 2014 - Nov 2015		1,419	0.0%		Q1 2016
	Mar 2015 - Feb 2016		1,367	0.0%		Q2 2016
	Jun 2015 - May 2016		1,336	0.0%		Q3 2016
	Sep 2015 - Aug 2016		1,096	0.0%		Q4 2016
	Fixed in EEG 2017	2.500 (gross)	-	0.0%		Okt 70
	(Jul 2016 - Dec 2016) x2		2,025	0.0%		Feb - Apr 17
	(Oct 2016 - Mar 2017) x2		2,149	0.25%		May 17 - Jul 17
	(Jan 2017 - Jun 2017) x2		1,802	0.0%		Aug 17 - Oct 17
	(Apr 2017 -Sep 2017) x2		1,966	0.0%		Nov 17 - Jan 18
	(Jul 2017 - Dec 2017) x2		1,704	0.0%		Feb 18 - Apr 18
	(Oct 2017 - Mar 2018) x2		2,037	0.0%		May 18 - Jul 18
	(Jan 2018 - Jun 2017) x2		2,727	1.0%		Aug 18 - Oct 18
	(Apr 2018 -Sep 2018) x2		3,193	1.0%		Nov 18 - Jan 19
Onshore wind	Aug 2014 - Jul 2015	2,400 - 2,600 (net)	3,666	1.2%	quarterly	Q1 2016
	Nov 2014 - Oct 2015		3,712	1.2%		Q2 2016
	Feb 2015 - Jan 2016		3,564	1.2%		Q3 2016
	May 2015 - Apr 2016		3,941	1.2%		Q4 2016
	Fixed in EEG 2017	2,400 - 2,500 (gross)	-	1.2%	one-off	Okt 70
	Fixed in EEG 2017		-	1.05%	monthly	Mar 17 - Aug 17
	May 2016 - Apr 2017		4,676	2.4%	quarterly	Q4 2017
	Aug 2016 - Jul 2017		5,038	2.4%		Q1 2018
	Nov 2016 - Oct 2017		5,516	2.4%		Q2 2018
	Feb 2017 - Jan 2018		5,378	2.4%		Q3 2018
	May 2017 - Apr 2018		5,308	2.4%		Q4 2018

Table 24: Lowering of the values to be applied

With the exception of the months of May, June and July, the commissioning of new photovoltaic installations did not result in a reduction of the values to be applied because actual growth during the respective reference periods (2.4 to 2.6 GW gross total per year) was in all cases below the target corridor. There was, however, an increase in the capacity of photovoltaic installations in 2018 and the target corridor in the respective reference periods was exceeded again so that the values to be applied were reduced in the months from August to December 2018 by 1%.

With the entry into force of the EEG 2017 on 1 January 2017 the values to be applied for onshore wind power were reduced in the first three quarters of 2017 in accordance with the specific provisions of this law. In the following quarters (fourth quarter of 2017 through to the fourth quarter of 2018) the values to be applied were reduced by 2.4% each as expansion in the respective reference periods for the calculation of the reduction exceeded the target corridor (2.4 to 2.6 GW net total per year) by more than 1,000 MW.

2.3 Auctions

Following the amendment to the EEG at the end of 2016/beginning of 2017, the level of payment for around 80% of new renewable capacity is now determined through competitive auctions. Since the beginning of 2017 EEG payments are only made for new installations producing renewable energy using onshore wind, offshore wind and biomass technologies if the relevant bid has previously been accepted within the framework of an auction. The only exceptions are for onshore wind installations and PV installations with an installed capacity of up to 750 kW and newly commissioned biomass installations with an installed capacity of up to 150 kW. Payments for these renewable energy installations continue to be fixed by law.

Bids are accepted on the basis of the price specified in the bid ("pay as bid"). Exceptions only apply to bids made by citizens' energy companies for auctions for onshore wind power and existing biomass installations with an installed capacity of less than 150 kW. In these cases, rates are fixed in a uniform pricing system with the value of the highest successful bid determining the value to be applied.

Successful awards lapse after defined periods of time, the duration of which differs according to energy source. Bidders pay penalties if installations are not commissioned within the defined period.

Auctions like those under the EEG have also been introduced under the Combined Heat and Power Act (see chapter I.B.1.5.3).

In 2018, for the first time cross-technological auctions were jointly held for onshore wind and photovoltaic power installations.

The following auctions have been held since early 2017:

Auctions held 2017-2018

Technology	Tender deadlines	Winning bids in ct/kWh*
Solar	1 February 2017	6.58
	1 June 2017	5.66
	1 October 2017	4.91
	1 February 2018	4.33
	1 June 2018	4.59
	1 October 2018	4.69
Onshore wind	1 May 2018	5.71
	1 August 2018	4.28
	1 November 2018	3.82
	1 February 2018	4.73
	1 May 2018	5.73
	1 August 2018	6.16
	1 October 2018	6.26
Offshore wind	1 April 2017	0.44
	1 April 2018	4.66
CHP	1 December 2017	4.05
	1 June 2018	4.31
	1 December 2018	-
Innovative CHP systems	1 June 2018	10.27
	1 December 2018	-
Biomass	1 September 2017	14.3
	1 September 2018	14.73
Onshore wind and solar across all technologies	1 April 2018	4.67
	1 November 2018	5.27

*Volume-weighted average winning bid

Table 25: Auctions held since 2017

In auctions payments for power stations are determined competitively with the aim of reducing costs and, as a result, reducing the EEG surcharge in the long term.

Auctions for photovoltaic installations have brought about a significant reduction in price. In respect of the other technologies there is less competition in auctions and the available potential therefore cannot yet be fully utilised.

2.3.1 Auctions for photovoltaic installations

Since 2017 auctions have been held for all photovoltaic installations with installed capacity of over 750 kW. Bids for projects on grassland or arable land in disadvantaged areas are acceptable if permitted by ordinance by the individual federal states; to date this has only happened in Baden-Württemberg and Bavaria. Three auctions, each for 200 megawatts, are held every year.[37]

The bid volumes for all the auctions were significantly oversubscribed. Competitive pressure is reflected in falling winning bids. In the first four rounds, the value of the highest successful bid fell from round to round. Bids rose again slightly in the last two rounds (June and October) in 2018. Winning bids for all photovoltaic installations have fallen in price by 29% since auctions were introduced in early 2017. If the outcomes of the previous six auctions for ground-mounted photovoltaic installations under the Ground-mounted PV Auction Ordinance (FFAV) are also included, the prices of winning bids have fallen by 49% since the first auction round in April 2015. The current maximum payment for new photovoltaic installations determined by auction is 4.69 ct/kWh.

As shown in Figure 29 on page 93, awards for projects were concentrated in nine federal states, with most of these being awarded in the eastern and southern German Länder.

Awards must be implemented in between 18 and 24 months. The implementation periods from the past twelve rounds have now expired for the five auction rounds under the der Ground-mounted PV Auction Ordinance (FFAV); between 90% and 100% (Table 26) of awarded projects have since been realised, which is regarded as a success. The implementation periods for all auction rounds under the EEG have not yet expired. However, 76% of installations from the first round in February 2017 have already gone into operation.

[37] The auction volume is reduced on a regular basis by the capacity from smaller ground-mounted photovoltaic systems installed during the previous year and the awards for photovoltaic installations in the joint and technology-neutral auctions. This explains the lower auction volume from June 2018 onwards. If the auction volume is not used up in one round, the volume in the following year increases by the remaining bid volume.

Implementation rate for photovoltaic installation in all photovoltaic auctions since 2015

Tender deadline	Implementation status (end of July 2018) in %	Commissioning period (exclusion deadline)	Basis of tender
15 April 2015	99	6 May 2017	Ground-mounted PV Auction Ordinance (FFAV)
1 August 2015	90	20 August 2017	Ground-mounted PV Auction Ordinance (FFAV)
1 December 2015	92	18 December 2017	Ground-mounted PV Auction Ordinance (FFAV)
1 April 2016	100	18 April 2018	Ground-mounted PV Auction Ordinance (FFAV)
1 August 2016	96	12 August 2018	Ground-mounted PV Auction Ordinance (FFAV)
1 December 2016	73	15 December 2018	Ground-mounted PV Auction Ordinance (FFAV)
1 November 2016	99	5 December 2018	Cross-Border Renewable Energy Ordinance (GEEV)
1 February 2017	76	15 February 2019	Renewable Energy Sources Act (EEG)
1 June 2017	26	21 June 2019	Renewable Energy Sources Act (EEG)
1 October 2017	18	23 October 2019	Renewable Energy Sources Act (EEG)
1 February 2018	-	27 February 2020	Renewable Energy Sources Act (EEG)
1 June 2018	-	20 June 2020	Renewable Energy Sources Act (EEG)

Table 26: Implementation rates for photovoltaic auctions

Auctions for photovoltaic installations

	February 2017	June 2017	October 2017	February 2018	June 2018	October 2018
Volume put up for auction (MW)	200	200	200	200	182	182
Submitted bids	97	133	110	79	59	76
Submitted bid volume (MW)	488	646	754	546	360	551
Winning bids*	38	32	20	24	27	30
Volume of winning bids (kW)	200,079	200,646	222,203	201,114	182,293	151,102
Excluded bids	9	17	6	16	1	3
Volume of excluded bids (MW)	27	56	20	66,908	5,500	24,548
Maximum value permitted (ct/kWh)	8.91	8.91	8.84	8.84	8.84	8.75
Average volume weighted winning bid (ct/kWh)	6.58	5.66	4.91	4.33	4.59	4.69
Lowest bid (awarded) (ct/kWh)	6.00	5.34	4.29	3.86	3.89	3.86
Highest bid (awarded) (ct/kWh)	6.75	5.90	5.06	4.59	4.96	5.15

* After receipt of second security

Table 27: Auctions for photovoltaic installations in 2017

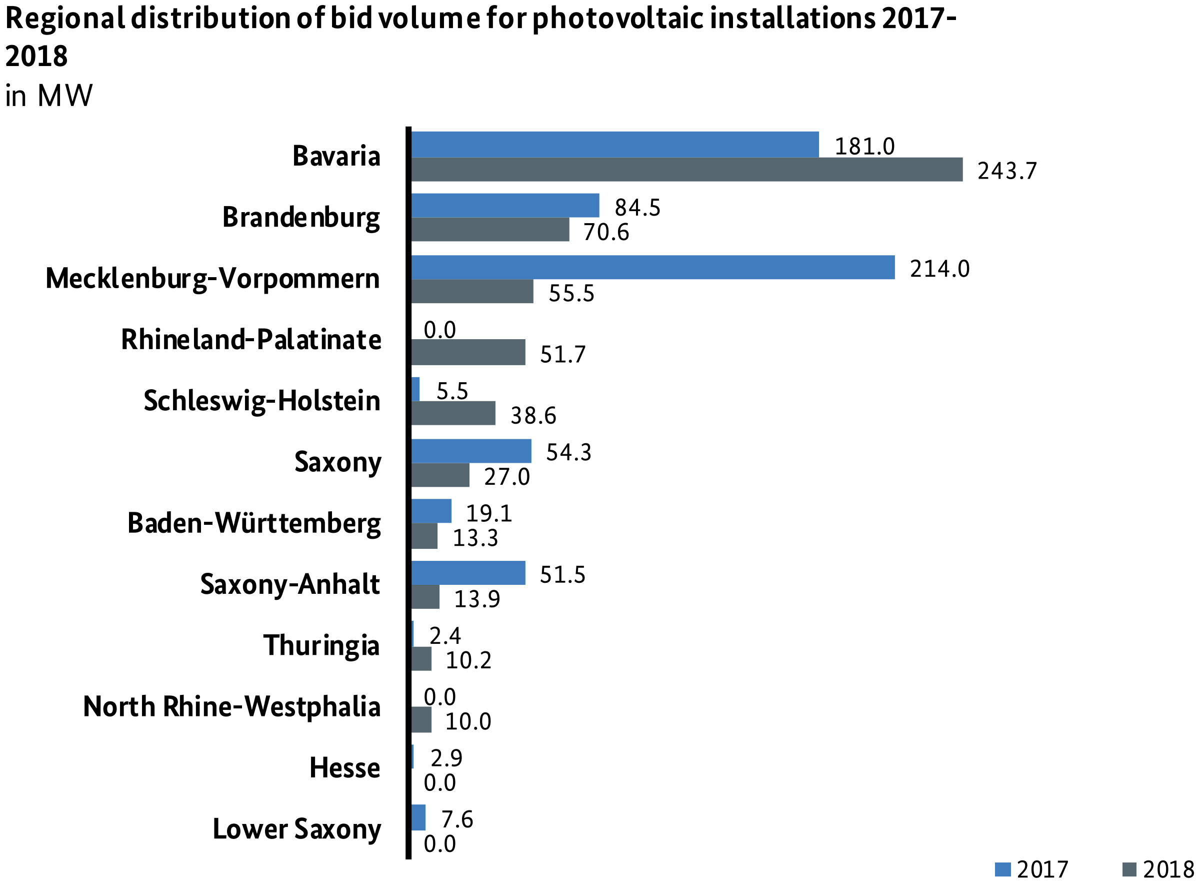


Figure 29: Regional distribution of bid volume for photovoltaic installations

2.3.2 Auctions for onshore wind installations

Since the beginning of 2017 payments for wind installations have also been determined by auction. All onshore wind installations with an installed capacity of at least 750 kW must participate in such auctions. The procedure involves three to four rounds of bidding with an auction volume of between 2,800 and 2,900 megawatts per year. Permits pursuant to the Federal Immission Control Act must be submitted for the installations. Bids are made for the reference value of an installation at a defined 100% reference site; the actual payments may, however, diverge from this.

There are two special features of auctions for onshore wind installations: The grid expansion area and citizens' energy companies.

- The grid expansion area is an area in northern Germany which includes the states of Schleswig-Holstein, Mecklenburg-Vorpommern, Bremen, Hamburg and parts of Lower Saxony. As there have been delays in the construction of electricity lines, awards may only be made there for a limited volume.

- Citizens' energy companies must consist of at least ten people of whom at least six must be resident in the district in which the installation for which a bid is made will be built. These companies receive two forms of preferential treatment under the EEG. Firstly, they only have to include an expert report on wind conditions with their bid and do not have to obtain approval pursuant to the Federal Immission Control Act. Secondly, they are awarded the uniform price for the last bid accepted in a round.

Auctions for onshore wind plants in 2017/2018

	2017			2018			
	1 May	1 Aug	1 Nov	1 Feb	1 May	1 Aug	1 Oct
Volume put up for auction (MW)	800	1,000	1,000	700	670	670	670
Submitted bids	256	281	210	132	111	91	62
Submitted bid volume (MW)	2,137	2,927	2,591	989	604	709	396
Submitted bid volume (MW) in the NAG	477	632	697	125	100	183	93
Winning bids	70	67	61	83	111	86	57
Volume of winning bids (MW)	807	1,013	1,000	709	604	666	363
Volume of winning bids in the NAG (MW)	261	213	231	88	100	183	93
Excluded bids	12	14	15	2	0	5	5
Excluded bids in MW	60	103	172	16	0	42	32
Maximum value permitted (ct/kWh)	7.0	7.0	7.0	6.3	6.3	6.3	6.3
Average volume weighted winning bid (ct/kWh)	5.71	4.28	3.82	4.73	5.73	6.16	6.26
Lowest bid (awarded) (ct/kWh)	4.20	3.50	2.20	3.80	4.65	4.00	5.00
Highest bid (awarded) (ct/kWh)	5.78	4.29	3.82	5.28	6.28	6.30	6.30
Highest bid in the NAG (awarded) (ct/kWh)	5.58	Upper threshold not applicable					

Table 28: Auctions for onshore wind installations in 2017/2018

All auction rounds were significantly oversubscribed in 2017 and resulted in winning bids of under 4 ct/kWh in the last round, which was significantly lower than the maximum rate of 7 ct/kWh. These low award prices are the result of the strong level of participation of citizens' energy companies. Citizens' energy companies used their auction privileges to submit bids which were lower than those of other bidders and consequently won over 90% of the awards made in all rounds. The extended implementation periods allowed citizens' energy companies to submit bids for prices and revenue expectations for the year 2022 and thus to refer to wind installations which will only become available in several years' time. The EEG stipulates that, from 1 January 2018, the maximum auction value will be derived from the average of the maximum value of the three last auctions, increased by 8%. In connection with the low auction results in 2017 some professional associations and experts expressed concerns that, owing to the resulting low maximum value, legally-defined targets might not be met as it would only be possible to generate power at such low prices with wind installations which would be available in several years' time – if at all. Against this background, the Bundesnetzagentur has responded to the actual cost of electricity production anticipated for wind installations currently in the market today through to 2021 by changing the maximum value for auctions in 2018 to 6.3 ct/kWh. The EEG has also been revised to suspend through to 2020 the special rules which enabled citizens' energy companies to participate without having permission.

The four rounds of auctions held in 2018, for which the special rules for citizens' energy companies were suspended, were less competitive, produced higher winning bids and were participated in by fewer citizens' energy companies than in the previous year. The second round in May 2018 was slightly undersubscribed for the first time and awards were made for bids by all eligible bidders. Although the third round was slightly oversubscribed, competition remained weak and the last bidding round in October 2018 was significantly undersubscribed.

The quality of bids in wind auctions is high and fewer than 10% of bids were excluded in both 2017 and 2018.

There was a strong regional concentration in 2017 in the north and east of Germany with just under 70% of successful bids being made in Brandenburg (26.3%), Lower Saxony (20.2%), Schleswig-Holstein (11.6%) and Mecklenburg-Vorpommern (11.1%). In 2018 in addition to Brandenburg (18.4%) an especially high number of successful bids were also made in North Rhine-Westphalia (19%).

Distribution of bids and awards for onshore wind energy by federal state

	Number of bids		Capacity bids in kW		Number of awards		Awarded capacity in kW	
Federal state	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**
Baden-Württemberg	28	21	232,100	195,000	0	15	0	157850
Bavaria	14	18	119,320	138,150	4	16	44,200	121,950
Brandenburg	102	63	1,311,850	397,980	52	62	813,660	395,680
Bremen	0	1	0	3,400	0	1	0	3,400
Hesse	43	18	533,250	188,630	11	18	166,130	188,630
Mecklenburg-Western P.	55	32	790,680	228,100	22	25	357,400	188,250
Lower Saxony	130	39	1,406,210	325,476	40	34	575,510	284,276
North Rhine-Westphalia	160	84	1,550,985	405,000	26	64	367,975	325,550
Rhineland-Palatinate	51	40	402,560	281,350	5	32	50,100	238,800
Saarland	0	5	0	30,900	0	2	0	6,900
Saxony	6	9	45,600	31,900	3	8	35,100	29,600
Saxony-Anhalt	14	14	219,300	177,460	4	12	66,000	145,780
Schleswig-Holstein	106	38	736,560	195,550	23	36	214,400	179,150
Thuringia	36	14	294,250	91,500	8	12	129,450	76,900
No location data provided	2	0	11,850	0	0	0	0	0
Total	747	396	7,654,515	2,690,396	198	337	2,819,925	2,342,716

Table 29: Distribution of bids and awards per federal state

The reference yield model merely takes account of differences in wind conditions prevailing at locations; the main explanations for the auction results are therefore the differences in available space and grid connection costs. The sites which are most economic are always successful in auctions and a complete levelling of conditions is neither intended nor possible.

2.3.3 Other auctions (cross-border and across all technologies, offshore wind, biomass)

Cross-border auctions for ground-mounted installations

An open, cross-border auction was held for the first time with Denmark in November 2016 in which projects with a location in Denmark or Germany were able to participate. The tender was for 50 megawatts. Awards were all made exclusively to projects in Denmark for winning bids of 5.38 ct/kWh. All five projects went into operation in May 2018 within the legally stipulated period.

Offshore wind auctions

The auctions for determining payments for offshore wind installations started in 2017. On 1 April 2017 and 1 April 2018, a total of 3,100 MW was auctioned for the transition period among existing projects. “Existing projects” are offshore wind farms which received approval or planning permission before 1 August 2016 or for which at least a hearing has been held. Awards for a total of ten projects (four in 2017 and six in 2018) entitled project developers to EEG payments and to connection to the grid – financed from network charges paid by electricity consumers – as well as to operate their wind farms for 25 years. The volume weighted average winning bid was 0.44 ct/kWh in 2017 and 4.66 ct/kWh in 2018. All the projects which were successful in the first round are in the North Sea; three successful projects in the second round are in the North Sea and three in the Baltic Sea.

Offshore wind auctions 2017-2018

	1 April 2017	1 April 2018
Volume put up for auction (MW)	1,550	1,610
Submitted bids	19	16
Submitted bid volume (MW)	7,023	5,606
Winning bids	4	6
Volume of winning bids (MW)	1,490	1,610
Excluded bids	1	1
Maximum value permitted (ct/kWh)	12.00	10.00
Average volume-weighted winning bid (ct/kWh)	0.44	4.66
Lowest bid (awarded) (ct/kWh)	0.00	0.00
Highest bid (awarded) (ct/kWh)	6.00	9.83

Table 30: Offshore wind auctions

Auctions for biomass installations

The Bundesnetzagentur holds auctions for biomass installations on 1 September every year; the first auction of this kind was held in 2017. One special feature of this procedure is that installations which were already in operation were also able to take part in the auction if they were entitled to less than a further eight years of payments under the EEG. Despite the much higher level of participation than in the first auction round (85 as opposed to 33 bids), the second round was also significantly undersubscribed. The bid volume of 88,958 kW was significantly lower than the auction volume of 226,807 kW. The exclusion rate (owing to formal errors in the bid documentation submitted) of just 7% of bids was a significant improvement on the previous year (2017: 30%). The volume weighted average value for all winning bids was 14.73 ct/kWh. The medium winning bids for new installations was for 14.72 ct/kWh. On average, bids for existing installations with installed capacity exceeding 150 kW were awarded at 14.68 ct/kWh. Bids for existing installations with installed capacity equal to or less than 150kW were, on average, awarded at 16.73 ct/kWh. Regardless of the actual price at which awards are made, the value to be applied for existing installations is limited to the average in the three years preceding the auction.

Biomass auctions

	1 September 2017			1 September 2018		
	New facilities ≥ 150 kW	Existing facilities ≥ 150 kW	Existing facilities ≥ 150 kW	New facilities ≥ 150 kW	Existing facilities ≥ 150 kW	Existing facilities ≥ 150 kW
Volume put up for auction (MW)	122,446			225,807		
Submitted bids	10	3	20	14	15	56
Submitted bid volume (MW)	13,542	236	27,134	29,847	1,370	57,741
Winning bids	4	3	17	13	15	51
Volume of winning bids (MW)	6,134	236	21,181	29,481	1,370	45,686
Excluded bids	6	0	3	1	0	5
Excluded bids in MW	7,408	0	5,953	366	0	12,055
Maximum value permitted (ct/kWh)	14.88	16.90	16.90	14.73	16.73	16.73
Average volume weighted winning bid (ct/kWh)	14.81	16.90	14.13	14.72	16.73	14.68

Table 31: Biomass auctions in 2017/2018

Joint auction for wind power and photovoltaic installations

The Bundesnetzagentur held the first joint auctions for onshore wind installations and photovoltaic installations in April and October 2018. One special feature of these auctions was the inclusion of distribution network expansion areas, i.e. districts in which reverse feed-in into the distribution network from renewable energy installations which are already in operation is higher than the installed peak load. Distribution network areas introduce a tool for pricing in the network and system integration costs resulting from additional onshore wind power and solar installations and in this way of slowing down the pace of growth in the distribution system expansion areas. This tool applies a bid premium (calculated according to technology: onshore wind or solar power) to bids submitted in auctions for installations in the distribution network expansion area. The premium merely relates to the order of bids and has no effect on the payments later made for each installation.

Results of joint auctions for photovoltaic installations and onshore wind

	April 2018	November 2018
Volume put up for auction (MW)	200	200
Submitted bids	54	50
Submitted bid volume (MW)	395	319
Winning bids*	32	36
Total volume of winning bids in MW	210	201
Volume of winning bids, solar in MW	210	201
Volume of winning bids, wind in MW	0	0
Excluded bids	3	2
Volume of excluded bids (MW)	30	12
Maximum value permitted (ct/kWh)	8.84	8.75
Average volume weighted winning bid (ct/kWh)	4.67	5.27
Lowest bid (awarded) (ct/kWh)	3.96	4.65
Highest bid (awarded) (ct/kWh)	5.76	5.79

*The number of awards may vary for the auction in November as the number of bids actually awarded only becomes known after second securities have been received.

Table 32: Joint auctions for onshore wind power and photovoltaic installations 2018

54 bids were received in the first round in April 2018; 18 of these bids were for onshore wind power installations and 36 for photovoltaic installations. All 32 awards were exclusively for solar bids totalling 210 MW. The average volume-weighted award price was 4.67 ct/kWh, which was somewhat higher than the 4.33 ct/kWh winning bid for the last purely solar power auction held prior to April 2018. The lowest award price was 3.96 ct/kWh and the highest was 5.76 ct/kWh.

50 bids were received in the second round in November 2018, 1 for a wind power installation and 49 for photovoltaic installations. All the awards in this round were also for solar installations with a capacity of

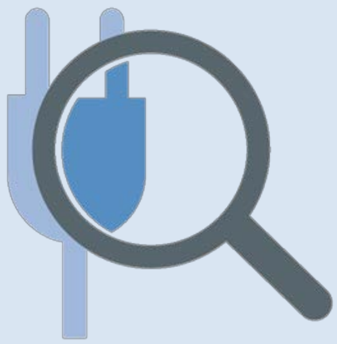
201 MW. The volume-weighted average award price was somewhat higher than in the previous round and, at 5.27 ct/kWh, was also higher than the 4.69 ct/kWh award price for the last purely solar power auction held prior to this date. The lowest award price was 4.65 ct/kWh and the highest was 5.79 ct/kWh. The number of awards may still be slightly lower if successful bidders do not all provide a second security within a stipulated period of time.

The bids made in these joint auctions for onshore wind power installations were not competitive. One possible reason may have been the lack of a correction factor for less windy locations which – in contrast to ordinary onshore wind power auctions – was not applied. With photovoltaic installations a technology was successful which had already demonstrated its cost-cutting potential in previous auctions.

The special arrangements for distribution network expansion areas did not especially impact the award decision in either of the auctions. If this bid premium procedure had not been applied, however, at least one bid for wind power installations could have been accepted in the first round.

C Networks

1. Status of grid expansion



The Energy Industry Act (EnWG) and Grid Expansion Acceleration Act (NABEG) give the public a wide range of opportunities to be involved in the grid expansion. The Bundesnetzagentur aims to make the planning of the grid expansion understandable to the general public. In addition to the hearings that the Bundesnetzagentur is legally obliged to organise, it also hosts public information/dialogue events and method conferences in order to promote transparency and acceptance of the line expansion.

The authority provides information on various important issues via its website www.netzausbau.de and on its Twitter feed and YouTube channel. People can contact the Bundesnetzagentur's energy grid expansion public liaison service if they have any questions or suggestions.

1.1 Monitoring of projects in the Power Grid Expansion Act

Attention was already being focused on speeding up grid expansion at the extra-high voltage level back in 2009 with the passing of the Power Grid Expansion Act (EnLAG).

The current version of the Act lists 22 projects that require urgent implementation in order to meet energy requirements. Project no 22 was deleted following a review preceding production of the network development plan 2022 and project no 24 during the production of the network development plan 2024. Six of the 22 projects are designated as underground cable pilot projects.

The individual federal state authorities are responsible for conducting the spatial planning and planning approval procedures for the projects. The Bundesnetzagentur regularly updates the information on the status of the approval procedures for the individual projects on its website at www.netzausbau.de/vorhaben. The information is based on the quarterly reports produced by the four TSOs on the current state of construction and planning work.

Current status

The projects currently listed in the EnLAG as at the third quarter of 2018 comprise lines with a total length of about 1,800 km. Up to the end of the third quarter of 2018, about 1,200 km of the lines had been approved; around 800 km of these – or about 45% of the total – had been completed. The TSOs anticipate that some 70% of the line kilometres listed in the Act will be completed by 2020. So far, none of the underground cable pilot lines have been put into full operation. Operational testing is in progress for the first 380 kV underground cable pilot project in Raesfeld.

The following map shows the status of the EnLAG projects in the third quarter of 2018:

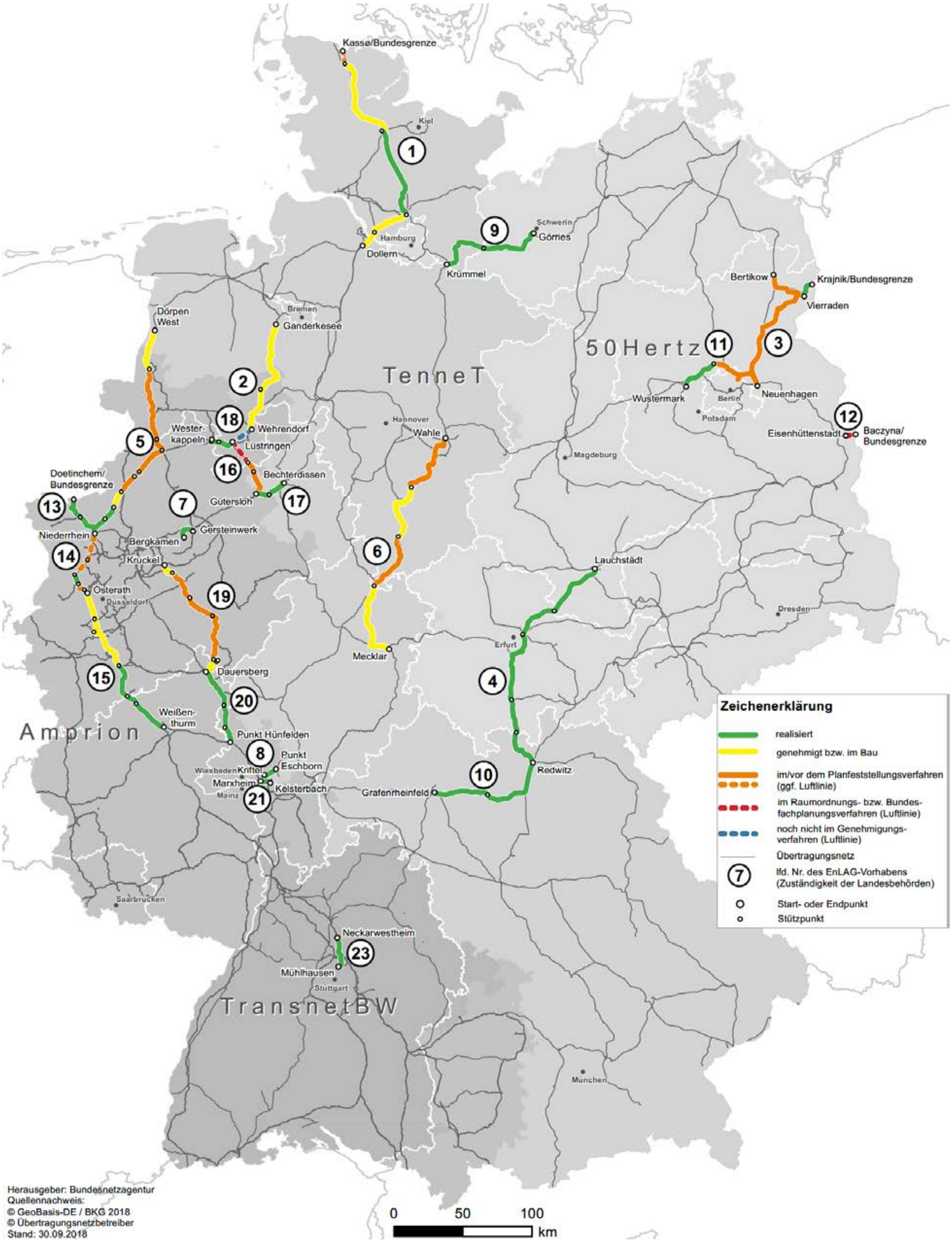


Figure 30: Status of line expansion projects in the Power Grid Expansion Act: 3rd quarter 2018

1.2 Monitoring of projects in the Federal Requirements Plan

Alongside monitoring the projects in the Power Grid Expansion Act, the Bundesnetzagentur publishes quarterly updates on the status of the expansion projects listed in the Federal Requirements Plan Act (BBPlG) on its website at www.netzausbau.de/vorhaben.

Of a total of 43 projects nationwide, 16 are designated as crossing federal state or national borders within the meaning of the Grid Expansion Acceleration Act (NABEG). The Bundesnetzagentur is responsible for the federal sectoral planning and the subsequent planning approval procedure for these projects.

Eight of the 43 projects have been designated as pilot projects for low-loss transmission over long distances (high voltage direct current (HVDC) transmission). Five direct current (DC) projects have been earmarked for priority underground cabling and five alternating current (AC) projects for partial underground cabling. In addition, one project is designated as a pilot project using high-temperature conductors and two are designated as submarine cable projects.

The law that was passed at the end of 2015, which "amends the laws governing power grid expansion", gives priority to underground cables for DC power. The DC power lines listed in the law are to be installed using underground cables in preference to overhead power lines. As a consequence, TSOs had to complete replan these projects.

Current status

The projects currently listed in the Federal Requirements Plan Act as at the third quarter of 2018 comprise lines with a total length of about 5,900 km. According to the network development plan, around 3,050 km of these lines will serve to reinforce the system. The total length of the lines in Germany will largely depend on the route of the north-south corridors and will become apparent over the course of the procedure. In total, around 600 km have been approved and about 150 km have been completed.

The following map shows the status of the projects listed in the Federal Requirements Plan Act as at the third quarter of 2018.

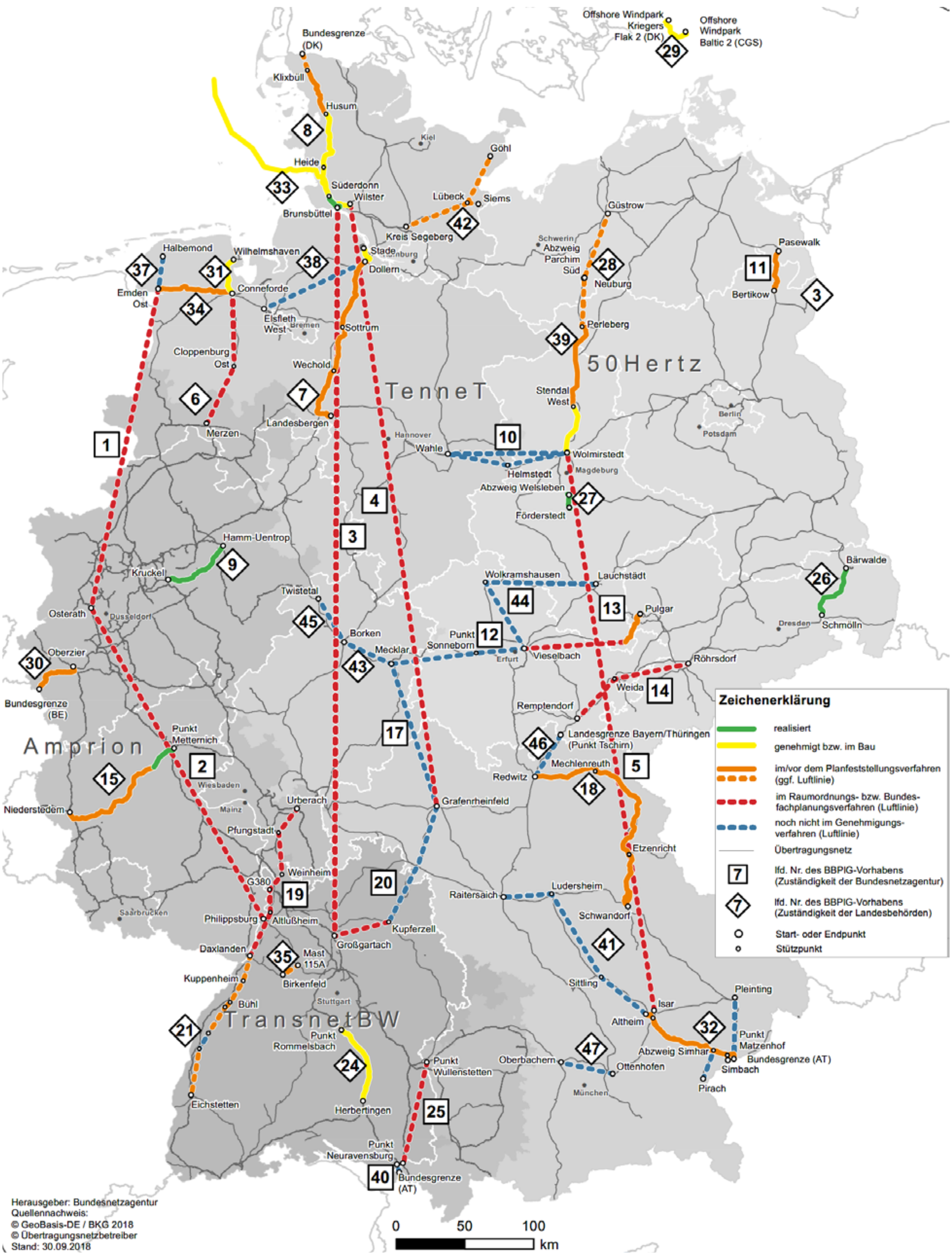


Figure 31: Status of expansion projects in the Federal Requirements Plan Act: 3rd quarter 2018

1.3 Electricity Network Development Plan Status

The Bundesnetzagentur confirmed the Electricity Network Development Plan 2017 on 22 December 2017 and published it on www.netzausbau.de. Public agencies and members of the public took a great interest in the confirmation process, with the Bundesnetzagentur evaluating about 15,000 responses. It was confirmed that all 60 projects in the applicable Federal Requirements Plan from 2015 are still necessary. 96 of the total 165 proposed projects were confirmed, including six fixed-site and nine ad-hoc measures. The high-voltage direct current (HVDC) lines already included in the 2015 Federal Requirements Plan were also included in this confirmation. More HVDC lines are likely to be included in future NDP processes due to the expanded reference period and the increasing expansion of renewable energies in northern Germany, both on and offshore. The rollout of HVDC lines could reduce the expansion of the AC grid in future.

In preparation for the upcoming NDP 2019-2030, the Bundesnetzagentur approved the sixth scenario framework 2019-2030 on 15 June 2018. The public was also actively involved in this process. In contrast to the 2017-2030 scenario framework, which formed the basis for the NDP 2017-2030, the new scenario framework takes account of the energy and climate targets of the coalition agreement of 12 March 2018, leading to a greater emphasis on the expansion of renewables and the reduction of conventional power plant capacity. The scenario framework 2019-2030 includes the effects of sector coupling and various power generation structures (decentrality and centrality). The TSOs must use the scenario framework 2019-2030 as a basis to submit a first draft of the NDP 2019-2030, probably by 10 December 2018. The Bundesnetzagentur has called on TSOs to weigh up the different expansion options in the NDP 2019-2030 more clearly than has so far been the case. These options include raising the utilisation of power lines with existing and/or new technology, increasing the willingness to take risks in network operation and weighing up AC and HVDC technology.

Alongside the approval of the NDP 2017-2030, the Bundesnetzagentur also confirmed and published the Offshore Network Development Plan (O-NDP) for the last time. From 2019 on, the transmission systems in the North Sea and Baltic Sea will be integrated into the NDP and are included for the first time in the NDP 2019-2030.

1.4 Offshore Network Development Plan status

The O-NDP determines demand for transmission links and the time sequence to be followed in connecting each offshore wind farm cluster to the grid on the mainland. The Bundesnetzagentur confirmed three transmission systems in the North Sea and five in the Baltic Sea in the O-NDP 2017-2030 on 22 December 2017. One transmission system in the North Sea was not confirmed. The implementation of three Baltic Sea transmission links is due to start in 2018. All approved transmission links due to be completed between 2021 and 2030. Taking into account the transmission links confirmed in the O-NDP 2025 and the O-NDP 2017-2030, the Bundesnetzagentur conducted two auctions for offshore wind turbines and published the results on 1 April 2017 and 1 April 2018 respectively. The table below provides an overview of the confirmations for transmission links and results of the auctions.

Confirmed transmission links and OFW auction results

Transmission system	Start of implementation	Planned completion	OWF with award in transitional system 2021-2025 (earliest possible completion[1])
OST-2-1	2018	2021	ARCADIS Ost 1 (2021)
OST-2-2	2018	2021	Baltic Eagle (2021/2022)
OST-2-3	2018	2022	Baltic Eagle (2021/2022)
OST-2-4[4]	2022	2027	-
OST-6-1[4]	2024	2029	-
(NOR-4-2)[2]	-	-	KASKASI II (2021)
(NOR-3-3)[3]	2017	2023	Gode Wind III (2023) Gode Wind 04 (2023)
(NOR-1-1)[3]	2019	2024	Borkum Riffgrund West (2024) Borkum Riffgrund West II (2024) OWP West (2024)
(NOR-7-1)[3]	2020	2025	EnBW He Dreiht (2025)
NOR-5-2[4]	2020	2025	-
NOR-3-2[4]	2023	2028	-
NOR-7-2[4]	2025	2030	-

[1] Earliest possible completion is based on completion of the transmission link.
[2] Operational start network, which was not confirmed in the O-NDP.
[3] Confirmation in O-NDP 2025, no further examination in O-NDP 2017-2030, because already part of the start network due to award in first auction round with confirmation in O-NDP 2017-2030.
[4] Repeated confirmation in NDP 2019-2030 only if necessary on the basis of the determinations in the site development plan. Initial draft of site development plan indicates that far-reaching changes will be necessary.

Table 33: Confirmed transmission links and OFW auction results

The O-NDP process was brought to an end on 1 January 2018 in accordance with section 17b EnWG. A new model was brought in at that time, according to which the expansion of offshore transmission links based on the site development plan is included directly in the network development plan pursuant to sections 4 to 8 of the Offshore Wind Energy Act. The site development plan officially lays down which sites will be auctioned in which order, with the aim of bringing offshore wind turbines on these sites into operation from 2026 on and to have finished the offshore transmission links required to connect the sites by the same time. The Federal Maritime and Hydrographic Agency is responsible for producing the site development plan and needs to publish the first one by 30 June 2019. The new model is to be included for the first time in the NDP 2019-2030, so that it can show the need both for onshore grid expansion and for offshore transmission links.

2. Distribution system expansion

Consumers bear the costs of investing in the grid expansion through their network charges. These costs are driven by factors including the continuing increase in embedded generators and the rollout of charging infrastructure for electric vehicles. The grid expansion also contributes to the security and quality of supply in the distribution system and has a direct impact on consumers.

2.1 Optimisation, reinforcement and expansion in the distribution networks

Distribution system operators (DSOs) are required to optimise, reinforce and expand their networks in line with the state of the art so as to ensure the uptake, transmission and distribution of electricity. The substantial expansion in renewable energy installations and the legal obligation to integrate the installations and the energy generated regardless of network capacity represent considerable challenges for the DSOs. Alongside conventional expansion measures, system operators are responding to these challenges by developing smart grids that will allow them to adapt to the changing requirements. The way forward and the measures adopted may differ considerably from one operator to the next. Given the highly heterogeneous nature of the networks in Germany, DSOs need to work out their own individual strategies for accommodating future energy developments and achieving efficient network operation.

A total of 815 DSOs (829 in the previous year) took part in the 2018 monitoring and provided information about the extent to which they had taken action to optimise, reinforce or expand their networks. A total of 526 companies reported network optimisation measures, about 2.5% more than in the previous year. The following diagram shows the number of operators taking action in the period since 2009.

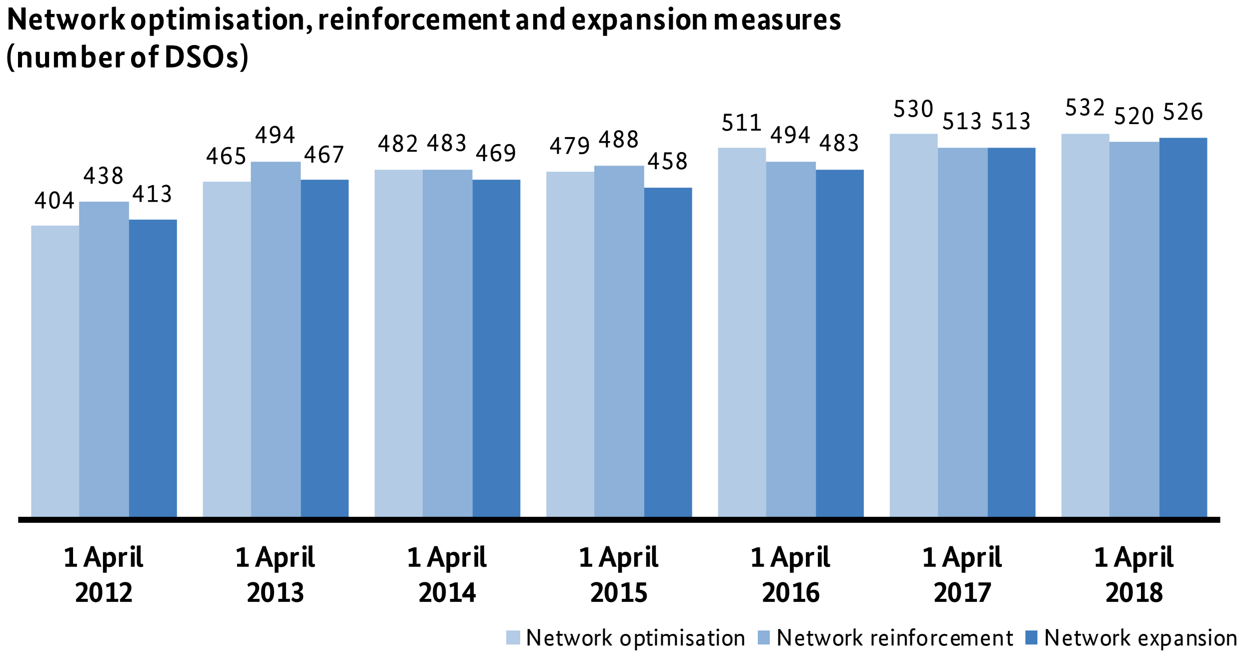


Figure 32: DSOs' network optimisation, reinforcement and expansion measures

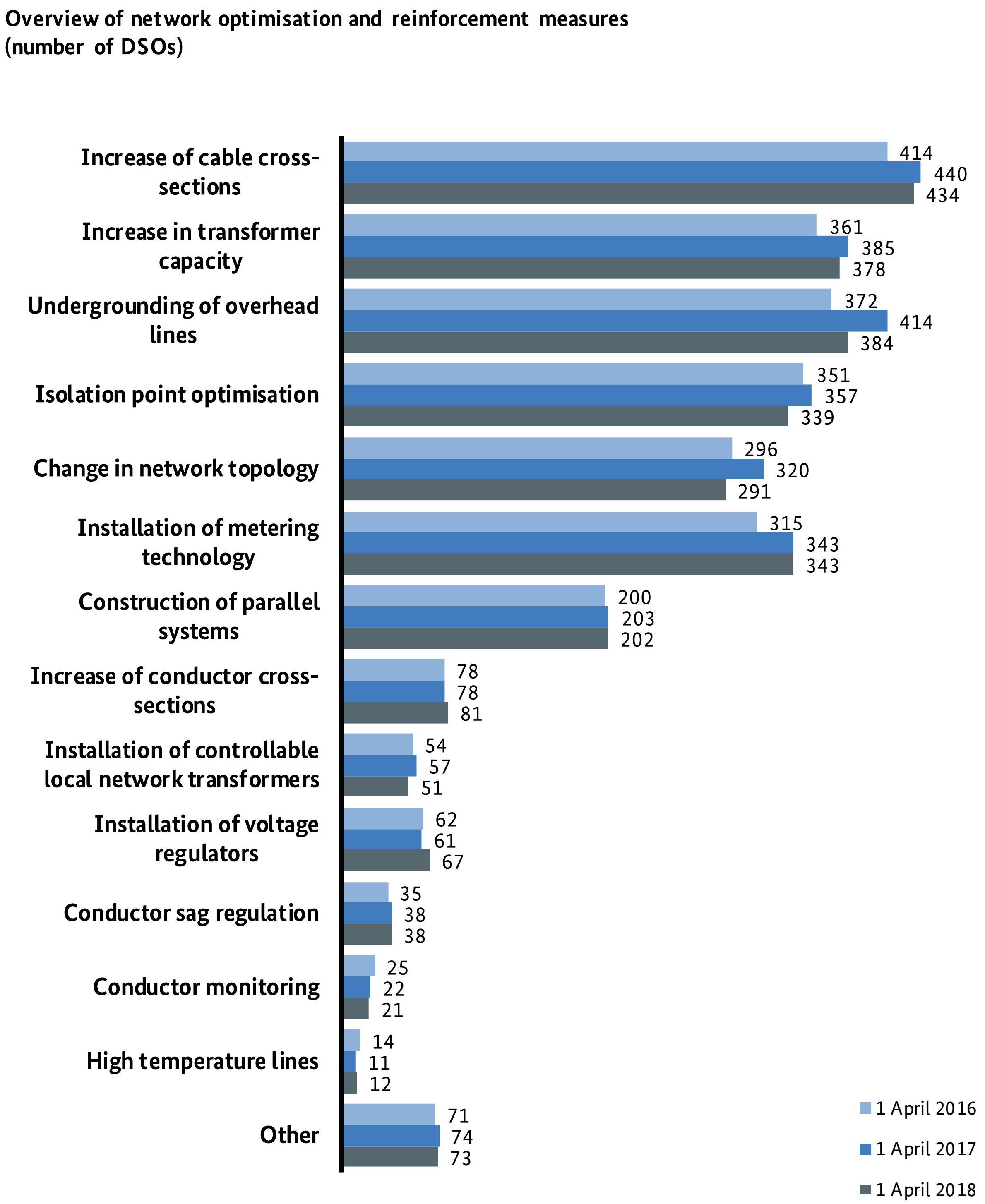


Figure 33: Overview of network optimisation and reinforcement measures taken

Figure 33 shows the measures implemented by the DSOs to optimise and reinforce their networks. There were year-on-year decreases in particular in the number of measures for replacing overhead lines with underground cables (-30 DSOs), optimising isolation points (-18 DSOs), and changing network topology (-29 DSOs). There was a slight rise in measures to increase the cross-section of conductors and install voltage regulators. DSOs were asked for the first time for the 2018 monitoring whether they use peak shaving as a network optimisation measure. 49 of them reported that they did.

2.2 Future grid expansion requirements

2.2.1 High-voltage network operators' expansion requirements

Operators of electricity distribution networks are required by section 14(1a) of the Energy Industry Act (EnWG) to draw up and submit to the regulatory authority a report on the status of their grids and their grid expansion plans within two months of a request from the authority.

In this year's monitoring survey, 57 DSOs operating high-voltage networks were asked to submit reports for the reporting year 2017 so as to identify their expected grid expansion requirements for the next 10 years. The reports submitted by the DSOs cover 98% of the total circuit length at high-voltage level, 69% at medium-voltage level and 64% at low-voltage level.

2.2.2 Total expansion requirements (all voltage levels)

The planned and ongoing grid expansion measures reported to the Bundesnetzagentur as at 31 December 2017 comprise a total investment volume of €11.1bn in the next 10 years (2018-2028). This represents another increase compared to the previous years (€10bn and 57 DSOs at the end of 2016, €9.3bn and 57 DSOs at the end of 2015, and €6.6bn and 56 DSOs at the end of 2014).

The following diagram shows the investment volume forecast by the DSOs for grid expansion at all voltage levels.

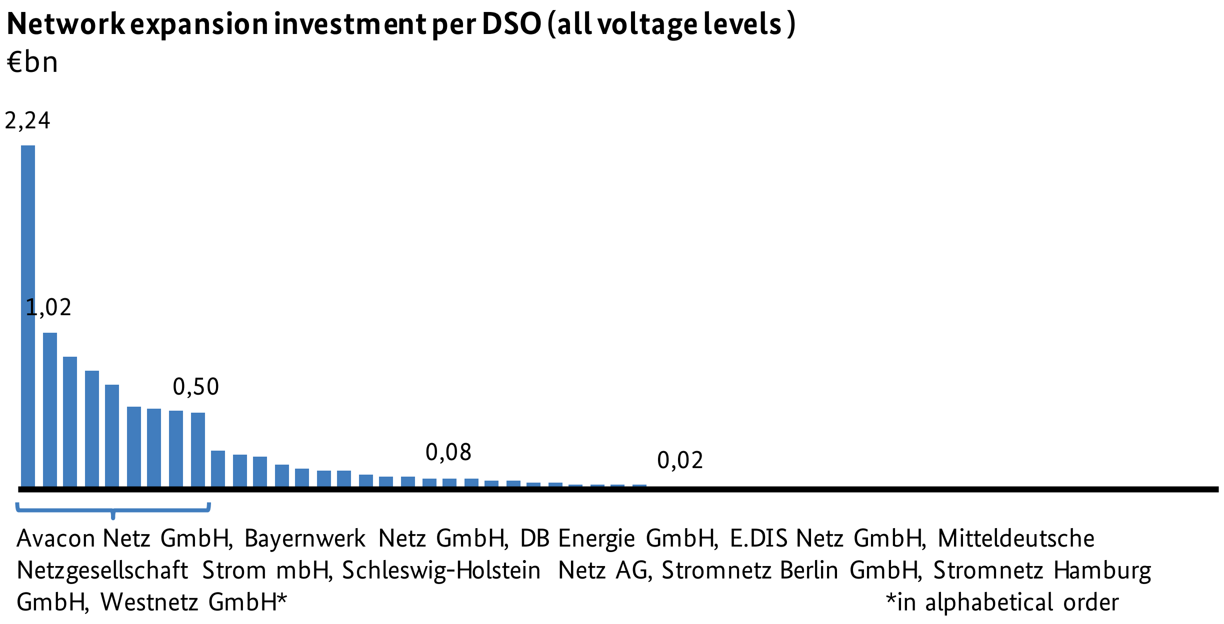


Figure 34: Grid expansion investment per DSO (all voltage levels)

Expansion requirements continue to be very varied. 14 DSOs forecast expansion measures comprising a volume of up to €10m in the next 10 years, a further 27 DSOs forecast measures of up to €100m, and the remaining 16 DSOs forecast a high volume exceeding €100m and accounting for nearly 90% of the total forecast by all the DSOs. The nine DSOs with the highest planned and ongoing investment volumes are, as in the previous year, Avacon Netz GmbH, Bayernwerk Netz GmbH, DB Energie GmbH, E.DIS Netz GmbH, Mitteldeutsche Netzgesellschaft Strom mbH, Schleswig-Holstein Netz AG, Stromnetz Berlin GmbH, Stromnetz Hamburg GmbH and Westnetz GmbH.

The forecasted grid expansion measures are necessary not only because of the growth in renewable energy and embedded generation, but to a large extent also because of restructuring and – in some cases age-related – replacement investments. Only 370 (398 as at 31 December 2016) of the 2086 planned or ongoing investment measures reported are due in technical terms to the expansion in renewable energy installations. The growth in renewable energy thus accounts for around €1.76bn (31 December 2016: €1.84bn) of the total planned investment volume of €11.1bn across all network and voltage levels in the distribution network. The reasons for the DSOs' grid expansion measures vary considerably. While Stromnetz Berlin GmbH, with the highest investment requirements, is planning virtually no investment measures to connect and integrate embedded generation, more than three quarters of E.DIS Netz GmbH's planned or ongoing investments are linked to the growth in embedded generation.

The DSOs' reports also show that many DSOs continue to find it difficult to plan grid expansion over a period of 10 years: not only are new measures added every year, decisions are also taken not to implement some of the planned measures. Planning uncertainties arise in particular from the fact that it is difficult to make long-term predictions about the exact siting of renewable energy generating facilities, a factor that is even more important at distribution than at transmission level. Other reasons include lengthy procedures for obtaining official permits, objections from public agencies or land owners, and modifications to high-voltage grid expansion plans to accommodate expansion in the transmission network. The planning uncertainties concern not only details such as the chance of realising the planned investment measures and the timetable for the planned investments, however, but also – to a considerable extent – the estimated investment volume, with planned investments for projects sometimes varying up or down by more than 50%. DSOs cite the approval process and coordination with upstream operators, the public and other stakeholders as the most common reasons for changing their plans.

The Bundesnetzagentur was notified of a total of 2321 measures for the period up to 2028 (compared to 2089 at the end of 2016, 1984 at the end of 2015, and 1318 at the end of 2014). At the time of the survey, 1464 or 63% of these measures were still at the planning stage and 622 or 27% were in progress, while 235 or 10% had been completed by the beginning of 2018. This represents a further increase in absolute terms in particular in the number of planned grid expansion measures.

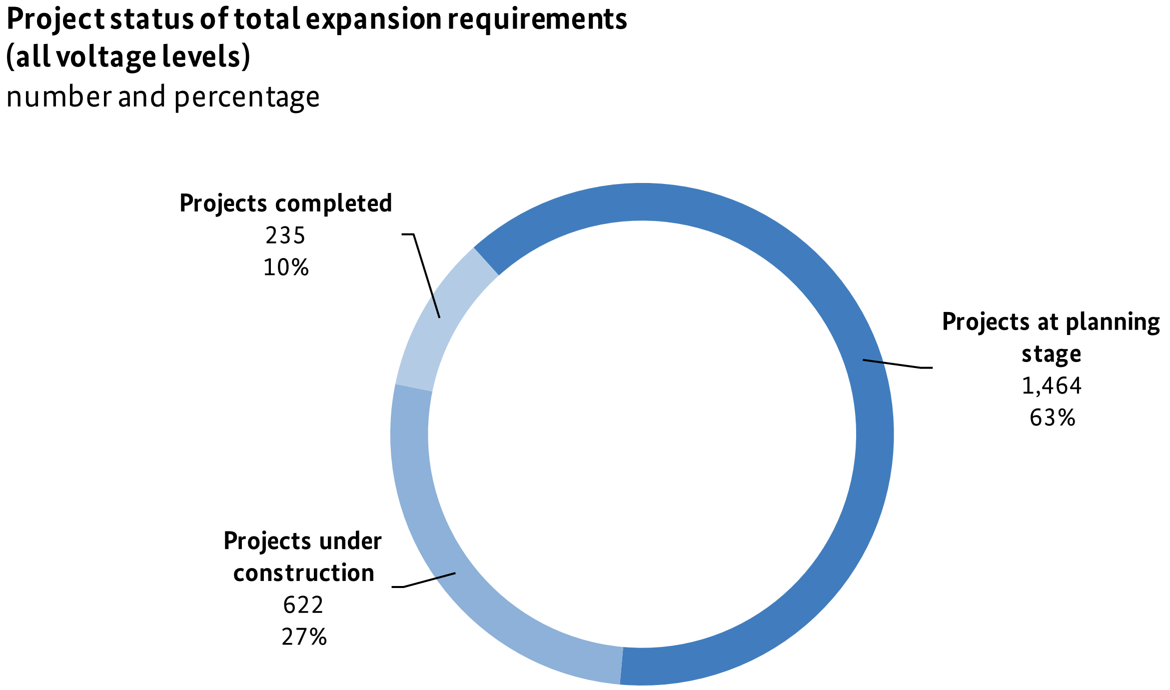


Figure 35: Project status of total expansion requirements (all voltage levels)

3. Investments

For the purposes of the monitoring survey, investments are defined as the gross additions to fixed assets capitalised in 2017 and the value of new fixed assets newly rented and hired in 2017. Expenditure arises from the combination of all technical or administrative measures taken during the life cycle of an asset to maintain or restore working order so that the asset can perform the function required.

The following figures are the values under commercial law derived from the TSOs' and DSOs' balance sheets. The values under commercial law do not correspond to the implicit values included in the operators' revenue caps in accordance with the provisions of the Incentive Regulation Ordinance (ARegV). A comparative calculation of the values under commercial law with the values from incentive regulation will only be able to be made following the introduction of index-based investment monitoring pursuant to section 33(5) of the Ordinance. Medium to long-term trends can be derived from the evaluations on the basis of the survey of commercial values. The introduction of an index-based investment monitoring pursuant to section 33(5) ARegV is currently being prepared by the Bundesnetzagentur taking account of the effort required for companies to transmit data.

3.1 Transmission system operators' investments and expenditure

In 2017, investments in and expenditure on network infrastructure by the four German TSOs amounted to approximately €3,096m, which is 5% less than a year earlier (2016: €3,261m). The difference between actual investments and expenditure in 2017 and the figure of €2,468m forecast in last year's monitoring survey is about €628m. The TSOs thus realised 80% of their planned investments and expenditure.

The individual categories for network infrastructure investments and expenditure are shown in Table 26:

TSOs' network infrastructure investments and expenditure

	2016	2017
Investments (€m)	**2,901**	**2,708**
New build, upgrade and expansion projects other than for cross-border connections	2,298	1,972
New build, upgrade and expansion projects for cross-border connections	401	523
Maintenance and renewal excluding cross-border connections	203	213
Maintenance and renewal of cross-border connections	0	0
Expenditure (€m)	**360**	**388**
Expenditure excluding cross-border connections	357	385
Expenditure on cross-border connections	3	3
Total	**3,261**	**3,096**

Investments were updated retrospectively to include offshore investments from 2008.

Table 34: TSOs' network infrastructure investments and expenditure

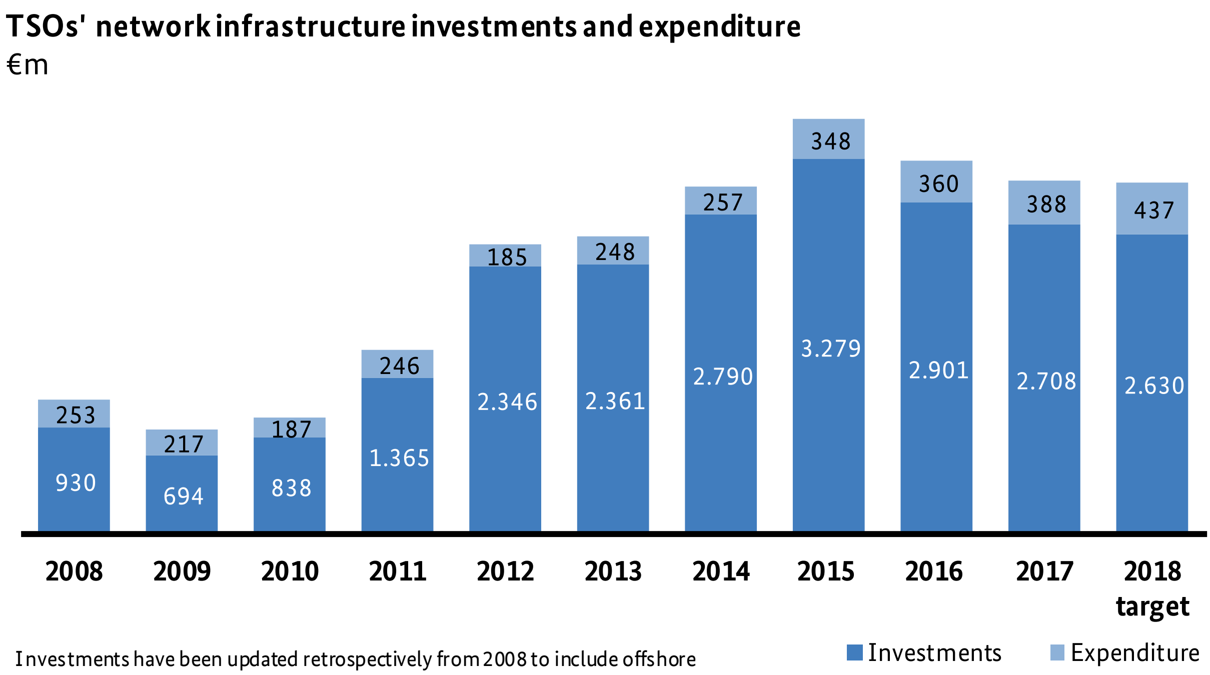


Figure 36: TSOs' network infrastructure investments and expenditure since 2008 (including cross-border connections)

Total investments of around €2,630m and total expenditure of €437m are currently planned for 2018. The planned total for investments and expenditure of about €3,067m is around the same as the total amount realised in 2017. Figure 36 shows the figures for investments, expenditure and cross-border connections since 2008 and the planned figures for 2018.

3.2 Distribution system operators' investments and expenditure

In 2017, investments in and expenditure on network infrastructure by the 815 DSOs that provided data in the monitoring amounted to around €6,629m, down about 8% on the previous year's figure of €7,157m. Investments and expenditure for metering systems amounted to around €572m in 2017, compared to €506m in 2016. The planned total for investments and expenditure in 2018 is €6,521m. Figure 37 shows the figures for investments, expenditure and combined investments and expenditure since 2008 and the planned figures for 2018.

The two noticeable peaks of investment in 2011 and 2016 are likely to be related to the incentive regulation. Both years were used as base years that were decisive for the revenue that the DSOs were allowed to attain in the subsequent years. There was therefore an incentive to bring investments forward or postpone them for the base years.

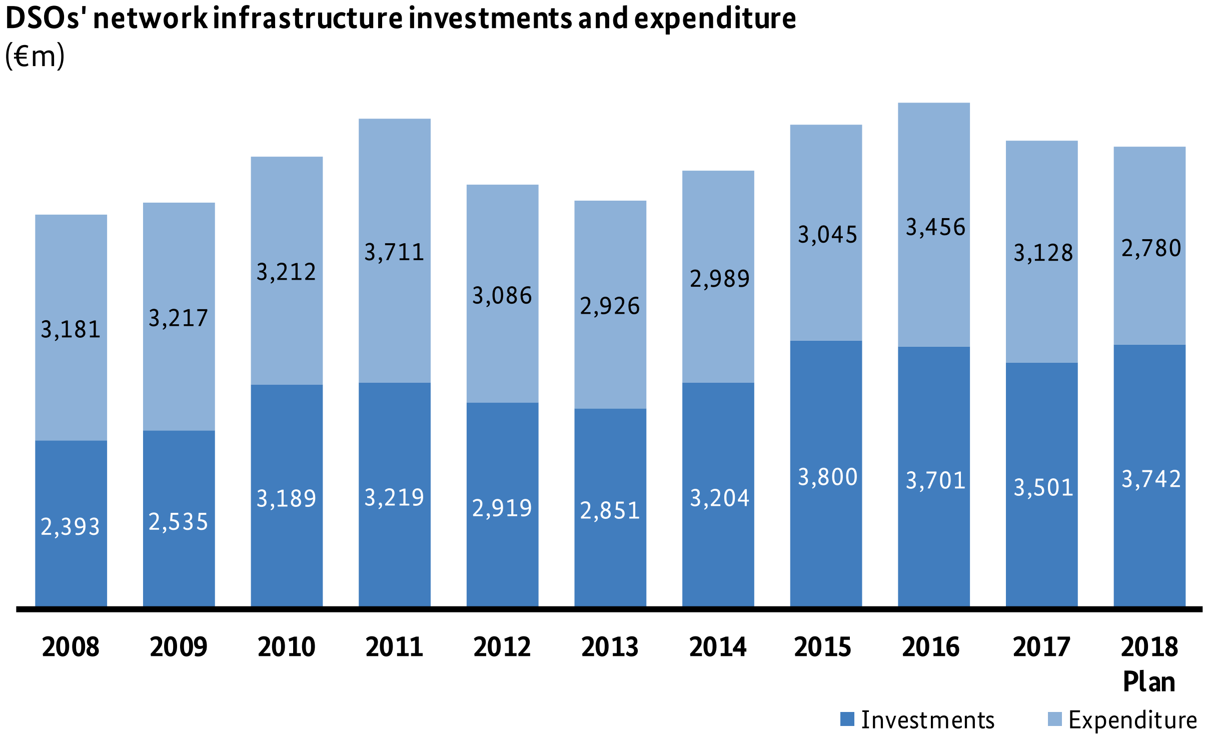


Figure 37: DSOs' network infrastructure investments and expenditure

The level of investment by DSOs depends on circuit lengths, the number of meter points served, and other individual structural parameters, including in particular geographical factors. DSOs with longer circuits tend to have higher investments. 187 or 23% of the DSOs are in the €0-€100,000 investment category. 70 or around 9% of the DSOs are in the top category with investments exceeding €5m per network area. About 65% of the total investments are made by the 20 network operators with the greatest investments. Figure 38 shows the percentage of DSOs in each investment category:

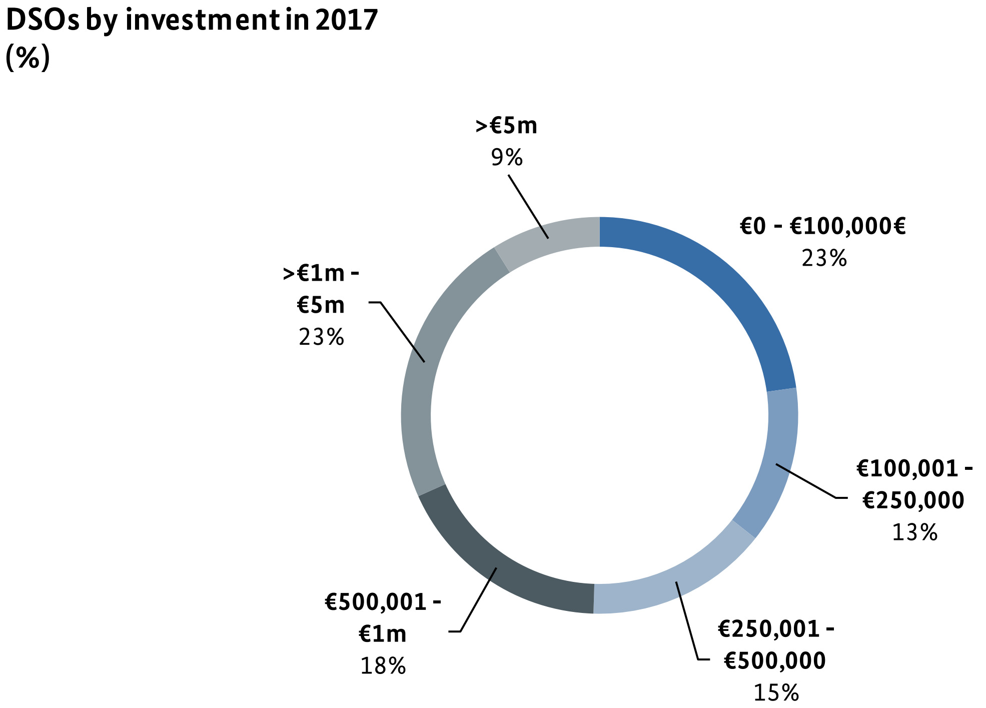


Figure 38: DSOs by investment amounts

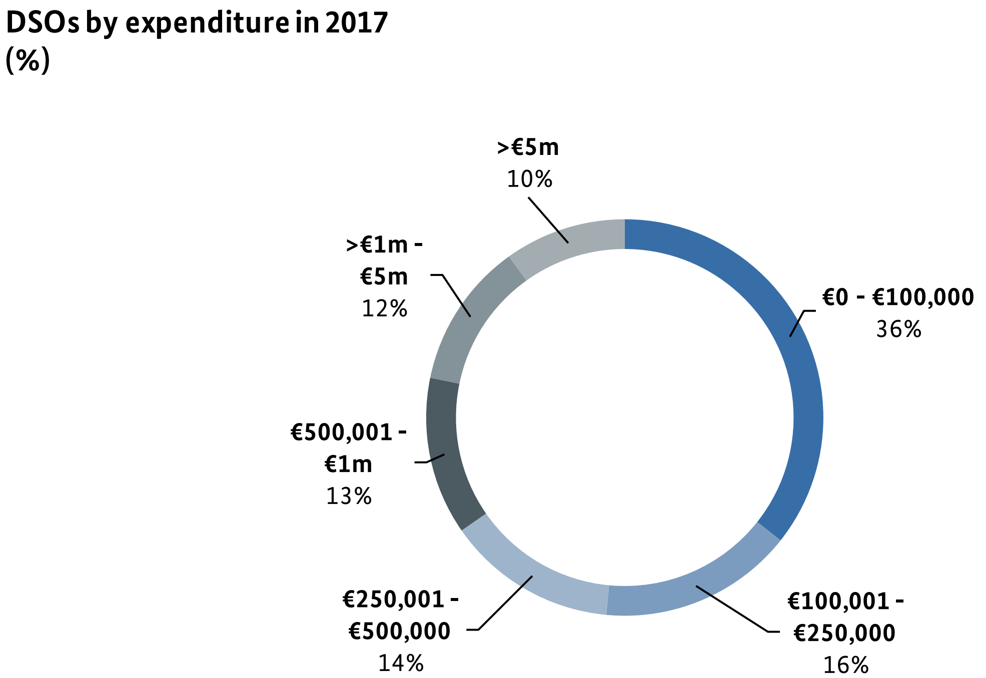


Figure 39: DSOs by expenditure amounts

291 or 36% of the DSOs are in the €0-€100,000 expenditure category. 82 or 10% of the DSOs are in the category with expenditure exceeding €5m. As can be seen in Figure 39, in 2017, just over half of the DSOs – 52% – recorded network expenditure exceeding €250,000.

3.3 Investments and incentive regulation

The Incentive Regulation Ordinance gives network operators the opportunity to budget for expansion and restructuring investment costs in the network charges over and above the level approved in the revenue caps. The amended version of the Ordinance of 17 September 2016 introduced different processes for this purpose.

3.3.1 Expansion investments by TSOs

For TSOs, it is still the case that under section 23 of the Ordinance, the Bundesnetzagentur grants approval upon application for individual projects that meet the stated requirements. Once approval has been given, TSOs may adjust their revenue caps by the operating and capital expenditure associated with their project immediately in the year in which the costs are incurred. The operators' costs are then subject to ex post checks by the Bundesnetzagentur.

As of 31 March 2018, 34 new applications for investment projects have been submitted by TSOs to the competent Ruling Chamber. Costs of acquisition and production of about €7.48bn are linked to these investment measures. Both the number and volume of applications made by TSOs are lower than in 2017.

3.3.2 Expansion factor and capital expenditure adjustment for DSOs

Under section 4(4) para 1 in conjunction with section 10 of the Incentive Regulation Ordinance, electricity DSOs were able to apply for an adjustment to their revenue caps for networks below high-voltage (110 kV) level based on what is known as an "expansion factor" until the end of the second regulatory period in 2018. Such applications had to be made by 30 June each year, so the last deadline was 30 June 2017. The adjustment made took effect on 1 January of the following year.

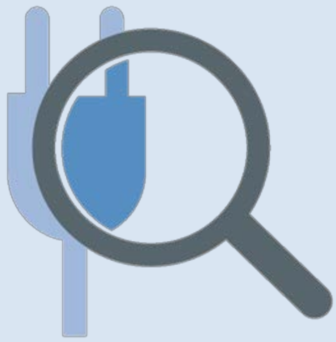
The expansion factor ensured that the costs of expansion investments resulting from a sustainable change in the scope of the services provided by a DSO during a particular regulatory period are taken into account with as little delay as possible when setting the revenue cap.

Overall, the adjustments made to the revenue caps for 2017 on the basis of expansion factors amounted to €386.6m. The adjustments resulted from 124 applications relating to the revenue caps for 2017, 96 of which were submitted by the deadline of 30 June 2016 and 28 in previous years.

As a result of the 2016 revision of the Incentive Regulation Ordinance, the expansion factor (cf. section 34(7) ARegV) is no longer used as from the third regulatory period and has been replaced by the adjustment of capital expenditure Furthermore, it is no longer possible for DSOs to apply for investment measures under section 23 of the Ordinance, as these also come under the adjustment of capital expenditure.

As of 1 January 2019, DSOs can claim all planned investment costs directly in the revenue cap and thus price them into network charges. The regulatory authorities subsequently carry out a check of the actual outgoings. The previously applicable ex ante examination of external factors justifying an expansion investment is no longer carried out.

4. Electricity supply disruptions



The System Average Interruption Duration Index – $SAIDI_{EnWG}$ is the average length of supply interruption experienced by each customer in a year in the low and medium voltage level, and is calculated from the reports of network operators about the interruptions that occurred in their network area. The $SAIDI_{EnWG}$ for 2017 is 15.14 minutes.

Operators of energy supply networks are required under section 52 of the Energy Industry Act to submit to the Bundesnetzagentur by 30 April of each year a report detailing all interruptions in supply that occurred in their networks in the previous calendar year. This report states the time, duration, extent and cause of each supply interruption lasting longer than three minutes. Furthermore, the network operator must provide information on the measures to be taken to avoid supply interruptions in the future.

The System Average Interruption Duration Index value ($SAIDI_{EnWG}$[38]) does not take into account planned interruptions or those which occur owing to force majeure, for instance natural disasters. Only unplanned interruptions caused by atmospheric effects, third-party intervention, ripple effects from other networks or other disturbances in the network operator's area are included in the calculations.

For the year 2017, 862 operators reported 166,560 interruptions in supply for 869 networks for the calculation of the $SAIDI_{EnWG}$. The figure of 15.14 minutes calculated for the low-voltage and medium-voltage levels is below the average from 2006 to 2016 of 15.59 minutes per year. Despite an increase, the quality of supply remained at a consistently high level in 2017.

[38] The System Average Interruption Duration Index $SAIDI_{EnWG}$ differs from the index $SAIDI_{ARegV}$ calculated for each individual company for the quality management pursuant to the Incentive Regulation Ordinance (ARegV).

Supply interruptions under section 52 Energy Industry Act (electricity)
(minutes)

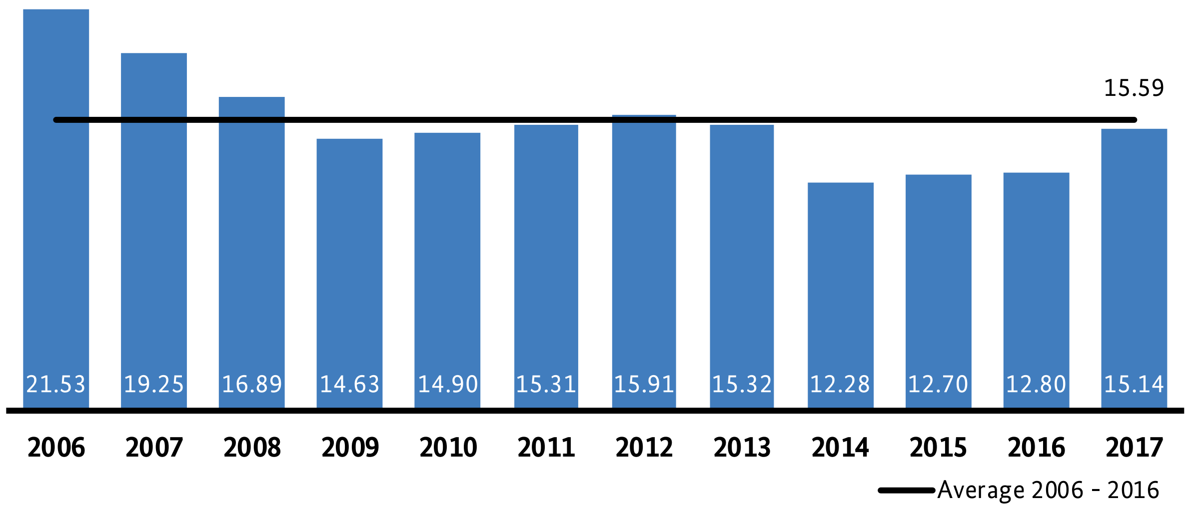


Figure 40: SAIDI$_{EnWG}$ from 2006 to 2017

The slight increase in the average interruption duration is predominantly due to an increase of 2.22 minutes to 12.92 minutes at the medium-voltage level. Last year's SAIDI$_{EnWG}$ registered a slight rise, of 0.12 minutes, to 2.22 minutes at the low-voltage level.

Supply interruptions under section 52 Energy Industry Act by network level (electricity)
(minutes)

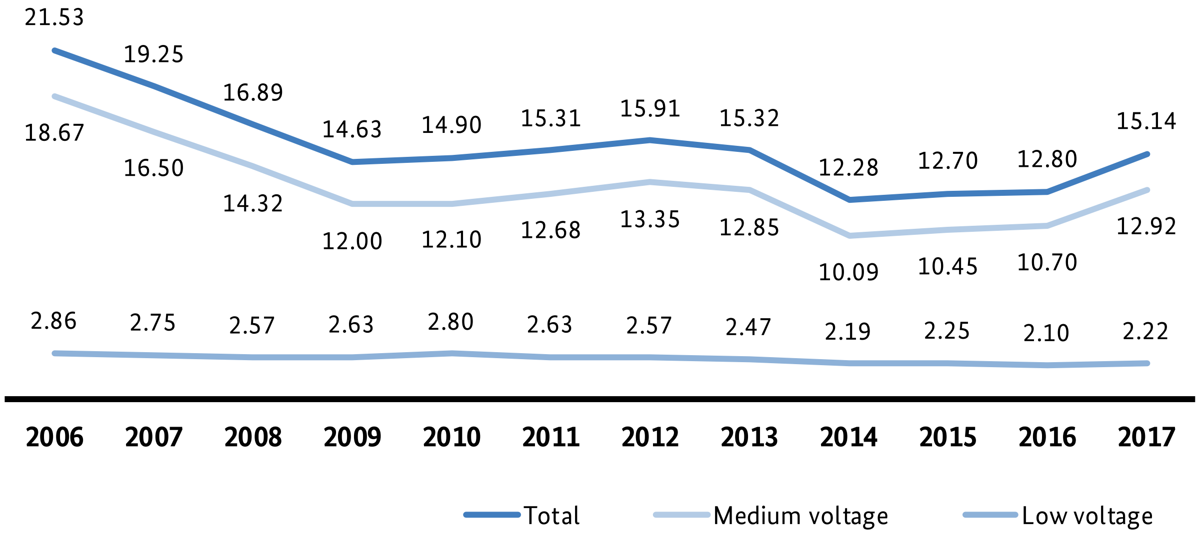


Figure 41: SAIDI$_{EnWG}$ at low-voltage and medium-voltage level: 2006 - 2017

There was a significant year-on-year increase in supply interruptions due to atmospheric effects and ripple effects. "Atmospheric effects" refers to interruptions caused by meteorological phenomena such as thunder, storms, ice, flooding, etc.

Ripple effects are interruptions that are caused in a network by a disturbance in an upstream or downstream network or at the final consumer's facility or by an interruption in supply at a power plant feeding in to the grid.

There were considerably more outage times brought about by extreme weather conditions in 2017 than there were in 2016, although transmission systems remained largely unscathed.

The energy transition and the associated growth in embedded generation again do not appear to have had a significant impact on the quality of supply in 2017.

In 2016, a total of 172,522 supply interruptions were reported, but this figure fell by nearly 6,000 to 166,560 in 2017. The number of interruptions is therefore on a downwards trend, while the average duration has risen slightly again in the past three years.

5. Network and system security measures

Network operators are legally entitled and obliged to take certain measures to maintain the security and reliability of the electricity supply system. There are various possible measures:

- **Redispatching**: reducing and increasing electricity feed-in from power plants according to a contractual arrangement with a network operator or with a statutory obligation towards the network operator with costs being reimbursed.
- **Grid reserve power plants**: deploying grid reserve plant capacity to compensate for a deficit of redispatch capacity according to a contractual arrangement with costs being reimbursed.
- **Feed-in management**: curtailing feed-in of renewable energy and combined heat and power (CHP) electricity at the network operator's request with compensation being paid. The curtailing of renewable generation requires a simultaneous increase in generation at another, compatible point in the network for physical balancing. However, as with redispatching, economic balancing can be carried out by the network operator as well. Balancing can lead to costs and revenues (eg due to imbalance payments) for the balance responsible party. The Bundesnetzagentur takes the view that these costs or revenues must be taken into consideration in the feed-in management compensation and are partially included in the specified estimated claims for compensation. The Bundesnetzagentur does not have data on the volumes of energy used for balancing.
- **Adjustment measures**: adjusting electricity feed-in and/or offtake at the network operator's request without compensation, where other measures are insufficient.

These network and system security measures are at the disposal of all network operators and are reported to the Bundesnetzagentur.

The following tables summarise the regulatory content, primary mechanisms and scope of measures (redispatching with operational and grid reserve power plants, feed-in management and adjustment measures) in 2017. They contain updated values for redispatching that may differ from the figures for 2017 published in the quarterly reports on network and system security measures. The table also contains updated figures for the feed-in management compensation payments. The other figures correspond to those published for the full year 2017 in the quarterly report.

Network and system security measures under section 13 of the Energy Industry Act: 2017

	Redispatching	Feed-in management	Adjustment measures
Legal basis and regulatory content	Energy Industry Act sections 13(1), 13a(1) and 13b(4) Network-related and market-related measures: topological measures such as balancing energy, interruptible loads, redispatching, countertrading, use of grid reserve	Energy Industry Act section 13(2) and (3) sentence 3 in conjunction with RES Act sections 14 and 15, for CHP installations in conjunction with CHP Act section 3(1) sentence 3 Feed-in management: reduction in feedin from renewable energy, mine gas and CHP installations	Energy Industry Act section 13(2): Adjustment of electricity feed-in, transit and offtake
Rules for affected installation operators	Measures according to contractual arrangement with network operator with reimbursement of costs: Energy Industry Act sections 13(1), 13a(1) and 13c	Measures at network operator's request with reimbursement of costs: Energy Industry Act section 13(2) and (3) sentence 3 in conjunction with RES Act sections 14 and 15, for CHP installations in conjunction with CHP Act section 3(1) sentence 3	Measures at network operator's request without reimbursement of costs: Energy Industry Act section 13(2)
Scope in reporting period	Total redispatching volume, increases and reductions of operational power plants and increase of reserve power plants (not inc test starts and test runs): **20,439 GWh**	Curtailed energy of installations remunerated under RES Act (TSOs and DSOs): **5,518 GWh**	Curtailed volume from adjustment measures (TSOs and DSOs): **34.5 GWh**
Estimated costs in reporting period	Preliminary cost estimate for redispatching, countertrading and use and reserving of grid reserve power plants: **€901m**	Preliminary estimated claims for compensation from installation operators under RES Act section 15 (TSOs and DSOs:) **€609.9m**	No entitlement to compensation for installation operators for adjustment measures under Energy Industry Act section 13(2)

Table 35: Network and system security measures under section 13 of the Energy Industry Act: 2017

Network and system security measures

		2015	2016	2017
Redispatching				
Total volume[1] of operational plants	GWh	15,436	11,475	18,456
Cost estimate[2] for redispatching	€m	412	223	392
Cost estimate for countertrading	€m	24	12	29
Grid reserve power plants				
Volume[3]	GWh	551	1,209	2,129
Cost estimate for activation	€m	66	103	184
Capacity[4]	MW	7,660	8,383	11,430
Annual costs of holding in reserve	€m	162	183	296
Feed-in management				
Volume of curtailed energy[5]	GWh	4,722	3,743	5,518
Estimated compensation	€m	478	373	610
Feed-in adjustments				
Volume	GWh	27	4	35

[1] Amounts (reductions and increases) including countertrading and remedial action measures according to monthly report to the Bundesnetzagentur.
[2] TSOs' cost estimate based on actual measures including costs for remedial actions.
[3] Activations of grid reserve power plants including test starts and test runs. The feed-in of grid reserve power plants is only increased.
[4] Total capacity of German and foreign grid reserve power plants in MW. As at 31 December of the respective year.
[5] Reduction of installations remunerated in accordance with the RES or CHP Acts.

Source: network operators' data reports to the Bundesnetzagentur

Table 36: Overview of network and system security measures for the years 2015 to 2017

5.1 Overall development of redispatching in 2017

Section 13(1) of the Energy Industry Act (EnWG) entitles and obliges TSOs to remove threats or disruptions to the electricity supply system by taking network-related and market-related measures. Insofar as DSOs are responsible for the security and reliability of the electricity supply in their networks, these too are both authorised and required to implement such measures as set out in section 14(1) EnWG.

Network-related measures, most notably topological measures, are taken by the TSOs practically every day of the year. Market-related measures include in particular contractually agreed arrangements to maintain the security of the electricity supply system.

Redispatching describes interventions in the market-based operating schedules of generating units to shift feed-in. In this context, power plants are instructed by TSOs, either under a contractual arrangement or a statutory obligation, to reduce/increase their feed-in while, at the same time, other power plants are instructed to increase/reduce their feed-in accordingly.[39] These interventions have no impact on the overall balance between generation and load since action is taken to ensure that the reductions in feed-in are balanced physically and economically by increases elsewhere. Redispatching is undertaken by network operators to ensure the secure and reliable operation of the electricity supply networks. The aim is either to prevent or relieve overloading of power lines. Network operators reimburse the plant operators involved in the redispatching measures for the costs incurred. A distinction is made between electricity-related and voltage-related redispatching. Electricity-related redispatching is used to avoid or relieve sudden overloading affecting power lines and transformer stations. Voltage-related redispatching, by contrast, is used to maintain the voltage in the affected network area, for instance by adjusting reactive power. This involves adjusting the active power feed-in from power plants to enable them to provide the reactive power needed to maintain voltage stability. This can be done, for example, by firing idle power plants up to their minimum active power feed-in level or by reducing feed-in from power plants operating at full capacity down to their minimum level. As with electricity-related redispatching, this form of reactive power provision only involves conventional power plants on account of the priority dispatch rules. In the case of voltage-related redispatching, system balancing measures may take the form of electricity exchange transactions. Redispatching can be an internal measure applicable to one control area only or a wider measure applicable to more than one control area.

The German TSOs provide the Bundesnetzagentur with detailed data on the redispatching measures. The following analysis is based on the data reported in 2017.

Total reductions in feed-in in 2017 amounted to 10,200 GWh, increases in feed-in from operational plants to 8,256 GWh and increases in feed-in due to the use of grid reserve power plants to 2,129 GWh.[40] In 2017, the reductions in feed-in from power plants as a result of redispatching measures corresponded to 2.6% of total non-renewable generation fed into the grid. Overall, a total of 20,439 GWh[41] of reductions and increases in feed-in was requested.

The costs for power plants operating in the electricity market as estimated by the TSOs were around €456.6 m (without countertrading costs). Estimated costs are about €234m higher than in 2016, when they were €222.6m.

There are various steps to operation redispatch planning. This report makes a distinction between individual overloading measures in a control area and measures taken by the four TSOs together ("4-TSO process"). In the latter, the four TSOs use model calculations to carry out joint planning of redispatching.

These 4-TSO measures are growing in importance, rendering the reporting procedure previously used no longer adequate. The Bundesnetzagentur therefore consulted with the TSOs and established a new reporting

[39] All redispatching information and data in this report relate to measures under contractual arrangements or statutory obligations in line with sections 13(1) and 13a(1) of the Energy Industry Act.

[40] This total value on the use of grid reserve power plants also includes test starts and test runs.

[41] This total value on the requests for using grid reserve power plants to manage network restrictions does not include test starts and test runs.

procedure that specifically details the use of power plants in redispatching and makes it possible to distinguish between the types of measures.

In 2017 about 71% of redispatching measures were carried out due to overloading of individual lines. The remaining 29% were 4-TSO measures.

5.1.1 "Four-TSO measures"

The joint requests by all four TSOs are based on modelling results carried out both before and after the market outcome for the whole of Germany.

It is necessary to optimise the deployment of redispatching power plants at an early stage so that grid reserve power plants that take longer to start up can be requested in good time. The joint modelling also improves coordination between the TSOs, so it may be assumed that the power plants used can be selected efficiently.

The calculations show both the requests for grid reserve power plants and planning for the use of operational plants, which are requested once the market outcome is available. A total of 2,979 GWh was curtailed and 3,020 GWh increased on the basis of advance measures by the four TSOs (5,999 GWh overall). These measures make up 29% of the total redispatching and grid reserve volume.

Most measures are electricity-related redispatching (98.9%), with just 1.1% coming under voltage-related measures.[42]

According to the TSOs, it is not possible to allocate the volumes of measures requested jointly to individual network elements that cause them. The current reports only enable conclusions to be drawn about the cause of 4-TSO measures at the aggregated level of network groups. They show that the network groups that trigger the majority of advance measures by the four TSOs are also the ones where the network elements shown under I.C.5.1.2 are located.

5.1.2 Individual overloading measures

The volume of reductions in feed-in caused by overloading in one TSO control area (or across control areas in the case of interconnectors) was around 7,209 GWh in 2017. Increases in feed-in for balancing were around 7,205 GWh. Therefore the total volume of these redispatching measures (reductions and increases in feed-in) for the whole of 2017 was approximately 14,414 GWh.

In the whole of 2017, the Bundesnetzagentur received reports of electricity-related and voltage-related redispatching due to overloading in a control area totalling about 14,202 hours. Since all measures taken to ease restrictions in the network, including measures taken in parallel, are recorded, the sum of the hours in which measures were taken cannot be put in relation to the total number of 8,760 hours in a year. In 2017, redispatching measures were taken on a total of 353 days.

Table 37 below provides an overview of the redispatching due to overloading in one control area in 2017.

[42] See also section I.C.5.1.2 for further explanations on the difference between electricity-related and voltage-related redispatching.

Redispatching measures: individual overloading measures in 2017

Control area	Duration (hours)	Volume of reductions in feed-in (GWh)	Total volume (reductions and increases in feed-in) (GWh)
TenneT	9,429	4,371	8,743
50Hertz	1,889	1,623	3,246
Transnet BW	1,174	280	556
Amprion	1,712	935	1869
Total	14,202	7,209	14,414

[1] If a joint request for redispatching is made by two neighbouring TSOs, the total duration and total volume is halved between the two TSOs for the purpose of the Bundesnetzagentur's analysis.

Table 37: Redispatching: individual overloading measures by TSO control area in 2017

Electricity-related individual overloading measures

Redispatching in 2017 was mainly electricity-related. The electricity-related measures comprised a total of 11,511 hours of overloading and reductions in feed-in amounting to 6,640 GWh.

In comparison to 2016, there was a clear increase both in duration, of 1,251 hours (2016: 10,260 hours), and in volume of feed-in reductions caused by electricity-related redispatching, of 919 GWh (2016: 5,721 GWh).

As can be seen in Table 38, the most heavily loaded network element for individual overloading measures in 2017 was again the line between Remptendorf and Redwitz. Nevertheless, there has been a significant decrease in loading on this network element compared with last year and in particular with 2015. It is noteworthy that the full commissioning of the "Thuringian power bridge" on 14 September 2017 led to a much lower level of loading. Measured in time, overloading on the "Remptendorf-Redwitz" line went down to only 18 hours in the fourth quarter of 2017, compared with 945 hours in the same period a year earlier.

Overloading in the Dörpen area increased significantly in 2017. Power lines running from Dörpen to Hanekenfähr, which are used in particular to transport electricity from offshore wind farms in the North Sea, were the second most frequently affected network elements in 2017. Overloading remained high on the network element Brunsbüttel and the lines from Pleinting and Altheim to Sankt Peter in Austria.

The numbering of the network elements in Table 38 should not be understood as a ranking, since the volumes would be listed differently if the 4-TSO advance measures, which are not shown in this table, were included. Rather, the numbers serve to identify the network elements on the map (Figure 42), which shows the location of the critical network elements from Table 38 (≥ 20 hours per line).

Electricity-related redispatching on the most heavily affected network elements: 2017

No	Network element	Control area [1]	Duration (hours)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)
1	Remptendorf-Redwitz	50Hertz/ TenneT	1,791	2,455	2,455
2	Dörpen area (Dörpen-Niederlangen-Meppen-Hanekenfähr (Amprion control zone))	TenneT/ Amprion	1,346	556	561
3	Brunsbüttel-Brunsbüttel 50 Hertz zone	TenneT/ 50Hertz	1,017	600	600
4	Pleinting area (Pleinting transformer, Pleinting - Sankt Peter (AT))	TenneT	729	489	489
5	Altheim area (Altheim-Sittling, Altheim-Simbach-Sankt Peter (AT))	TenneT	550	381	381
6	Ville Ost (Rommerskirchen - Sechtem)	Amprion	393	273	271
7	Lehrte - Godenau	TenneT	359	58	58
8	Borken-Giessen-Karben	TenneT	354	215	215
9	Landesbergen area (Landesbergen-Wechold-Sottrum, Landesbergen-Sottrum)	TenneT	354	136	136
10	Großkrotzenburg-Dettingen /Amprion-Zone	TenneT/ Amprion	290	148	148
11	Altbach area (Altbach transformer, Altbach-Muehlhausen	TransnetBW	228	17	17
12	Stalldorf area (Kupferzell-Stalldorf, Grafenrheinfeld-Stalldorf)	TransnetBW	222	74	75
13	Dipperz-Großkrotzenburg	TenneT	183	70	70
14	Conneforde-Sottrum area (Sottrum - Huntorf - Conneforde-Unterweser)	TenneT	145	62	62
15	Goldgrund (Maximiliansau-Daxlanden)	Amprion/ TransnetBW	129	41	41
16	Großkrotzenburg area (Großkrotzenburg transformer, Großkrotzenburg-Karben)	TenneT	123	51	51
17	Mikulowa area (PSE-Netz PL, Hagenwerder-Mikulowa, Mikulowa Czarna, Mikulowa-Cieplice)	50Hertz	118	33	33
18	Irsching-Zolling area (Irsching-Zolling, Zolling transformer, Irsching transformer	TenneT	113	16	16
19	Kugelberg Ost line (Bürstadt-Hoheneck-Weingarten-Daxlanden)	Amprion	103	66	66

1 The first control area denotes the TSO reporting the redispatching measure to the Bundesnetzagentur.

Electricity-related redispatching on the most heavily affected network elements: 2017

No	Network element	Control area [1]	Dauer (in Std.)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)
20	Nette Ost line (Sechtem-Weissenthurm)	Amprion	85	94	94
21	Mehrum-Hallendorf area (Mehrum - Gleidingen - Hallendorf, Mehrum - Hallendorf)	TenneT	67	12	12
22	Walberberg West (Knapsack-Sechtem)	Amprion	65	75	75
23	Daxlanden area (Daxlanden-Maximiliansau-Goldgrund, Daxlanden-Weingarten)	TransnetBW /Amprion	63	14	14
24	Großkrotzenburg-Urberach/Amprion control zone	TenneT/ Amprion	62	29	29
25	Helmstedt - Wolmirstedt (TenneT control zone)	50Hertz/ TenneT	52	36	36
26	Bärwalde area (Graustein-Bärwalde, Bärwalde-Schmölln)	50Hertz	48	16	16
27	Lehrte-Wahle area (Lehrte-Mehrum, Lehrte-Wahle)	TenneT	48	5	5
28	Borken-Waldeck-Twistetal	TenneT	43	16	16
29	Ovenstädt-Bechterdissen area (Ovenstädt-Eickum-Berchterdissen)	TenneT	39	16	16
30	Dollern-Wilster	TenneT	36	13	13
31	Germersheim Süd (Weingarten-Daxlanden)	Amprion/ TransnetBW	35	10	10
32	Donau Ost/West (Vöhringen-Hoheneck-Dellmensingen, Vöhringen-Dellmensingen)	Amprion/ TransnetBW	35	10	10
33	Sottrum - Blockland	TenneT	34	5	5
34	Helmstedt area (Wahle-Helmstedt, Hattorf-Helmstedt)	TenneT	31	19	19
35	Audorf-Hamburg Nord	TenneT	27	13	13
36	Mecklar-Dipperz area (Borken-Mecklar, Mecklar-Dipperz)	TenneT	24	7	7
37	Brunsbüttel-Büttel	TenneT	24	11	11
38	Conneforde-Maade	TenneT	21	9	9

[1] The first control area denotes the TSO reporting the redispatching measure to the Bundesnetzagentur.

Table 38: Electricity-related redispatching on the most heavily affected network elements: 2017

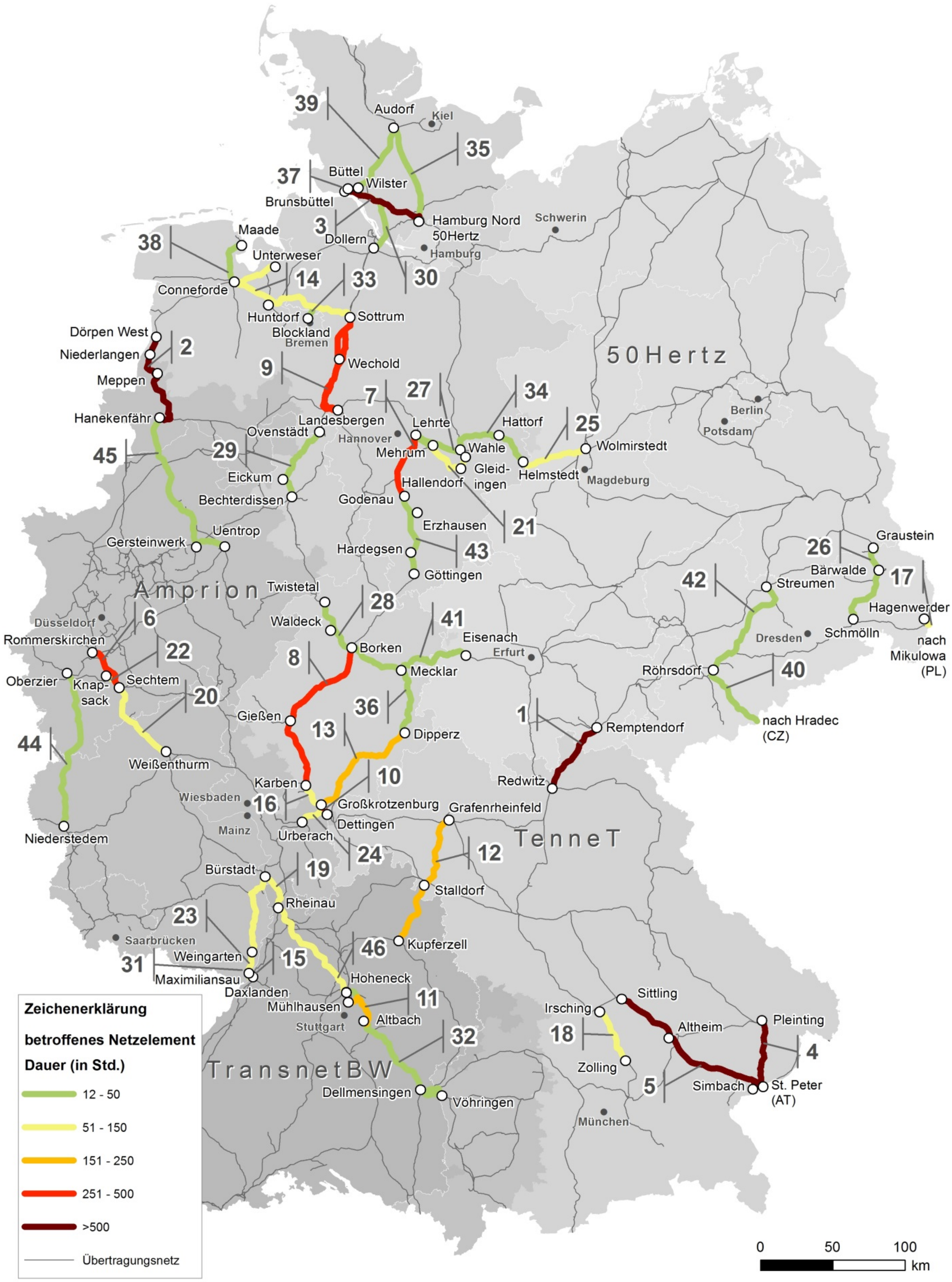


Figure 42: Duration of electricity-related redispatching measures in cases of individual overloading of the most heavily affected network elements according to TSO reports: 2017

Voltage-related individual overloading measures

In addition to electricity-related redispatching, the TSOs reported voltage-related individual overloading measures totalling about 2,691 hours and a volume of around 569 GWh in 2017. This was supplemented by counter trades amounting to 563 GWh. The need for voltage-related redispatching measures in 2017 was broadly unchanged from the previous year. Duration rose by 386 hours (2016: 3,077 hours), while the volume of the measures carried out rose by 35 GWh (2016: 534 GWh).

Table 39 shows the duration and volume of the measures required in the individual control and network areas.[43]

The TSOs report that there is generally a greater need for voltage-related redispatching in the summer months than in the winter. It is usually the case that the lower load in summer leads to a greater need for reactive power in order to keep within the upper voltage limits in the networks. As well as conventional generating installations, network equipment such as phase shifters can also provide reactive power. However, currently it is mostly provided by conventional generating installations. During the summer and especially at weekends, some conventional power plants are not available on the market because of the low demand for electricity, so their provision of reactive power has to be achieved via redispatching.

[43] No overview map has been provided for practical reasons, since voltage-related redispatching takes place across larger network regions, and not in individual lines or transformer stations.

Voltage-related redispatching measures: 2017[1]

Network area	Duration (hours)	Volume (GWh)
TenneT control area: northern network area	**130**	**25**
Conneforde network area	130	25
TenneT: central network area	**1,870**	**392**
Ovenstädt-Bechterdissen-Borken	801	152
Borken (Borken-Dipperz-Großkrotzenburg, Gießen, Karben) network area	1,040	234
Mehrum-Grohnde-Borken network area	29	6
TenneT control area: southern network area	**170**	**18**
Oberbayern network area	170	18
50Hertz control area	**8**	**4**
TransnetBW control area	**513**	**130**
Dellmensingen, Kupferzell, Wendlingen	8	1
Altbach area (Altbach-Muehlhausen, Endersbach, Wendlingen, Buenzwangen)	305	73
Daxlanden area (Daxl.-Eichstetten, Daxl.-Philipsburg, Daxl.-Heidelberg)	169	51
Grossgartach area (Grossgartach-Hueffenhardt, Grossgartach-Kupferzell)	23	5
Muehlhausen-Pulverdingen	8	1

[1] Since these measures relate to larger network regions (and not individual lines or transformer stations), the measures are only listed in tabular form and not illustrated on a map.

Table 39: Voltage-related redispatching in 2017

5.1.3 Countertrading

Unlike the usual redispatching measures, which involve curtailing or increasing the output of specific power plants, countertrading measures aim to remove network restrictions between two bidding zones. There is no specific intervention in the deployment of power plants. Instead, targeted transactions across bidding zones are used to alleviate the restriction on the interconnection line. Countertrading measures are therefore primarily suitable for situations in which, for reasons to do with the topology of the grid, it is not necessary to activate specific power plants.

Countertrading, which forms part of the individual overloading measures, made up about 1,799 GWh of the total redispatching in 2017. It incurred costs of around €29.2m, which was higher than the €23.5m in 2015 and €12m in 2016.

5.1.4 Deployment of grid reserve capacity

Grid reserve power plants are included in the operational planning for ramp-ups in redispatching. The TSOs consider which grid reserve plants would be most efficient to resolve the predicted network restrictions. Foreign grid reserve plants have often proved to be more efficient in terms of having a better network-related effect on restrictions than domestic grid reserve plants. The TSOs require less power to start up foreign grid reserve plants than if they use positive redispatch capacity from the domestic plants. As a result, the TSOs need smaller redispatch volumes to ease the restrictions; this reduces the risk of error in carrying out redispatching measures, which in turn improves the level of system security.

In 2017, the grid reserve was requested on 145 days to provide a total of around 2,129 GWh of energy. Grid reserve power plants can be called upon, by all four TSOs together, or as individual overloading measures. The TSOs estimated the related call-off costs at about €183.9m. The contingency costs for the grid reserve amounted to €296.1m (including one-off costs for making the facility ready to operate). The number of days was up on the 2016 figure of 108 days and the amount of energy provided was around 920 GWh higher than the previous year's figure of 1,209 GWh.

Table 40 summarises the usag of the grid reserve in 2017. The average deployment in MW shows the average volume of reserve requested per day of deployment. This average value peaked in January 2017 at 1,436 MW. The largest volume of grid reserve use was 3,324 MW and also occurred in January 2017.

Summary of grid reserve deployment: 2017

	Number of days	Average deployment (MW)	Maximum volume of use (MW)	Total (MWh)
January	26	1,436	3,324	877,674
February	23	913	2,682	482,668
March	15	555	1,648	143,976
April	10	332	979	47,068
May	5	135	464	6,135
June				
July	5	233	550	9,878
August	9	238	625	39,671
September	4	169	550	6,726
October	20	437	1,516	154,074
November	16	627	2,098	220,742
December	12	519	1,058	139,891
Total	**145**			**2,128,501**

Source: TSOs' reports of redispatching to the Bundesnetzagentur

Table 40: Summary of grid reserve deployment in 2017

The electricity supply situation in January 2017

Towards the end of the second week in January 2017, the storm "Egon" brought cold Polar air to Europe, which got influenced by a high pressure area at the weekend.

At that time of high loads in the grids, five nuclear power plants in France with a total capacity of 5.5 GW were undergoing maintenance simultaneously and therefore not in operation.

On 18 January 2017, the German TSOs initially requested the feed-in of 2,465 MW of power from the grid reserve. It was possible to raise this up to 4,940 MW, when necessary. The grid reserve plants had a total of 8,383 MW at their disposal (4,458 MW domestically, 3,925 MW internationally). The reserve was activated due to findings in the German transmission network, primarily in the control areas of Amprion and TransnetBW. During these critical weeks in January, the system was always in balance and sufficient generation capacity for load coverage was available. However, the low amount of energy generated by wind turbines placed high transport requirements on the transmission grids of Amprion and TransnetBW. Power generated by plants in North Rhine-Westphalia had to be transported to Baden-Württemberg. These requirements were further increased by the non-availability of some power plants in Baden-Württemberg, including the nuclear power plant Philippsburg 2.

5.1.5 Deployment of power plants in redispatching

A total volume of 14,867 GWh, (8,619 GWh of reductions in feed-in and 6,258 GWh of increases) was provided by operational plants within Germany and grid reserve power plants both in and outside Germany in 2017. Among other things, the difference between the feed-in reduction and increase results from the fact that power plants are instructed by foreign TSOs for cross-border redispatching. These instructions are not included in the evaluations below.

Power plants with different energy sources are used for redispatching, as shown in Figure 43. 60 percent of the curtailed volume in 2017 came from lignite. Lignite-fired power plants were not involved in increases in feed-in. Hard coal and natural gas were the energy sources providing the most feed-in increases (over 35% each). Some redispatching also takes place on the exchange and is classed as "unknown" since it cannot be allocated to any one energy source. In a few cases, the TSO does not know what type of fuel the power plant uses, and these are also put down as "unknown". For plants with more than one source, it is only possible to evaluate the energy source specified in the Bundesnetzagentur power plant list. In this case, the volume of redispatch is allocated to the main energy source.

Nuclear power plants are rarely used for increases in feed-in for redispatching because they are usually being operated to full capacity already, but they are sometimes used to reduce feed-in. Nuclear power plants are generally able to carry out changes in generation at the same speed as lignite-fired power plants. They are particularly flexible in operation at the upper end of capacity up to 80% nominal capacity,[44] but starting them

[44] See https://www.tab-beim-bundestag.de/de/pdf/publikationen/berichte/TAB-Hintergrundpapier-hp021.pdf; accessed 6 September 2018

up or shutting them down completely takes up to two days, so they are not suited for such regulating measures in the course of redispatching. Moreover, it must be pointed out that nuclear power plants were not designed to provide maximum flexibility. On the contrary, they were built with a focus on other parameters, such as maximum efficiency or operational lifetime. Starting up or shutting down the plants frequently, in particular in the capacity range below 80% nominal capacity, would put too much strain on the components, so their flexibility is limited.

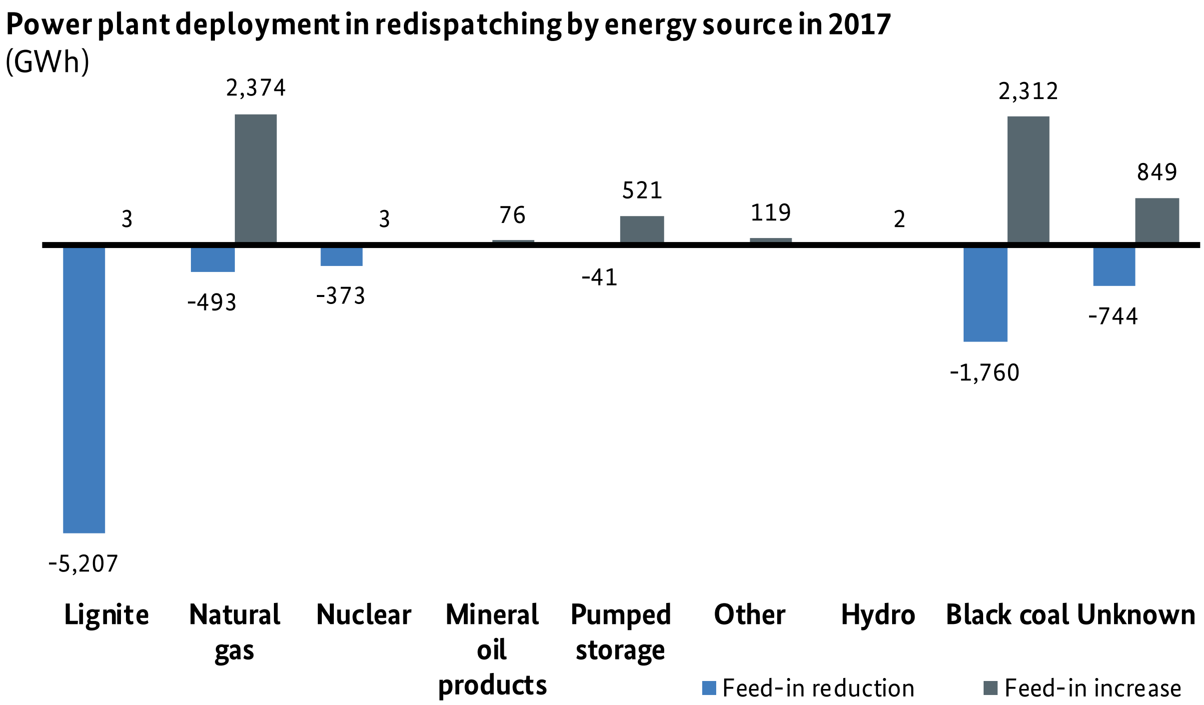


Figure 43: Power plant deployment in redispatching by energy source in 2017

Reductions and increases in feed-in are distributed differently by volume to the instructing TSOs. The instructing TSO is the TSO in whose control area the power plant used for redispatching is located. For grid reserve power plants, the instructing TSO is the one that has concluded the contract with the power plant. Figure 44 shows the distribution of instructions to power plants by TSO, regardless of the location of the cause of redispatching, which may be in a different control area. The TSO responsible for the control area in which the power plant required is located receives the request for deployment either from the TSO responsible for the control area where the cause is located or, in the case of advance measures, by all four TSOs jointly. In 2017, 50Hertz accounted for 51% of volume reductions, followed by TenneT (27%) and Amprion (21%), while TransnetBW requested almost exclusively increases in feed-in. The majority of increases in feed-in by domestic operational plants and domestic and international reserve power plants was in the TenneT control area (55%).

Reductions and increases in feed-in by control area in 2017 as a proportion of the total reduced or increased redispatched volume

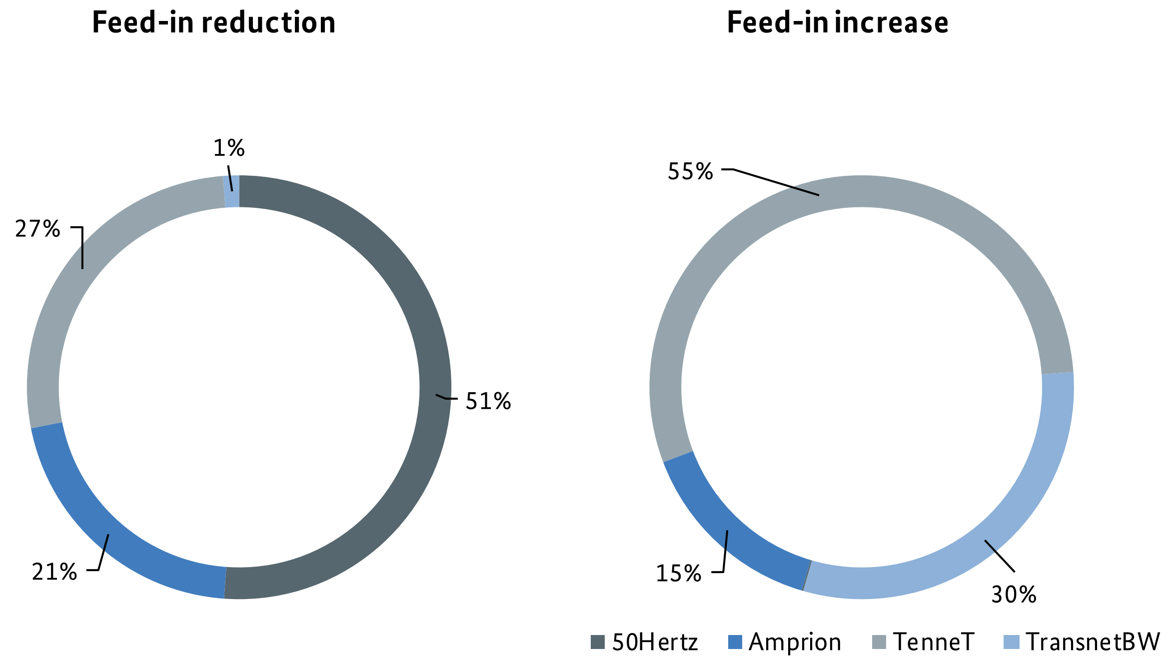


Figure 44: Reductions and increases in feed-in by control area in 2017 as a proportion of the total reduced or increased redispatched volume.

The maps in Figure 45 and Figure 46 show how power plants are deployed across the individual federal states for redispatch. It can be seen that in the south of Germany, power plants mostly increase their generation to remove network restrictions, but in the rest of the country their generation is usually reduced. Foreign grid reserve and operational plants are not included.

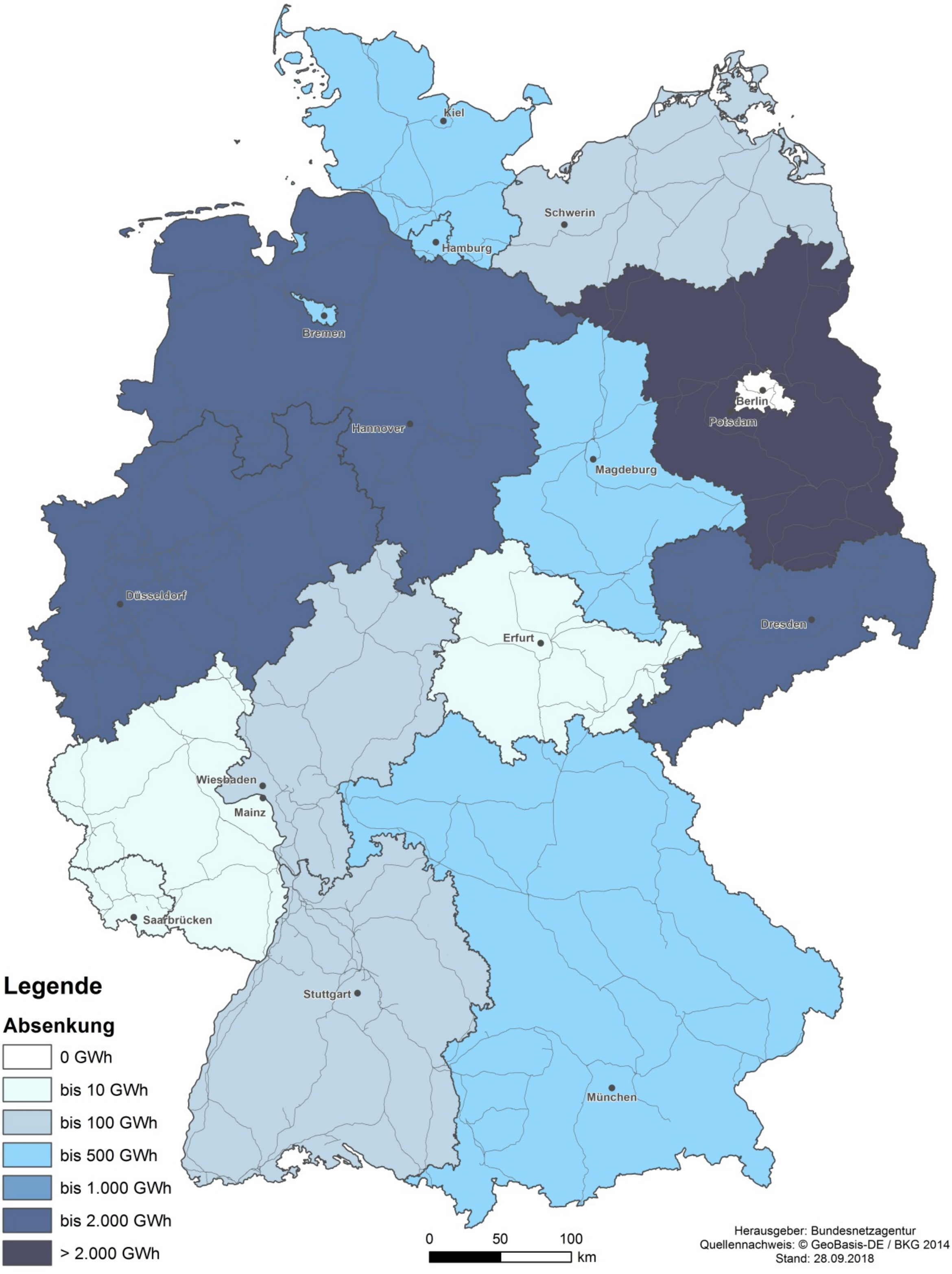


Figure 45: Power plant reductions as requested by German TSOs in 2017

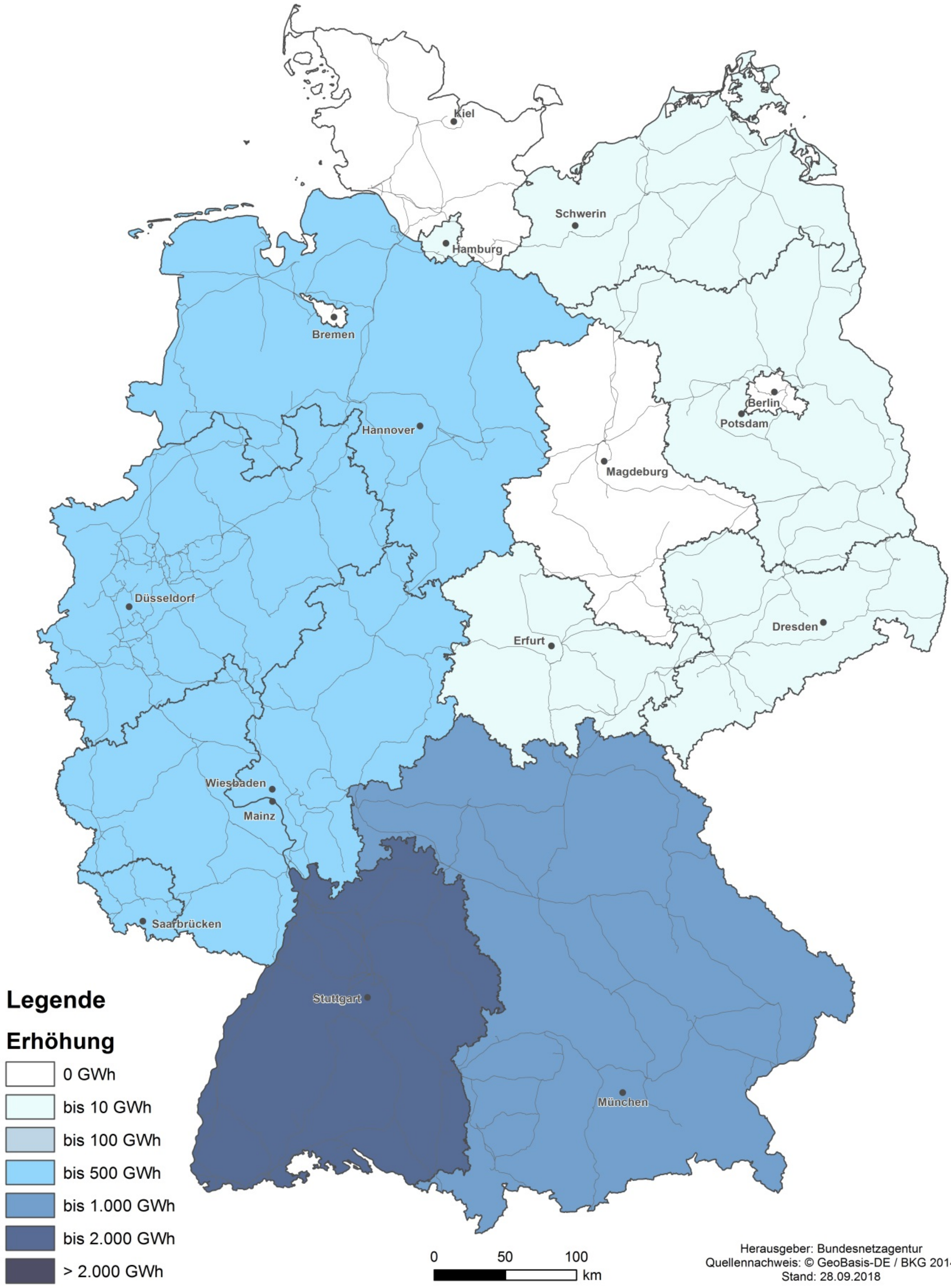


Figure 46: Power plant increases as requested by German TSOs in 2017

5.2 Feed-in management measures and compensation

Feed-in management is a special measure regulated by law to increase network security and relating to renewable energy, mine gas and highly efficient CHP installations. Priority is to be given to feeding in and transporting the renewable and CHP electricity generated by these installations. Under specific conditions, however, the network operators responsible may also temporarily curtail such priority feed-in if network capacities are not sufficient to transport the total amount of electricity generated. Importantly, such feed-in management is only permitted once the priority measures for non-renewable and non-CHP installations have been exhausted. The expansion obligations of the operator answerable for the network restrictions remain despite these measures.

The operator of an installation with curtailed feed-in is entitled to compensation for the energy and heat not fed in (section 15(1) EEG). The costs of compensation must be borne by the operator in whose network the cause for the feed-in management measure is located. The operator to whose network the installation with curtailed feed-in is connected must pay the compensation to the installation operator. If the cause lay with another operator, the operator responsible is required to reimburse the costs of compensation to the operator to whose network the installation is connected.

5.2.1 Curtailed energy

The following graph shows the amount of unused energy as a result of feed-in management measures for the energy sources most affected by such measures since 2009:

Curtailed energy resulting from feed-in management measures
(GWh)

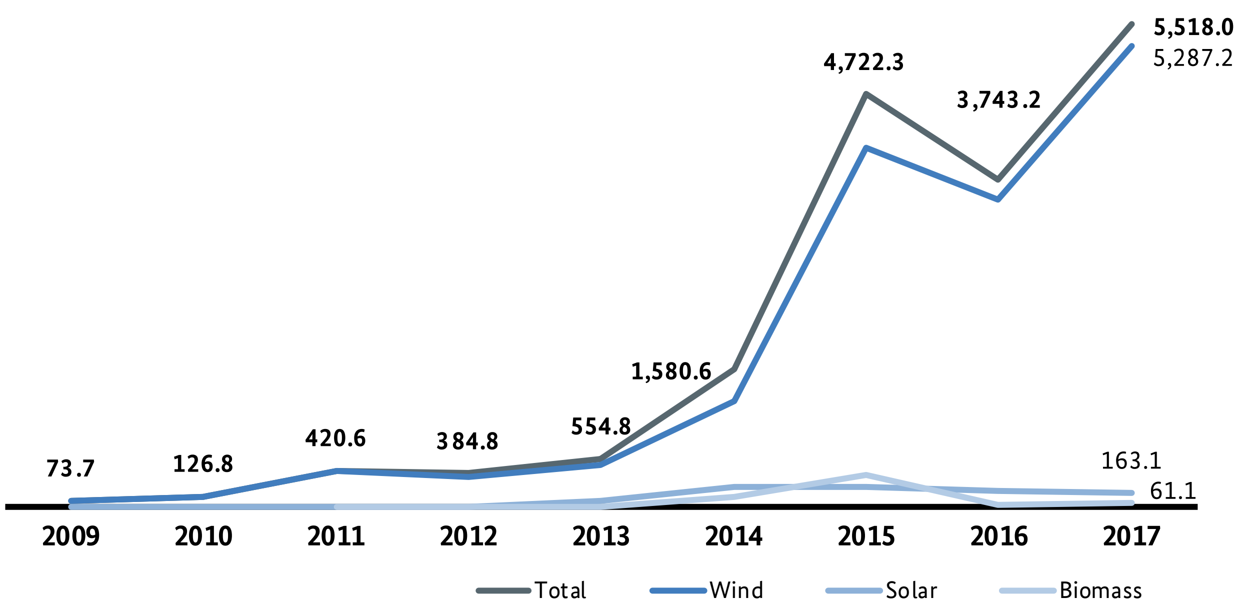


Figure 47: Curtailed energy resulting from feed-in management measures

The amount of energy curtailed as a result of feed-in management measures increased by a good 47% from 3,743 GWh in 2016 to 5,518 GWh in 2017, making the total amount of unused energy produced by renewable and CHP installations the highest ever. This corresponds to 2.9% of the total amount of electricity generated in 2017[45] by installations eligible for payments under the Renewable Energy Sources Act (including direct selling), up from 2.3% in 2016.

The increase in feed-in management measures is essentially due to various factors. One of these factors is the weather. The 2017 increase was both due to the general wind situation and, above all, to the curtailment of offshore wind turbines. There was a significant rise of about 794 GWh over 2016 in curtailed energy for offshore wind turbines, which was caused by the strong growth in offshore wind installations that occurred in 2015 and 2016. Given the increased need for feed-in management measures and assuming that there will be a further steady increase in renewables, the measures required for network optimisation, reinforcement and expansion must be implemented without delay. Detailed and up-to-date information on feed-in management measures is included in the Bundesnetzagentur's quarterly reports on network and system security.

In 2017, as in previous years, feed-in management measures primarily involved onshore wind power plants, accounting for 80.8% of the total amount of curtailed energy, down from 93.5% in 2016. Offshore wind power plants, which were first affected by feed-in management measures in 2015, accounted for about 826 GW or 15% of the total amount of curtailed energy in 2017, up from around 32 GW or 0.9% in 2016. CHP electricity generation was affected by curtailment from feed-in management to a far lesser extent. CHP electricity made up less than 0.1% of curtailed energy in 2017, and biomass, which is also often combined with heat generation, made up 1.1%. The third edition of the feed-in management guidelines was published on 25 June 2017 and provided an obstacle to the processing of feed-in management vis-à-vis CHP electricity generation. The new edition contains specific explanations of how curtailed CHP electricity and the corresponding compensation payments for CHP installation operators can be properly calculated.

The following table shows the individual amounts of curtailed energy and the percentages of the total amount for the energy sources affected by feed-in management measures:

[45] This does not include the amount of electricity curtailed through feed-in management.

Curtailed energy resulting from feed-in management measures by energy source

Energy source	Curtailed energy (GWh)	Share
Wind (onshore)	4,461.19	80.8
Wind (offshore)	825.96	15.0
Solar	163.14	3.0
Biomass, including biogas	61.11	1.1
Run-of-river	2.71	< 0.1
CHP electricity	2.70	< 0.1
Landfill, sewage and mine gas	0.77	< 0.1
Energy source unknown	0.38	< 0.1
Total	**5,517.96**	**100**

Table 41: Curtailed energy resulting from feed-in management measures by energy source: 2017

The network operators' reports on system and network security measures provided the following details of the use of feed-in management: the operators' daily and quarterly reports to the Bundesnetzagentur show that the TSOs were responsible for the majority of the feed-in management measures taken in 2017. Overall, restrictions in the transmission networks accounted for around 89% of the energy curtailed, although installations connected to transmission networks accounted for only around 16% of the energy curtailed and compensated. The remaining 84% was accounted for by installations connected to distribution networks. Support measures requested by the TSOs but taken by the DSOs accounted for the great majority – 89% – of the curtailed energy (see Table 42). Compensation for the support measures taken by the DSOs must be paid by the TSOs.

Although many regions in Germany now require feed-in management measures, around 87% of curtailed energy from such measures occurs in the federal states of Schleswig-Holstein, Lower Saxony and Brandenburg. Schleswig-Holstein is particularly affected (about 59%, see Figure 48).

Network levels of curtailments and cause of feed-in management measures in 2017

	Curtailed energy (GWh)	Percentage of total curtailed energy (%)
Measures taken by TSOs (cause in transmission network)	**892.41**	**16**
Measures taken by DSOs	**4,625.56**	**84**
DSOs' own measures (cause in distribution network)	590.87	11
DSOs' support measures (cause in transmission network)	4,034.69	73
Total feed-in management measures	**5,517.97**	**100**

Table 42: Network levels of curtailments and cause of feed-in management measures in 2017

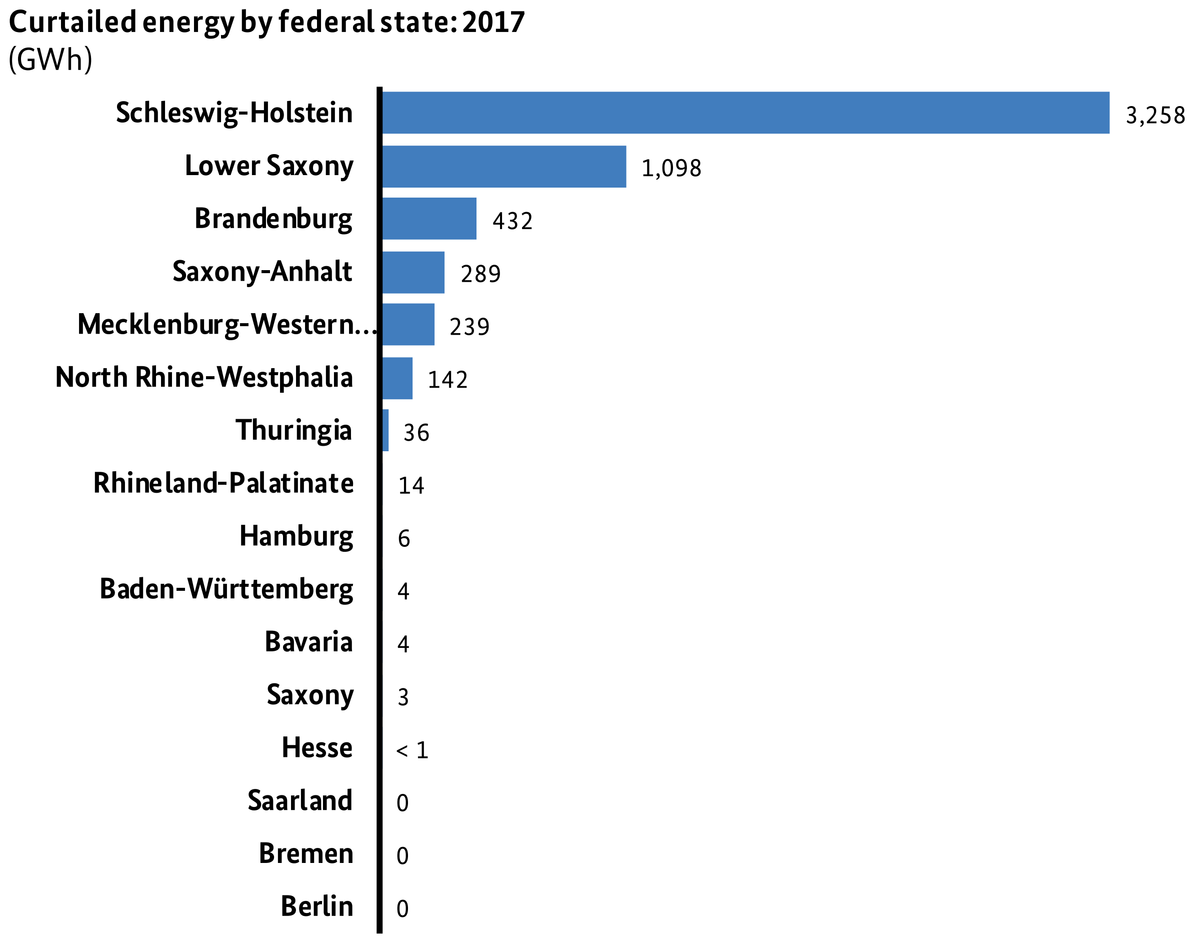


Figure 48: Curtailed energy by federal state: 2017

5.2.2 Compensation claims and payments

A distinction must be made between the estimates of the claims for compensation to installation operators for feed-in management measures in a specific year and the actual compensation paid in that year. The estimates are made by network operators based on the amount of curtailed energy from renewable energy installations and reported to the Bundesnetzagentur on a quarterly basis. The actual compensation paid is the amount of compensation paid by network operators to installation operators during the year under review and reported on an annual basis in the monitoring survey. This includes the costs of compensation for measures taken up to three years previously. This means, for example, that the figure for 2017 may include costs arising from measures taken in 2014, 2015 and 2016. Consequently, the compensation paid in one year does not reflect the actual costs incurred for curtailments in that year. A revised questionnaire now makes it possible to determine the amount of compensation paid for curtailments in previous years. The compensation paid to operators of the renewable and CHP installations affected – in economic terms similar to conventional plants whose feed-in has been curtailed through redispatching – is such that the operators are in more or less the same position as if feed-in from their installations had not been prevented by network restrictions.[46]

The amount of compensation claims paid to installation operators in 2017 was approximately €574m, up around €60m on 2016 (2016[47]:€514m). Most of the compensation paid in 2017 came under the EEG payments, with only about €30,000 coming under the CHP payments. The costs of the compensation paid to the installation operators are borne by the network charges paid by final consumers, adding an average of around €11.37 per final consumer in 2017, compared to €10.13 in 2016, €6.26 in 2015 and €1.65 in 2014. The additional costs are higher for consumers in regions particularly affected by feed-in management measures. These higher costs are offset by lower surcharges payable by the consumers in all network areas under the Renewable Energy Sources Act, since no payments have to be paid for the electricity generated but not fed in from the renewable and CHP installations. Figure 49 below shows the compensation paid each year since 2009 as a result of feed-in management measures.

The compensation is generally settled through bills from the installation operators. A number of network operators also offer credits (without bills from the installation operators). The compensation paid in 2017 therefore does not reflect the actual amounts payable for the curtailments in 2017. The compensation paid in 2017 also includes amounts payable for curtailments in previous years.

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[46] Feed-in management measures carry considerably fewer residual risks for the renewable and CHP installation operators through, for instance, the cost-sharing arrangement under section 15 of the Renewable Energy Sources Act (EEG). Plants whose feed-in has been curtailed receive equivalent amounts of electricity from the system operator through redispatching; this eliminates marketing risks created by network restrictions.

[47] The figure for 2016 has been corrected downwards by about €129m due to information provided by a TSO.

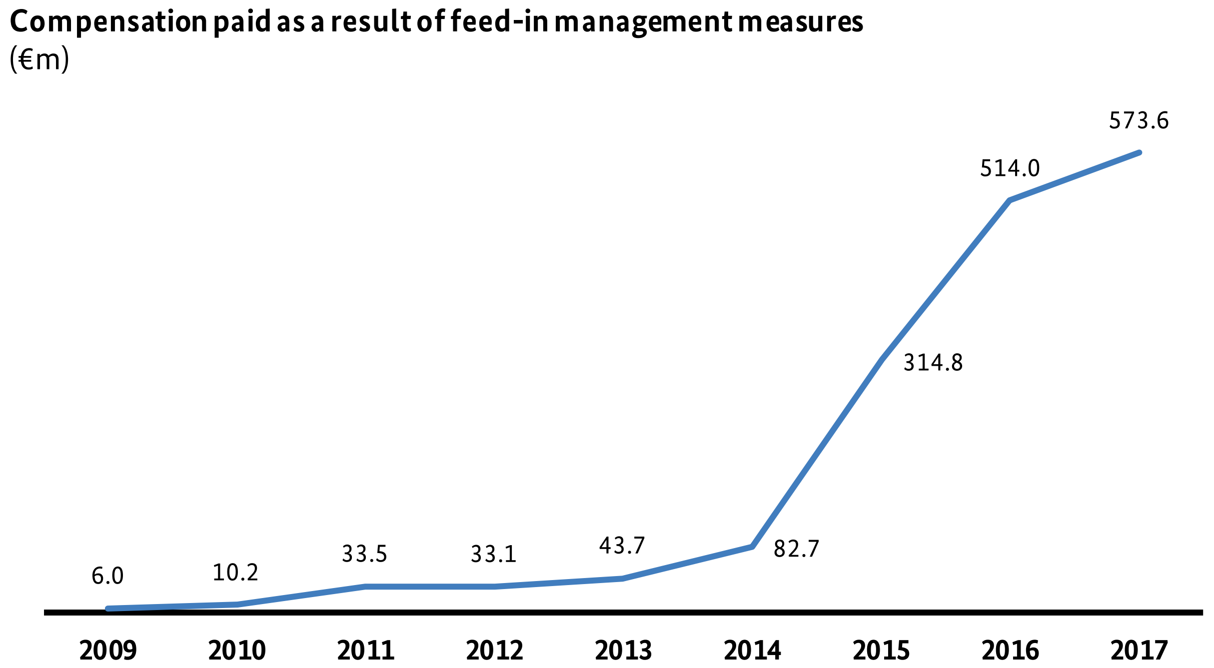

Figure 49: Compensation paid as a result of feed-in management measures

The claims for compensation from installation operators in 2017, based on the network operators' quarterly estimates, were well up at around €610m, €237m higher than in 2016.[48]

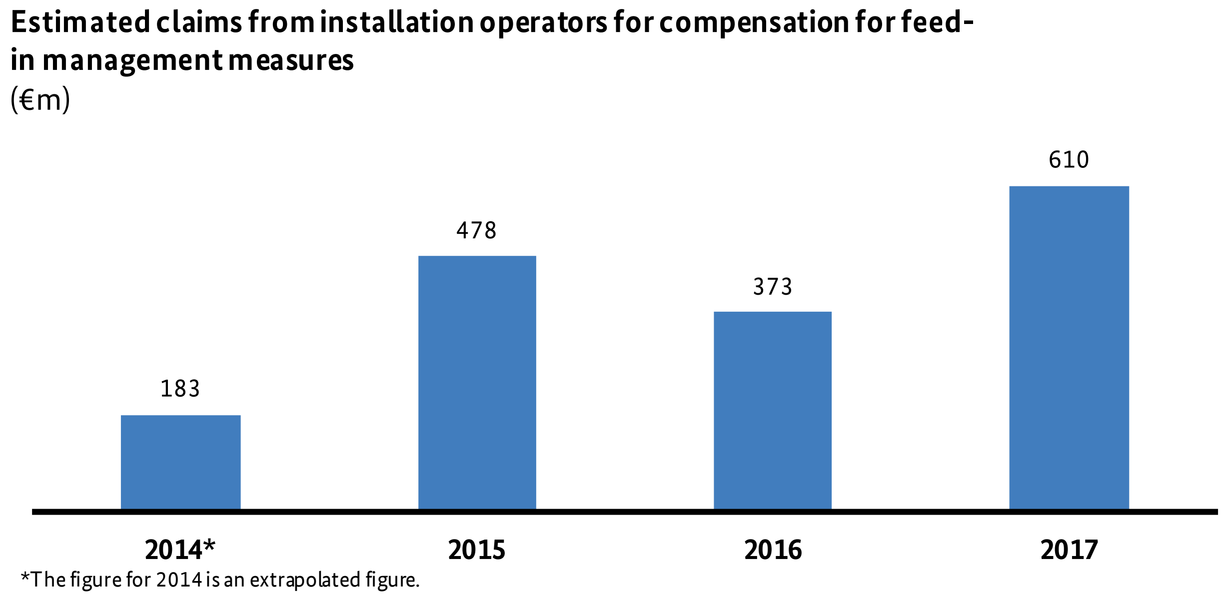

Figure 50: Estimated claims from installation operators for compensation for feed-in management measures

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[48] See the Bundesnetzagentur's quarterly reports available at: https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Netz_Systemsicherheit/Netz_Systemsicherheit_node.html.

In 2017, the network operators paid a total of around €574m in compensation to the installation operators. Approximately €313m was compensation for curtailments actually occurring in 2017, while the remaining amount of around €260m was compensation for curtailments in previous years. This means that some 51% of the claims from installation operators for compensation for curtailments in 2017, as estimated by the network operators, have already been settled. At the time of the survey, around 49% or €297m of the estimated compensation claims had not yet been settled; this will have a knock-on effect on the amount of compensation paid in subsequent years. Table 43 shows the detailed figures for the network operators' estimates of compensation claims and the actual compensation paid:

Compensation payments by measures taken and compensation paid, and causes of feed-in management measures, according to network operators' reports: 2017

	Estimated claims for compensation from installation operators (€)		Total compensation paid (€)		Compensation for measures in previous years (€)
Measures taken and compensation paid by TSOs (cause in transmission network)	**164**	**27%**	**35**	**6%**	**6**
Measures taken and compensation paid by DSOs	**446**	**73%**	**539**	**94%**	**254**
DSOs' own measures (cause in distribution network)	50	8%	81	14%	26
DSOs' support measures (cause in transmission network)	396	65%	458	80%	228
Total feed-in management measures	**610**	**100%**	**574**	**100%**	**260**

Table 43: Compensation payments by measures taken and compensation paid, and causes of feed-in management measures, according to network operators' reports: 2017

5.3 Adjustment measures

The TSOs are legally entitled and obliged to adjust all electricity feed-in, transit and offtake or to demand such adjustment (adjustment measures) where a threat or disruption to the security or reliability of the electricity supply system cannot be removed or cannot be removed in a timely manner by network-related or market-related measures.

Where DSOs are responsible for the security and reliability of the electricity supply in their networks, they too are legally entitled and obliged to take adjustment measures. Furthermore, DSOs are required to take their own measures to support measures implemented by the TSOs, as instructed by the TSOs (support measures).

Curtailing feed-in from renewable energy, mine gas and CHP installations may also be necessary in situations other than those covered by the feed-in management provisions if the threat to the system is caused not by network restrictions but by another security problem. The measures to be taken in such cases do not affect grid expansion measures that may also be required in the particular network area concerned.

In 2017, a total of three distribution system operators took adjustment measures, resulting in feed-in adjustments of about 34.5 GWh. Natural gas was by far the most frequently adjusted source of energy, accounting for around 68%. Saxony-Anhalt accounted for the majority of the adjustment measures with about 82%, followed by Brandenburg with 17% and Thuringia with 1%.

Feed-in and offtake adjustments by energy source: 2017

Energy source	Adjustments under section 13(2) (GWh)	Share (%)
Natural gas	23.55	68
Waste (non-biodegradable)	10.95	32
Total	**34,50**	**100**

Table 44: Feed-in and offtake adjustments by energy source: 2017

6. Network charges

6.1 Setting network charges

Network charges are levied by the TSOs and DSOs and make up part of the retail price for electricity (see also "I.G.4 Price level" in section Retail). Network charges are based on the costs incurred by the network operators for the operation, maintenance and expansion of their networks. These regulated costs are the basis for the prices that network operators are allowed to charge network users for transporting and distributing energy. Under the legislative provisions in Germany, network charges are only payable when electricity is drawn from a network. Generators feeding electricity into a network who are also "network users" do not have to pay network charges. There are three steps in the process of setting network charges:

Determining the network costs

The regulatory regime is divided into five-year regulatory periods. The base level of costs is set before the beginning of each regulatory period by means of a cost examination in accordance with section 6 of the Incentive Regulation Ordinance (ARegV). The competent regulatory authorities examine each operator's network operation costs as set out in the certified annual accounts in accordance with the principles laid down in the Electricity Network Charges Ordinance (StromNEV). The most recent cost examination took place beginning in the second half of 2017 on the basis of the costs of the year 2016. This step results in determining the networks costs recognised as necessary for network operation, which in turn form the basis for setting the revenue cap in 2018.

Setting the revenue caps

In the second step, the recognised network costs are used to set a revenue cap in accordance with the provisions of the Incentive Regulation Ordinance. The DSOs' controllable costs are subject to an efficiency benchmarking exercise to compare the costs (input) with the scope of the services supplied (output). In preparation for the third regulatory period, a relative generic network analysis to measure efficiency is applied for TSOs.

The recognised network costs form the basis of the revenue cap, taking into consideration the results of the efficiency analysis. Any inefficiencies need to be remedied in the course of the regulatory period. The revenue cap stipulates the revenue each operator is allowed to generate over the years of a regulatory period.

Within the regulatory period, the revenue cap can be adjusted and reviewed once a year only under certain legal conditions. The factors leading to such adjustments include:

- changes to what are known as the permanently non-controllable costs; these costs include, for example, costs for the DSOs from avoided network charges (see section I.C.6.4) or for the use of upstream network levels; for all network operators costs of retrofitting renewable energy installations in accordance with the System Stability Ordinance (SysStabV) (see section I.C.6.5) or feed-in management costs (see section I.C.5.2). For TSOs, there is an array of costs for means to ensure security of supply and grid expansion, in particular costs for investment measures pursuant to section 23 of the Incentive Regulation Ordinance (see section I.C.3.3), costs for redispatching with operational and grid reserve power plants (see section I.C.5.1) and costs of procuring balancing reserves (see chapter I.D "System services"). Offshore transmission link costs (see section I.C.1.4) were also included in the revenue cap until 2018 and were then transferred into a surcharge as of 1 January 2019;

- the retail price index, which reflects general inflation;

- the expansion factor, which covers extraordinary costs of grid expansion for DSOs within a regulatory period (but which will no longer be used after the end of 2018); as of 1 January 2019 the capex mark-up;

- for DSOs under the standard procedure, the quality element;

- the incentive regulation account balance: differences between forecast and actual figures are entered into the account and then added to or deducted from the revenue cap; if projected costs are included in the revenue cap, they are compared with actual developments. This applies particularly in the case of differences between forecast and actual consumption quantities leading to higher or lower revenues, but planned volumes are included in the revenue cap for other items as well, eg various items in the permanently non-controllable costs such as costs for approved investment measures and for the use of upstream network levels. The difference between the capex mark-up approved on the basis of projected values and the capex mark-up arising from the costs actually incurred will also be entered into the regulatory account. The balance of the regulatory account is subject to interest. The numerous special circumstances make settling the regulatory account a complex process.

Deriving network charges

The network charges are derived by the network operators on the basis of the principles laid down in the Electricity Network Charges Ordinance. The allowed revenues (revenue cap) are allocated to the network or substation levels as cost-reflectively as possible.

The specific annual costs for each network or substation level in euros per kilowatt per year ("postage stamp" tariff) are then calculated by dividing the total costs for the voltage level by the simultaneous maximum load at that voltage level in the year, beginning with the highest voltage level operated. The "coincidence function" (section 16 of the Electricity Network Charges Ordinance) is applied to derive four charges from the specific annual costs: a capacity charge and a unit charge for less than 2,500 hours and for more than 2,500 hours of network usage. The basic idea is to make a plausible assumption about a network user's contribution to the network costs: a network user whose individual annual maximum load very probably contributes to the annual maximum load of the network pays a higher capacity charge. The probability is derived from a network user's hours of usage and is reflected in the charging scheme by the different charges for more than 2,500 hours and less than 2,500 hours of network usage. A unit charge and, in some cases, a standing charge is to be set for non-interval-metered network users (those with an annual offtake of less than 100,000 kWh – mainly household customers and smaller commercial customers at low-voltage level). In this case, there is no general rule, but the two charges must be "in reasonable proportion" to each other, which allows for a certain margin.

The charges calculated on the basis of the planned sales volumes cover the network or substation level costs. Offtake at the next, downstream network or substation level is treated as consumption, with the costs being passed on.

This principle is applied at all further levels; however, as the low-voltage network is the lowest level, no costs are passed on and all the network costs need to be covered at that level.

The network operators publish their provisional network charges on their websites on 15 October each year for the following calendar year and then publish their final charges on 1 January of the year in which the charges take effect. They are not allowed to make any changes to the published network charges in the course of the year. Operators must demonstrate to the regulatory authority that their published network charges as validated in accordance with section 20(1) of the Electricity Network Charges Ordinance cover the network costs (revenue cap) as determined in the first step of the process and do not exceed the costs.

In light of the significant changes in generation and usage structures as a result of the energy transition, with increasingly volatile feed-in and a rise in self-supply, and given that sector coupling aims to provide additional incentives, there has been increasing discussion about the need to adjust the system of network charges. However, any reform that were to be implemented must ensure that the grid is not overwhelmed by excessive, simultaneous loads. This discussion may – but will not necessarily – lead to changes in the structure of network charges.

Other surcharges that form components of the final consumer price are detailed in section I.G.4.3.

6.2 Average network charges in Germany

The analysis of average network charges in Germany is based on data on the individual price components submitted in the monitoring survey by electricity suppliers. The suppliers provide data on their average net network charges[49] for customers in specific consumption groups and different contract categories. The consumption groups are as follows:

- household customers: as from 2016, the network charges relate to an annual consumption of between 2,500 kWh and 5,000 kWh (Eurostat Band DC) and low-voltage supply; prior to this, the charges related to households with an annual consumption of 3,500 kWh;

- "commercial customers": annual consumption 50 MWh, annual peak load 50 kW, annual usage period 1,000 hours, low-voltage supply (0.4 kV);

- "industrial customers": annual consumption 24 GWh, annual peak load 4,000 kW, annual usage period 6,000 hours, medium-voltage supply (10 kV/20 kV), interval metering; no account is taken here of the reductions pursuant to section 19 of the Electricity Network Charges Ordinance.

The electricity suppliers' data is used to calculate the national average network charge for each consumption group. The network charge for household customers is volume-weighted, while for commercial and industrial customers it is determined arithmetically. It should be noted that the arithmetic mean reflects neither the wide spread of the network charges nor the heterogeneity of the network operators for these consumption groups (on spread see chapter 6.2 in this part).

Figure 51 shows the change in volume-weighted net network charge (including the charge for meter operation) from 2006 to 2018 in ct/kWh for household customers.

Figure 52 shows the arithmetically determined net network charge (including for meter operation) for commercial and industrial customers from 2006 to 2018.

In the period up to 2011, the first cost examinations since the introduction of regulation led to falling network charges. Having been broadly stable in the period between 2013 and 2015, the network charges for household customers showed an increase in 2016 and 2017 and are now falling slightly. In the period from 2017 to 2018, the charges dropped by 0.14 ct/kWh or almost 2% to 7.17 ct/kWh. For non-household customers the arithmetic mean charges are up on a year earlier. The charges for commercial customers rose by 0.08 ct/kWh or 1.3% to 6.27 ct/kWh, while the arithmetic mean charges for industrial customers with an annual energy consumption of 24 GWh increased by 0.1 ct/kWh or 4.4% to 2.36 ct/kWh.

Since 2012, various factors have been influencing the rise in network charges up to 2017. There was an increase in embedded generation leading to higher costs for avoided network charges, while at the same time there was an increased need for redispatching and feed-in management measures. Finally, the growth in renewable energy installations made further grid expansion necessary. All of these factors pushed up network costs. A turning point occurred in 2018. The volume-weighted average network charge fell for the first time in

[49] Net network charges do not include VAT.

years, although it is still at a high level. The main reason for the drop was the effect of the Network Charges Modernisation Act (see below chapter I.C.6.4) bringing down costs for avoided network charges.

The net network charge is likely to reduce from 2019 on, as the new offshore surcharge will include the costs for the offshore connections for the first time. The costs involved for network users will in future be made up of the sum of network charges and the offshore surcharge. For nationally regulated DSOs, the calculations for 2019 show that this total will generally rise for three consumption groups.

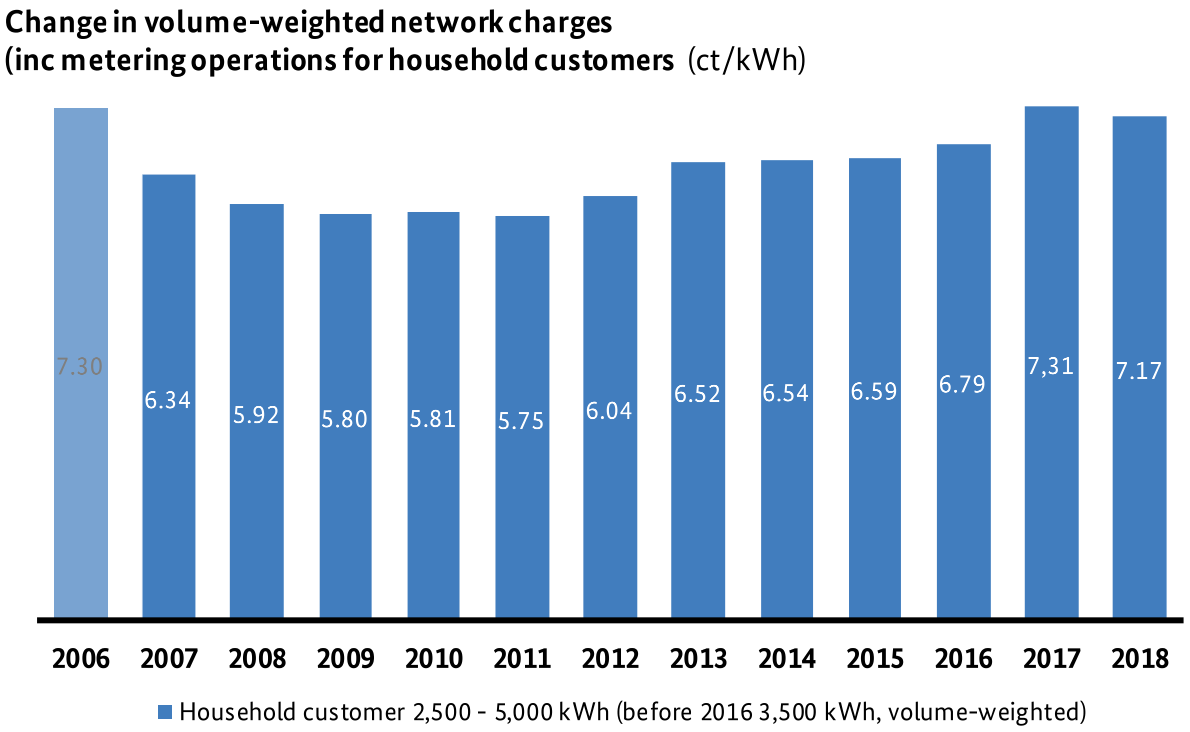


Figure 51: Network charges 2006[50] to 2018[51]

[50] The year 2006 was marked by special effects arising from the introduction of regulation, which initially resulted in excessive network charges being reported by companies. It was only once regulation began to take effect and network charges were reduced that costs that had been erroneously allocated to network charges could be assigned to the price components that they belonged to under the principle of causation. The increases in price components other than network charges that took effect after regulation began, particularly in "supply", were thus only partly as a result of reductions in network charges. The year 2006 is therefore only of very limited use as a reference year for a comparison over time.

[51] The figures for industrial and commercial customers before 2014 were volume-weighted.

Change in arithmetic net network charges (including meter operation) for "commercial customers" (50 MWh) and "industrial customers" (24 GWh)
(ct/kWh)

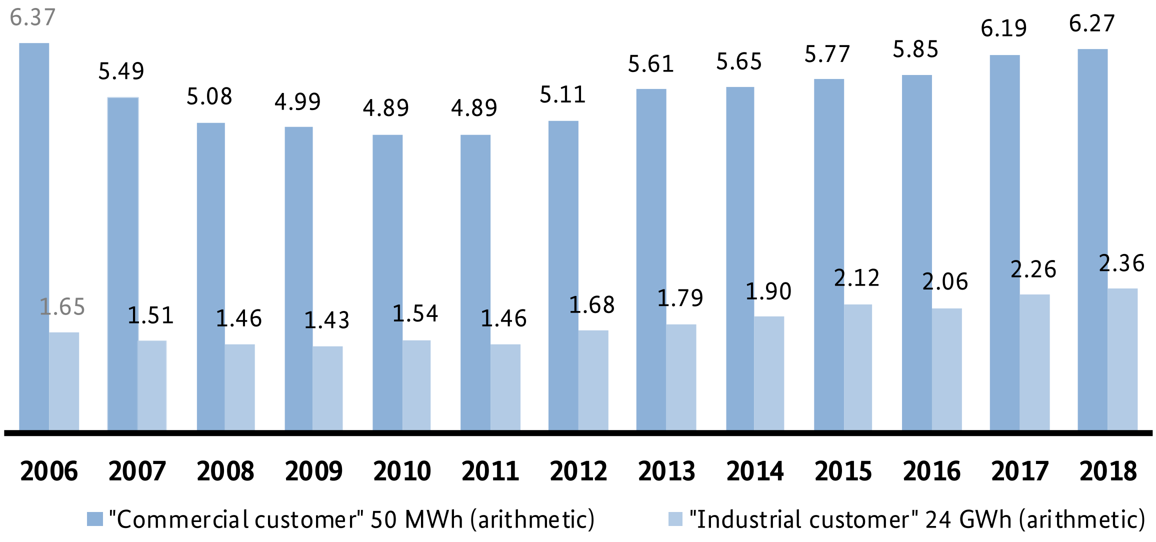
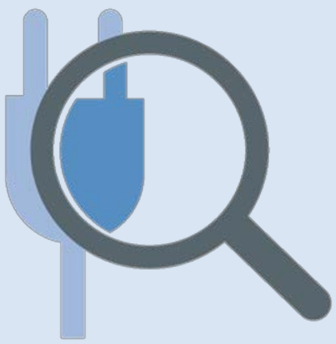


Figure 52: Change in arithmetic net network charges (including meter operation) for "commercial customers" (50 MWh) and "industrial customers" (24 GWh)



Network charges are part of the electricity price and have to be paid by both household customers and industrial and commercial customers. The costs for the electricity grid (eg expansion and system security measures) are passed on to final consumers using network charges. Network charges make up nearly 23% of the price for household customers with annual consumption of between 2,500 and 5,000 kWh a year (see also chapter I.G "Retail" starting on page 237). A slight decrease is becoming evident, following increases in 2016 and 2017. The average network charge fell by almost 2% to 7.17 ct/kWh from 1 April 2017 to 1 April 2018.

6.3 Regional differences in network charges

There are large regional differences in the network charges. In the monitoring survey, network charges across Germany have been compared using the information in the DSOs' published price lists relating to the three consumption groups (household, commercial and industrial customers – see I.C.6.2 "Average network charges in Germany"). Section 27(1) of the Electricity Network Charges Ordinance requires all network operators to publish the network charges applicable in their networks on their websites. The information relating to each DSO's unit and capacity charges was used to calculate the network charges (in cents per kilowatt hour) applicable for 2018. The information does not include either the charges for metering and meter operations or

VAT; the billing charges are included in the network charge. Seven categories from <5 ct/kWh to >10 ct/kWh have been used to illustrate the differences in network charges more clearly. The network charges were calculated regardless of whether or not the DSOs actually have customers in a specific consumption group. This is relevant in particular in the case of industrial customers. An overview of the network charges in each federal state was also created: the individual network charges were weighted with the relevant number of meter points to obtain the average network charge in each federal state.

The network charges for household customers range from 2.5 ct/kWh to 25.4 ct/kWh, although only very few household customers within the meaning of section 3 para 22 of the Energy Industry Act with a very low consumption pay the maximum charges. This represents a difference by a factor of up to 10. It is notable that network charges are relatively high in the states of Brandenburg, Schleswig-Holstein and Saxony-Anhalt. There are also differences between urban and rural areas. The map below shows that the major cities of Berlin, Hamburg, Munich, Frankfurt am Main, Dortmund, Bremen, Stuttgart and Düsseldorf fall into the three lowest categories of network charges of under 5 ct/kWh to 7 ct/kWh. In those cities, the network charges payable are generally lower than in the outlying areas. The federal state with the lowest average network charges is Bremen.

Net network charges for household customers in Germany: 2018
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Brandenburg	8.62	4.84	9.28	27
Schleswig-Holstein	8.49	5.40	11.62	42
Saxony-Anhalt	7.48	5.59	8.63	26
Mecklenburg-Western Pomerania	7.09	4.57	10.54	18
Lower Saxony	6.98	4.26	25.38**	69
Saxony	6.94	4.33	9.47	33
Baden-Württemberg***	6.75	2.52	10.33	120
Thuringia	6.75	5.01	9.75	31
Bavaria	6.74	4.23	10.88	219
Saarland	6.67	5.36	13.96	20
Hamburg	6.63	6.63	6.63	1
Hesse	6.59	4.13	8.77	47
Rhineland-Palatinate	6.55	4.53	9.20	51
North Rhine-Westphalia	6.32	4.37	9.24	97
Berlin	5.64	5.64	5.64	2
Bremen	4.56	4.28	6.60	3

*The weighting was based on the number of the operators' meter points in each network area.
**Only affects a very few household customers within the meaning of section 3 para 22 of the Energy Industry Act with very low consumption.
***Includes the coverage area of the German enclave of Büsingen within Switzerland.

Table 45: Net network charges for household customers in Germany: 2018

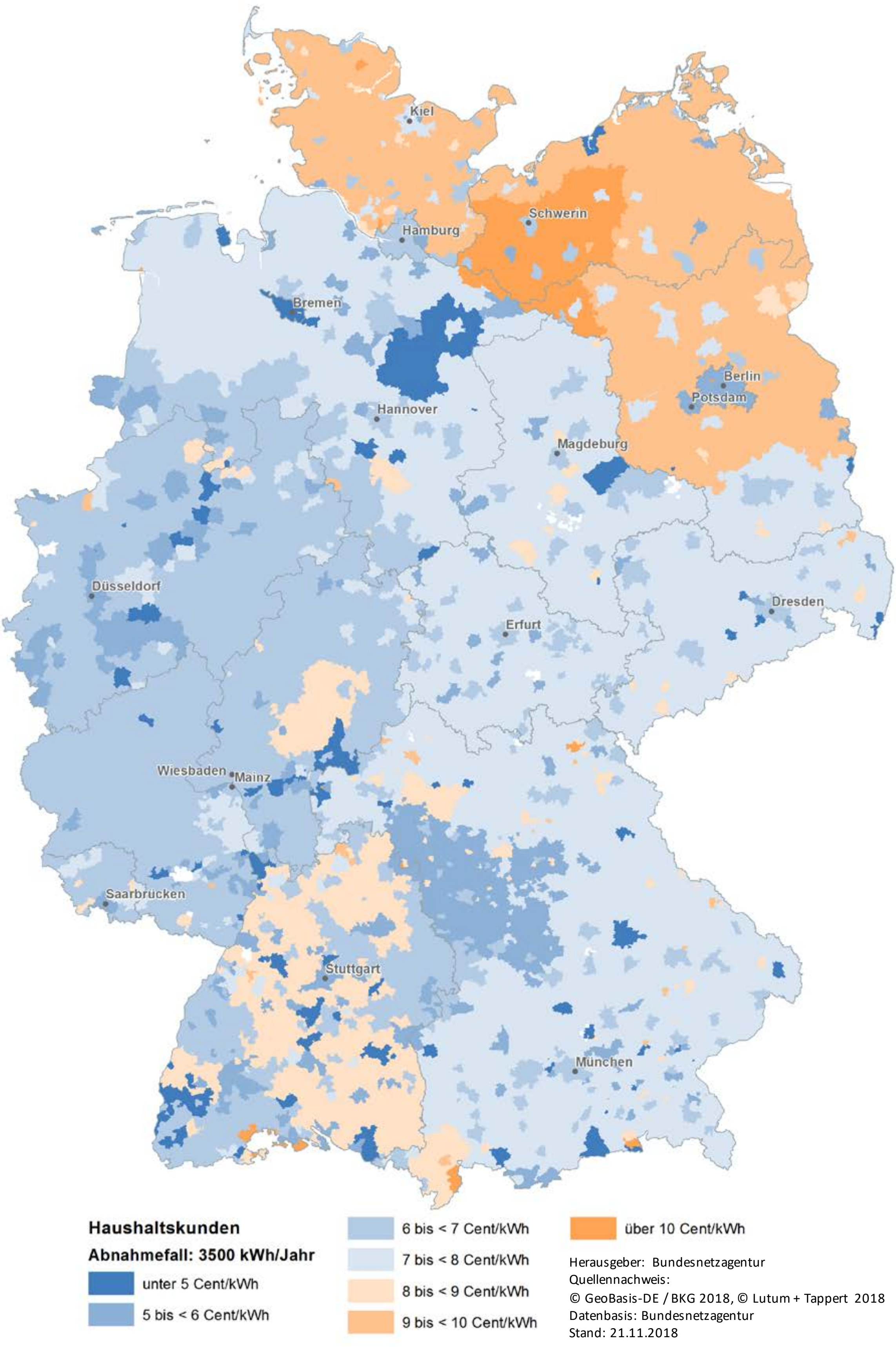


Figure 53: Spread of network charges for household customers

The spread of network charges for the 50 MWh annual consumption group (commercial customers) is similar to that for household customers, with charges ranging from 2.2 ct/kWh to 24.6 ct/kWh. Overall, however, charges are lower than for household customers. On average, Brandenburg and Schleswig-Holstein have the highest charges and Bremen the lowest compared to the other federal states.

Net network charges for commercial customers in Germany: 2018
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	7.27	4.20	10.03	42
Brandenburg	6.46	3.91	7.84	27
Mecklenburg-Western Pomerania	6.24	4.04	10.43	19
Saxony-Anhalt	6.12	4.86	8.35	27
Baden-Württemberg**	5.92	2.17	9.61	120
Saxony	5.85	3.35	8.48	33
Thuringia	5.75	3.76	8.14	31
Rhineland-Palatinate	5.64	3.30	8.63	51
Saarland	5.51	4.62	13.32	20
Lower Saxony	5.50	3.38	10.27	69
Bavaria	5.49	3.50	9.57	219
Hamburg	5.36	5.36	5.36	1
Hesse	5.15	3.47	8.13	47
North Rhine-Westphalia	4.95	3.18	8.18	96
Berlin	4.76	4.76	5.17	2
Bremen	3.23	2.95	8.14	4

*The weighting was based on the number of the operators' meter points in each network area.
**Includes the coverage area of the German enclave of Büsingen within Switzerland.

Table 46: Net network charges for commercial customers (annual consumption 50 MWh) in Germany: 2018

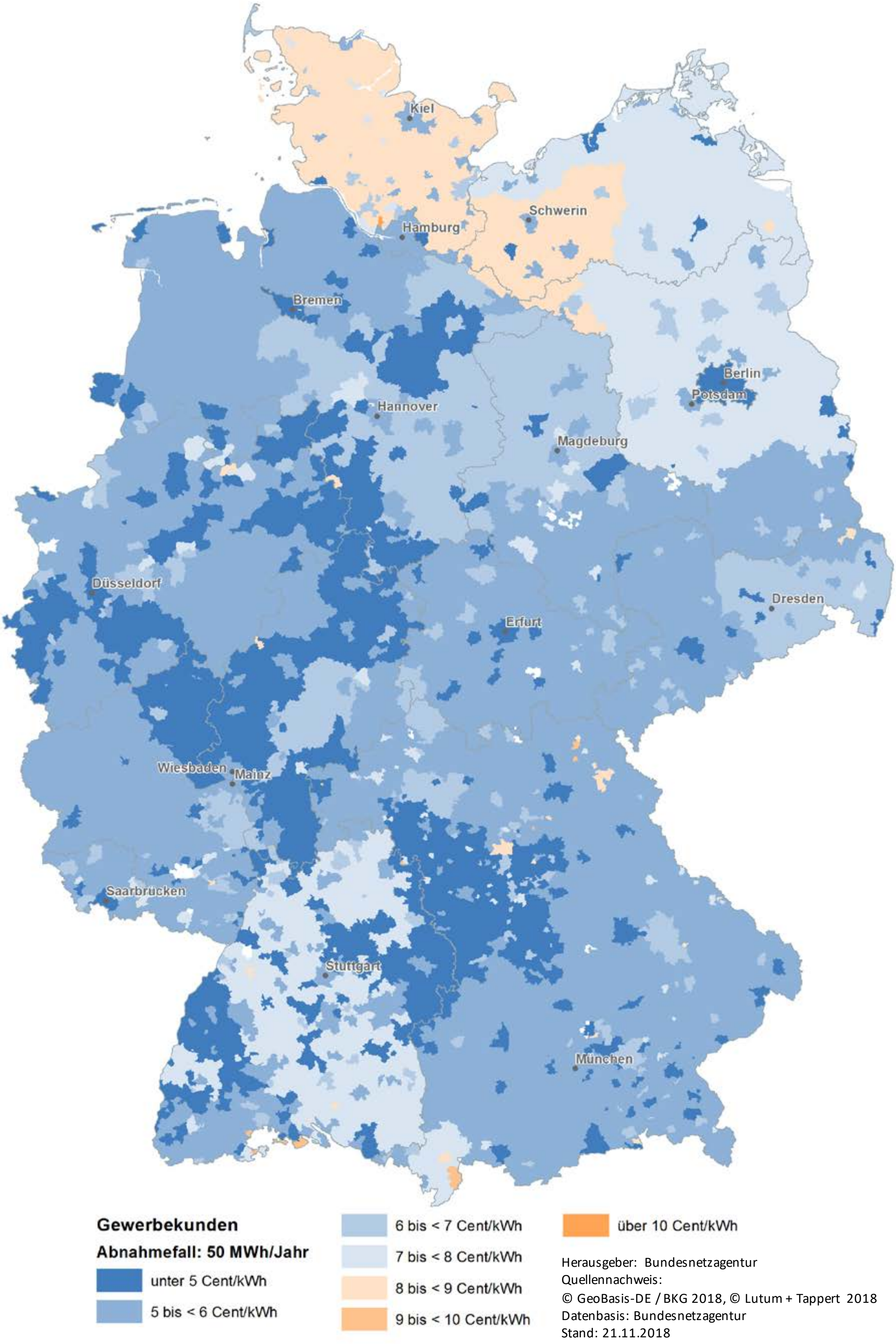


Figure 54: Spread of network charges for commercial customers

The spread of network charges for the 24 GWh annual consumption group (industrial customers) is different. It should be noted that, in the case of industrial customers, the picture is distorted by the weighting of meter points since the actual consumption of the reported meter points of industrial customers ranges widely around the example given of 24 GWh a year. Although charges in Brandenburg, Schleswig-Holstein and Mecklenburg-Western Pomerania, in particular, are generally higher than in other areas, there are also higher charge in some other, smaller network areas. The lowest average charges are in Rhineland-Palatinate. The network charges for industrial customers range from around 0.6 ct/kWh to 5.8 ct/kWh. These charges do not take account of possible reductions through individual network charges pursuant to section 19(2) of the Electricity Network Charges Ordinance. In some cases, the charges for industrial customers entitled to individual network charges may therefore be lower. The map makes clear that, as for the other customer categories, the network charges payable in major cities are generally lower than in the outlying areas.

Net network charges for industrial customers in Germany: 2018
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Brandenburg	3.08	2.09	3.68	28
Mecklenburg-Western Pomerania	2.82	1.40	4.19	19
Saxony-Anhalt	2.75	1.88	3.58	27
Saxony	2.65	0.64	3.41	33
Schleswig-Holstein	2.55	1.43	4.32	40
Lower Saxony	2.52	0.69	5.52	69
Hesse	2.50	1.31	3.34	49
Thuringia	2.47	1.63	3.10	29
Berlin	2.44	2.44	2.52	2
Saarland	2.42	1.49	4.98	20
Bavaria	2.28	1.17	5.76	212
North Rhine-Westphalia	2.27	1.24	3.68	94
Hamburg	2.25	2.25	2.25	1
Baden-Württemberg	2.20	1.08	3.81	120
Bremen	2.10	2.04	2.73	4
Rhineland-Palatinate	2.09	1.38	5.67	51

*The weighting was based on the number of the operators' meter points in each network area.

Table 47: Net network charges for industrial customers (annual consumption 24 GWh) in Germany: 2018

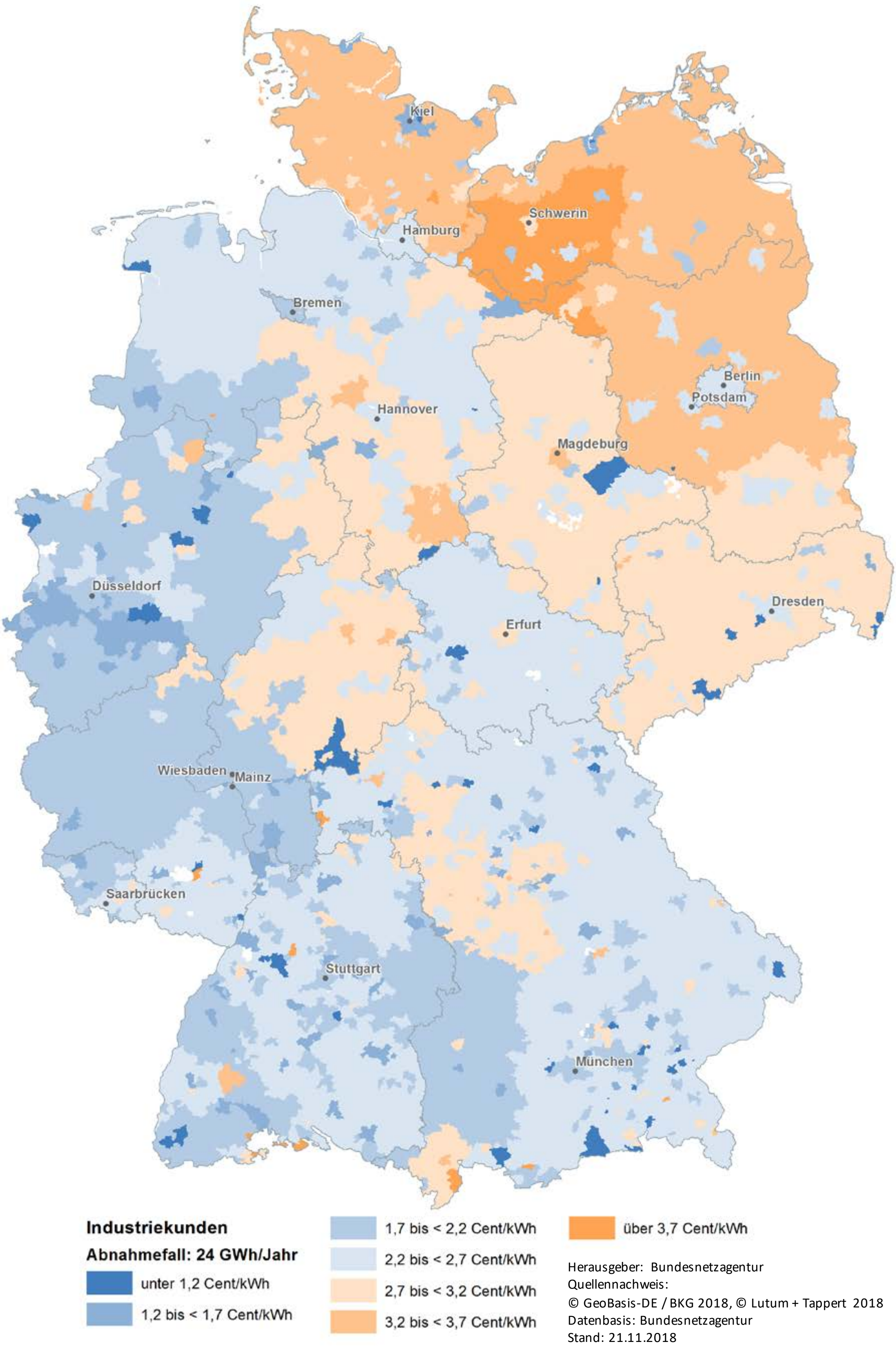
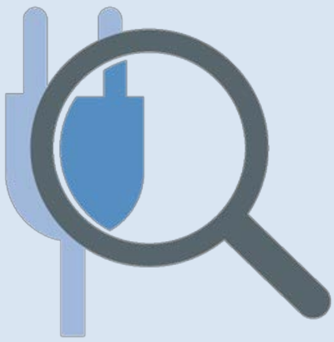


Figure 55: Spread of network charges for industrial customers

The regional differences in network charges are due to a complex range of factors.[52] One of the main factors is lower network utilisation. Many of the networks modernised in the east following Germany's reunification are now seen as oversized. Although some of these networks are under-utilised, the network costs are still based on the networks' size. Another key factor is population density. In less densely populated areas, the network costs have to be shared out between a small number of network users, while in more densely populated areas the costs are shared among a high number. In recent years, the costs of integrating renewables, including the costs of feed-in management, have become a further factor contributing to the differences in network charges. Renewable energy installations are being installed primarily in rural areas, resulting in costs in these areas. The age of the networks also plays a role. Older networks with a lower residual value are cheaper than new networks for the network users. The quality of the networks is also relevant, since it has a direct influence on the network operators' revenue caps. In addition to these factors relating to the DSOs' own networks, the upstream transmission networks also have an influence on the network charges. Increases in the TSOs' charges – for instance as a result of an increase in network and system security measures such as redispatching and the use of grid reserve plant capacity – lead to higher costs that have varied between control areas. The legislature has responded to this with the Network Charges Modernisation Act (NEMOG): the charges at transmission network level are to be gradually harmonised as from 2019, and uniform national charges are to apply from 1 January 2023. This will ensure that in particular the network and system security costs, which are all essentially incurred at transmission network level, are also shared between all network users.



The level of network charges varies according to network operator and region. There are many reasons for this, including:
• network utilisation: the networks in, for example, the eastern German states are oversized and therefore not always sufficiently utilised.
• population density: in less densely populated areas, the network costs are shared out between a small number of network users.
• costs of integrating renewables, including the costs of feed-in management.
• network age: older networks with a low residual value are cheaper for the network operators.
• network quality: this has an influence on the revenue cap.
• network operators' charging policy: use of leeway in the allocation of costs to network levels and user groups.

6.4 Avoided network charges

Under section 18(1) of the Electricity Network Charges Ordinance, operators of embedded generation facilities are entitled to payment from the operator of the distribution network into which they feed electricity. The sum paid must correspond to the network charge avoided by feeding in less electricity at an upstream

[52] See also page 21 of the Bundesnetzagentur's report on the system of electricity network charges in Germany.

network or substation level. The concept of avoided upstream network charges must not be confused with avoided costs. As a rule, network costs are not avoided by plants at lower voltage levels.

The concept of avoided network charges originated in the Associations' Agreement II/II+: plants connected downstream are generally smaller and thus generate electricity at higher costs than large-scale plants at extra-high-voltage level. The smaller and larger plants compete with each other on the power exchange through the electricity prices. The aim of paying the avoided network charges to the downstream facilities was to help the downstream facilities become competitive.

The avoided network charges within the meaning of section 18(1) of the Electricity Network Charges Ordinance have increased significantly in recent years, as a result in particular of the changes in the generation structure and the TSOs' increasing network costs. At the same time, it has become clear that the installations do not contribute to the avoidance of grid expansion.

The following table shows a breakdown of the avoided network charges for each network and substation level. The figures comprise the sum of the avoided network charges for the network operators under the Bundesnetzagentur's responsibility through its own or an official delegation of powers.

Avoided network charges by network and substation level
(€m)

Level	2013 (actual figures)	2014 (actual figures)	2015 (actual figures)	2016 (actual figures)	2017 (actual figures)	2018 (forecast figures)
EHV/HV	67	64	2	4	16	21
HV	479	594	640	860	1,321	612
HV/MV	88	84	92	110	140	74
MV	466	550	594	661	798	477
MV/LV	37	37	36	50	45	37
LV	142	160	420	168	206	123
Total	**1,279**	**1,489**	**1,784**	**1,852**	**2,526**	**1,344**

Table 48: Avoided network charges (section 18(1) of the Electricity Network Charges Ordinance) by network and substation level

The table shows a continual increase in the total amount of avoided network charges up to 2017. The rise in costs is due to various factors, including the following:

The growth in embedded generation means the existing capacity of the upstream network is used to a lesser extent. The infrastructure costs, which still remain, are spread over a smaller volume of sales. This leads to an increase in the network charges at the upstream level. This in turn results in an increase in the avoided network charges since they are calculated on the basis of the network charges at the upstream network or substation level. This mechanism creates incentives to connect plants at lower voltage levels than in the past and thus reinforces itself. This was the subject of an abuse case brought by the Bundesnetzagentur (BK8-17/3764-01-M), relating to a large-scale power plant that generally feeds its generated power into the extra-high voltage network. A phase-shifting transformer was added to the plant in order to enable it to feed significant amounts of power into the lower high-voltage network. This type of power plant does not meet the requirements of section 18 of the Electricity Network Charges Ordinance, because it is not classed as embedded generation within the meaning of the Energy Industry Act. Ruling Chamber 8 consequently decided that the power plant could not receive avoided network charges. An appeal against this decision is currently pending at the Higher Regional Court of Düsseldorf. In another case involving a power plant that only fed into the extra-high voltage network, the Federal Court of Justice ruled that avoided network charges were not permissible (Bundesgerichtshof, ruling of 27 February 2018, EnVR 1/17).

The investments required for line expansion and the associated operational costs mean that the infrastructure costs for the upstream distribution and transmission networks will continue to rise. On account of the economic life of these investments, line expansion in the upstream network will lead to an increase in the avoided network charges in the long term.

The increasing offshore expansion costs at the transport network level result in higher upstream network costs and thus higher network charges in the distribution networks.

Under the Network Charges Modernisation Act, adopted by the German Bundestag on 30 June 2017, there will be a gradual reduction in the remuneration for intermittent generators. The framework conditions will be adapted step by step in light of the successive developments in the market. The most important changes in the phasing out of avoided network charges are as follows:

- abolition of avoided network charges for new conventional plants as from 1 January 2023 and for new intermittent plants as from 1 January 2018;

- abolition of avoided network charges for existing intermittent plants as from 1 January 2020, with an annual reduction of one third in the original base figure as from 1 January 2018;

- since 2018: the remaining avoided network charges will be calculated with the highest price based on the price list for 2016, with

- offshore connection costs and underground cabling costs being excluded from the transmission network costs in the price list for 2016 as of 2018.

The first signs that the law is having an effect can thus be seen in the planning estimate for 2018. The avoided network charges will be included to a far lesser extent in the revenue cap for 2018. There may be some compensation in the renewable energy surcharge in future, since fewer avoided network charges for intermittent plants mean lower renewable energy surcharges.

Regardless of the implementation of the Network Charges Modernisation Act, the Bundesnetzagentur still sees a need to reform the system of avoided network charges to minimise misguided incentives and windfall profits.

6.5 Costs of retrofitting renewable energy installations in accordance with the System Stability Ordinance

The significant increase in the number of embedded generators in recent years has long meant that it is fundamentally important to the stability of the network for these generators to operate correctly in the event of frequency changes. As a solution to the "50.2 Hz problem", which related to the frequency protection parameters for solar photovoltaic (PV) installations, the System Stability Ordinance was enacted with effect from 26 June 2012, requiring PV inverters to be retrofitted. Section 10 of the Ordinance in conjunction with section 57(2) of the Renewable Energy Sources Act provides for the costs to be divided between the network charges and the renewable energy surcharge.

The 2015 amendment to the Ordinance extended the retrofitting requirements to apply to operators of CHP and other renewable energy installations, namely wind, biomass and hydro power installations. The operators must bear a certain proportion of the costs themselves as specified in section 21 of the Ordinance; the excess costs are financed through the network charges as provided for by section 22 of the Ordinance.

Most of the retrofitting work on PV installations was carried out by the network operators in the period from 2013 to 2015, leading to corresponding increases in the revenue caps based on the predicted costs. Retrofitting was completed in 2017. The costs actually incurred ín the previous years were significantly lower than forecast. The resulting differences are balanced out in the network operators' incentive regulation accounts.

Retrofitting work on CHP, wind, hydro power and biomass installations began in 2015, also leading to increases in the revenue caps from 2017 onwards.

Retrofitting costs in the revenue caps
(€m)

	2013	2014	2015	2016	2017	2018
Forecast	48.5	73.1	4.9	22.6	6.1	1.0
Actual	12.2	35.3	6.8	2.7	1.4	
Figures acc to section 22 SysStabV						
Forecast			0.0	22.4	6.1	1.0
Actual			1.3	2.6	1.4	

Table 49: Retrofitting costs in the revenue caps

It is worth noting that the forecast costs are considerably higher than the actual costs. This does not result in any disadvantages for network users, however, since the differences, together with interest, are reimbursed to network users under the incentive regulation account scheme provided for by section 5 of the Incentive Regulation Ordinance.

The TSOs expect retrofitting work to be completed in 2019. The planned estimate for 2018 is already relatively low.

6.6 Transfer of electricity networks

Section 26(2) to (5) of the Incentive Regulation Ordinance states that when part of an energy supply network is transferred to another operator, the regulatory authority will decide how the revenue cap for the network is to be split between the operators concerned. Partial network transfers occur in particular when a local authority grants rights of way for the purpose of operating energy supply networks to a different operator (section 46 of the Energy Industry Act). The decision is taken by either the Bundesnetzagentur or a federal state regulatory authority, depending on which authority is responsible for the operator transferring part of a network.

The 2016 amendment to the Incentive Regulation Ordinance has led to substantial changes in the procedure for splitting the revenue caps. Section 26 (3) to (6) of the revised Ordinance, in force since September 2016, states that when part of an energy supply network is transferred, the regulatory authority will decide ex officio which part of the revenue cap is to be allocated to the part to be transferred should the network operators concerned not reach agreement themselves.

As at the end of December 2017, the Bundesnetzagentur had received 94 applications for electricity network transfers in 2017. The following graph shows the number of applications made in the last three years.

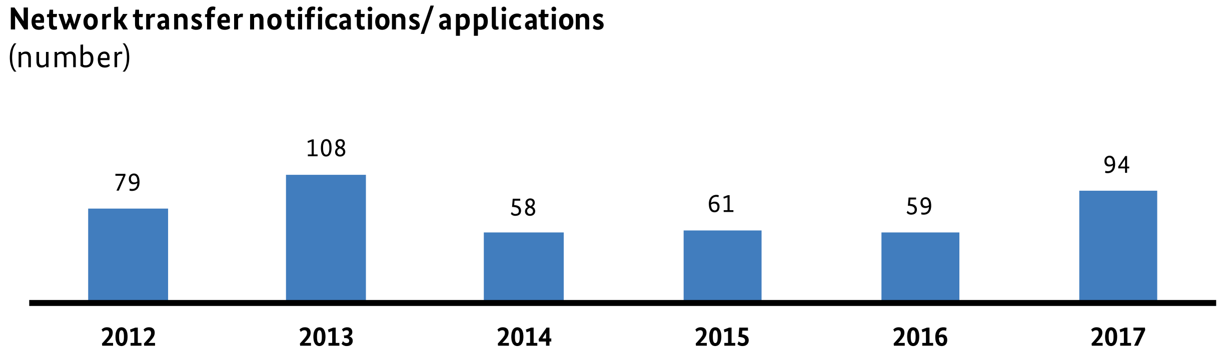


Figure 56: Network transfer notifications/applications

In 2017, Ruling Chamber 8 took decisions on 209 network transfers.

6.7 Individual network charges – Electricity Network Charges Ordinance section 19(2)

Individual network charges are granted as a reduction on the general network charge to network users meeting certain defined criteria. Section 19(2) of the Electricity Network Charges Ordinance therefore essentially grants privileges to final consumers whose specific consumption behaviour makes an individual contribution to lowering and/or avoiding network costs. A distinction is currently made between atypical network users as per section 19(2) first sentence of the Ordinance and electricity-intensive network users as per section 19(2) second sentence. While atypical network users shift their peak load to outside the network's peak load period, electricity-intensive network users have both even and permanent consumption patterns. The criteria for determining these individual network charges were last clarified and defined in the Bundesnetzagentur's decision of 11 December 2013 (BK4-13-739).

The approval procedure to be followed when agreeing individual network charges was replaced by a notification procedure as a result of the provisions effective from 1 January 2014 on appropriate arrangements for setting individual network charges under section 19(2) of the Ordinance (ruling BK4-13-739 of

11 December 2013). Individual network charges are no longer verified in an approval procedure before they take effect, but are notified to the regulatory authority responsible and may then be subject to ex post checks.

Final consumers are able to notify agreements with network operators for individual network charges as provided for by section 19(2) of the Ordinance by 30 September of each year. After the end of each billing period, the final consumers are required to provide the regulatory authority responsible with proof of compliance with the criteria for appropriately setting individual network charges.

The first notifications for individual network charges under the Bundesnetzagentur's responsibility were registered and settled for 2014. The number of final consumers actually granted individual network charges rose continually up to 2016. In 2016, a total of 3,375 notifications for individual network charges for atypical network users were registered with the Bundesnetzagentur (see Table 50).

Notifications for individual network charges for atypical network users in accordance with Electricity Network Charges Ordinance section 19(2) first sentence

	Closing stock 2014	Closing stock 2015	Closing stock 2016	Closing stock 2017*	New items 2018	Closing stock 2018*
Total number of offtake points granted reductions	1,500	2,987	3,375	4,124	802	4,926
Total energy (TWh)	8.6	25.3	25.8	29.5	6.0	35.5
Total reductions (€m)	85.6	292.2	310.8	341.5	26.9	368.4

* Data for 2017 and 2018 are based on forecasts from the notifications submitted and are therefore classed as estimates.

Table 50: Notifications for individual network charges for atypical network users

The total amount of reductions in network charges granted to these final consumers, following the assessment for 2016, which is still provisional, was around €310.8m. Results for the 2017 ex post checks are not yet available.

The total amount of reductions in network charges granted to electricity-intensive network users in 2016 was considerably higher at €388m (see Table 51), although the number of notifications for reductions for these users was significantly lower. In 2016, reductions were granted for a total of 317 offtake points for final consumers such as large businesses or industrial enterprises with particularly energy-intensive production processes. According to the current schedule, the Bundesnetzagentur has not yet completed its ex post checks on the billing documents submitted for 2015 and 2016.

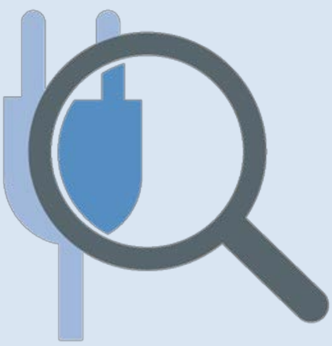
In the 2018 notification period, the Bundesnetzagentur received 802 further notifications for individual network charges. Based on a preliminary estimate, the total amount of reductions in network charges granted for atypical users is set to increase again to some €368m, with a total of 802 offtake points. The total amount of reductions for electricity-intensive network users is also expected to increase significantly to around €535m. The final figures for 2018 will not be available until completion of the checks on notifications and receipt of the actual billing data as required from the final consumers concerned.

Notifications for individual network charges for electricity-intensive network users in accordance with Electricity Network Charges Ordinance section 19(2) second sentence

	Closing stock 2014	Closing stock 2015	Closing stock 2016	Closing stock 2017*	New items 2018	Closing stock 2018*
Total number of offtake points granted reductions	255	275	317	389	60	449
Total energy (TWh)	40.0	42.6	45.2	50.0	8.7	58.7
Total reductions (€m)	272.4	324.5	388.4	446.0	89.1	535.1

* Data for 2017 and 2018 are based on forecasts from the notifications submitted and are therefore classed as estimates.

Table 51: Notifications for individual network charges for electricity-intensive network users



Individual network charges can be agreed with the network operator by individual companies entitled to do so and, subject to the legal criteria, lead to a reduction in network charges for the company in question.

6.8 Load control

Section 14a of the Energy Industry Act gives DSOs at the low-voltage level the ability to use consumers' flexibility. They are able to conclude load control agreements in the interest of the grid in return for a reduction in the network charge. The aim is to prevent the consumption of a large amount of electricity from the low-voltage network at the same time, leading to localised overloading. The provision generally refers to consumer equipment such as night storage heating systems and heat pumps.

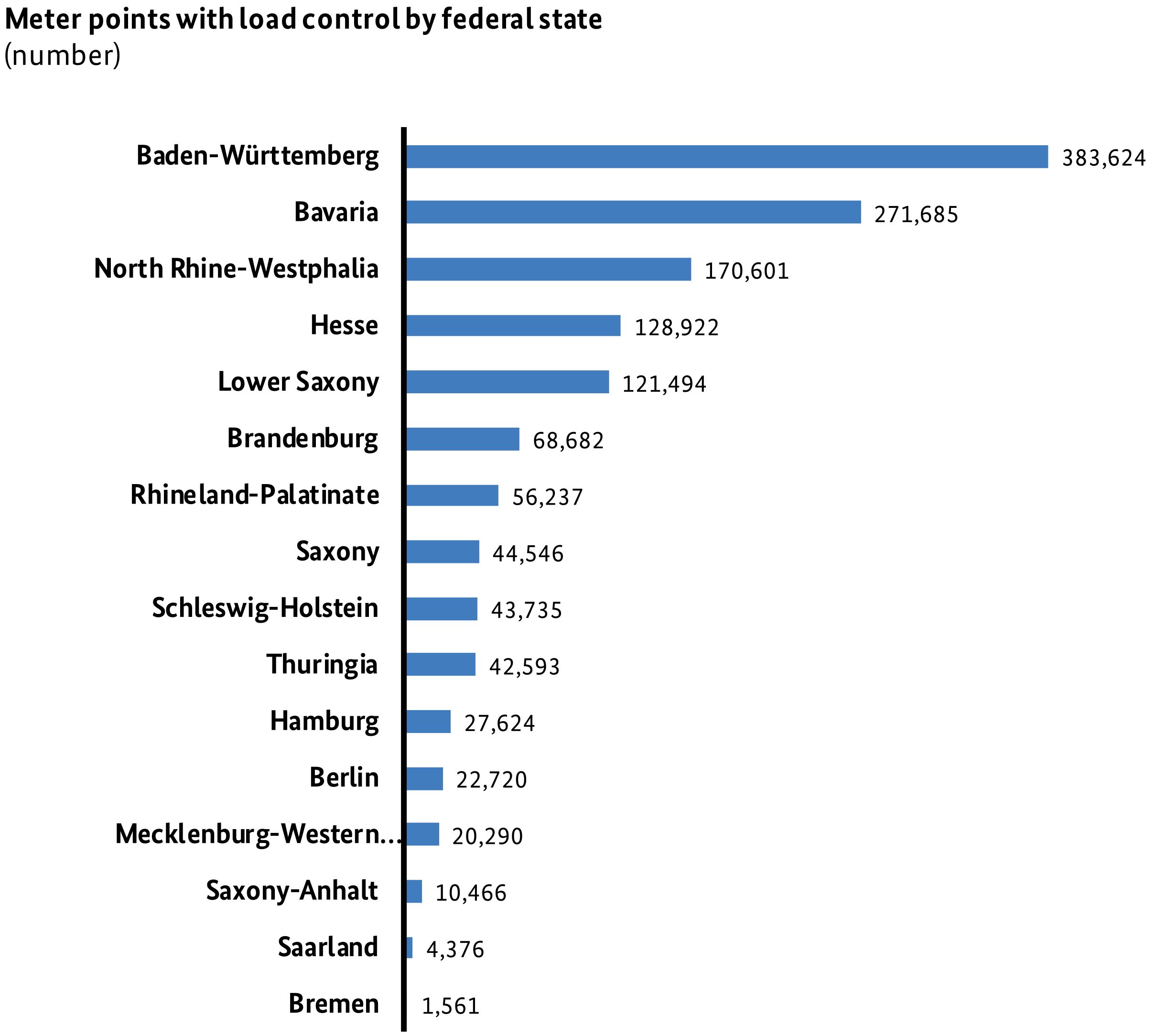


Figure 57: Meter points with load control by federal state

635 out of the 799 network operators surveyed stated that they made use of the provision and levied reduced network charges for a total of 1,419,968 meter points with load control, a slight increase of about 3,000 on last year. The regional distribution is shown in Figure 57. The chart shows a high concentration in Baden-Württemberg and Bavaria, with around half of all the meter points with load control in these two southern federal states. The reason for this is likely to be historical, since the provision was originally intended to create constant demand for the constant production by nuclear power plants.

Meter points by load type
(%)

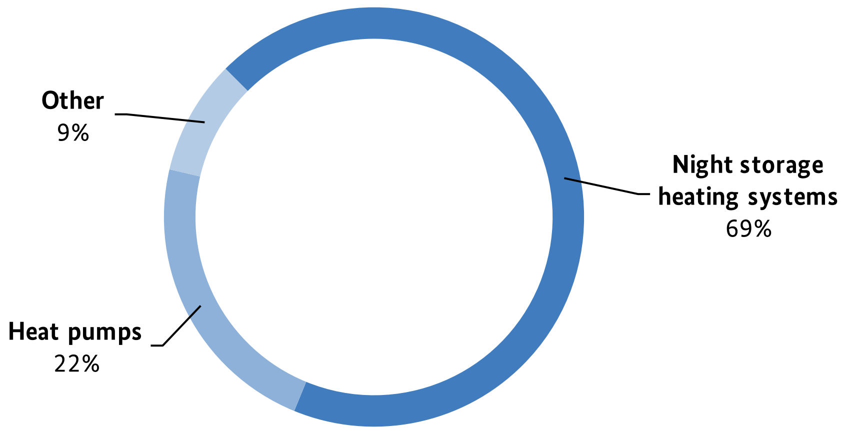


Figure 58: Breakdown of meter points with reduced network charges by load type

It is still the case that almost all the meter points with load control are for heating systems (see Figure 58), and direct electric heating also accounts for most of the "Other" loads, with only a few sprinkler or street lighting systems also counted in this category. The proportions of different types of load have changed slightly in comparison with last year, with the share of night storage heaters down about four percentage points and the share of heat pumps, direct heating and charging points up by about the same amount.

The average reduction in the network charge given by network operators in return for load control is 57%, which corresponds to a discount of 3.53 ct/kWh. As the size of the discount is not specified by regulation, there is a wide range of reductions offered by network operators. The highest discount is 83% of the charge for the use of the network, while the lowest is just 11%, although the difference between the reductions for the different types of load is negligible.

It is also clear that in very few cases does the "control" of consumption behaviour really mean "smart" intervention based on the current status of the network. The use of the different load control technologies for night storage heating systems and for heat pumps is very similar: just under 60% of the network operators use ripple control for night storage heating systems and for heat pumps, while barely 3% use the more modern remote control technology. About 5% do not use any control technology at all, while more than 30% use time switching. Figure 59 shows a more detailed breakdown of the control technologies used.

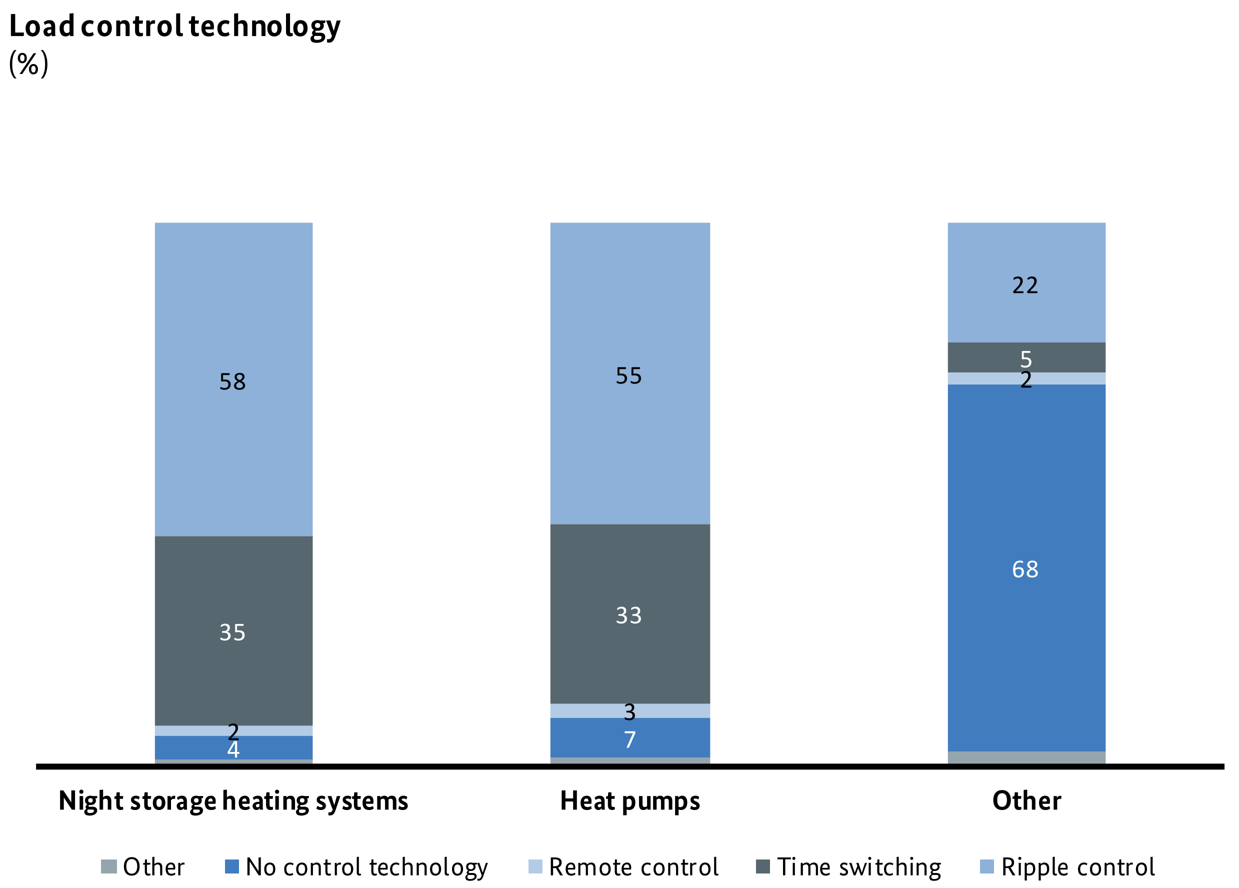
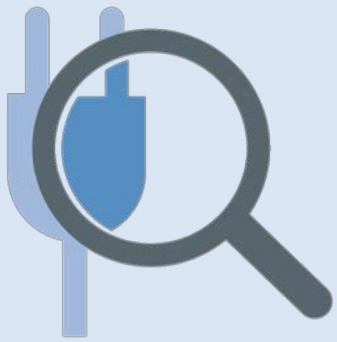


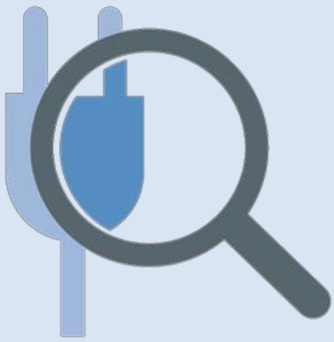
Figure 59: Load control technology

As far as a move to more modern technology is concerned, there has been no significant change from last year. In future, any loads wishing to benefit from the arrangements in section 14a of the Energy Industry Act must be fitted with smart meters. The advantage of smart metering systems compared to time switches and ripple control, which are mainly used at present, is that they support bidirectional communication. In future, therefore, network operators will be able to retrieve data on the current status of the load and on the status of the control actions. Another advantage of smart metering systems not generally offered by time switches is that it is possible to easily change a pre-set control profile and carry out ad hoc control actions not within a profile.



Consumers can benefit from significantly lower network charges if they allow their distribution system operator to control equipment such as night storage heating systems and heat pumps.

7. Electric vehicles/charging stations



Drivers of electric vehicles can find information about the location and type of recharging points in Germany on the Bundesnetzagentur website. This information is provided by operators of recharging points accessible to the public and published, creating transparency. Charging points are assessed for compliance with interoperability requirements, ensuring that users can find the plug they need on any recharging point.

The Charging Station Ordinance (LSV) entered into force on 17 March 2016. It specifies minimum technical requirements for the safe and interoperable establishment and operation of publicly accessible recharging points for electric vehicles. Germany is thus the first country to transpose the EU standards for charging plugs from Directive 2014/94/EU on the deployment of this infrastructure into national law. The LSV also contains binding provisions on charging plug standards and an obligation for operators of recharging points accessible to the public to notify the Bundesnetzagentur.

The Bundesnetzagentur has been recording the notifications from operators of normal and high-power recharging points since July 2016 because of the assessment of compliance with the technical safety specifications and interoperability requirements of recharging points pursuant to the LSV.

All recharging points accessible to the public that have been taken into operation since the ordinance entered into force are subject to the notification obligation. In addition, recharging points accessible to the public that are not subject to the notification obligation may be voluntarily notified to the Bundesnetzagentur. Further information can be found at https://www.bundesnetzagentur.de/ladesaeulen

The Bundesnetzagentur was notified of a total of 5,890 charging stations with 11,740 recharging points by 2 July 2018, of which 10,105 recharging points had a power less than or equal to 22 kW (normal-power recharging points) and 1,635 were high power recharging points.

By contrast, according to information from the mineral oil industry association (MWV), there are 14,478 petrol stations in Germany as at 2018. The number of German petrol stations is falling slightly.[53]

The recharging points notified are spread across the federal states as follows:

[53] https://www.mwv.de/statistiken/tabellenstand

Distribution of notified charging infrastructure in the federal states

Federal states	Charging stations	Total recharging points	High-power recharging points
Baden-Württemberg	801	1,525	315
Bavaria	1,176	2,471	304
Berlin	341	662	38
Brandenburg	68	138	18
Bremen	38	78	8
Hamburg	390	786	50
Hesse	497	988	141
Mecklenburg-Western Pomerania	75	141	20
Niedersachsen	550	1,048	184
North Rhine-Westphalia	997	1,981	165
Rhineland-Palatinate	242	469	148
Saxony	194	408	55
Saxony-Anhalt	84	168	45
Schleswig-Holstein	228	457	68
Thuringia	199	397	68
Saarland	10	23	8

Table 52: Distribution of notified charging infrastructure in the federal states (as at July 2018)

In April 2017, the Bundesnetzagentur started publishing an interactive map of charging stations on its website showing all notified normal and high-power recharging points. Key information is shown, such as the location of the charging station, the type of plug with its power and the operator. It is also possible to visualise the regional distribution of charging infrastructure using a heat map. The map may be found at https://www.bundesnetzagentur.de/ladesaeulenkarte.

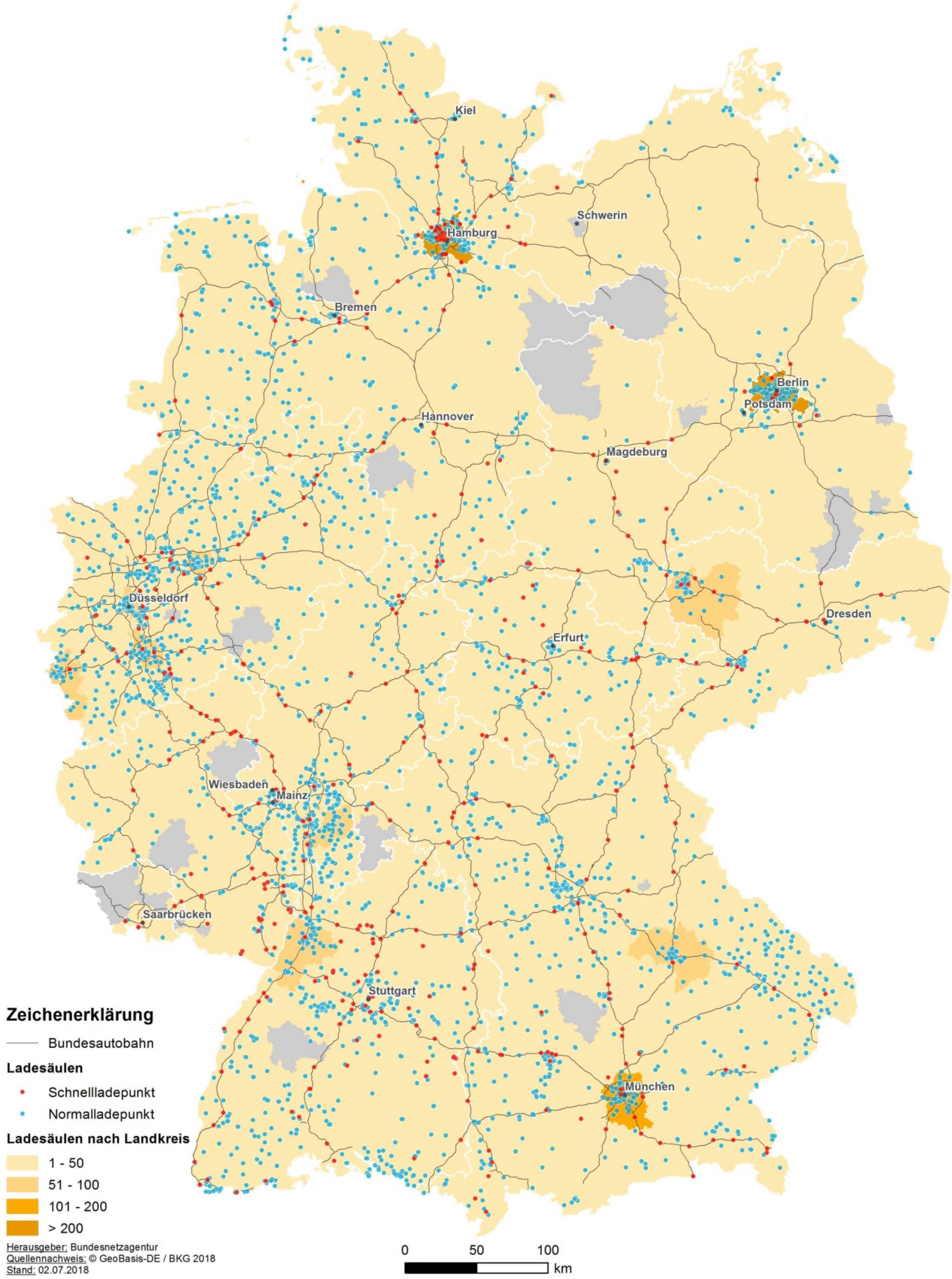


Figure 60: Charging stations in Germany notified pursuant to the Charging Station Ordinance (LSV), as at July 2018

Publishing the charging station map has caused the number of notifications of charging stations submitted by operators to rise, with the Bundesnetzagentur increasingly receiving notifications about charging stations not subject to the notification obligation, in particular. The number of notified recharging points nearly doubled in the first few months following publication. The development in the number of recharging points notified each month since publication in April 2017 is shown in the following graph.

Development in the number of recharging points notified since publication by the Bundesnetzagentur

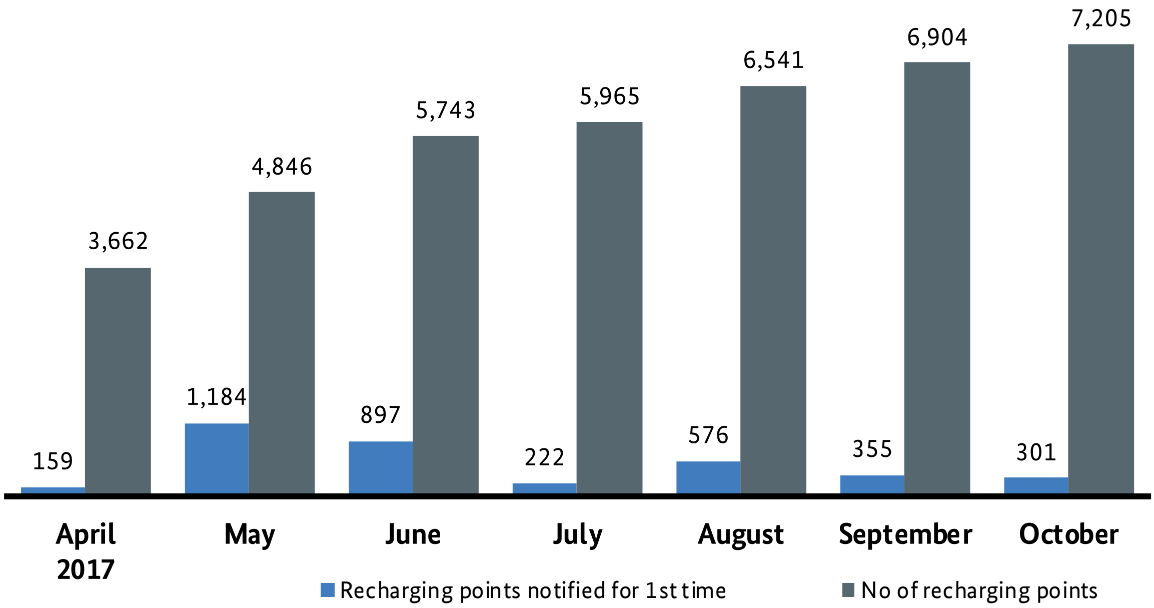


Figure 61: Development in the number of recharging points notified since publication by the Bundesnetzagentur

The LSV prescribes mandatory plug standards for recharging points accessible to the public in order to ensure interoperability. Direct current recharging points must be equipped with at least one vehicle connector of the "Combo 2" charging system. Alternating current recharging points require a "Type 2" plug system and there are differing requirements for normal and high-power recharging points. Normal-power recharging points with alternating current must have a "Type 2" socket outlet, while high-power recharging points require a "Type 2" vehicle connector. Any number of additional plugs may be provided at each charging point. The graph below shows the distribution of widely-used plugs at all notified recharging points. It should be remembered that recharging points may have several plug options and there are also older, existing recharging points that are not subject to the plug requirements of the LSV.

The charging capacities of the recharging points are distributed as shown in Figure 63. It can be seen that most of the recharging points are normal ones with a power less than or equal to 22 kW. The charging capacities most frequently mentioned in the notifications to the Bundesnetzagentur are 3.7 kW (AC Schuko), 11 kW/22 kW (AC Type 2), 43 kW (DC Combo connector) and 50 kW (DC CHAdeMO).

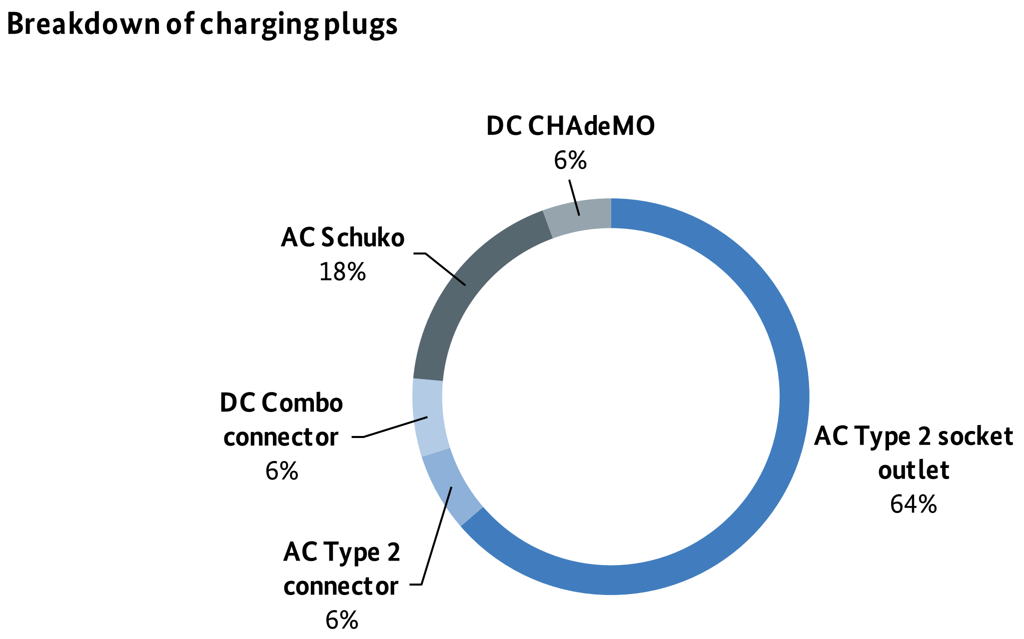


Figure 62: Breakdown of charging plugs

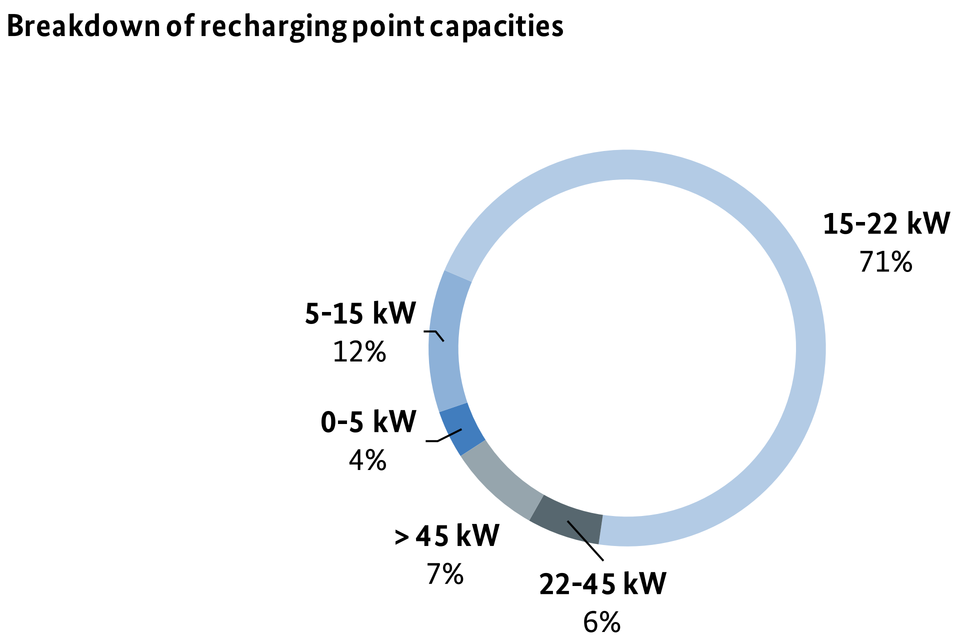


Figure 63: Breakdown of recharging point capacities

D System services

Guaranteeing system stability is one of the core tasks of the transmission system operators (TSOs) and is performed using system services. System services include maintaining the grid frequency by reserving and using three types of balancing capacity: primary (FCR, Frequency Containment Reserve), secondary (aFRR, automatic Frequency Restoration Reserve) and tertiary (mFRR, manual Frequency Restauration Reserve) control reserve.

They also include procuring energy to cover losses, reactive power and black start capability and, for the purposes of the monitoring survey, national and cross-border redispatching, countertrading[54] and feed-in management measures taken by the TSOs and the distribution system operators (DSOs). Contracting and using grid reserve plant capacity and interruptible loads under the Interruptible Loads Ordinance (AbLaV) are also part of the range of system services.

1. Costs for system services

The total costs for these system services[55], borne by network users recovered through the network charges, increased from €1,464.9m in 2016 to about €1,983.1m in 2017.

A large part of the costs in 2017 were accounted for by the costs of reserving and using grid reserve power plants at around €479.9m (2016: €285.7m), national and cross-border redispatching at €291.6m (2016: €222.6m), the estimated claims for compensation for feed-in management measures at €609.9m (2016: €372.7m), procuring primary, secondary and tertiary control reserves at €145.5m (2016: €198.1m) and energy to compensate for losses at about €280.4m (2016: €304.8m). The total costs of contracting capacities for balancing energy fell by €52.6m. One reason for this fall is the further decrease in the volumes of the three types of balancing reserve procured. The costs for energy to compensate for losses in 2017 around €24.4m 2016.

By contrast, there was a clear increase in the costs for network and system security measures. Costs for redispatching and countertrading were up around €169m and €17.2m respectively. There was also a further increase in the costs for grid reserve power plants. The costs for reserving the grid reserve plant capacity were up €113.3m compared to 2016. These costs depend on the specific types of power plants in the grid reserve, as well as on the contracted volume. The frequent use of the grid reserve power plants in 2017 resulted in a provisionally estimated increase of about €81m in deployment costs.

[54] Countertrading measures are taken by TSOs to prevent overloading of the grid. They are used when the agreed minimum trading capacity exceeds the capacity that can be transported in the networks. In this case, a countertrade is organised. This enables a minimum level of trading to be guaranteed at all times without the networks being overloaded.

[55] Net costs (outlay costs minus cost-reducing revenues) and costs for grid reserve power plants and interruptible loads under the Interruptible Loads Ordinance.

There was also a sharp rise in the estimated claims for compensation for curtailed energy from renewable energy and combined heat and power (CHP) plants. These were about €609.9m, up €237.2m compared to 2016, which was a year with relatively little wind.

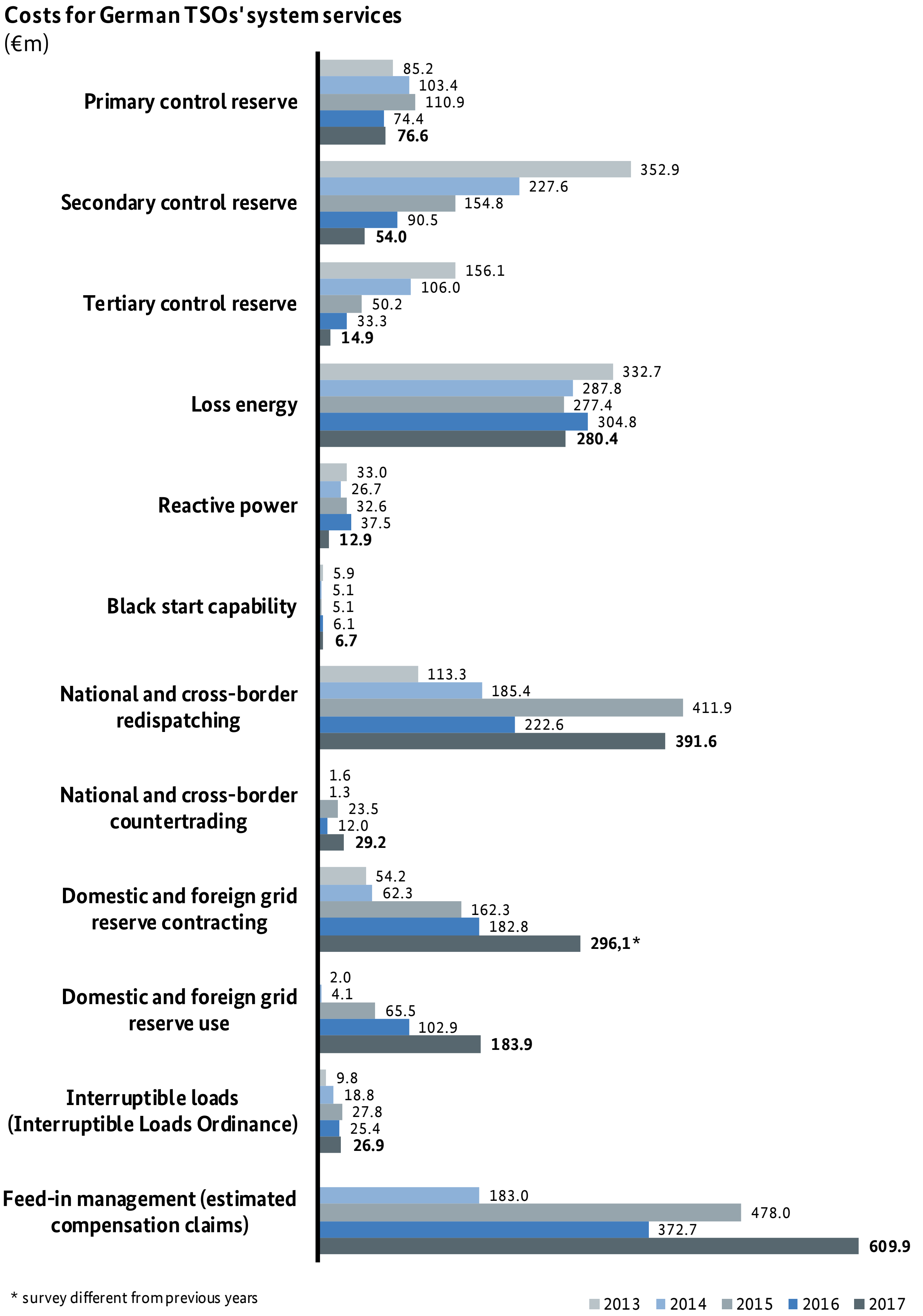


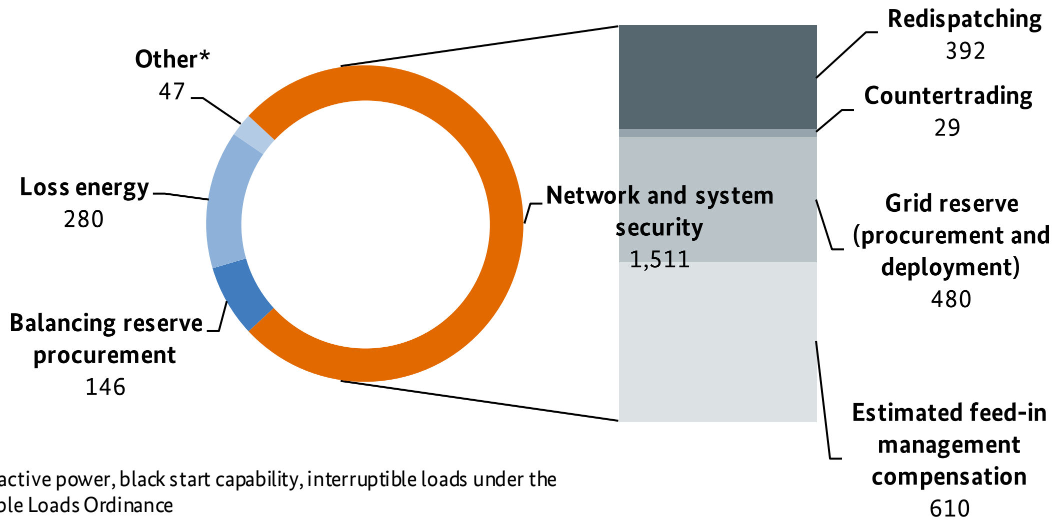
Figure 64: Costs of system services: 2013 - 2017

The strong increase in costs for network and system security measures is due to the rise in the number of curtailments of offshore wind installations, which receive a relatively high level of compensation and due to the exceptional circumstances at the start of 2017. A number of factors coincided to put an exceptionally severe strain on the grid during the period from the beginning of January to the beginning of February. These included unusual load flows in Germany, with large flows of electricity mainly to the south-west, the cold period throughout Europe leading to generally high loads and low generation from wind and solar power installations, as well as some German power plants becoming unavailable unexpectedly and other German nuclear power plants being turned off deliberately to avoid nuclear fuel duty. Several nuclear power plants in France were not available either.

Figure 64 shows the development in the costs for system services from 2013 to 2017.

Together with the TSOs' and DSOs' estimates of the claims from installation operators for compensation for curtailment measures, the costs for redispatching, grid reserve power plants and countertrading represent a significant proportion of the costs incurred by the network operators in maintaining network and system security.

Costs for system services and costs for network and system security: 2017
(€m)



*Other: reactive power, black start capability, interruptible loads under the Interruptible Loads Ordinance

Figure 65: Costs for German TSOs' system services and costs for network and system security: 2017

2. Balancing services

The TSOs procure and activate balancing reserves to balance demand and generation in the electricity supply system and thus maintain the stability and frequency of the system. Balancing reserves are procured by the TSOs in national tendering processes in accordance with the Bundesnetzagentur determinations issued in 2011 (BK6-10-097/098/099). While the costs of procuring balancing reserves are covered by the network charges, the actual balancing energy activated is settled in the form of imbalance settlement prices with the balance responsible parties (e.g. traders, suppliers) causing the imbalances.

A grid control cooperation scheme covering the control areas of the four responsible TSOs (50Hertz, Amprion, TenneT, TransnetBW) has been in place since 2010. The scheme, with a modular structure, prevents inefficient use of aFRR and dimensions the balancing reserve requirements for all four control areas together. The scheme also creates a nationally consistent, integrated market mechanism for aFRR and mFRR and optimises the costs of using balancing reserves for the whole of Germany. The imbalances in the individual control areas are netted so that only remaining imbalances need to be compensated for by activating reserves. Inefficient use is almost completely eliminated and the volume of balancing reserve required is reduced. Under the International Grid Control Cooperation (IGCC) scheme, Germany cooperates with Denmark, the Netherlands, Switzerland, Czech Republic, Belgium, Austria and France to avoid inefficient use of reserves. The growing cooperation is reflected by the lower levels of aFRR and mFRR capacities contracted and reduced volume of activations of balancing energy.

Balancing reserve is procured in accordance with the determinations on primary, secondary and tertiary reserves issued by the Bundesnetzagentur.[56] In the past, balancing reserve was mainly provided by conventional power plants. It is now also increasingly being offered by battery storage systems. Renewable generators supplying balancing reserve include hydro power and in particular biogas. The continual increase in the share of renewable energy in electricity generation means that renewables will need to take on greater responsibility for the stability of electricity supply in the future. To make it easier for volatile generators, such as wind power plants, to participate in the balancing energy markets, in June 2017 the Bundesnetzagentur issued new tendering conditions and publication requirements for secondary and tertiary reserves (BK6-15-158/159).[57] As a result, in July 2018 the auctioning period for secondary reserve was shortened from one week to one calendar day, and the blocks for the individual products have been made considerably shorter to four hour products. These changes are essential in particular for wind and photovoltaic generators to be able to better forecast feed-in and decide on a possible bid for balancing energy. The changes to the conditions for tertiary reserve include shortening the auctioning period from one working day to one calendar day. In addition, there are new rules on the minimum bid volumes and safeguards for both secondary and tertiary reserves.

2.1 Tendering for balancing reserves

The grid control cooperation scheme and the determinations issued by the Bundesnetzagentur contribute to increasing the potential for competition by enlarging the market area, creating a national market for secondary and tertiary reserves and aligning the conditions for tendering. By 26 April 2018, the number of pre-qualified secondary reserve providers had risen to 38 and that of tertiary reserve providers to 46.[58] The number of primary reserve providers was 24. The strong growth in the number of balancing service providers over the last few years shows how attractive this market is.

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[56] The determinations of Ruling Chamber 6 on balancing reserves (BK6-15-158, BK6-18-019, BK6-15-159, BK6-18-020) can be accessed at the following URL: https://www.bundesnetzagentur.de/DE/Service-Funktionen/Beschlusskammern/Beschlusskammer6/BK6_21_Abgeschlossene_Verfahren/AbgeschlosseneVerfahren-node.html

[57] A pilot project initiated by the TSOs responsible for the control areas and running until the end of 2017 already gives wind generators the opportunity to pre-qualify as tertiary reserve providers and to provide reserve.

[58] Although the first wind generators have successfully pre-qualified to provide negative tertiary reserve, they have yet to take part in the tendering for economic reasons, amongst others.

Table 53 shows the range of the volumes of primary, secondary and tertiary control reserves tendered in the period from 2012 to 2017. There was a slight year-on-year decrease in the maximum and minimum volumes of positive and negative secondary reserve tendered. There was also a decrease in the maximum and minimum volumes of positive and negative tertiary reserve tendered as well. The range between the minimum and maximum volumes for positive and negative secondary reserve and for positive tertiary reserve narrowed. By contrast, the range between the minimum and maximum levels for negative tertiary reserve widened. The demand for primary control reserve was at a similar level to the previous year at 603 MW, compared to 583 MW in 2016, and was broadly unchanged over the year.

The average volume of positive secondary reserve tendered in 2017 was 1,906 MW compared with 2,009 MW in 2016. The average volume of negative secondary reserve tendered also decreased from 1,945 MW in 2016 to 1,835 MW in 2017. An analysis of the period since 2010 shows that there have only been small fluctuations in the volumes tendered over the course of each year (see Figure 66).

Total volume of secondary reserve tendered in the 50Hertz, Amprion, TenneT und TransnetBW control areas
(MW)

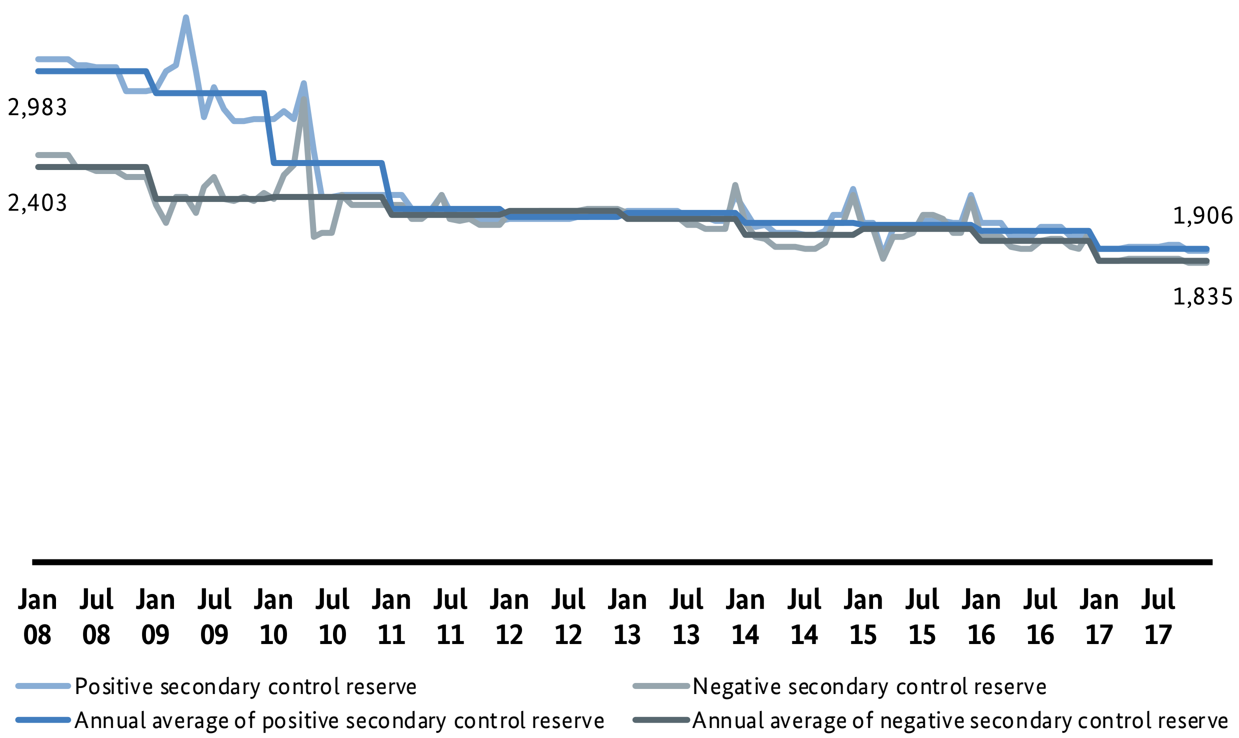

Figure 66: Total volume of secondary reserve tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

Balancing reserves (minimum and maximum volumes) tendered by the TSOs

	Year	Capacity tendered (MW)	
		Min	Max
Primary control reserve	2013	576	593
	2014	568	578
	2015	568	578
	2016	583	583
	2017	603	603
Secondary control reserve (positive)	2013	2,073	2,473
	2014	1,992	2,500
	2015	1,868	2,234
	2016	1,973	2,054
	2017	1,890	1,920
Secondary control reserve (negative)	2013	2,118	2,418
	2014	1,906	2,500
	2015	1,845	2,201
	2016	1,904	1,993
	2017	1,818	1,846
Tertiary control reserve (positive)	2013	2,406	2,947
	2014	2,083	2,947
	2015	1,513	2,726
	2016	1,504	2,779
	2017	1,131	1,850
Tertiary control reserve (negative)	2013	2,413	3,220
	2014	2,184	3,220
	2015	1,782	2,522
	2016	1,654	2,353
	2017	1,072	2,048

Table 53: Balancing reserves (minimum and maximum volumes) tendered by the TSOs

The picture is less consistent when it comes to tertiary reserve. While there was a continued decline in the average volume of positive tertiary reserve tendered from 2,309 MW to 1,907 MW between 2010 and 2012, the average volume in 2014 was 2,376 MW. In 2017, the average volume fell significantly compared with the previous year at 1,318 MW, compared to 2,059 MW in 2016. Demand for positive tertiary reserve ranged from 1,131 MW to 1,850 MW.

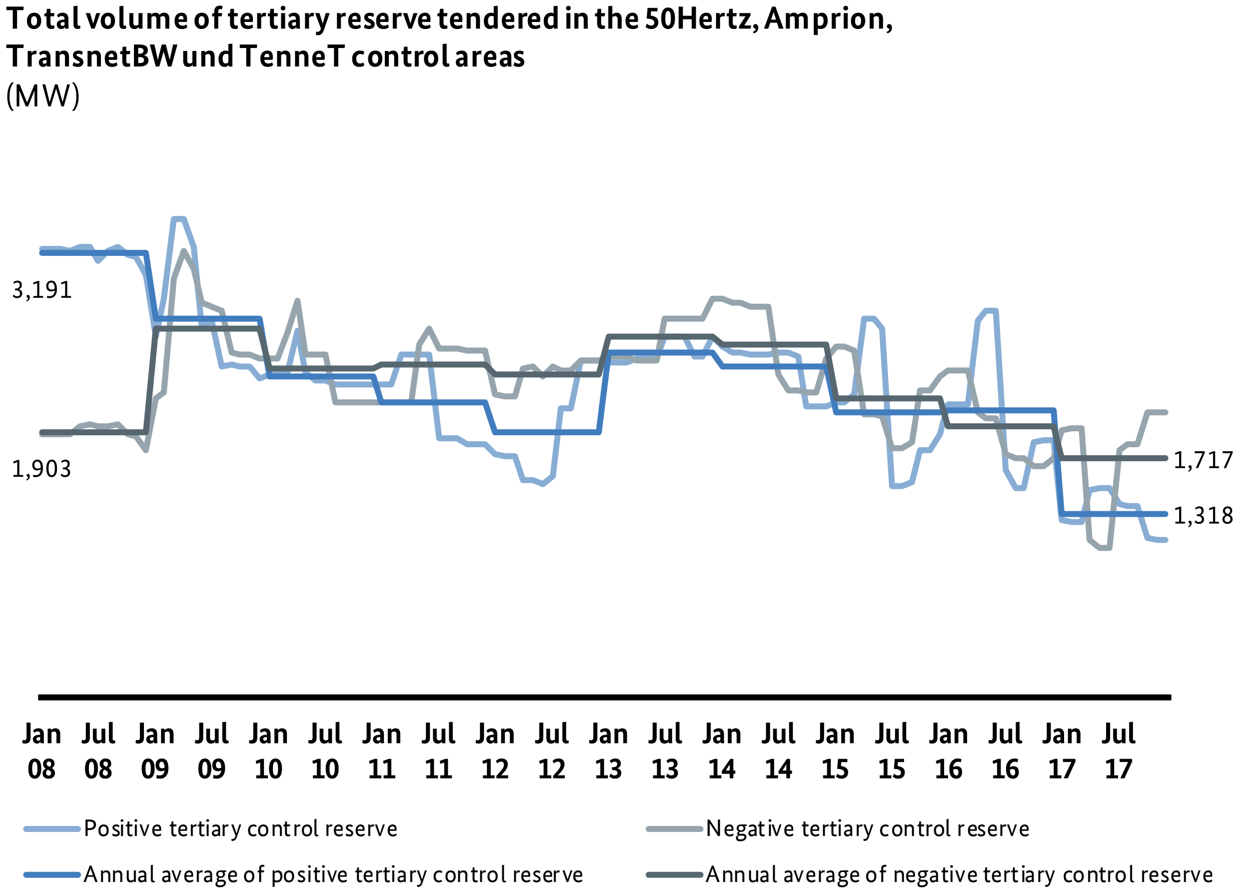

Figure 67: Total volume of tertiary reserve tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

There was also a year-on-year decrease in the annual average volume of negative tertiary reserve procured. The average volume of negative tertiary reserve tendered in 2017 was 1,717 MW, compared to 1,941 MW in 2016. As with positive tertiary reserve, however, volumes fluctuated considerably during the course of the year. In January 2017, the average volume of negative tertiary reserve tendered stood at 1,922 MW; this decreased in the period up to June 2017 to 1,072 MW, a new record low, and increased in December 2017 to 2,048 MW.

Overall, the changes in the volumes of positive and negative tertiary reserve tendered within the twelve-month period are considerably more volatile than for secondary reserve.

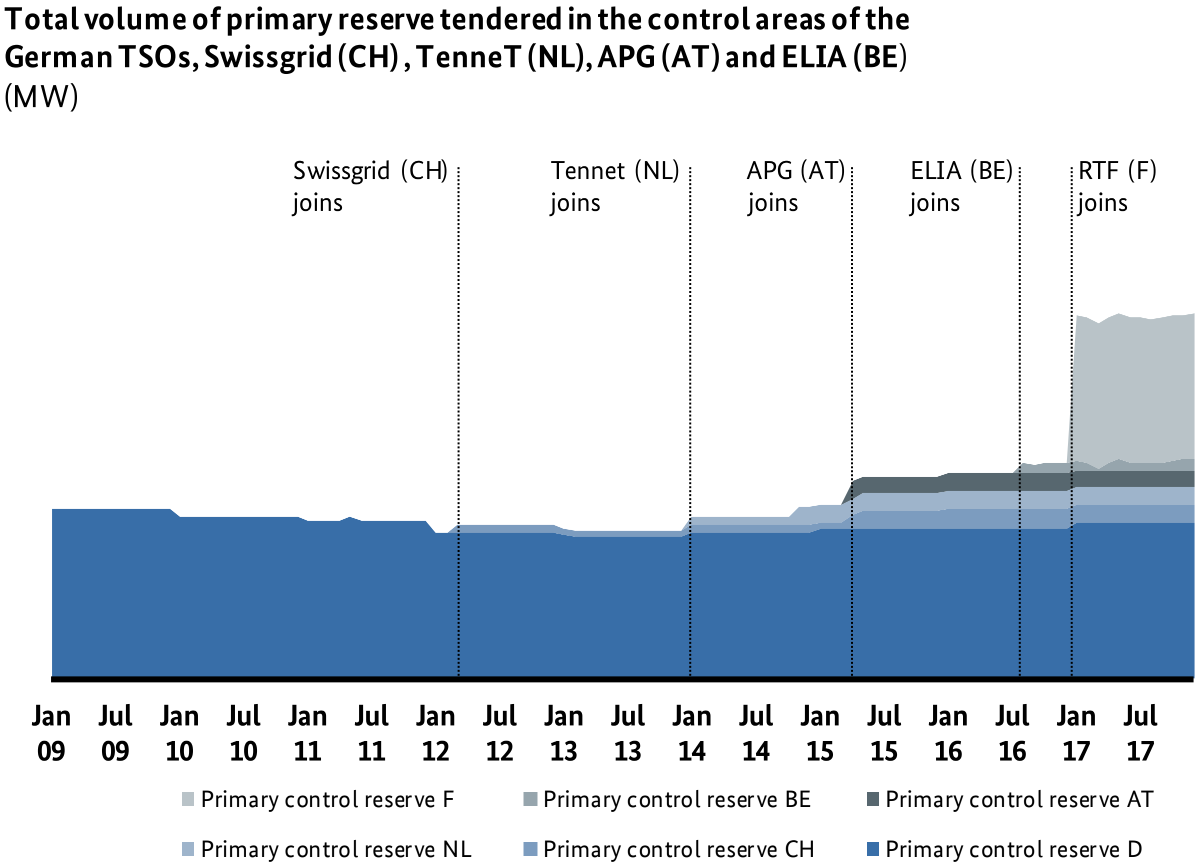

Figure 68: Total volume of primary reserve tendered in the control areas of the German TSOs, Swissgrid (CH), TenneT (NL), APG (AT) and ELIA (BE)

Figure 68 shows that the volume of primary reserve tendered has also remained stable over the long term. The German TSOs are seeking to harmonise the primary reserve markets across the borders in cooperation with the Bundesnetzagentur and other European TSOs and regulators. The Swiss network operator Swissgrid joined the German TSOs' joint primary reserve tendering scheme in March 2012; the volume of primary reserve procured for Switzerland through the scheme has risen from an initial 25 MW to the current 68 MW. TenneT TSO BV in the Netherlands joined in January 2014. Following an initial volume of 35 MW, currently 74 MW of the Netherlands' primary reserve requirements are tendered through the joint tendering scheme. In April 2015, the primary reserve tendering partnership scheme between Germany, the Netherlands and Switzerland was coupled with Austria and Switzerland's joint scheme. The average volume procured for Austria through the scheme in 2017 was 62 MW. The Belgian network operator ELIA joined the joint tendering scheme in August 2016 and the French TSO RTE in January 2017. The average volume procured for Belgium in 2017 was 31 MW and for France, 561 MW. The scheme has created the largest primary reserve market in Europe. The joint tendering procedure is open to all pre-qualified providers in the participating countries; the procedure follows the German regulations and uses the existing tendering systems.

2.2 Use of balancing reserves

As Figure 66 shows, the total volume of secondary control reserve tendered and procured between 2011 and 2017 remained at a similar, comparatively low level. There was only a slight increase in the volume of secondary reserve actually used in 2017 compared to 2016.

In 2017, the total amount of energy activated for positive secondary control was some 1.2 TWh (2016: 1.4 TWh), and that for negative secondary control 1.0 TWh (2016: 0.7 TWh). Compared with 2015, the total amount of energy activated for secondary control increased to 2.2 TWh (2016: 2.2 TWh), with again a slight shift towards positive secondary control.

On average in 2017, around 7% of the average volume of positive secondary reserve tendered and about 6.4% of the average volume of negative secondary reserve tendered was used. It should be noted, however, that in a total of 22 quarter hours in the year, at least 80% of the average secondary reserve capacity was required; overall this confirms the necessity of the volumes tendered.

The Bundesnetzagentur makes market data on balancing reserves available on its SMARD platform, where it is possible to view graphs and tables of the procured and activated volumes of the different types of balancing reserve.[59]

Average volume of secondary reserve used, including procurement and provision under online netting in the grid control cooperation scheme
(MW)

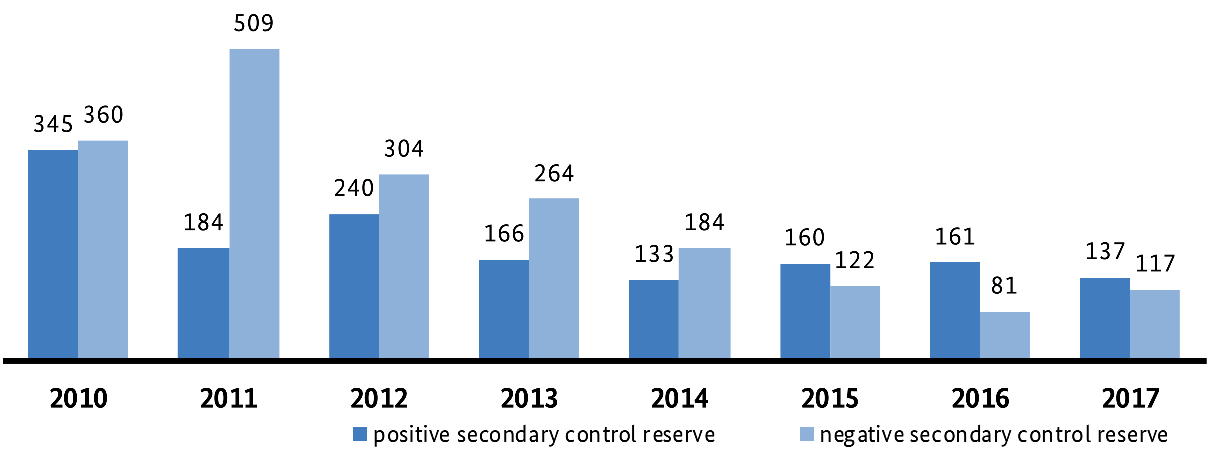

Figure 69: Average volume of secondary reserve used, including procurement and provision under online netting in the grid control cooperation scheme

At 4,998, the total number of dispatch requests for tertiary reserve was 9% lower than in the previous year. Overall, there were 1,639 requests for negative tertiary reserve in 2017, compared to 1,216 in 2016, and 3,359 requests for positive tertiary reserve, compared to 4,108 in 2016.

[59] https://smard.de/home/marktdaten/78?marketDataAttributes=%7B%22resolution%22:%22hour%22,%22from%22:1535148000000,%22to%22:1536097532454,%22moduleIds%22:%5B%5D,%22selectedCategory%22:null,%22activeChart%22:true,%22region%22:%22DE%22%7D

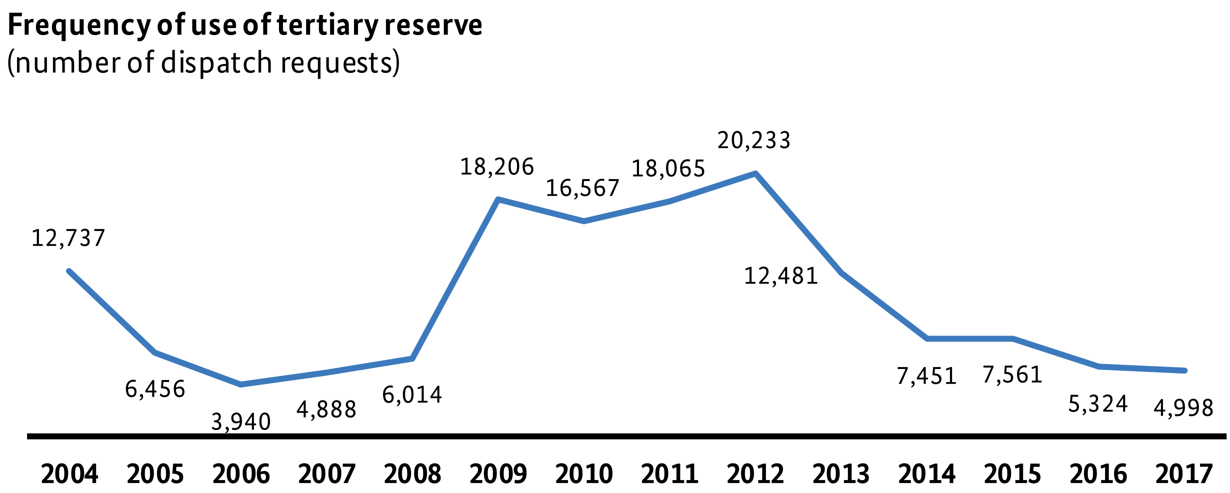

Figure 70: Frequency of use of tertiary reserve

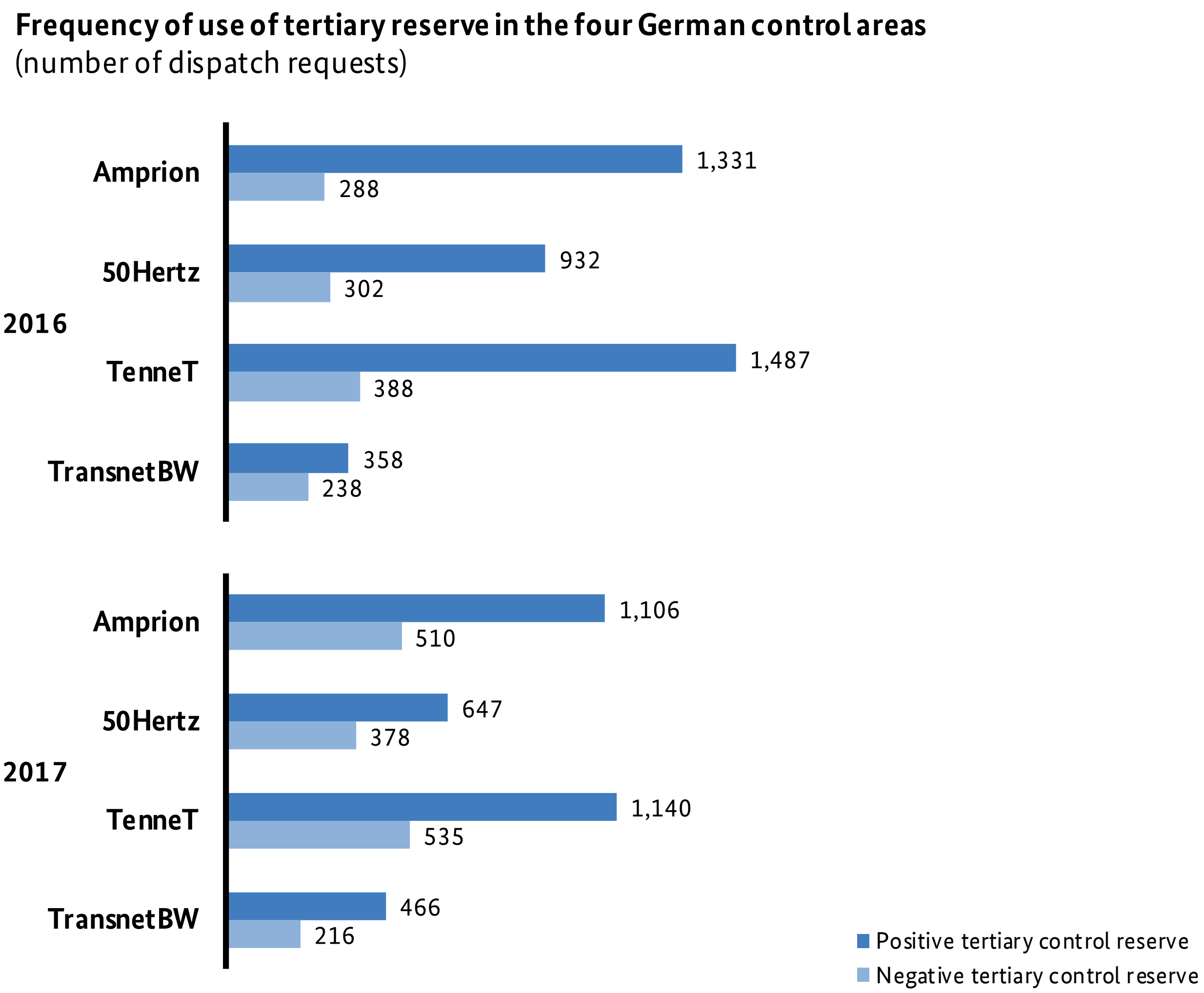

Figure 71: Frequency of use of tertiary reserve in the four German control areas: 2016 and 2017

There was a small decrease in the average volume of positive tertiary reserve requested from 149 MW in 2016 to 138 MW in 2017. Likewise, there was a decrease in the average negative tertiary reserve dispatched from 175 MW in 2016 to 155 MW in 2017. On average in 2017, around 10% of the average volume of positive tertiary reserve tendered and just under 9% of the average volume of negative tertiary reserve tendered was used. As with secondary reserve, however, it must be noted that in several quarter hours almost all of the tertiary reserve capacity was required. In 30 cases at least 80% of the average capacity was required; overall this again confirms the necessity of the volumes tendered.

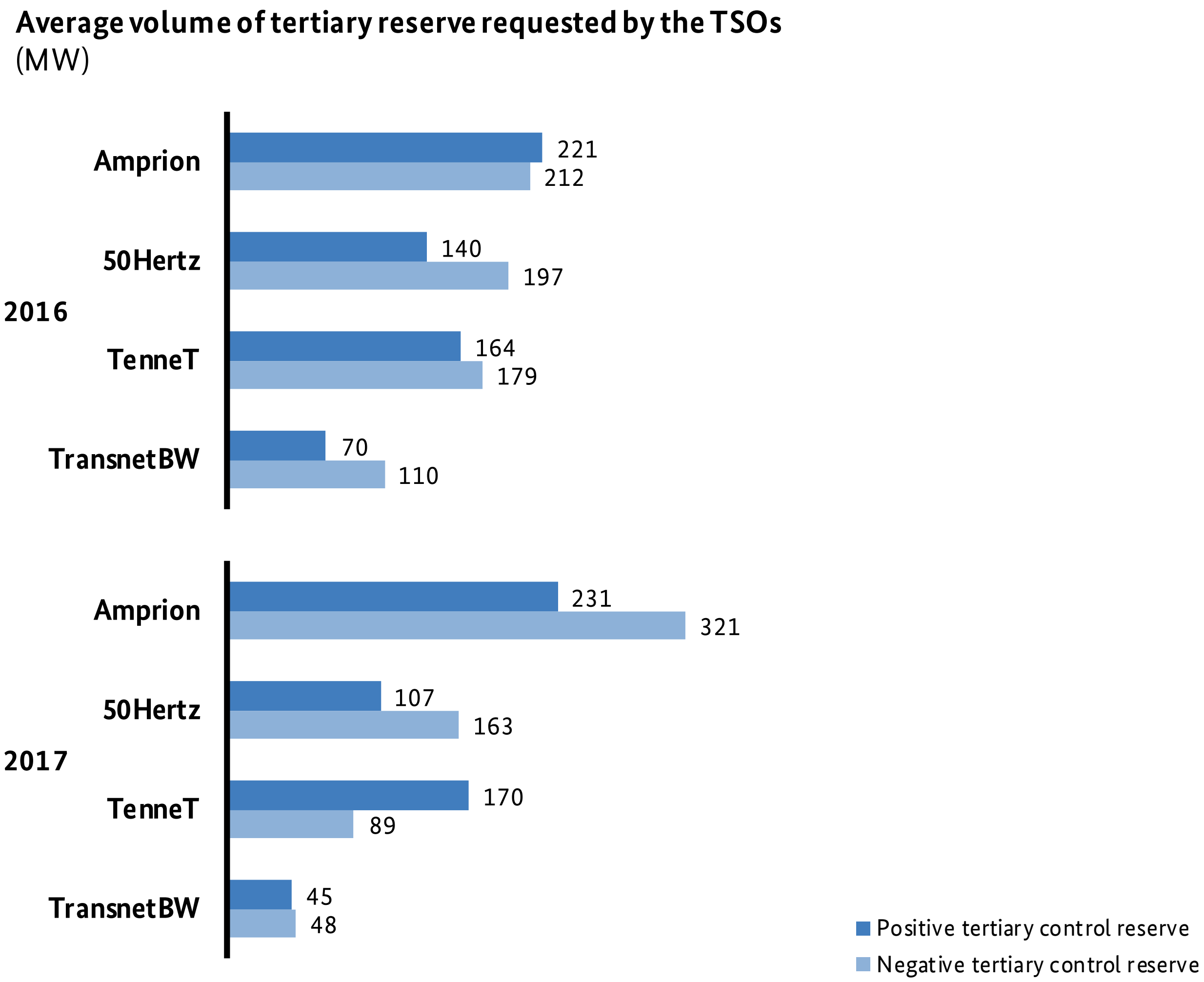

Figure 72: Average volume of tertiary reserve requested by the TSOs: 2016 and 2017

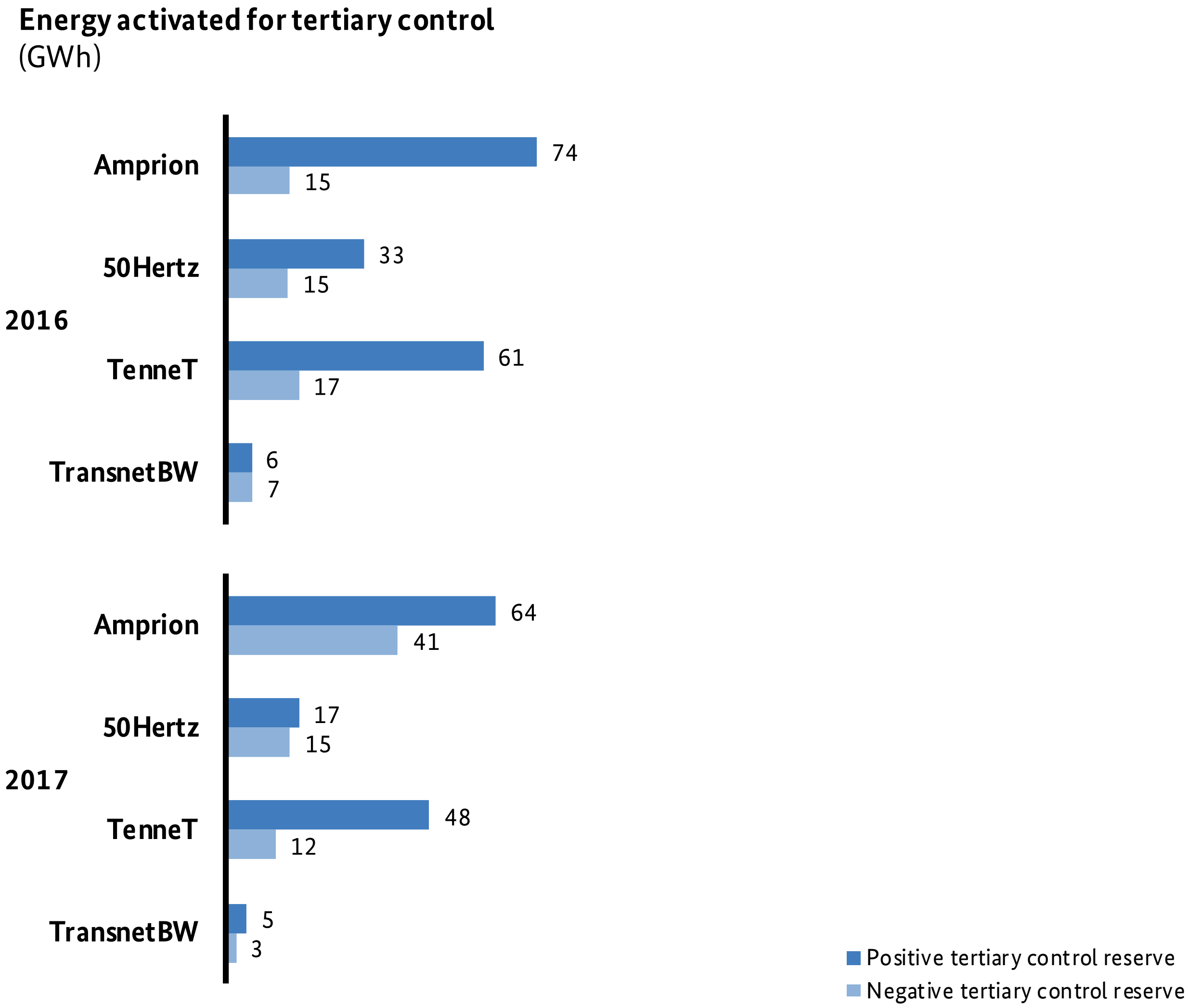

Figure 73: Energy activated for tertiary control: 2016 and 2017

Altogether about 134 GWh (2016: 174 GWh) was used in 2017 for positive tertiary reserve and 71 GWh (2016: 54 GWh) for negative tertiary reserve. Once again, there has been a shift away from negative to positive tertiary control.

Figure 74 illustrates the average use of secondary and tertiary control reserves in each calendar week from 2009 to 2017. It shows a decrease in the total average volume of secondary and tertiary reserves used and a reduction in volatility over time.

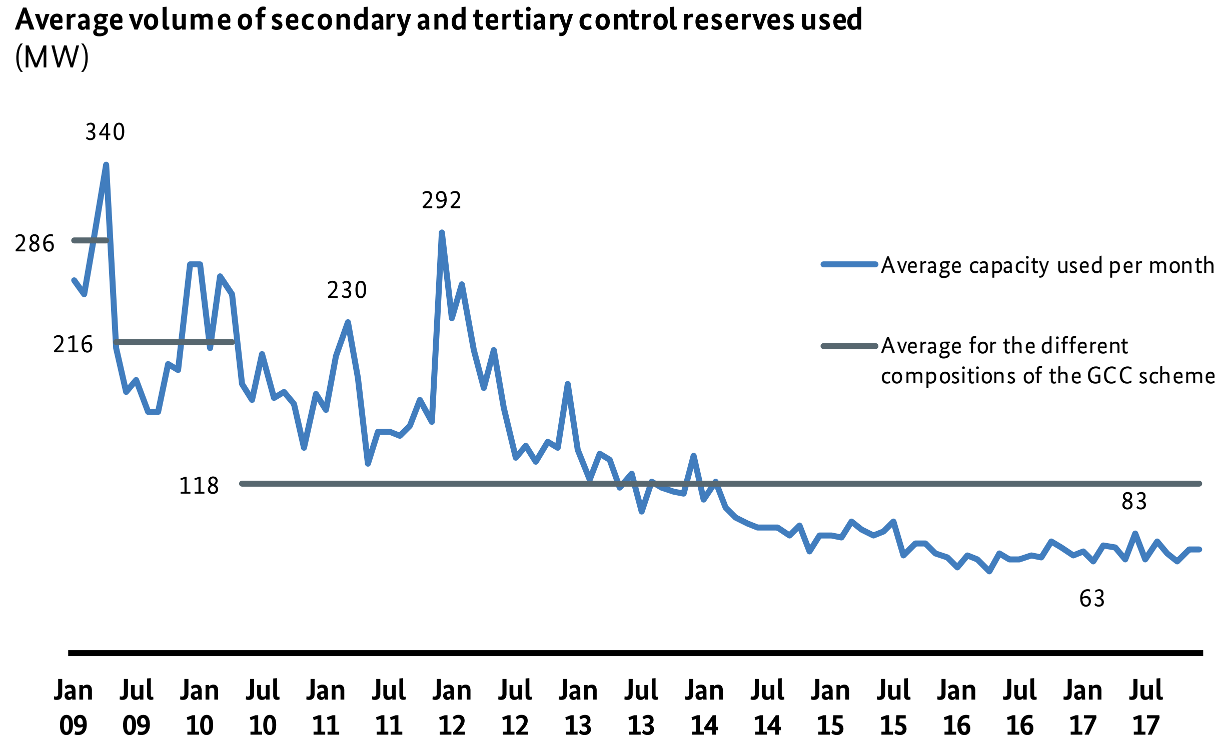

Figure 74: Average volume of secondary and tertiary control reserves used

2.3 Imbalance prices

Balance responsible parties (BRPs; electricity traders, suppliers, etc) are obliged to maintain the balance in their balancing group every quarter of an hour, i.e. the energy delivered to and drawn from the balancing group must balance each other out. Imbalances are corrected by TSOs with the use of balancing energy and settled at the imbalance price. The imbalance price passes on the costs for the use of balancing energy to the parties that caused the imbalance, i.e. the imbalanced BRPs.

The Bundesnetzagentur's determination reforming the imbalance price system has been in effect since December 2012. The aim of the reform was to provide better incentives for the proper management of balancing groups with a view to preventing system-relevant imbalances.

The maximum imbalance price within the grid control cooperation scheme in 2017 was €24,455/MWh. Further details about this high imbalance price may be found in the section "Imbalance prices on 17 October 2017" from page 187. The maximum price exceeded €500/MWh on a total of 30 quarter hours in 2017.

In cases where the control area imbalance within the grid cooperation scheme is close to zero (known as "zero crossings"), extreme imbalance prices may occur across control areas owing to the calculation formula used. In the period up to April 2016, the imbalance price was limited in such cases to the maximum price of a balancing energy bid activated in the particular quarter hour. However, if the prices bid by the suppliers were equally high, then the imbalance prices were also high despite being capped. In May 2016, an updated method to calculate imbalance prices was introduced; the linearised multi-step model was developed by the market players as an industry compromise and was accepted by the Bundesnetzagentur to supplement the existing regulations laid down in its determination (BK6-12-024).[60] In cases where the control area imbalance within the grid control cooperation scheme is between -500 MW and +500 MW, an additional cap is now placed on the imbalance price in the particular quarter hour as a new iteration step in the calculations. More detailed explanations of the calculation method may be found at https://www.regelleistung.net/ext/static/rebap.

Maximum imbalance prices

Year	Grid control cooperation scheme (€/MWh)
2010	600.90
2011	551.60
2012	1,501.20
2013	1,608.20
2014	5,998.41
2015	6,343.59
2016	1,212.80
2017	24,455.05

Table 54: Maximum imbalance prices

The average 15-minute price for balancing energy within the grid control cooperation scheme in 2017 in the case of a positive control area balance (short portfolio) showed a significant year-on-year increase of 27% to €63.90/MWh. The price in the case of a negative control area balance (long portfolio) showed a decrease of 9% to -12.89Euro/MWh. The average imbalance price in the case of a positive control area balance was thus around 60%[61] above the average (peak) intraday trading price in 2017.

[60] Bundesnetzagentur communication on using the linearised multi-step model (in German): https://www.bundesnetzagentur.de/cln_1421/DE/Service-Funktionen/Beschlusskammern/1BK-Geschaeftszeichen-Datenbank/BK6-GZ/2012/2012_0001bis0999/2012_001bis099/BK6-12-024/BK6-12-024_Mitteilung_vom_20_04_2016.html?nn=269594

[61] Based on the EPEX SPOT average (peak) intraday trading price of €38.10/MWh for 2017.

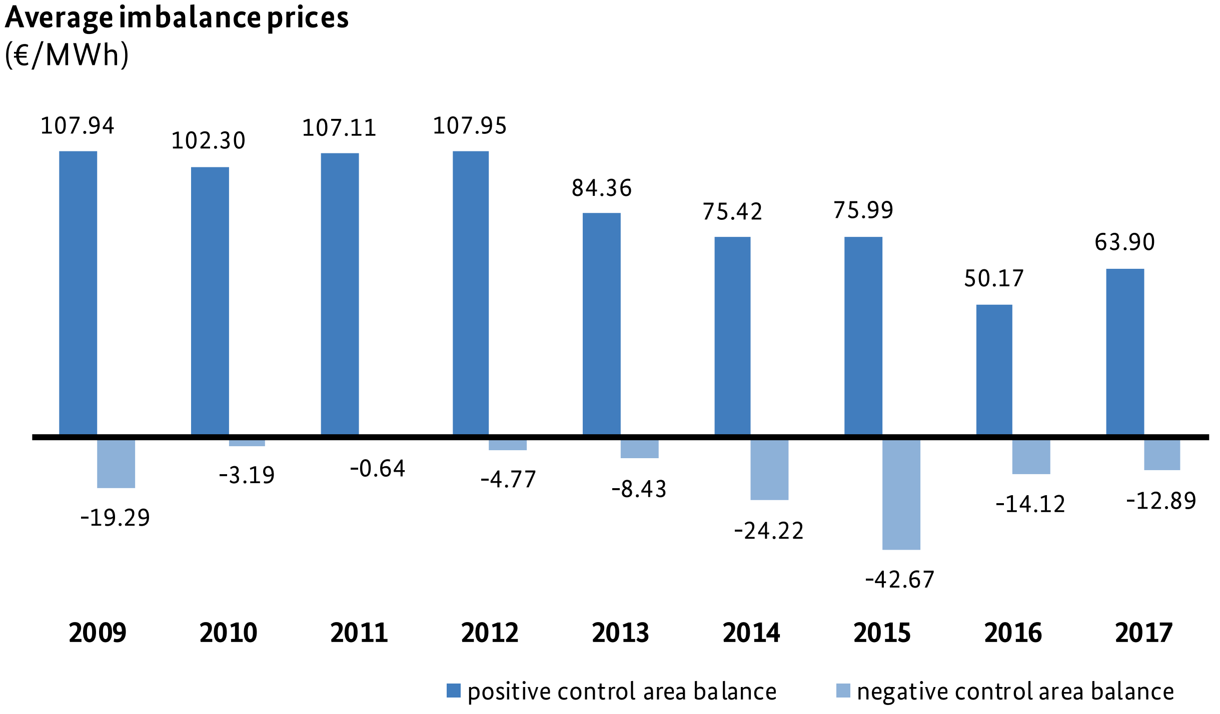

Figure 75: Average imbalance prices: 2009 - 2017

The following graph shows the frequency distribution of imbalance prices in the grid control cooperation scheme in 2016 and 2017. As in previous years, in 2017 there was an accumulation of prices around €0/MWh in the case of a negative control area balance. In addition, in 2017 there was again a greater frequency of prices around €40/MWh in the case of a positive control area balance.

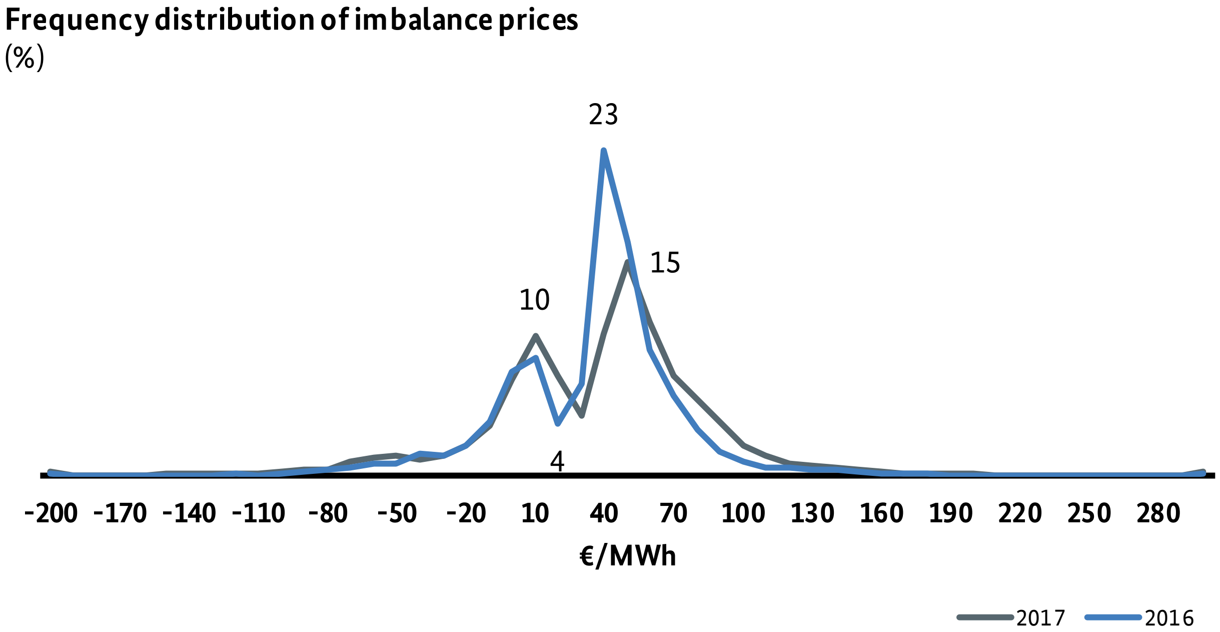

Figure 76: Frequency distribution of imbalance prices: 2016 and 2017

Imbalance prices on 17 October 2017

On 17 October 2017, bids of €77,777/MWh for activated tertiary balancing capacity led to the highest ever imbalance prices of €20,614.97/MWh (19:15-19:30) and €24,455.05/MWh (19:30-19:45). The BRPs, who are legally responsible for the costs incurred for balancing energy, therefore had to pay large sums for imbalances in their balancing group even though these were short-lived or small. Costs of €8m were incurred in this half-hour period. While similarly high bids have been made in the past for both secondary and tertiary balancing energy, on 17 October these bids occurred for the first time not at the end but in the middle of the merit order list, so that a significant amount of such bids were activated.

A causal analysis of the extremely high bids for balancing energy revealed that the current tendering method needed to be adjusted. The new determination, which was issued in May 2018 (BK6-18-019 and BK6-18-020), aims to raise the competitive pressure on prices on balancing energyand thus make the whole system of procuring balancing capacity more efficient.

Under the new determination, successful bids for secondary and tertiary balancing reserves will in future be decided on the basis of a mixed price procedure, i.e. the successful bids will partially take into account the price of balancing energy as well as the price of balancing capacity. Previously, tenders were only awarded on the basis of the bids for balancing capacity. Now a weighting factor corresponding to the average probability of activation of bids for each type of balancing capacity determines the influence of the price of balancing energy on the bid accepted. The weighting factor is recalculated each quarter based on the previous 12 months. For bids of the same value, the one with the lowest price of procured balancing capacity is successful. If this price is the same, the bids are taken in the order they were submitted.

This new method ensures that both the bids for balancing energy and balancing capacitywill be treated competitively in the procurement of balancing capacity. Taking the prices of balancing energy into account will prevent inappropriately high imbalance prices, which would otherwise have to be borne by the BRPs.

The determination stated that the new provisions would apply from 12 July 2018, but a ruling by the Higher Regional Court of Düsseldorf in proceedings for issue of a temporary order determined that they would apply from 16 October 2018.

The Bundesnetzagentur's Market Transparency Unit for Wholesale Electricity and Gas Markets is examining whether the behaviour of tertiary reserve bidders – both bidding activities and any balancing irregularities – breached the prohibitions on market manipulation contained in Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT).

3. Intraday schedule changes

Section 5(1) of the Electricity Network Access Ordinance (StromNZV) allows schedule notifications – in which balance responsible parties notify TSOs about planned electricity supply and commercial transactions in the period from the day following submission until the next working day (based on quarter-hour figures) – to be submitted up to 14:30 on a given day. Schedules can also be modified during the day, enabling balance responsible parties to respond to short-term changes in supply and demand. The following graph shows the number and volume of intraday changes to schedules in 2017.

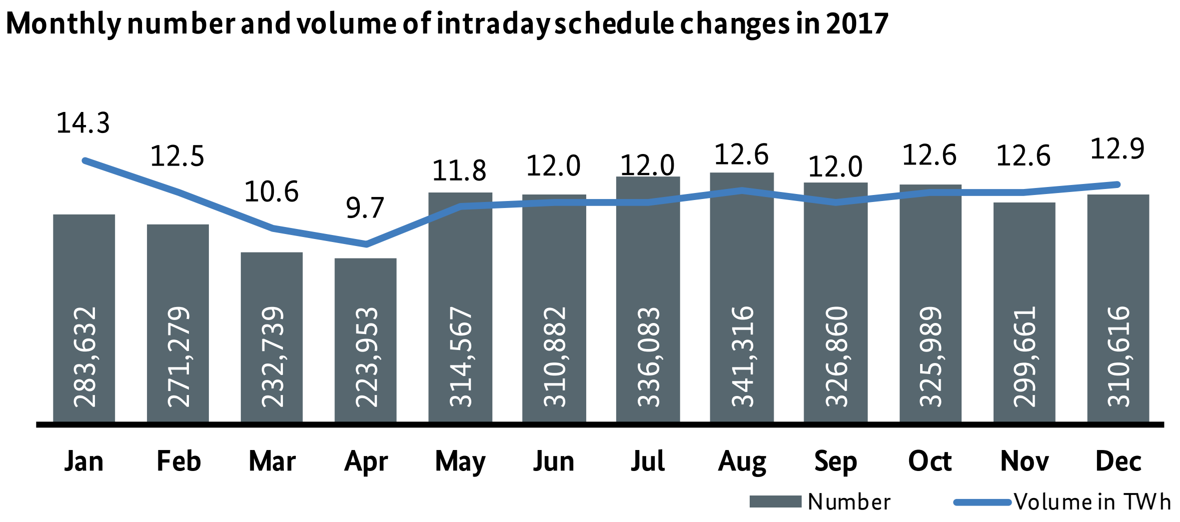

Figure 77: Monthly number and volume of intraday schedule changes: 2017

In 2017, a total number of 3,577,577 schedule changes accounted for a total volume of around 145.6 TWh, compared to 3,001,449 changes and 135.9 TWh in 2016. On average, some 298,131 schedule changes were made each month in 2016; the highest monthly number being 341,316 in August and the lowest 223,953 in April 2017. These figures represent a year-on-year increase in both the number and the volume of intraday schedule changes. One reason for the high level is the feed-in from renewables, which increasingly needs to be balanced out during the day through intraday trading.

4. European developments in the field of electricity balancing

4.1 International expansion of the grid control cooperation

Over the last few years the German TSOs have been pushing forward the expansion of module 1 of their joint grid control cooperation scheme, which aims to prevent the inefficient use (opposite deployment) of frequency restoration reserves with automatic activation (aFRR) in different control areas. Under the International Grid Control Cooperation (IGCC) scheme, Germany and the following countries cooperate to avoid inefficient use of aFRR: Denmark (since October 2011), the Netherlands (since February 2012), Switzerland (since March 2012), Czech Republic (since June 2012), Belgium (since October 2012) and Austria (since April 2014). Most recently the scheme expanded significantly when France joined in February 2016. Four other candidate countries are negotiating with the existing contract partners to join the scheme.

The IGCC enables the imbalances and hence the demand for aFRR in the participating control areas to be automatically registered and physically netted. This imbalance netting means that TSOs with a surplus of energy in their control areas provide power to those with a shortage. No cross-border transmission capacity needs to be reserved for this exchange of energy: the maximum amount of energy that can be exchanged across the border corresponds to the remaining capacity available after the close of trading in the intraday market.

The imbalances netted within the international cooperation scheme currently amount to around €4m to €6m per month. Overall, the international scheme has already achieved cost savings of over €350m through avoiding inefficient use of reserves. The concept of physically netting imbalances also promises high welfare gains for the whole of Europe. The guideline on electricity balancing[62] hence requires all European TSOs using aFRR to implement imbalance netting in the future. The IGCC has been designated by ENSTOE as a European pilot project to provide technical and organisational experience at an early stage; the project is being accompanied by the regulators, led by the Bundesnetzagentur.

4.2 aFRR cooperation scheme between Germany and Austria

The German TSOs have intensified their cooperation with the Austrian TSO APG relating to aFRR deployment. As of 14 July 2016, a common merit order list is used to activate aFRR. This ensures that – provided that there are no network restrictions – only the cheapest offer for aFRR is taken in both countries, enabling the costs for balancing energy to be reduced. If cooperation is not possible, for instance because of operative network restrictions, the German and Austria TSOs activate aFRR at a national level as before. This form of cooperation between the German and Austrian TSOs is also important with regard to the European guideline on electricity balancing in force since the end of 2017, which provides for cross-border activation of balancing energy based on a common merit order list, with a view to further integrating European balancing energy markets in the future.

5. Interruptible loads

5.1 TSOs' tendering for interruptible loads

The legal basis for tendering for interruptible loads is the Interruptible Loads Ordinance (AbLaV), which entered into force in January 2013 and was replaced by a revised version with effect from 1 October 2016. As of April 2017, the TSOs hold weekly auctions for delivery periods from 00:00 on a Monday to 24:00 on a Sunday for up to 750 MW each of immediate and fast interruption.

The following graph shows the capacity tendered and contracted for immediate and for fast interruption. The graph shows that the total capacity contracted has remained nearly stable over the whole period, with the ratio of immediate to fast interruption also nearly constant, with a few exceptions.

[62] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing

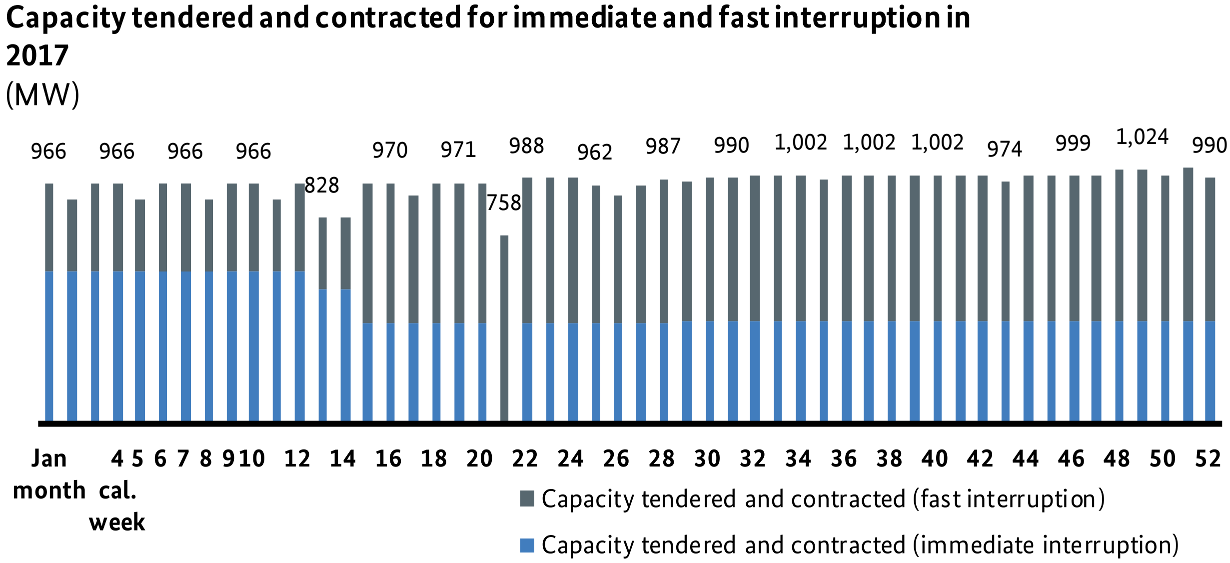

Figure 78: Capacity tendered and contracted for immediate and fast interruption:
January 2017 - December 2017

5.2 Pre-qualified capacity

By the end of 2017, 18 interruptible loads with a total interruptible capacity of 1,093 MW had taken part in the initial pre-qualification procedure pursuant to section 9 of the Interruptible Loads Ordinance and 15 of them, with a total interruptible capacity of 1,050 MW, had successfully pre-qualified.

Of the successfully pre-qualified loads, eight consumer devices pursuant to section 2 para 11 of the Interruptible Loads Ordinance had pre-qualified as immediately interruptible loads with a total interruptible capacity of 881 MW. A consortium pursuant to section 2 para 12 of the Interruptible Loads Ordinance also pre-qualified as an immediately interruptible load. In addition, 13 consumer devices pursuant to section 2 para 11 and two consortia pursuant to section 2 para 12 of the Interruptible Loads Ordinance pre-qualified as quickly interruptible loads. The pre-qualified capacity of quickly interruptible loads in 2017 thus amounted to 1,050 MW. The majority of the loads are connected to Amprion GmbH's control area, while others are in the control areas of 50Hertz GmbH and Tennet TSO GmbH.

5.3 Use of interruptible loads

In 2017, interruptible loads were used comparably with the use of balancing capacity on two days. Reductions in consumption of 405 MW and 240 MW were activated almost simultaneously for between 23 and 30 minutes. The interruptible loads were mostly used at the same time as positive tertiary reserve. Neither the full positive tertiary reserve capacity nor the full interruptible capacity had to be used. At the time the interruptible loads were used, between 39% and 100% of the unused positive tertiary reserve capacity was available. The highest energy-based price used for positive tertiary reserve at the time the interruptible loads were used was €450/MWh. Interruptible loads were used once in 2017 for redispatching purposes owing to large transport volumes from the north to the south of Germany. The interruptible capacity was 50 MW for eight hours.

The contracted immediately interruptible loads were registered as not available for 1,298 hours, ie 128,085 MWh of interruptible energy was not available from the immediately interruptible loads. The quickly interruptible loads were registered as not available in 2017 for as much as 2,280 hours, ie 153,861 MWh of interruptible energy was not available from the quickly interruptible loads. There was only one quarter-hour period in the year when quickly interruptible loads were not available in an unreliable manner. Regardless of the low level of availability, this shows the reliability of the contracted interruptible loads. However, the opportunity to register the contracted interruptible capacity as not available by the interruptible loads the day before was made significant use of and was thus not available for TSOs for system balancing and redispatching. Nevertheless, during the whole period the contracted loads were not registered as not available because of alternative marketing on the balancing market.

5.4 Costs for interruptible loads

The energy-based costs for the actual reductions in consumption are relatively low at €293,935, reflecting the comparatively low use of interruptible loads in 2017. By comparison, the capacity-based costs for contracting the interruptible loads in 2017 amounted to €26,940,103. The average interruptible load available in the period under review was 967 MW. The TSOs reported that their transaction costs for implementing the Interruptible Loads Ordinance amounted to €886,532 in 2017, making total costs for interruptible loads €28,120,570. The size of the total costs thus deviates from the surcharge pursuant to section 18 of the Interruptible Loads Ordinance, which contains the costs for 2016 and subsequent additions from previous years. The costs for contracting interruptible loads averaged at around €2,322 per month per MW.[63] In comparison, the costs for tertiary reserve amounted to about €1.24m[64] per month for an average capacity of 3,035 MW, which corresponds to an average of about €409 per month per MW.[65]

6. Findings from the data survey on demand-side management

In 2016 and 2017, the Bundesnetzagentur and the Federal Ministry for Economic Affairs and Energy (BMWi) monitored the contribution of demand-side management to the security of the electricity supply. In this data survey, which now takes place annually, the Bundesnetzagentur collects information from undertakings and associations of undertakings (final consumers) that have consumed at least 50 GWh of electricity per year in the last two calendar years. The authority's objective is to analyse the current and future contribution of demand-side management to security of supply on the electricity markets. In calculating the annual electricity consumption, all sites with at least 10 GWh were counted for final consumers with annual consumption of over 50 GWh.

Just under 470 undertakings with 1,010 sites took part in the 2016 survey, corresponding to a total electricity consumption of 150 TWh across all sites of these industrial companies. The number of participating undertakings rose to 490, with 1,112 sites, in 2017. The total electricity consumption of all these sites thus rose to 154 TWh.

[63] This figure differs from the capacity price of €2,500 per month per MW as set in the old ordinance and applicable until the new ordinance entered into force on 1 October 2016. The new ordinance sets a maximum capacity price of €400 per week per MW.

[64] These costs comprise the costs for both negative and positive tertiary reserve and cannot be broken down using the data available.

[65] The response time requirements for fast interruptions are comparable to those for tertiary reserve, while immediate interruptions can be activated significantly faster. In addition, there are further differences in quality between interruptible loads and balancing energy, for example with respect to availability.

Electricity consumption by sector/market coverage of DSM: 2016
(TWh/%)

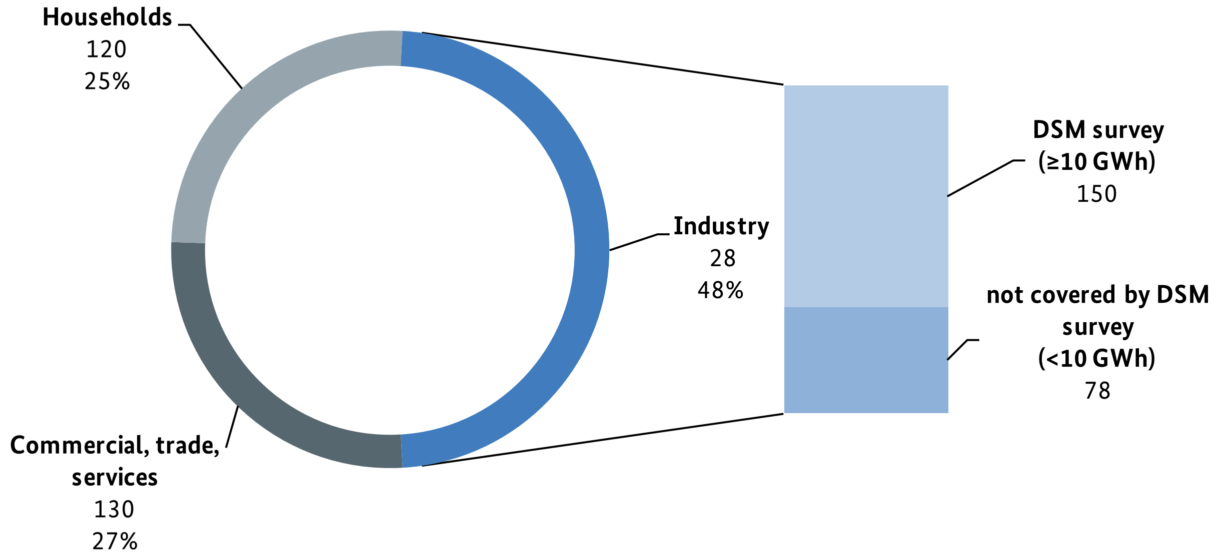

Figure 79: Electricity consumption by sector/market coverage of demand-side management: 2016

Electricity consumption by sector/market coverage of DSM: 2017
(TWh/%)

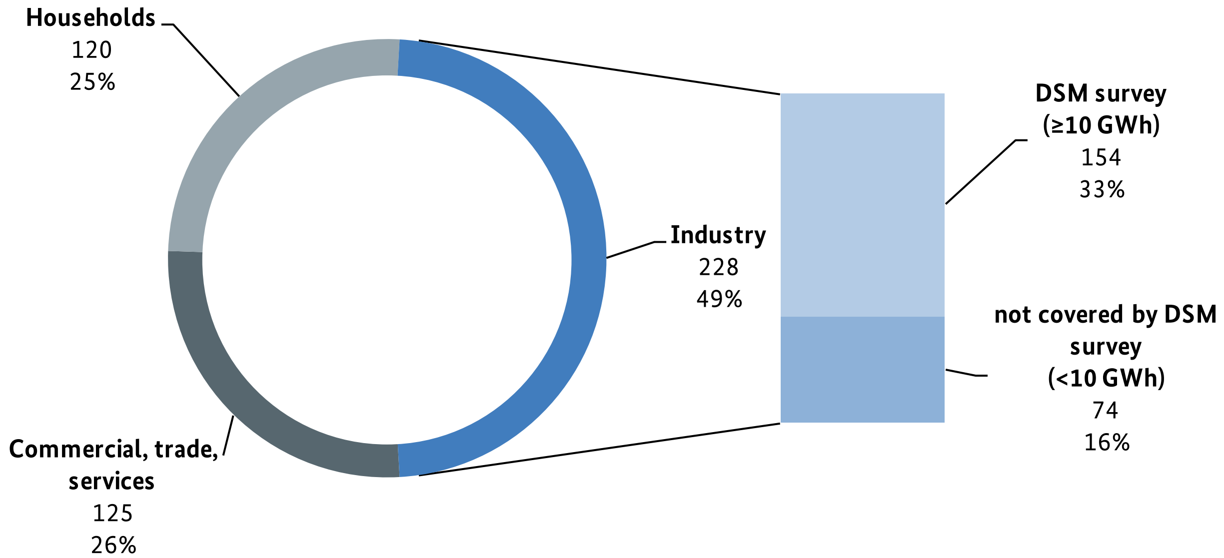

Figure 80: Electricity consumption by sector/market coverage of demand-side management: 2017

552 of the 1,112 sites participating in 2017 reported that they already had a demand-side management system in place, compared with 480 out of 1,010 in 2016. Major consumers from particularly energy-intensive

industries, such as chemicals, steel and paper, were particularly likely to use a demand-side management system. The highest proportion of sites operating a demand-side management system was for undertakings from the cement industry.

Undertaking sites with and without demand-side management system – top 10 in 2016
(Number of sites, annual consumption in TWh; sorted by Number of sites with DSM

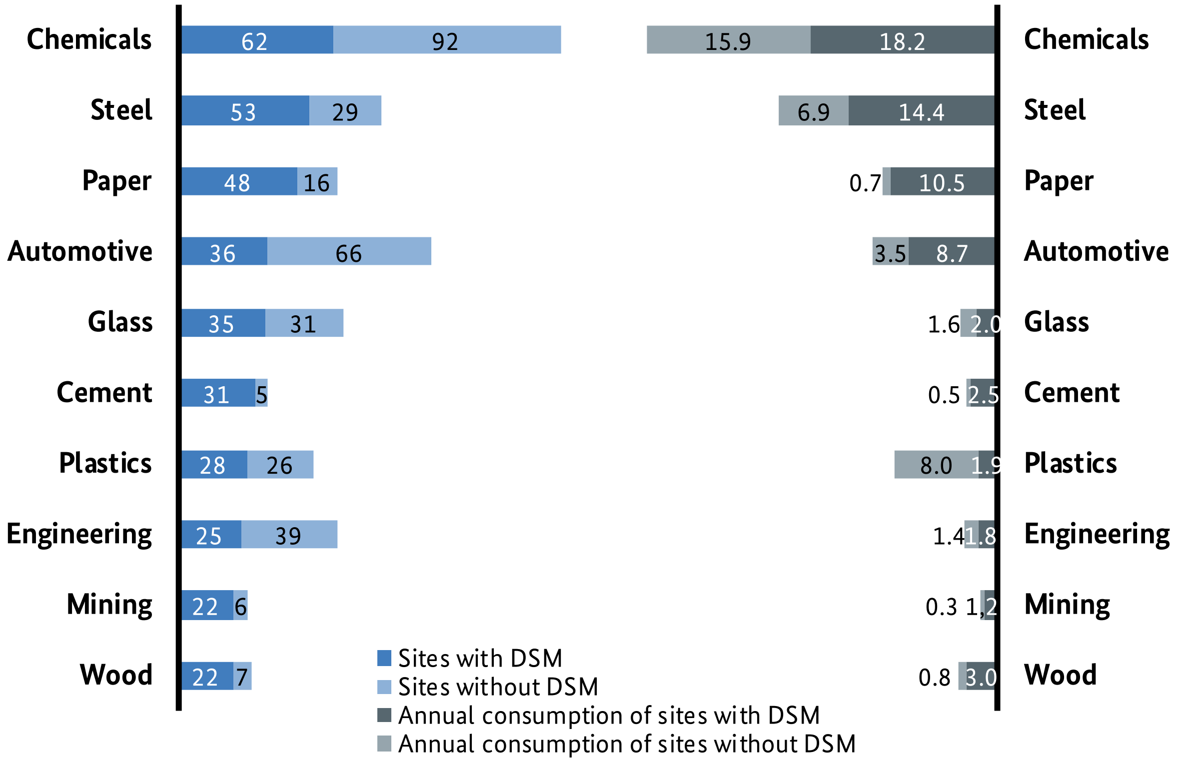

Figure 81: Undertaking sites with and without demand-side management system – top 10 in 2016

Undertaking sites with and without demand-side management system – top 10 in 2017
(Number of sites, annual consumption in TWh; sorted by Number of sites with DSM)

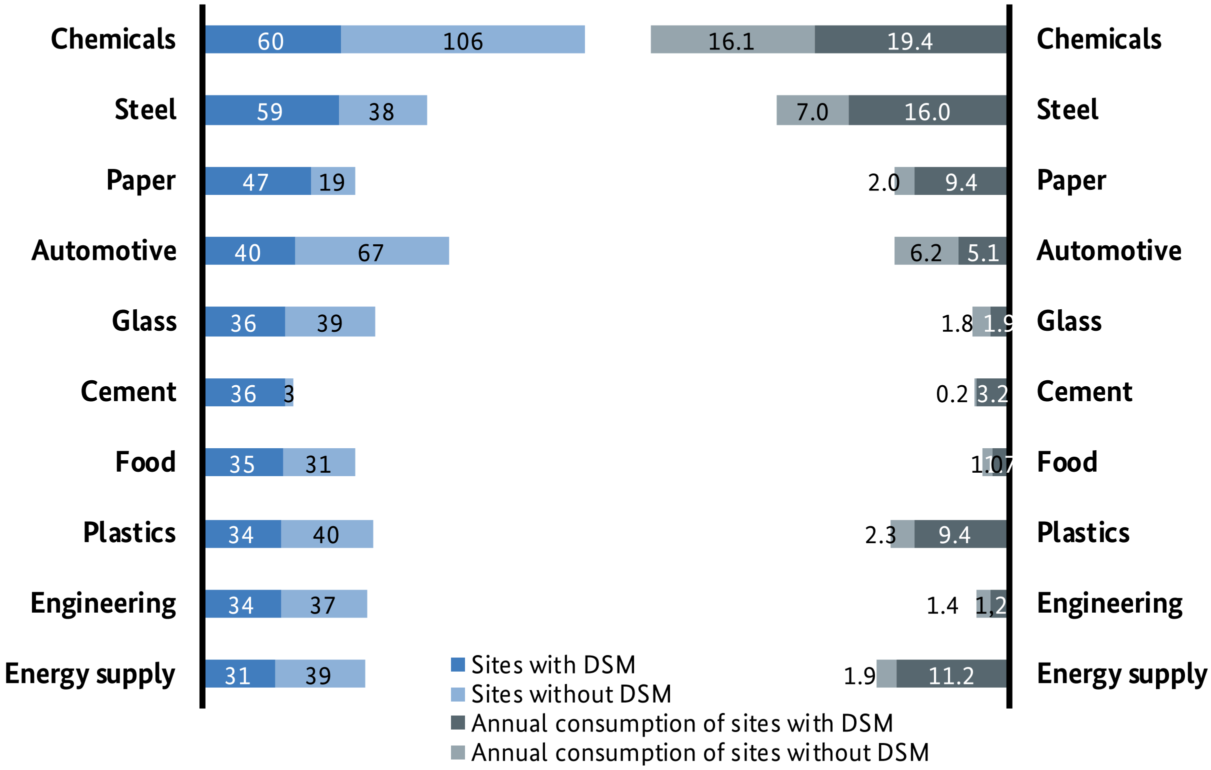

Figure 82: Undertaking sites with and without demand-side management system – top 10 in 2017

Undertakings specified as reasons for the use of demand-side management in particular section 17(2) of the Electricity Network Charges Ordinance (network charge optimisation – peak load reduction to reduce annual capacity price) and section 19(2) para 2 of the Ordinance (network charge reduction – compliance with annual minimum consumption and full load hours) as well as the optimisation of electricity purchase prices. The increase in responses giving section 17(2) of the Ordinance as their reason may be explained by the larger number of undertakings and sites responding and the explanation provided of the question. The Ordinance on Interruptible Load Agreements and redispatching were only rarely mentioned.

What reasons are given for using demand-side management at your site?
Number in 2016 and 2017

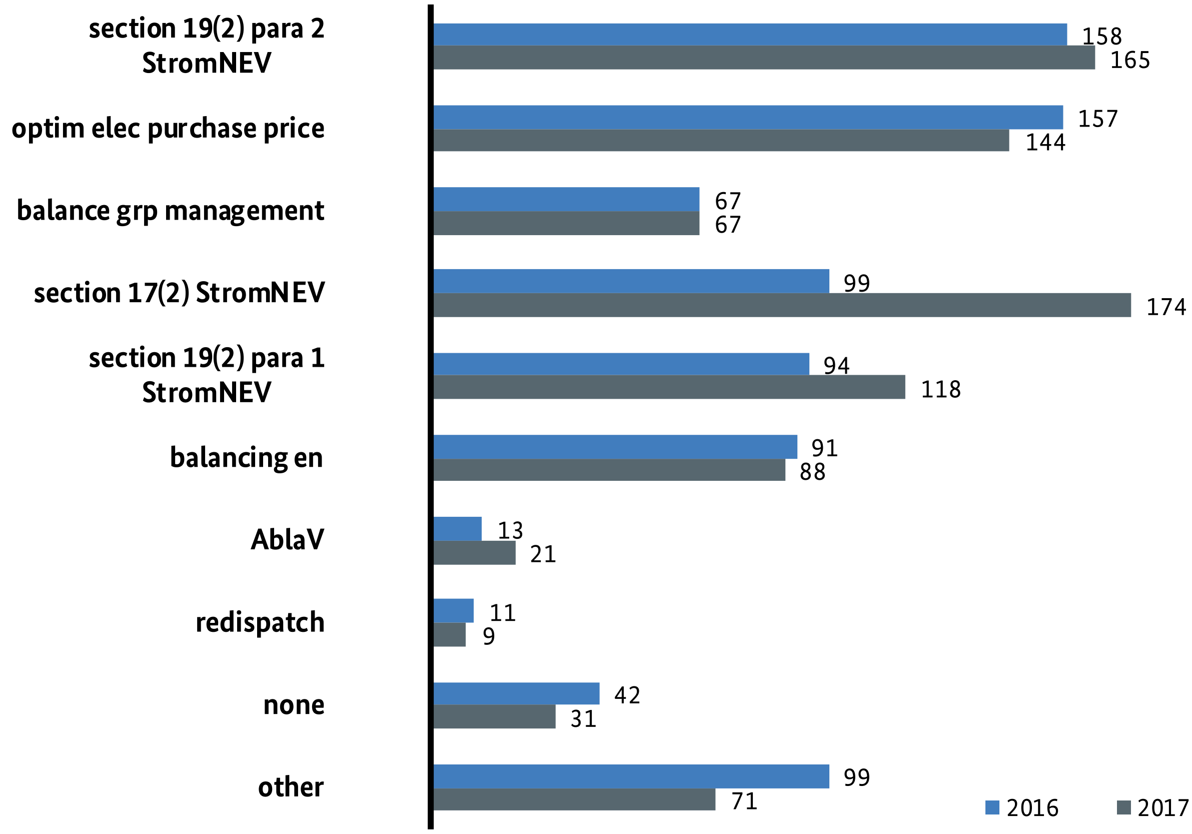

Figure 83: What reasons are given for using demand-side management at your site?

Sites generally control demand-side management themselves. In 2016, 415 sites (87%) said they controlled their demand-side management themselves. This figure rose by 69 sites, or 1.2%, to 484 in 2017. The table below provides an overview of the different types of control.

Please specify which party controls demand-side management at your site.
Number

Controlling party	2016	2017
Self	415	484
Company and network operator	18	25
Company and electricity supplier	14	16
Company and energy service provider	14	10
Company and third party	9	7
Network operator	4	4
Energy service provider	3	2
Other	2	2
Energy supplier	1	2
Total	480	552

Table 55: Data on control of demand-side management

In answer to the question about obstacles to using or increasing demand-side management, 832 sites (2016: 794) highlighted technical issues such as linked production processes, machinery utilisation and loss of productivity as reasons not to use demand-side management.

What are the obstacles to your undertaking using demand-side management?
(Number)

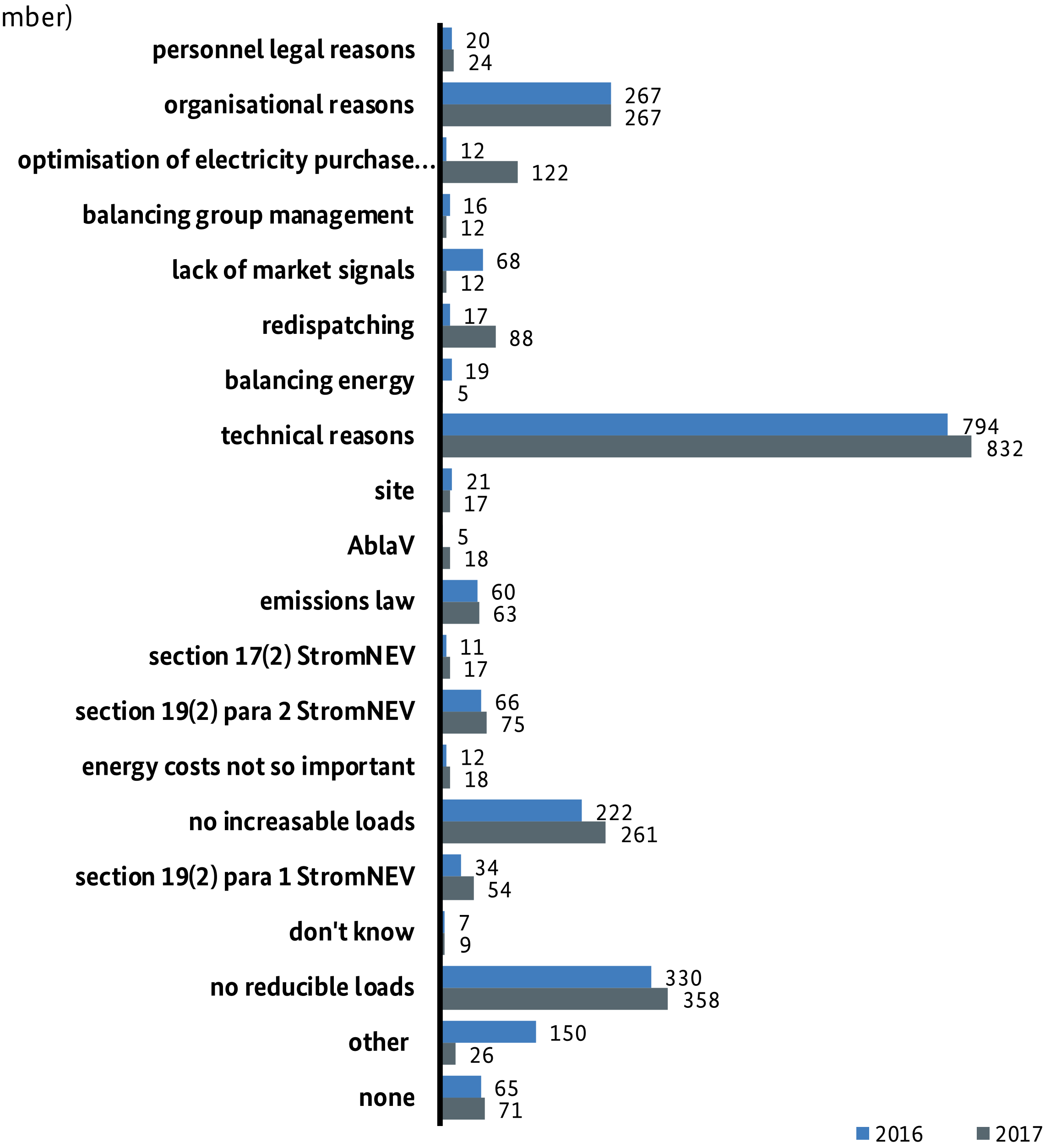

Figure 84: What are the obstacles to your undertaking using demand-side management?

The majority of registered sites are not planning any measures to reduce loads with demand-side management or to reduce them more than they already do. The breakdown can be seen in the chart below.

Are measures planned to employ demand-side management to reduce loads or to employ it to a greater extent than currently?

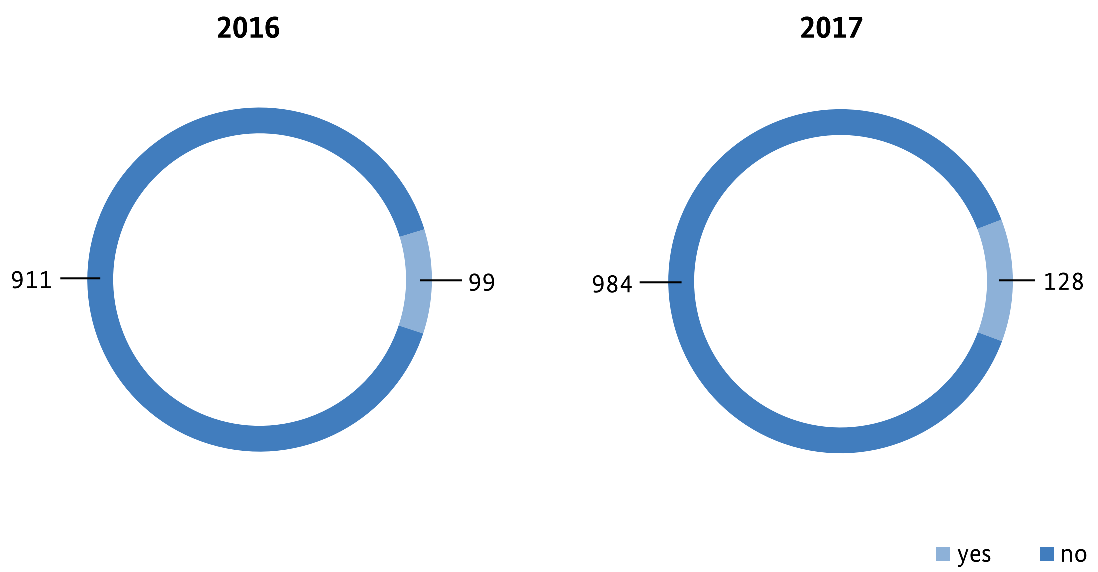

Figure 85: Are measures planned to employ demand-side management to reduce loads or to employ it to a greater extent than currently?

E Cross-border trading and European integration

The countries of the European Union are part of a European interconnected transmission system for the exchange of electricity in which Germany acts as a central hub. The aim of the envisaged European internal market for electricity is to integrate electricity markets more closely, to facilitate cross-border trade and to ensure a secure, cost-efficient and sustainable supply of electricity.

On the way to creating the internal market for electricity, Europe is currently divided into separate bidding zones, in which electricity prices are determined according to supply and demand. Electricity is transported within the bidding zone free of congestion (i.e. without capacity restrictions) from the generator to the consumer. In the monitored period Germany, Austria and Luxembourg constituted a common bidding zone with uniform prices. Due to price differentials between bidding zones electricity trade takes place also cross-border which may, however, be limited by capacity constraints, i.e. congestion.

As in previous years, Germany again exported considerably more electricity than it imported in 2017. Total cross-border traded volumes equalled 90.0 TWh in 2017. This is an increase of 15.2% on last year (2016: 78.1 TWh). Germany's export balance of 55.8 TWh and export surplus of €1,726 million makes it a major electricity exporter in Europe.

1. Average available transmission capacity

Transmission capacity between bidding zones is a scarce resource. Limited interconnector capacity and internal congestion limit the available capacity at the borders and consequently cross-border electricity trading.

In Europe the capacity made available to electricity markets is determined using the Net Transfer Capacity (NTC) values and the flow-based market coupling (FBMC) algorithm.

Net Transfer Capacity (NTC)

In the NTC process TSOs reach a bilateral agreement on the available – fairly long-term – cross-border capacity for trading. The overall trading capacity at the border is determined by the lowest NTC value of both sides of the border based on historical load flows affecting the part of the respective domestic grid leading to the border.

The average available transfer capacity was determined using the annual average of the German TSOs' hourly NTC values for this report. Gaps were filled using NTC values of the ENTSO-E transparency platform.

Flow-Based Market Coupling (FBMC)

Flow-Based Market Coupling for Central Western Europe (CWE: Belgium, Germany, France, Luxembourg, the Netherlands and Austria) calculates (exclusively) the day-ahead cross-border transmission capacity algorithmically. A grid model and the trading results are used to achieve a capacity allocation that maximises welfare. This method of calculation not only takes account of particular borders but of all the load flows in the area considered.

In order to estimate the evolution of cross-border capacity for this report, the maximum bilateral exchange is considered . This is the transmission capacity in a theoretical situation where no electricity is traded at any of the other borders considered. These hourly values are then used to calculate the average transmission capacity. The FBMC data for this report have been provided by the Joint Allocation Office (JAO).

The fundamentally different approach makes it impossible to directly compare the capacity values at NTC and FBMC borders with each other. The values for the development of German import and export capacities have therefore been aggregated and shown separately in Table 56 and Table 57.

Import capacity

Border	2015	2016		2017	
			Change compared to previous year (%)		Change compared to previous year (%)
NTC					
CH → DE	4,000.00	4,000.00	0	4,000.00	0
CZ → DE	1,233.11	1,295.00	5	1,289.89	< 1
DK → DE	777.95	731.03	-6	1,026.80	40
PL → DE	1,233.11	1,260.41	2	1,301.82	3
SE → DE	275.15	411.41	50	415.26	1
Flow-based					
FR → DE	3,765.66	4,011.40	7	3,763.79	-6
NL → DE	2,799.57	2,225.46	-21	2,345.85	5

Source: TSOs, ENTSO-E, JAO

Table 56: Overview of the development of import capacities

Export capacity

Border	2015	2016		2017	
			Change compared to previous year (%)		Change compared to previous year (%)
		NTC			
DE → CH	1,373.39	1,469.64	7	1,501.23	2
DE → CZ	430.92	139.44	-68	580.21	316
DE → DK	1,432.42	1,830.73	28	1,901.86	4
DE → PL	430.92	140.53	-67	604.14	330
DE → SE	158.83	350.61	121	248.32	-29
		Flow-based			
DE → FR	3,147.91	3,179.63	1	3,545.89	12
DE → NL	3,264.45	3,080.11	-6	2,917.94	-5

Source: TSOs, ENTSO-E, JAO

Table 57: Overview of the development of export capacities

Capacity has increased significantly following the installation of phase-shifting transformers on the borders between Germany and the Czech Republic and between Germany and Poland. Germany is connected with Sweden only by a single cable. This cable was out of operation for a period of time in 2017. This led to a drop in capacity. Capacity to Austria is not shown due to the common bidding zone which existed in 2017. Germany has no managed interconnection with Belgium.

Reasons for the long-term changes in capacity include construction of new transmission system lines and other grid elements (such as phase-shifters or transformers). Year-on-year changes in capacity may also be due to outages and maintenance work.

The bilateral agreement between Germany and Denmark brought about an increase in the capacity available for electricity trade across the border between Western Denmark and Germany in the second half of the reporting period. This agreement provides for a minimum capacity available for trading across the border between Western Denmark and Germany as well as a collaboration on countertrading measures between TSOs[66]. On the basis of this agreement, which involves an incremental increase in minimum capacities

[66] Countertrading is a measure taken by TSOs to avoid congestion. It is used when agreed minimum capacities available for cross-border trade exceed the actual transport capacity of the grid. In this case, a commercial transaction against the flow direction is organised to reduce the physical constraints on the grid. This guarantees a minimum of trading at all times without overloading the grids.

available for trade up to 1,100 MW by 2020, the minimum capacity available for trade was raised as planned to 400 MW by the end of 2017[67].

The European Commission has recently opened formal antitrust investigations into the bilateral agreement on electricity capacities available for trade at the Western Denmark border and is negotiating with the German TSO TenneT on increasing the minimum capacity available for trade up to 1,300 MW with no cost threshold and even further following the planned expansion of the interconnector.[68]

2. Cross-border load flows and implemented exchange schedules

The physical load flows[69] measured at bidding zone borders are confronted with the implemented exchange schedules. These are to be seen as virtual electricity flows triggered by commercial transactions. Electricity prices are formed in each bidding zone according to supply and demand. Cross-border commercial transactions take place until the differences in price in each of the zones are equalised or the available capacity for trade is exhausted. Commercial transactions (schedules) and thus physical load flows maximise welfare and economic efficiency by bringing electricity from a zone in which prices are temporarily lower to a zone where the price is higher. Theoretically, the balance of physical flows and trade flows should be practically identical. However, this is often not the case due to unscheduled flows (see I.E.3 on page 207 onwards), transmission losses, cross-border redispatch and measurement tolerances. As physical load flows always follow the path of least resistance, physical load flows and realised trade flows at individual borders may differ considerably from each other (see Figure 87). This is unavoidable in a highly meshed network with large bidding zones.

The implemented exchange schedules are decisive for assessing the net balance of electricity imports and exports at each external border and at all of Germany's borders as a whole. Figure 86 and Figure 87 show the realised exchange schedules and the physical load flows at Germany's borders in 2016 and 2017. Table 58 to Table 60 show summarised values.

[67] This value relates only to the western Denmark cross-border interconnector and is therefore lower than the capacity for Denmark as a whole.

[68] The commitment given by TenneT to the European Commission and an overview of the status of the antitrust procedure is available on the European Commission’s website at: https://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=1_40461 (Stand: 25 September 2018)

[69] i.e. the electricity which actually flows along the transmission line from the source (power plant) to the drain (consumer)

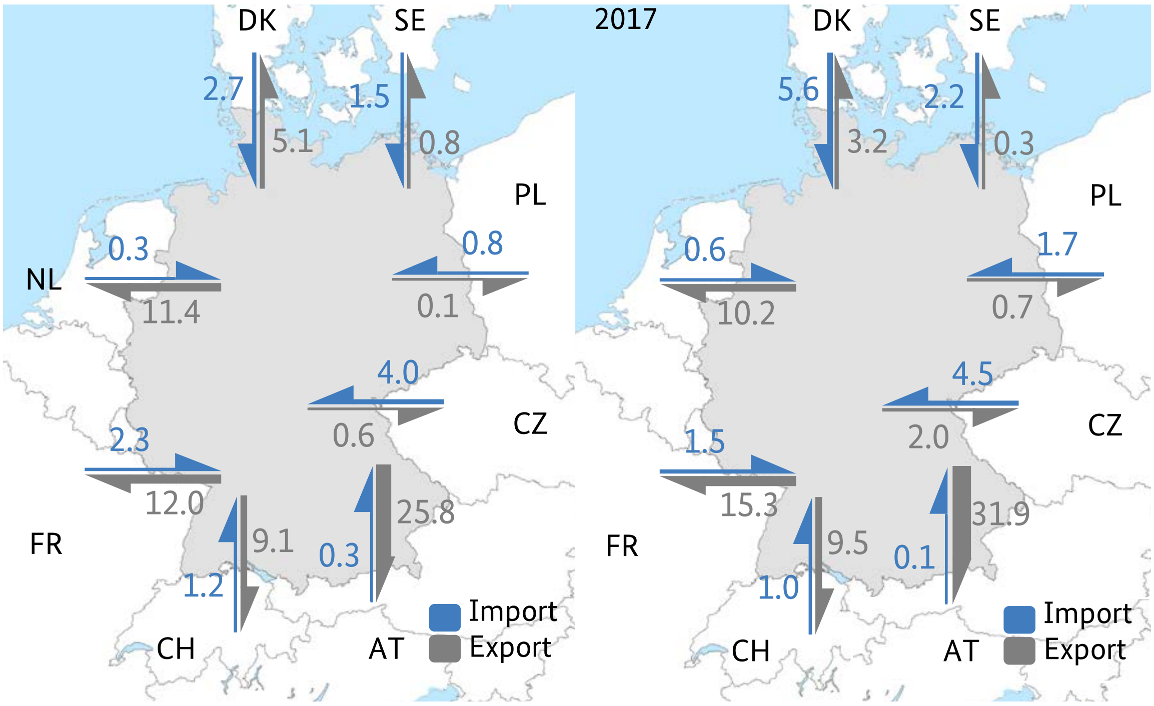

Figure 86: Exchange schedules (cross-border trading)

Physical flows (net) in TWh

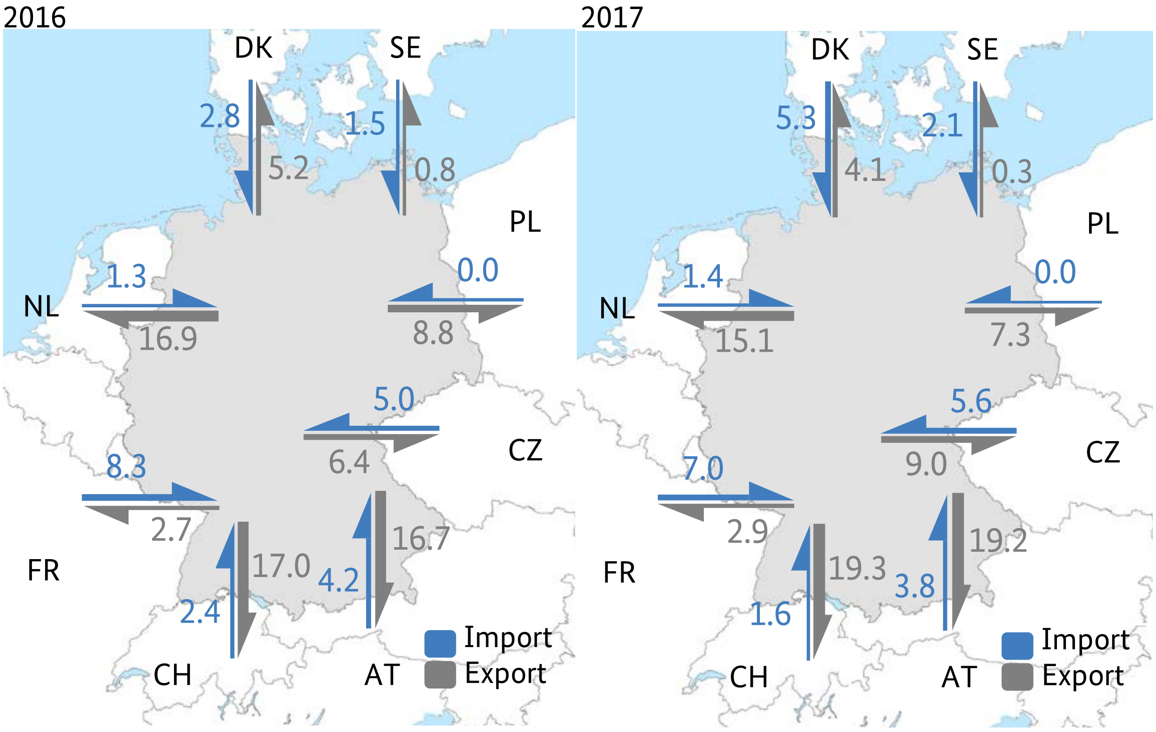

Figure 87: Physical flows

Comparison of the balance of cross-border electricity flows
(TWh)

	Actual physical flows in 2016	Binding exchange schedules 2016	Actual physical flows in 2017	Binding exchange schedules 2017
Imports	25.6	13.1	26.7	17.1
Exports	74.5	65.0	77.3	72.9
Balance	48.9	51.9	50.6	55.8

Source: TSOs, ENTSO-E

Table 58: Comparison of the balance of cross-border electricity flows

Comparison of imports from cross-border flows
(TWh)

	Actual physical flows in 2016	Binding exchange schedules 2016	Actual physical flows in 2017	Binding exchange schedules 2017
AT → DE	4.2	0.3	3.8	0.1
CH → DE	2.4	1.2	1.6	1.0
CZ → DE	5.0	4.0	5.6	4.5
DK→ DE	2.8	2.8	5.3	5.6
FR → DE	8.3	2.3	7.0	1.5
NL → DE	1.3	0.3	1.4	0.6
PL→ DE	0.0	0.8	0.0	1.7
SE → DE	1.5	1.5	2.1	2.2

Source: TSOs, ENTSO-E

Table 59: Comparison of imports from cross-border electricity flows

Comparison of exports from cross-border flows
(TWh)

	Actual physical flows in 2016	Binding exchange schedules 2016	Actual physical flows in 2017	Binding exchange schedules 2017
DE → AT	16.7	25.8	19.2	31.9
DE → CH	17.0	9.1	19.3	9.5
DE → CZ	6.4	0.6	9.0	2.0
DE→ DK	5.2	5.1	4.1	3.2
DE → FR	2.7	12.0	2.9	15.3
DE → NL	16.9	11.4	15.1	10.2
DE→ PL	8.8	0.1	7.3	0.7
DE → SE	0.8	0.8	0.3	0.3

Source: TSOs, ENTSO-E

Table 60: Comparison of exports from cross-border electricity flows

The following diagram clearly shows the extent to which actual physical flows differ from realised exchange schedules.

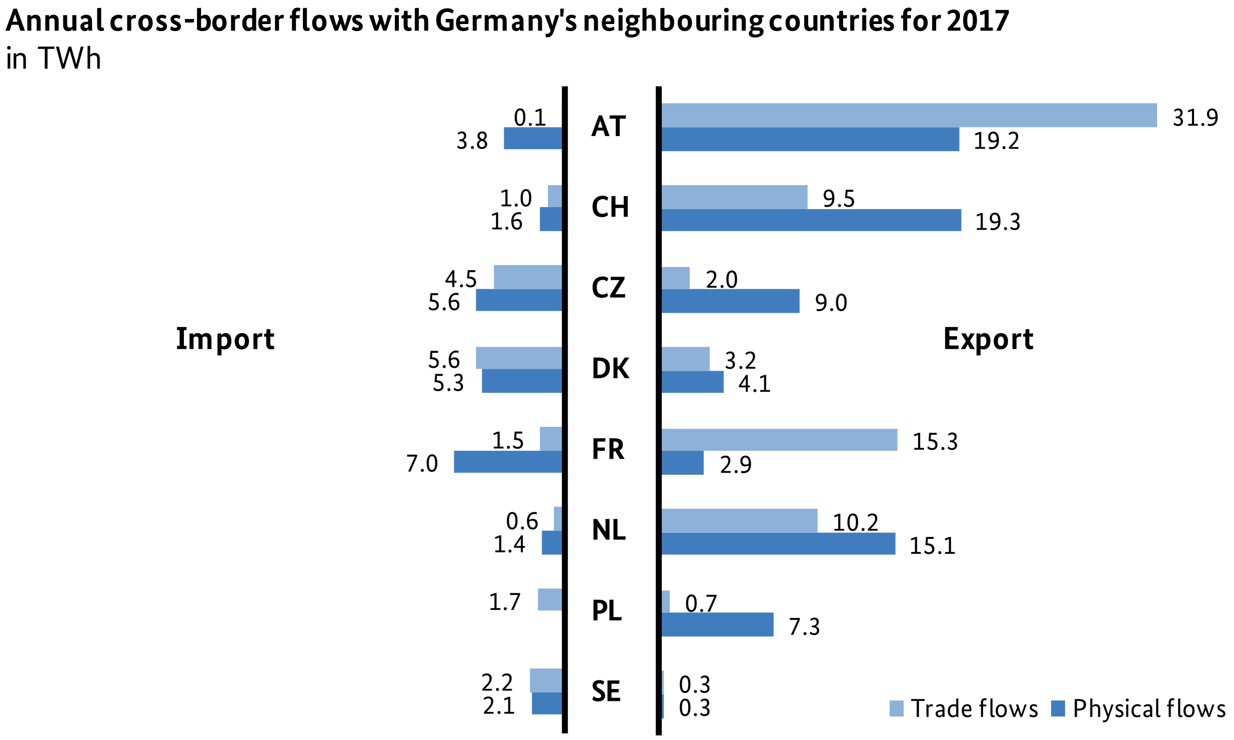

Figure 88: Total annual cross-border load flows and exchange schedules in 2017

Electricity trading between Germany and its European neighbours has been characterised by years of falling imports. However, imports rose again in 2017 for the first time since 2011. In contrast, net exports have risen continuously since 2011, reaching a new record in 2017 at 72.9 TWh after falling slightly in 2016.

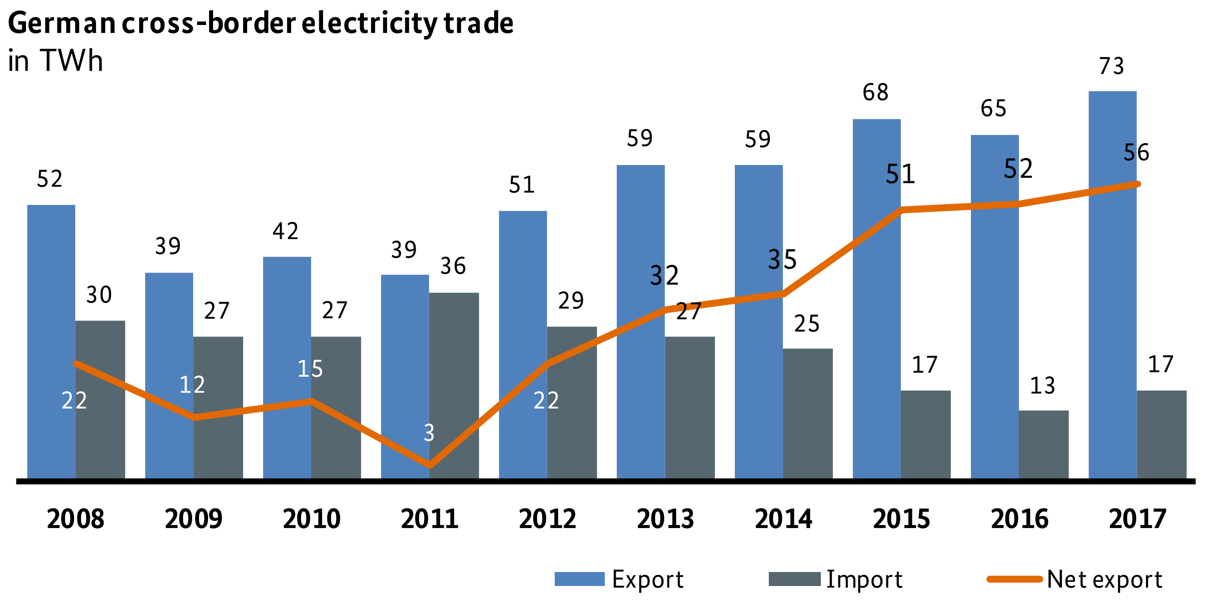

Figure 89: Germany's cross-border electricity trade

Imports and exports are evaluated by multiplying the traded volumes of realised exchange schedules with the day-ahead EPEX Spot price. Rational market behaviour is assumed insofar as longer-terms contracts will only be fulfilled if the price incentives are right. If this is not the case, electricity is purchased in the local market in which it is cheaper. The monetary value of electricity imported to or exported from Germany is calculated by regarding imports as costs and exports as revenues.

Monetary trends in cross-border electricity trade

	2016		2017	
	TWh	Trade volume (€)	TWh	Trade volume (€)
Exports	64.98	1,843,064,660	72.95	2,402,981,340
Imports	13.11	395,607,565	17.11	677,367,974
Balance	51.87	1,447,457,095	55.77	1,725,613,366
Export revenues (€/MWh)		28.36		32.94
Import costs (€/MWh)		30.18		39.60

Table 61: Monetary development of cross-border electricity trade (trade flows)

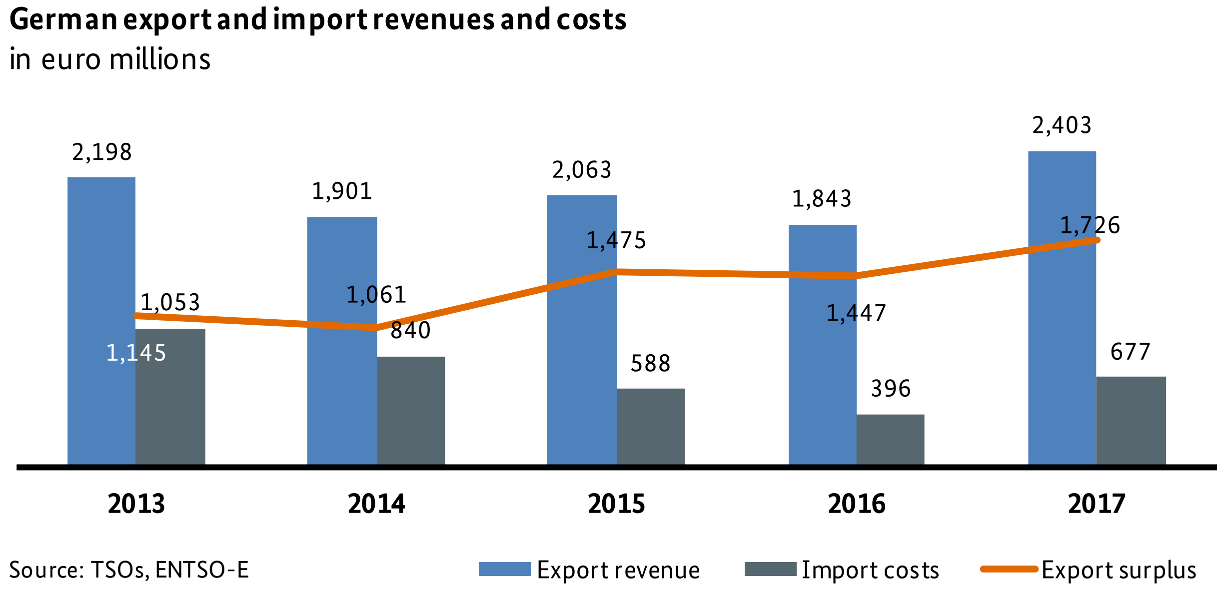

Figure 90: German exports and imports revenues and costs

Changes in cross-border trading volumes between Germany and its neighbouring countries reflect changes in price differences. The reasons for these differences depend on several factors that have a direct influence on the merit order and therefore in particular on wholesale prices in the individual countries. This means that changes in traded volumes are not determined solely by the German market, but also reflect shifts in supply and demand in each neighbouring country.

3. Unscheduled flows

Electricity always flows from a source to a sink taking the path of least resistance. For this reason, unscheduled flows cannot be avoided in an electricity trading system which is organised in zones. Unscheduled flows occur if the volume of electricity sold differs from the actual physical flows of electricity. Unscheduled flows can take two particular forms. Transit flows of electricity run from one bidding zone to another passing through a zone which is not involved in the commercial transaction. Loop flows of electricity occur when power from one bidding zone passes through a bidding zone which is not involved in the commercial transaction before returning to the zone from which it originated. There are no clear dividing lines between the effects of both types of flow. As large producer of energy in Europe and due to its geographical position as a large territorial state in the centre of Europe, Germany induces and absorbs unscheduled both transit and loops flows in and from neighbouring countries.

The unscheduled flows are determined as annual aggregate figures from the difference between the physical flow and the realised exchange schedules thereby deducting the export surplus from the physical exports.

The following example demonstrates how unscheduled flows are calculated: In 2017, Germany imported (trade) 0.6 TWh from and exported 10.2 TWh to the Netherlands. This is equal to an export surplus (trade) of 9.6 TWh. At the same, 1.4 TWh flowed physically from the Netherlands to Germany. In contrast, 15.1 TWh flowed from Germany to the Netherlands. This is equal to an export surplus (physical) of 13.7 TWh. This means that on balance (trade minus physical) 4.1 TWh of electricity flowed from Germany to the Netherlands which had not been traded between the two countries. This is called an unscheduled flow.

The following diagrams show the unscheduled flows, arising from the difference between the net physical and trade flows from the Germany/Austria/Luxembourg market area to its neighbouring countries and vice versa.

Unscheduled flows
in TWh

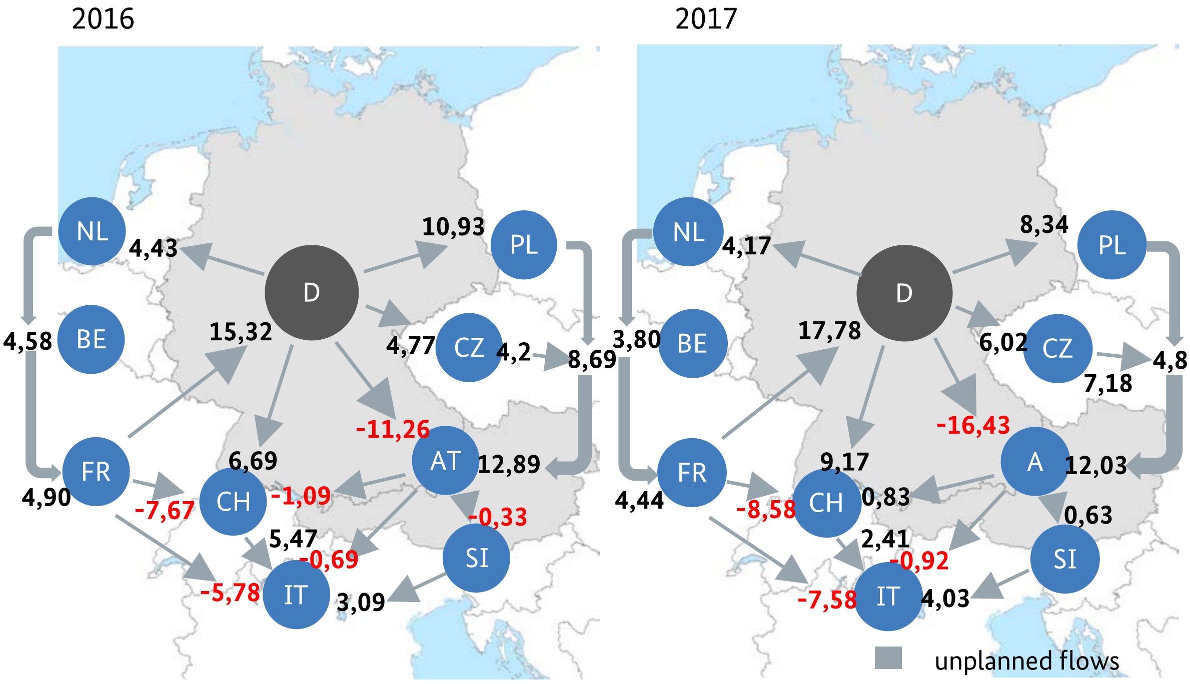

Figure 91: Unscheduled flows in 2017 compared to 2016

The arrows show the main direction of physical flow and the figures show the trade deficit: red figures reflect a physical deficit (trade > physics) while the black figures represent a trade deficit (physics > trade).

The figures show that some electricity flows across the western border of Germany to the Netherlands, through Belgium and France and then back to Germany. In return, loop and transit flows from France spill over into the power grids of southern Germany in particular. When this happens, the electricity which is traded in France does not flow directly from France to Switzerland, to Italy or to its destinations on French territory, but takes a detour through Germany. On Germany's eastern border, some electricity likewise flows into the Czech and Polish grid systems on its way to Austria. Unscheduled flows stemming from the German transmission network also loop through the Czech grid before returning to the German transmission network and being consumed there.

Irrespective of all expansion measures, electricity trading between different market areas inevitably results in unscheduled flows. These unscheduled flows are the result, in particular, of the high volumes transported as a result of trading within Germany and Europe. Germany is participating actively in various measures to prevent the problem of unscheduled flows leading to instable grid operation in other countries or to restricted electricity trading. A cross-border redispatch regime was first established by installing a virtual phase-shifting transformer at the German-Polish border which reduced unscheduled flows and increased network stability in Poland and Germany. The virtual phase-shifting transformer will be replaced as soon as all the physical phase-shifting transformers planned at the cross-border interconnectors have been installed. The partial installation and operation of physical phase-shifting transformers and the shut-down of the Vierraden-Krajnik line has already successfully reduced load flows between Germany and Poland to safe levels. Two physical phase-shifting transformers have also been installed at the northern cross-border interconnector towards the Czech Republic and four more have gone into operation on the Czech side of the border. Congestion management at the German-Austrian border limits transmissions to 4.9 GW and will significantly reduce loop flows through Poland and the Czech Republic compared to current levels with unrestricted trade.

4. Revenue from compensation payments for cross-border load flows

Under Article 1 of Regulation (EU) No 838/2010, the TSOs receive inter-TSO compensation (ITC) for the costs incurred from hosting cross-border flows of electricity (transit flows) on their networks. ENTSO-E established an ITC fund for the purpose of compensating the TSOs. The fund will cover the costs of losses incurred on national transmission systems as a result of hosting cross-border flows of electricity and the costs of making infrastructure available to host these cross-border flows.

ACER reports to the European Commission each year on the implementation of the ITC mechanism as required in point 1.4 of Part A of the Annex to Commission Regulation (EU) No 838/2010. The latest figures for the ITC year[70] 2017 are the following: The four German TSOs received compensation for losses and the provision of infrastructure totalling €2.32m and paid in return contributions of €4.47m. This means that on balance the German TSOs contributed a net amount of €2.15m to the ITC fund. As a result, Germany was a net contributor to the ITC fund in 2017 for the third year running (2016: -€12.48m, 2015: -€6.1m, 2014: €7.65m, 2013: €13.21m, 2012: €26.8m). This trend has emerged over a period of several years and is mainly due to the large increase in Germany's electricity exports and the related cross-border flows. Nonetheless, the net contributions were significantly lower than in the two previous years.

5. Market coupling of European electricity wholesale markets

The procedure for making efficient use of the limited transmission capacity available between the participating countries/bidding zones is commonly called market coupling. Market coupling is organised by TSOs together with power exchanges. Bids and offers of market participants are collected and matched while at the same time allocating cross-border transmission capacity for different bidding zones. This is also referred to as implicit capacity auctions.

The so-called MRC (Multi-Regional Coupling) now couples 20 European countries (accounting for approximately 85% of European electricity consumption). Between these countries power can be traded implicitly on exchanges for as long as sufficient cross-border transmission capacity is available.

[70] Compensation and contributions for an ITC year are calculated by the TSOs retroactively for each calendar year (settlement period), resulting in a delay of about six months between the end of a settlement period and the time when compensation and contributions are actually paid.

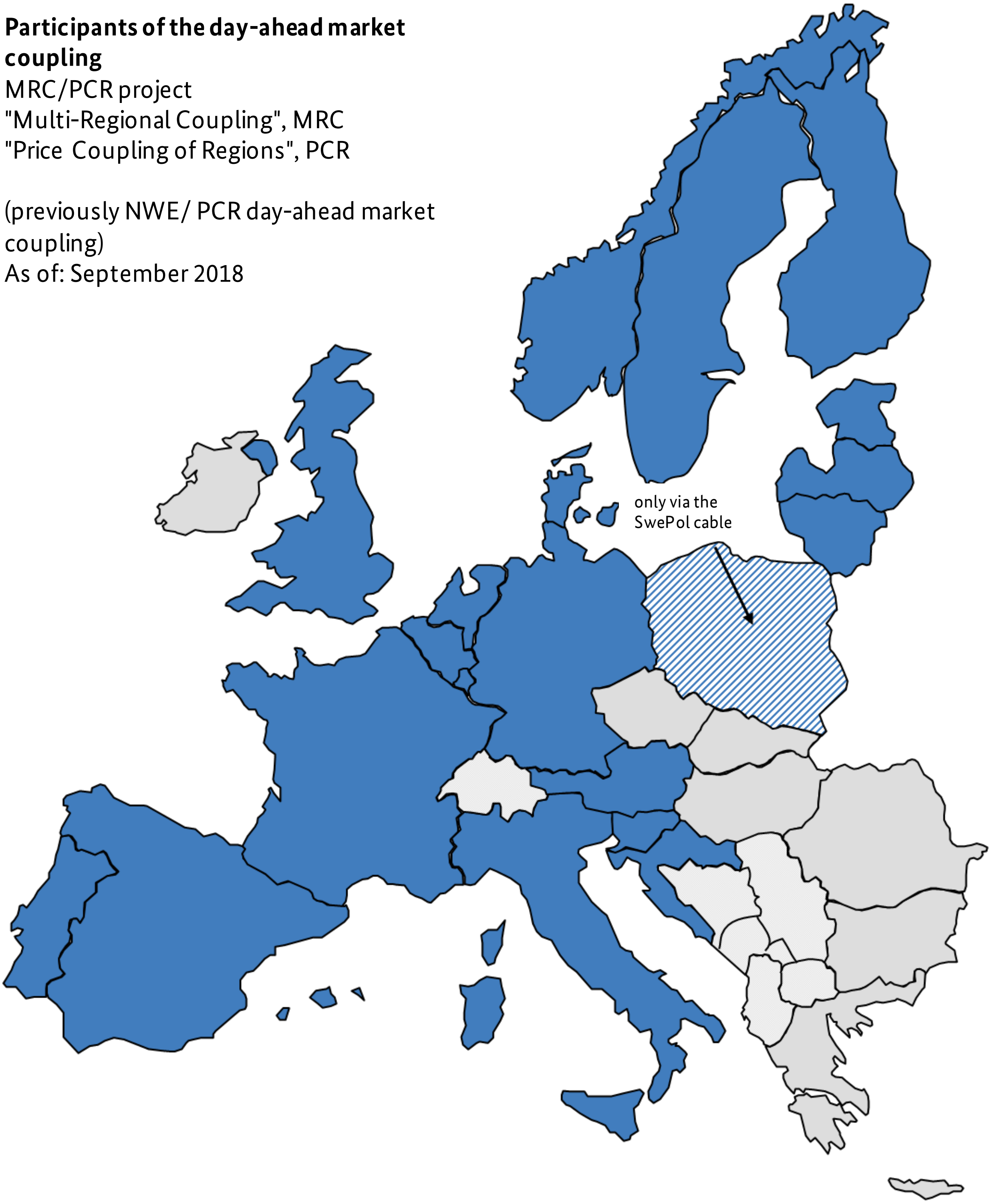

Figure 92: Countries participating in day-ahead trading in the MRC

The aim of market coupling is the efficient use of available day-ahead transmission capacity between the participating countries. This reduces the welfare losses that may result from congestion between the countries. As a result, the process therefore leads to an alignment of prices on the national day-ahead markets involved. Indeed, price convergence, which serves as an indicator of the efficient use of interconnector capacity, is significantly higher in coupled regions than in uncoupled regions.

At the European level, the Bundesnetzagentur is coordinating the implementation of market coupling throughout the whole of Europe as part of the cooperation of regulatory authorities within ACER.

6. Capacity allocations based on load flows

The Commission Regulation establishing a guideline on capacity allocation and congestion management (known as the CACM guideline) defines flow-based market coupling as the target model for central Europe. The essential basis for this is provided by a flow-based capacity calculation. This involves calculating cross-border capacities available for trade in dependence of the trade volumes at all other bidding zone borders and the load on the power lines resulting from the economic (scheduled) flows. This warrants higher transmission system security and an improved utilisation of transmission capacity between countries.

The flow-based capacity calculation method was successfully launched in the CWE region (the borders between AT, BE, DE, FR, LU and NL) in 2015. As was expected from analyses before, the actual results have confirmed an increase in transmission capacity and, consequently, a higher price convergence between the participating countries on the day-ahead electricity markets.

A decision was taken by ACER in September 2016 to merge the former regions of Central East Europe (the CEE region, i.e. the borders between AT, CR, CZ, DE, HU, PL, RO, SI, SK) and Central West Europe (CWE) into a common capacity calculation region, referred to as “Core”.

The flow-based capacity calculation method will continue to be further developed in CWE until this method is expected to be applied in the whole new Core region in the first six months of 2020. This will include determining a minimum share of capacity which must be made available for cross-border electricity trade on all the relevant power lines. Following the introduction of congestion management at the German-Austrian border on 1 October 2018 this border will be integrated in the CWE Region. In this way the capacity available for trading at the day-ahead market will be determined as a function of the other borders in this region.

The work in the Core region is coordinated by a special joint working group with the participation of all the regulatory authorities and TSOs. The first step was for the TSOs to develop a common proposal for a capacity calculation methodology in line with the CACM guideline which was submitted to the regulatory authorities for approval in mid-September 2017. Following a detailed evaluation, an initial request to the TSOs to amend the proposed method was made in March 2018. A revised version was submitted by the TSOs in June 2018. After an in-depth deliberation by the regulatory authorities, the procedure was transferred to ACER in August 2018 for the Agency to take a decision on that matter.

7. Current status regarding European regulations for the electricity sector

A great deal of progress was made in 2017 on the development and implementation of the EU network codes and guidelines in terms of harmonisation of European electricity trading and the deepening of the single European electricity market in the areas of grid connection, market and system operation. The Electricity Balancing Guideline (EB) and System Operation Guideline (SO) as well as the Emergency and Restoration Code (E&R) were the last three EU regulations that have entered into force and which were still negotiated in the comitology procedure in 2016.

Grid connection

All three network codes on the requirements for grid connection, RfG (Regulation (EU) 2016/631), DCC (Regulation (EU) 2016/1388) and HVDC (Regulation (EU) 2016/1447), entered into force in 2016 to create - as much as possible - harmonised grid connection conditions for market players with the aim of implementing the single European market for electricity and for reasons of network stability.
Each of the three grid connection codes provides considerable scope for action at national level. Germany's legislator used the scope provided and, in connection with the amendment of the Renewable Energy Sources Act (EEG) in 2017, assigned in section 19 of the Energy Industry Act (EnWG) the responsibility for defining the technical connection requirements – taking into account the framework conditions of the three network codes – to VDE, the German Association for Electrical, Electronic & Information Technologies. The Bundesnetzagentur is responsible above all for defining the threshold values on which the generator requirements are based, setting the criteria for applications for granting exemptions from the technical connection requirements and dealing with appeals from parties seeking connection.

Market

Transmission system operators and nominated electricity market operators are working with national regulatory authorities and ACER on the implementation of the CACM guideline (Regulation (EU 2015/1222), which came into force in 2015, for cross-border congestion management, capacity calculation and capacity allocation for day-ahead and intraday trading.

In this context the congestion income distribution methodology, the generation and load data provision methodology and the plan for the joint implementation of the market coupling operator (MCO) function were completed in 2017 and a proposal on harmonised maximum and minimum clearing prices at the European level adopted.

The FCA guideline on long-term forward capacity allocation (Regulation (EU) 2016/1719), which entered into force in 2016, is currently also being implemented. In 2017 the TSOs worked with the national regulatory authorities and ACER to establish the generation and load data provision methodology (Art. 17 FCA GL), the methodology for establishing the single allocation platform for long-term capacity products (Art. 49 FCA GL) and the arrangements for sharing the related costs (Art. 59 FCA GL).

The GL EB guideline on electricity balancing (Regulation (EU) 2017/2195), stipulating requirements for the integration of what are still largely nationally organised balancing markets and on the cross-border exchange of balancing energy, came into force on 23 November 2017. The first steps towards implementation by TSOs, national regulatory authorities and ACER are planned for the end of 2018.

System operation

The SO guideline on electricity transmission system operation (Regulation (EU) 2017/1485) came into effect on 14 September 2017. The Regulation provides for harmonised operational security requirements and the definition of security limits. It also adapts the procedure for the internal and cross-border notification of schedules as well as sets the minimum technical requirements for balancing energy and its relevant limits for cross-border exchange. In addition it establishes binding rules for load frequency control in the form of technical minimum thresholds and defined procedures. Implementation began in early 2018.

The E&R network code on electricity emergency and restoration (Regulation (EU) 2017/2196) also concerns system operation. The network code came into force on 24 November 2017 and implementation will begin in 2019.

7.1 Early implementation of the cross-border intraday project

The cross-border intraday project (XBID project) is intended to facilitate implicit intraday trading across the bidding zone borders of participating European countries. The project covers the territories of the following EU and EEA Member States: Germany, France, the Netherlands, Belgium, Luxembourg, Austria, the United Kingdom, Denmark, Sweden, Finland, Norway, Spain, Italy, Portugal, Greece, Estonia, Latvia, Lithuania. Switzerland, which originally participated as an observer, has now left the project as the agreement between Switzerland and the EU required by Article 1(4) and (5) of the CACM guideline and relating to cooperation in the electricity sector had not been reached by the end of 2016.

In 2017, work was undertaken in particular on the implementation of the XBID platform. The platform, which will comprise a capacity management module and a joint order book, will be used to bundle and then link the power exchanges' local electricity trading systems with the TSOs' available cross-border transmission capacity. This will facilitate the continuous and implicit matching of electricity trading supply offers in one bidding zone with demand in another bidding zone of this region, provided that sufficient cross-border transmission capacity is available to realise the trades. To enable the bundling of the order books and the capacity calculations, the parties to the project also worked on developing local implementation projects at the same time as developing the main platform.

XBID was put into operation successfully on 12 June 2018 after an extensive test phase. The platform is also to be extended in the future to cover other European countries (Croatia, Poland, Czech Republic, Hungary, Romania, Slovenia).

7.2 Early implementation of the bidding zone review process

The focus of discussion in Europe on the future electricity market design is increasingly also set on the amendment of currently existing bidding zones. In this respect, the CACM guideline provides for a review every three years, beginning with the entry into force of the Regulation (2015), of the efficient configuration of the existing bidding zones by the participating TSOs, national regulatory authorities and ACER.

The process for the bidding zone study was launched in 2013 as an CACM “early implementation” and carried out by the European Network of Transmission System Operators for Electricity (ENTSO-E). The technical report providing the underlying data was submitted by the TSOs in January 2014. Based on this report ACER decided in December 2016 to launch the bidding zone review. Two consultancy firms provided support with the calculation of the model-based scenarios. The bidding zone study was completed and published on 5 April 2018 following a public consultation which was held in spring 2018. The study considered various expert-based scenarios on the splitting and merging of bidding zones. Splitting the large territorial states Germany, France and Poland, merging Netherlands-Belgium and Slovakia-Czech Republic, splitting Germany-Austria and the existing bidding zones configuration have all been analysed. The analysis has, in the unanimous view of the participating regulatory authorities and European TSOs, turned out to be insufficiently reliable. It only provided a qualitative evaluation of the different bidding zone areas as the model-based results were unusable.

The complexity of the chosen methodology (nodal pricing approach with flow-based calculation) and the data availability (differing ways of operating and controlling the 220kV grid) was such that a final and specific recommendation could not be made. The report therefore recommends maintaining the existing bidding zone configuration in Europe. The Bundesnetzagentur welcomes this outcome and has worked within the process to ensure that appropriate account is taken of criteria such as planned grid expansion. The resulting grid status is sufficient.

F Wholesale market

Well-functioning wholesale markets are vital to competition in the electricity sector. Spot markets, where electricity volumes that are required or offered at short notice can be bought or sold, and futures markets, which permit the hedging of price risks and speculation in the medium and long term, play an equally important role. Sufficient liquidity, that is, an adequate volume on the supply and demand sides, increases the scope for new suppliers to enter the market. Market players are given opportunities to diversify their choice of trading partners and products as well as their trading forms and procedures. Besides bilateral wholesale trading (referred to as over-the-counter trading or OTC), electricity exchanges also create reliable trading places and provide important price signals for market players in other areas of the electricity industry.

There was a strong decline in the trading volume or liquidity on the electricity wholesale markets in 2017. One reason for this is the decline in long-term contracts due to the introduction of congestion management at the German-Austrian border on 1 October 2018 which de facto split the joint Germany/Austria market area (so-called bidding zone splitting).[71] Market players on the EEX were able to prepare for this development early on with new products for trading solely in the German market area – with so-called Phelix-DE contracts. It was apparent by the end of 2017 that the trading volume had clearly shifted from Phelix-DE/AT to Phelix-DE due to the introduction of the congestion management. Volumes in on-exchange futures trading and volumes traded via broker platforms also decreased. There was also a significant decline in the volume of over-the-counter (OTC) clearing of Phelix-DE/AT futures on the EEX in 2017. This was also caused by the introduction of the new product Phelix-DE. In 2017 the OTC clearing volume of Phelix-DE/AT exceeded the volume of exchange trading. The spot market witnessed various developments. There was a slight decline in the volume of day-ahead trading whilst the volume of intraday trading rose by around 15%.

In 2017 average electricity wholesale prices rose again for the first time since 2011. Spot market prices rose by around 18% year-on-year and futures contracts for the subsequent year were around 22% higher.

1. On-exchange wholesale trading

As in previous years, the review of on-exchange electricity trading relates to the market area covering Germany, Austria and Luxembourg and to the exchanges in Leipzig (European Energy Exchange AG – EEX), Paris (EPEX SPOT SE)[72] and Vienna (Abwicklungsstelle für Energieprodukte AG– EXAA). These exchanges took part in collecting energy monitoring data again this year.[73] Since Germany, Austria and Luxembourg constituted a common bidding zone in 2017, the specific electricity "products" were traded on all three exchanges at exchange prices that are the same for the three countries ("single price zone"). EEX offers

[71] This bidding zone was dissolved on 1 October 2018, leaving a separate German/Luxembourg and German/Austrian bidding zone. The Bundesnetzagentur and the Austrian energy regulator E-Control agreed on this measure on 15 May 2017. Cf:. https://www.bmwi.de/Redaktion/DE/Pressemitteilungen/2017/20170515-bnetza-e-control-einigen-sich.html (retrieved on 13 September 2018) [Verlinkung zur EN-Seite?]

[72] EEX and EPEX SPOT are affiliated under corporate law; the EEX Group is the indirect majority shareholder of EPEX SPOT SE.

[73] In addition, Nord Pool Spot AG also provides facilities for the trading of electricity destined for Germany. It offers intraday trading to Germany as the supply area and is gaining in importance. The trading volume in 2017 was around 2.5 TWh, (in 2016: approx.1.5 TWh). Nord Pool Spot AG also offers the trading of market coupling products for Germany (from and to Sweden or Denmark)

electricity products in futures trading; EPEX SPOT SE and EXAA supply electricity products on the spot markets

The total number of participants authorised at the electricity exchanges in the market area covering Germany, Austria and Luxembourg has grown for years and reached a new all-time high on the EEX on 31 December 2017. The number of participants authorised at EPEX Spot fell minimally to 203 and the number of participants on EXAA fell to 72.

Development of the number of registered electricity trading participants on EEX, EPEX SPOT und EXAA

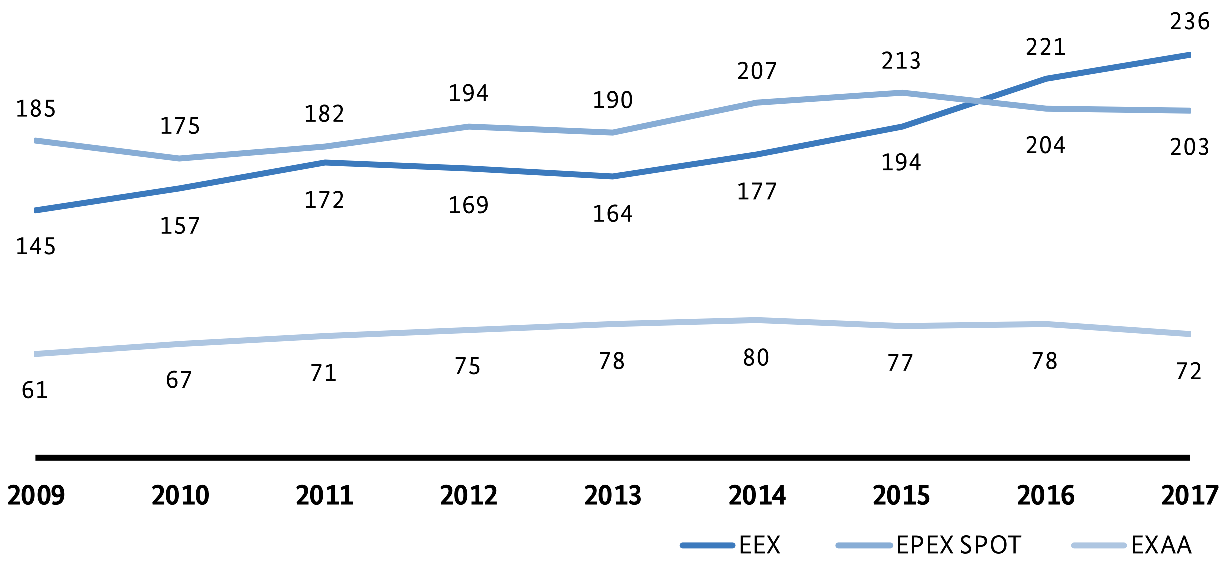

Figure 93: Development of the number of registered electricity trading participants on EEX, EPEX SPOT and EXAA

Not every company requires its own access to the exchange. Alternatively, companies can use the services offered by brokers that are registered with the exchanges. Large corporations often combine their trading activities in an affiliate with relevant exchange registration. In the categories according to which EPEX SPOT and EEX classify their exchange participants[74], in 2017 most of participants were supra-regional suppliers and energy trading companies or electricity producers, followed by municipal utilities and regional suppliers, then financial service providers and credit institutions. Only few participants are commercial consumers. Transmission system operators (TSO) are mainly active on EPEX Spot.

[74] EXAA does not classify its exchange participants.

Classification of registered electricity trading participants on EEX and EPEX SPOT on 31 December 2017

	EPEX SPOT	EEX
Transmission system operators	4	2
Commercial consumers	9	5
Financial service providers and credit institutions	6	52
Municipal utilities and regional suppliers	50	75
Supra-regional suppliers and energy trading companies (EEX) or electricity producers and energy trading companies (EPEX SPOT)	134	102
Total	**203**	**236**

Table 62: Number of registered electricity trading participants by EEX and EPEX SPOT classification on 31 December 2017

Futures trading and spot trading perform different but largely complementary functions. While the spot market focuses on the physical fulfilment of the electricity supply contract (supply to a balancing group), futures contracts are largely fulfilled financially. Financial fulfilment means that ultimately no electricity is supplied between the contracting parties by the agreed due date; instead, the difference between the pre-agreed futures price and the spot market price is compensated in cash. The bids that can be placed on EPEX SPOT for Phelix futures originating from futures trading on EEX for physical fulfilment provide the relevant link. The on-exchange spot markets (section I.F.1.1) and the futures markets (section I.F.1.2) are dealt with separately below.

1.1 Spot markets

Electricity is traded on the on-exchange spot markets a day ahead and for the following or current day (intraday). The two spot markets examined here, EPEX SPOT and EXAA, offer day-ahead trading and continuous intraday trading. Contracts can be physically fulfilled (supply of electricity) on the two on-exchange spot markets for the Austrian control area (APG), for Luxembourg (Creos) and for the four German control areas (50Hertz, Amprion, TenneT, TransnetBW).

The day-ahead auction on EPEX SPOT takes place at 12 noon every day; the final result is published at 12.40 p.m. Auctions on EXAA are held on five days a week at an earlier time than those on EPEX SPOT (trading closes at 10:12 a.m. and the final result is announced at 10:30 a.m.) In addition to single hours and standardised blocks, a combination of single hours chosen by the exchange participant (user-defined blocks) can also be traded in the day-ahead auction on EPEX SPOT. Bids for the complete or partial physical fulfilment of futures traded on EEX (futures positions) may also be submitted.

Auctions for quarter-hour contracts are held on both EXAA and EPEX SPOT. Quarter hours have been traded in day-ahead auctions on EXAA alongside single hours and blocks since September 2014. EPEX SPOT introduced an auction for quarter-hour contracts (known as “intraday auctions”) for the German control areas in December 2014. The auction is held at 3 p.m. each day. The results are available from 3.10 p.m. All three auction formats are uniform price auctions.

Continuous intraday trading on EPEX SPOT involves single hours, 15-minute periods and standardised or user-defined blocks. Intraday trading begins at 3 p.m. for next-day single-hour supplies and at 4 p.m. for 15-minute periods. It is possible to trade electricity contracts for the German control areas and within the Austrian control area up to 30 minutes before the commencement of supply. In the four German control areas this is even possible up to five minutes before commencement of supply. Since 2015 continuous intraday trading of fifteen-minute periods has been extended to Austria (control area APG).

The expansion of trading opportunities to include quarter-hour contracts and the reduction in the minimum lead time take particular account of the increased input of electricity from supply-dependent (renewable) sources. Another product that promotes the market integration of renewable energies in the spot market sector is green electricity, which is tradable on EXAA and combines renewable energy certificates with physical electricity.

1.1.1 Trading volumes

The volume of day-ahead trading on EPEX SPOT was 233 TWh in 2017, a slight decline compared to the previous year (235 TWh). However, the volume of intraday trading rose to 47 TWh, a substantial increase of around 6 TWh or around 15%.[75] The volume of the day-ahead market on EXAA remained stable and was once again around 8 TWh. Around 66% of this volume was supplied to the German control areas.

[75] Cf. EPEX Spot press release of 11 January 2017

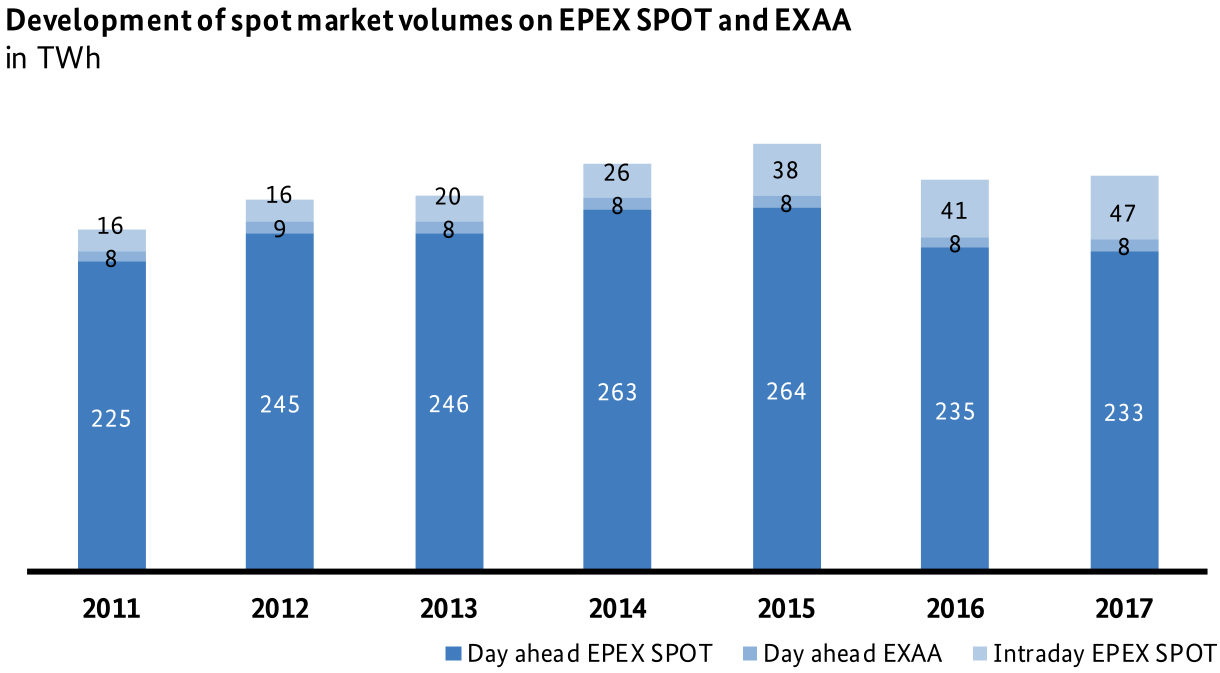

Figure 94: Development of spot market volumes on EPEX SPOT and EXAA

1.1.2 Number of active participants

There were some minor changes to the number of participants active on both exchanges.

A participant registered on EPEX SPOT is regarded as "active" on the trading day if at least one bid has been submitted by the participant (purchase or sale). The average number of active buyers in 2017 was 124 (compared to 122 buyers in 2016) and the average number of sellers was 112 (compared to 117 in 2016). An average of 156 participants (compared to 156 participants in the previous year), or about 77% of all registered participants, were active per trading day. The number of net buyers per trading day (balance in favour of "purchase") was at 85 participants slightly above the level of previous years. The number of net sellers (balance in favour of "sale") fell to 71.

A participant registered on EXAA is regarded as "active" if at least one purchase or sale bid has been submitted for each supply day.[76] In 2017, around 40 participants (43 in the previous year), or just over half of all registered participants, were active per supply day. Some 82% of all participants on the EXAA (in 2016: 74%) have trading accounts in the German control areas. An average of 29 participants per supply day (29 in 2016) submitted bids for supplies to the German control areas.

1.1.3 Price dependence of bids

Bids in day-ahead auctions on SPOT EXAA can be submitted on a price-dependent or price-independent basis. In contrast to price-dependent bids (limit orders), participants do not set fixed price-volume combinations for

[76] A different approach – supply day instead of trading day – is meant to provide a uniform basis for a review of the figures from the two spot market places despite different trading conditions (auction days, auction times). However, this is possible to only a limited extent because of further differences between EPEX SPOT and EXAA.

price-independent bids (market orders). Price independence means that a volume is to be bought or sold regardless of price.

The relatively high proportion of price-independent bids on EPEX SPOT fell slightly in 2017 compared to the previous year. 67% of purchase bids submitted were price-independent compared to 69% in 2016. The proportion of price-independent bids among selling bids submitted was 60%, down by around two per cent in the previous year.

Price dependence of bids submitted in hour auctions on EPEX SPOT in 2017

	Sales bids submitted		Purchase bids submitted	
	Volume in TWh	Percentage	Volume in TWh	Percentage
Price-independent bids	139.1	62.3%	157	67.3%
by TSOs	38.6		0.6	
physically fulfilled Phelix Futures	27.1		44.7	
other	73.5		111.7	
Price-dependent bids (in a broader sense)	94.1	37.7%	76.2	23.6%
blocks	26		11.1	
market coupling contracts	32.3		10	
Price-dependent bids (in a narrower sense)	35.8		55	
Total	233.2	100%	233.2	100%

Table 63: Price dependence of bids submitted in hour auctions on EPEX SPOT in 2017

The marketing of renewable energy (EEG) volumes by the transmission system operators plays a major role on the seller side and was again almost completely price-independent at 99.8%.[77] However, according to the power exchanges, the volume marketed by the transmission system operators continued to fall to around 38.6 TWh (41.6 TWh in 2016 and even 47.7 TWh in 2015).

The reason for the decline is the continuously rising proportion of the volumes remunerated under the EEG in the form of the market premium to most recently 78% (cf. chapter I.B.2.1.3). The installed capacity of installations that sell electricity via direct marketing increased. In January 2017, the market premium was

[77] Section 1 (1) of the Equalisation Scheme Execution Ordinance (Verordnung zur Ausführung der Verordnung zur Weiterentwicklung des bundesweiten Ausgleichsmechanismus – AusglMechAV) requires transmission system operators to market the hourly inputs of renewable energies forecast for the following day for which there is an entitlement to feed-in tariffs (Section 19 (1) (2) of the German Renewable Energy Sources Act (Gesetz für den Ausbau erneuerbarer Energien, EEG) on a spot market exchange and offer them on a price-independent basis.

drawn on by operators of installations with a capacity of approximately 60 GW; in December 2017 it was already drawn on by installations with a capacity of just under 68 GW. The installed capacity of installations with other direct marketing also rose from around 165 MW to over 176 MW in the same period (January to December 2017).[78]

On the seller side, the volume of bids on EPEX SPOT for the physical fulfilment of Phelix-Futures fell slightly from 28 TWh in 2016 to 27 TWh in 2017. On the buyer side, the volume also fell from 57 TWh in 2016 to 45 TWh in 2017.

1.1.4 Price level

The most commonly used price index on the spot market for the German/Austrian market area is the Phelix (Physical Electricity Index), which is published by EPEX SPOT. The Phelix day base is the arithmetic mean of the 24 single-hour prices of a full day and the Phelix day peak is the arithmetic mean of hours 9 to 20, i.e. 8 a.m. to 8 p.m. EXAA publishes the bEXAbase and the bEXApeak, which relate to the corresponding single hours for the same market area.

Average spot market prices rose again in 2017 for the first time since 2011. The Phelix day base average on EPEX SPOT rose from €28.98/MWh in 2016 to €34. 20/MWh, or by about 18%. At 38.06/MWh the Phelix day peak was also nearly 19% higher than the previous year's level of €32.01/MWh. The difference between Phelix day base and Phelix day peak was about €3.86 Euro/MWh in 2017. As a result the day peak was around 11% higher than the Phelix day base.

Development of average spot market prices on EPEX SPOT in €/MWh

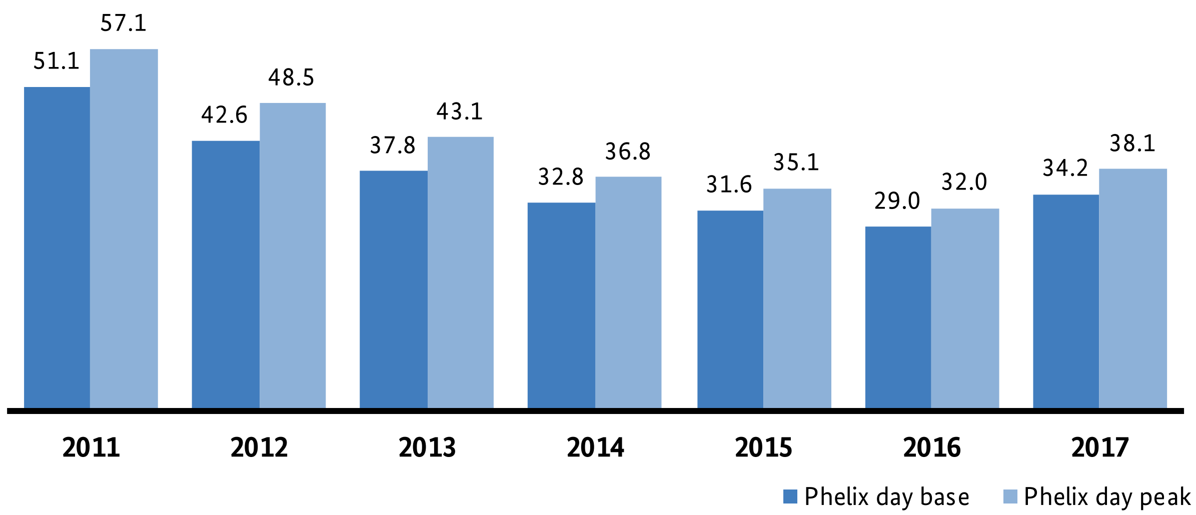

Figure 95: Development of average spot market prices on EPEX SPOT

[78] For information provided by the TSOs on direct marketing, see https://www.netztransparenz.de/portals/1/Direktvermarktung-Uebersicht_Dezember2017.pdf, retrieved on 25 June 2018.

The bEXA and Phelix indices for 2017 are very close to each other. The slight increase in the difference, which became apparent in the previous year, continued in 2017.

Furthermore, the annual average electricity prices in day-ahead auctions were lower on EPEX SPOT than on EXAA – this applies both to the Phelix day base when compared to the bEXAbase and to the Phelix day peak when compared to the bEXApeak. The difference between Phelix day Base and bEXAbase was around €0.9 Euro/MWh, compared with €0.16/MWh in 2016. The difference between Phelix day peak and bEXApeak was around €0.34/MWh in 2017 –and 0.25 Euro/MWh in 2016.

Difference between annual average spot market prices on EPEX SPOT and EXAA
in €/MWh

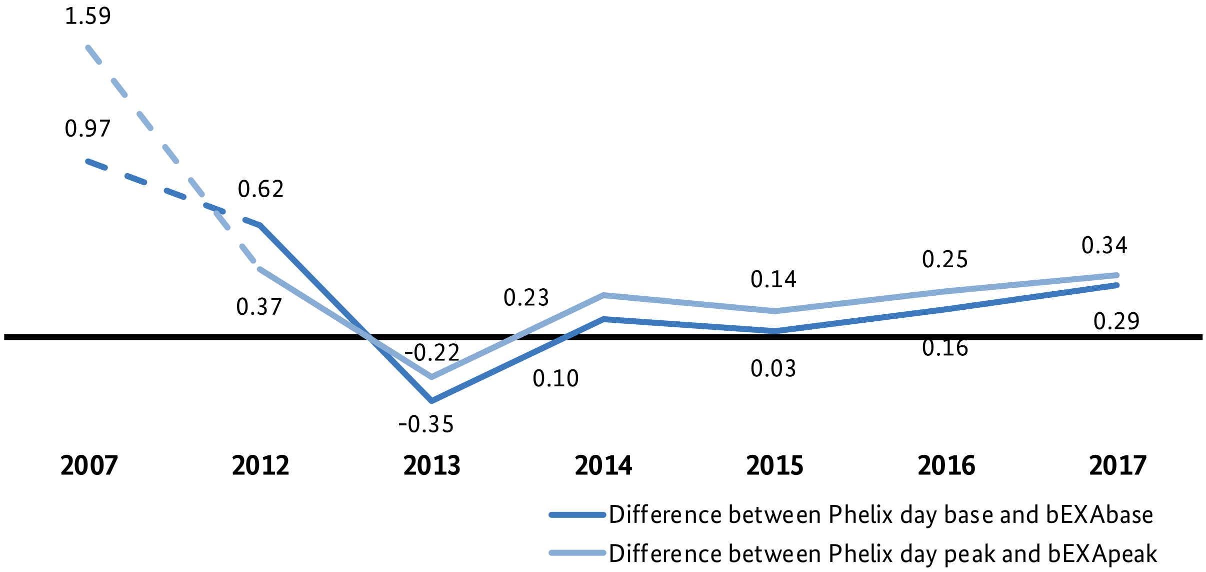

Figure 96: Difference between average base and peak spot market prices on EPEX SPOT and EXAA

1.1.5 Price dispersion

As in previous years, daily average spot market prices exhibit considerable dispersion. The following figure shows the development of spot market prices over the year, using the Phelix day base as an example. Daily average prices typically have a weekly profile with lower prices at the weekend. As in the previous year there were some occasional peaks and troughs in 2017 that went far beyond the usual fluctuations. These extreme values showed even greater variation that the previous year's figures.

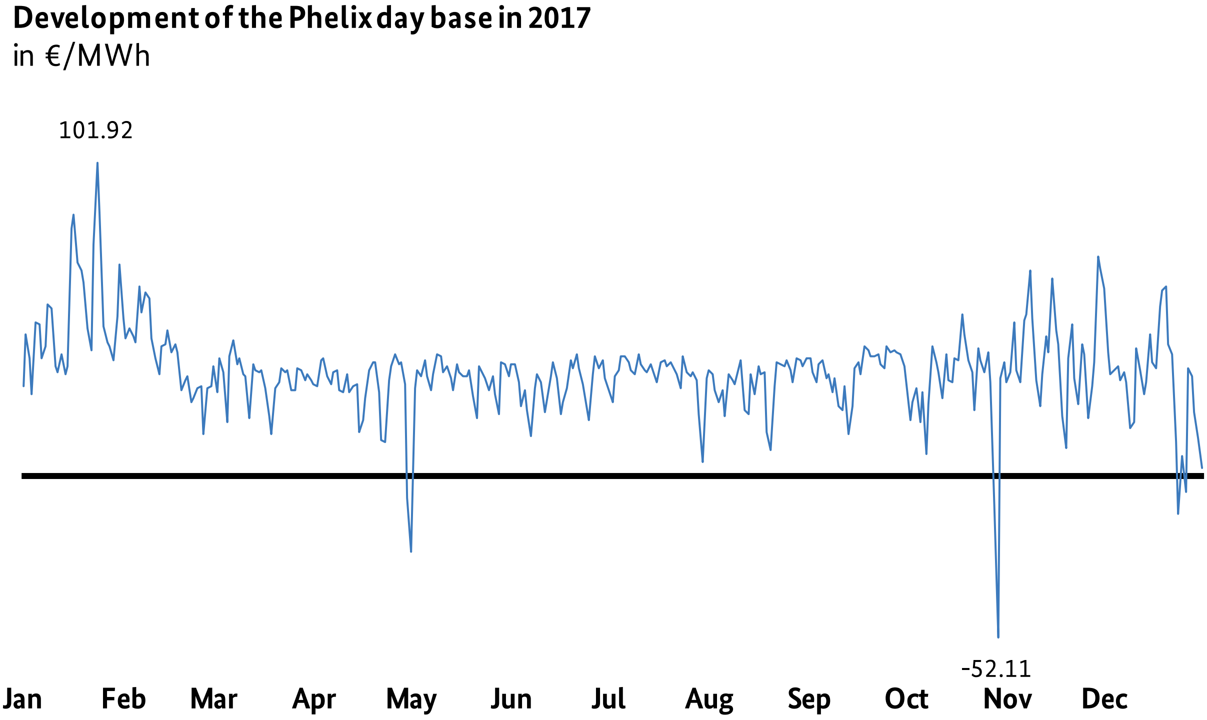

Figure 97: Development of Phelix day base in 2017

There were significant positive and negative values in the Phelix base and peak on EPEX SPOT in 2017. The range of the middle 80% of the graded Phelix day base values fell significantly in 2017. In 2016 the difference was still €21.81 /MWh – in 2017 the difference was only €12.03/MWh. The corresponding peak range of the middle 80% also fell significantly from €28.56/MWh in 2016 to only €16.26/MWh.

There were six negative values[79] in the Phelix day base and in the Phelix day peak in 2017. The highest negative Phelix day base price of -€52.11/MWh was recorded on 29 October 2017 and the Phelix day peak reached its lowest value on the same day at -€45.27/MWh. On this day, a Sunday, which was followed by two holidays, high volumes of electricity were generated by onshore wind power plants as a result of Storm HERWART. This was accompanied by low demand which is usual at weekends. In 2016 the minimum day base value was still -€12.89 /MWh and the minimum day peak value was €-36.46/MWh. The day base value increased by around 304% over the previous year and the day peak value rose by around 24%.

The maximum values of both indices also increased significantly. In 2017 the highest Phelix day base price was €101.92/MWh, 70% higher than the previous year's value. In 2016 the highest Phelix day base price was €60.06/MWh. The maximum day base price was reached in the first month of the year, on 24 January 2017. The reason for this increase in price was a cold spell at the beginning of the year and the dark doldrums.[80] The

[79] Negative prices are price signals on the electricity market that occur when high and inflexible power generation meets weak demand. Inflexible power sources cannot be quickly shut down and started up again without major expense.

[80] See https://www.next-kraftwerke.de/wissen/strommarkt/dunkelflaute; retrieved on 17 July 2018.

Phelix day peak also increased. It rose from €76.84/MWh in 2016 to €130.18/MWh in 2017, which is equivalent to an increase of around 70%.

Price ranges of Phelix day base and Phelix day peak in €/MWh

	Middle 80 per cent	Range of the middle 80 per cent	Extreme values	Range of extreme values
	10 to 90 per cent of the graded values		min – max	
Phelix day base 2015	20.30 – 42.38	22.08	-0.80 – 51.27	52.07
Phelix day base 2016	18.57 – 40.38	21.81	-12.89 – 60.06	72.95
Phelix day base 2017	27.95 – 39.98	12.03	-52.11 – 101.92	154.03
Phelix day peak 2015	20.82 – 49.09	28.27	-11.38 – 65.12	76.5
Phelix day peak 2016	18.38 – 46.94	28.56	-36.46 – 76.84	113.3
Phelix day peak 2017	28.35 – 44.61	16.26	-45.27 – 130.18	175.45

Table 64: Price ranges of Phelix day base and Phelix day peak between 2015 and 2017

EXAA shows a similar pattern. Both the maximum and minimum values for bEXAbase and bEXApeak and the resulting range between these values increased significantly year-on-year. The highest bEXAbase value at €90.69/MWh and the highest bEXApeak value at €122.39/MWh were also recorded on 24 January 2017. There were four negative values in the bEXAbase. The lowest value of €-15.88/Mwh was recorded on 29 October 2017. In the bEXApeak the lowest value was €-9.17/MWh and was recorded on 31 December 2017.

Price ranges of bEXAbase and bEXApeak in €/MWh

	Middle 80 per cent	Range of the middle 80 per cent	Extreme values	Range of extreme values
	10 to 90 per cent of the graded values		min – max	
bEXAbase 2015	20,41 – 42,48	22.07	-0,79 – 49,27	50.06
bEXAbase 2016	18,62 – 40,92	22.30	-4,50 – 59,12	63.62
bEXAbase 2017	27,75 – 40,32	12.57	-15,88 – 90,69	106.57
bEXApeak 2015	20,74 – 49,09	28.35	0,40 – 59,10	58.70
bEXApeak 2016	19,43 – 46,89	27.46	-12,60 – 74,90	87.50
bEXApeak 2017	29,28 – 45,06	15.78	-9,17 – 122,39	131.56

Table 65: Price ranges of bEXAbase and bEXApeak from 2015 to 2017

1.2 Futures markets

Futures with standardised maturities can be traded on EEX for the German/Austrian market area if the Phelix (base value) is the subject matter of the contract. Options for specific Phelix futures can generally also be traded, however, as in the last few years, there were no such transactions on EEX. Trading in German intraday cap futures (for week contracts) has been possible since September 2015 to hedge price peaks in light of the growing share of renewable energy on the market.[81] Since March 2017 the "German Intraday Floor Futures" programme has been extended. The Floor Futures serve to hedge against low prices.[82] Since October 2016 participants admitted to the EEX can also trade in wind power futures and thus hedge against the growing share and resulting volume risks of the generation of wind power.[83]

EEX started trading separate electricity futures for Germany and for Austria with a view to splitting the German/Austrian bidding zone. Phelix-DE have been tradeable in the German AT bidding zone since April 2017 and in the Austrian bidding zone since 26 June. There are also options for trading solely on the Phelix-DE.[84] The new Phelix-DE and Phelix-AT futures will initially be settled against the existing German/Austrian day-ahead auction price. Following the separation, Phelix-DE futures will be settled against a German day-ahead auction price and Phelix-AT futures will be settled against an Austrian day-ahead auction price.[85]

The following section deals solely with on-exchange transaction volumes, excluding OTC clearing (cf. section on OTC clearing).

1.2.1 Trading volumes

Following substantial growth in the previous years, the on- exchange trading volumes of Phelix DE/AT futures fell significantly for the first time from 1,466 TWh to only 786 TWh, a decline of 46%. The main cause of this decline is the introduction of Phelix-DE, which is more closely examined in the following section. The number of active participants on the EEC futures market also fell. The average number of active participants per trading day was 64 in 2017 (75 participants in 2016).

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[81] Cf. EEX press release of 14 September 2015.

[82] Cf. EEX press release of 18 January 2017. https://www.eex.com/de/about/newsroom/news-detail/eex-erweitert-angebot-fuer-strommarkt-um-floor-futures-und-schweizerische-tages--und-wochenend--futures-/63300

[83] Cf.EEX press release of 31 August 2016, https://www.eex.com/de/about/newsroom/news-detail/eex--handel-mit-wind-power-futures-startet-anfang-oktober/56352

[84] Cf. EEX press release of 11 April 2017 - https://www.eex.com/en/about/newsroom/news-detail/eex-to-launch-power-futures-for-germany/66308; EEX press release of 16 May 2017 https://www.eex.com/en/about/newsroom/news-detail/eex-to-launch-austrian-power-future-and-extend-phelix-de-future-products/67020

[85] Cf. EEX press release of 16 May 2017. https://www.eex.com/de/about/newsroom/news-detail/eex-fuehrt-stromfutures-fuer-oesterreich-ein-und-ergaenzt-phelix-de-produktpalette/67016

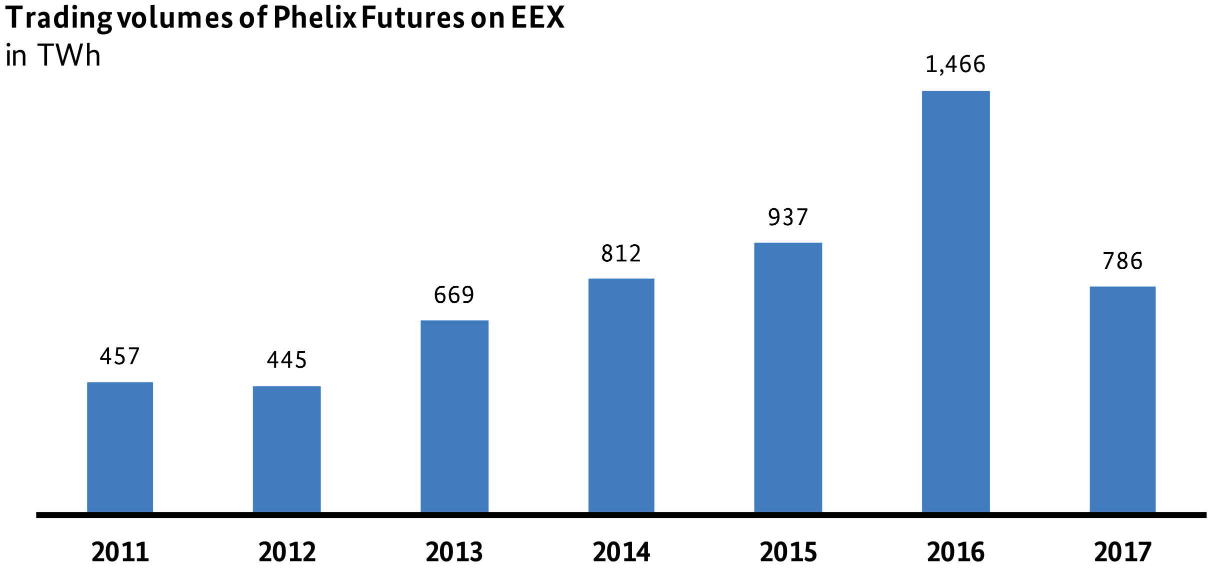

Figure 98: Trading volumes of Phelix-DE/AT futures on EEX

Futures trading in 2017 predominantly focussed on contracts for the year ahead (2018) as the fulfilment year with some 63% of the total trading volume, i.e. around 499 TWh. Trading for 2019 made up the second largest share with approximately 24%, i.e. a total of 188 TWh. Whilst trading for two years ahead still accounted for the second largest share in 2016, this share fell from 222 TWh in 2016 to only 80 TWh. Trading for 2020 and for the next few years was 1 TWh, a very marginal share of the total volume, the same level as the previous year.

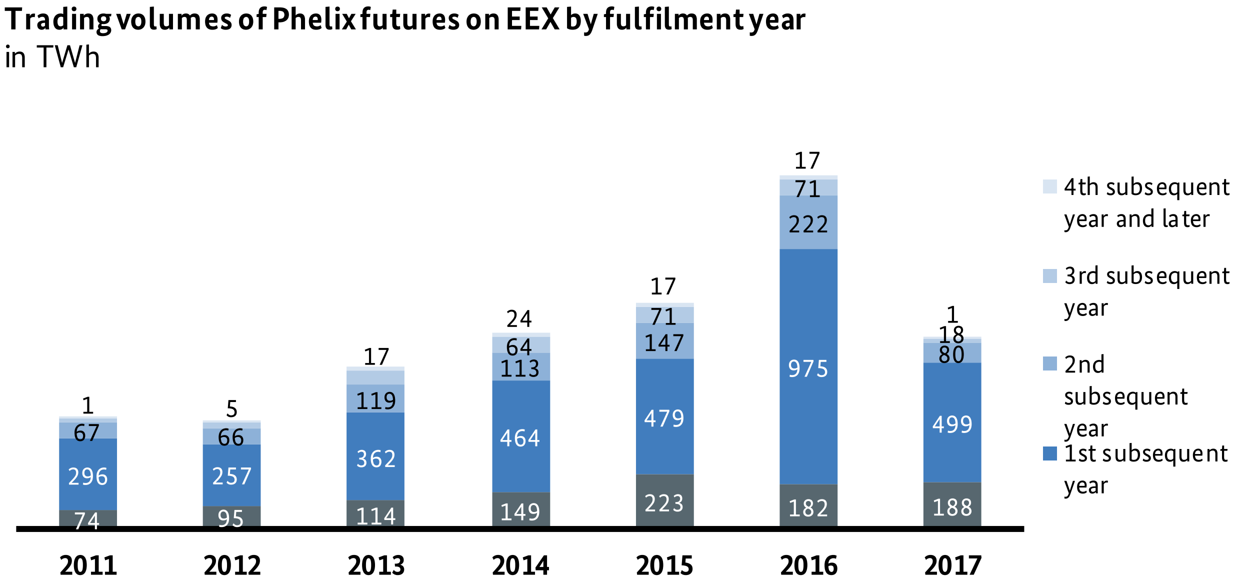

Figure 99: Trading volumes of Phelix DE/AT futures on EEX by fulfilment year

1.2.2 Trading volumes of Phelix-DE

On 25 April 2017 the EEX introduced the new futures market product "Phelix-DE" for trading in electricity supply exclusively for the German bidding zone. Since its introduction around 197 TWh had been traded in Phelix-DE futures by the end of 2017. By comparison, during the same period the volume of trading in the "old" product Phelix-DE/AT reached 390 TWh.

In view of the planned splitting of the German/Austrian bidding zone, the Phelix-DE had established itself as a benchmark contract. Since the launch of Phelix-DE there has been a clear shift in liquidity and trading volumes from Phelix-DE/AT to Phelix-DE. Whilst the share of Phelix-DE of total Phelix-DE and Phelix DE/AT futures transactions was only 24% in July, this exceeded the Phelix-DE-AT share between October and November in 2017. In December 2017 Phelix-DE already accounted for 62% of the total contracts for Germany and gained in increasing importance.[86]

Development of volumes of Phelix DE/AT and Phelix DE on EEX for Germany from April to December 2017
in per cent

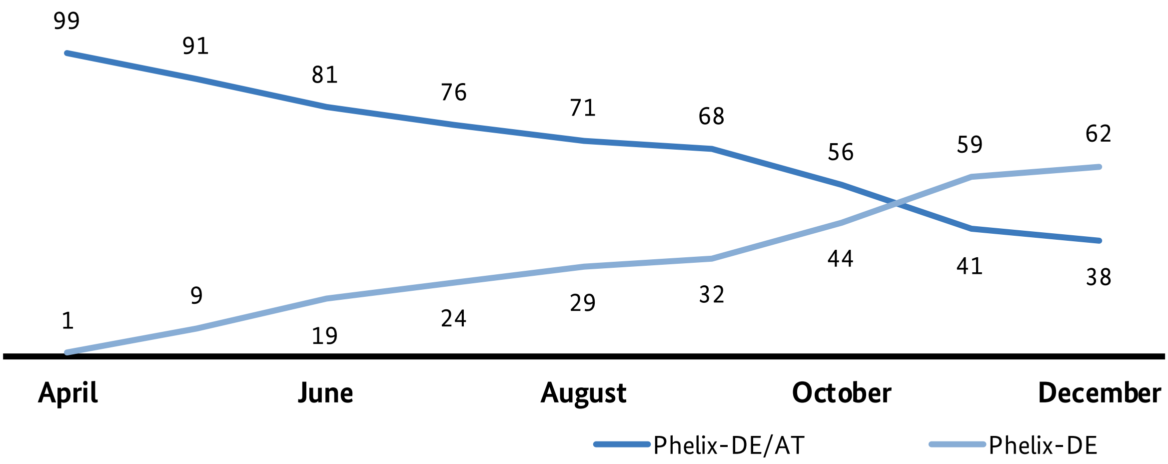

Figure 100: Trading volumes of Phelix-DE/AT and Phelix-DE on EEX for Germany from April to December 2017.

Futures trading in 2017 predominantly focussed on contracts for the year ahead (2018) as the fulfilment year with some 53% of the total trading volume, i.e. around 104 TWh. Trading for 2019 made up the second largest share with approximately 28%: i.e. a total of 55 TWh. Contracts for the current year 2017 accounted for only a small share at around 12 TWh, i.e. approx. six per cent. Contracts for 2020 and later accounted for around twelve per cent, at around 25 TWh.

1.2.3 Price level

The Phelix year futures base and peak are the two most important futures traded on EEX for the German/Austrian market area in terms of volume. Baseload futures relate to a constant and continuous

[86] The futures product Phelix-AT was also introduced, which envisages a separate supply of electricity only for Austria. Since its launch in mid 2017, only 0.8 TWh had been traded in Phelix-AT by the end of 2017.

supply rate (every hour, every day), while peakload futures cover the hours from 8:00 a.m. to 8:00 p.m. from Monday to Friday.

In the course of 2017 futures prices continued to rise. One cause of this was the shutdown or removal of further power plants from the market.

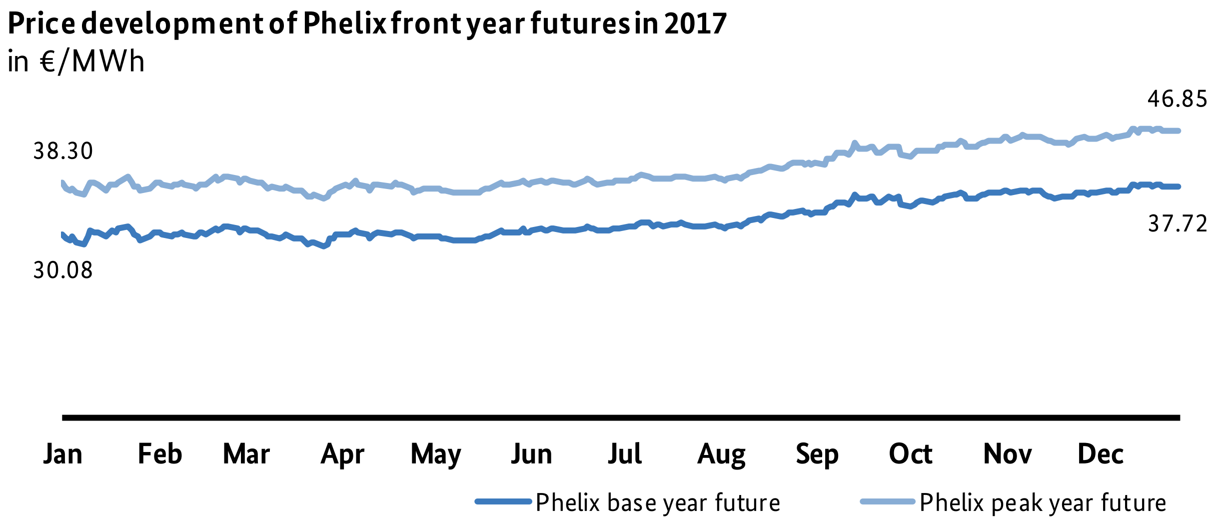

Figure 101: Price development of Phelix-DE/AT front year futures in 2017

An annual average can be calculated on the basis of the Phelix-DE/AT front year futures prices recorded on EEX on individual trading days. This average would correspond to the average electricity purchase price or electricity sales price) of a market player if the latter bought or sold the electricity not at short notice but pro rata in the preceding year.

The annual averages of the Phelix DE/AT futures prices rose again year-on-year. With an annual average of €32.38/MWh, the Phelix base year futures rose by €5.81/MWh from €26.58/MWh in 2016, an increase of approximately 22%. The price of the Phelix peak front year futures averaged €40.51/MWh over the year. The price rose by from the previous year's figure of €33.51 by exactly €7, or around 21%. The downward trend of the last few years has therefore stopped. Due to the nuclear phase out and the continuous shutdown/closure of coal-fired power stations, base and peak prices have increased.

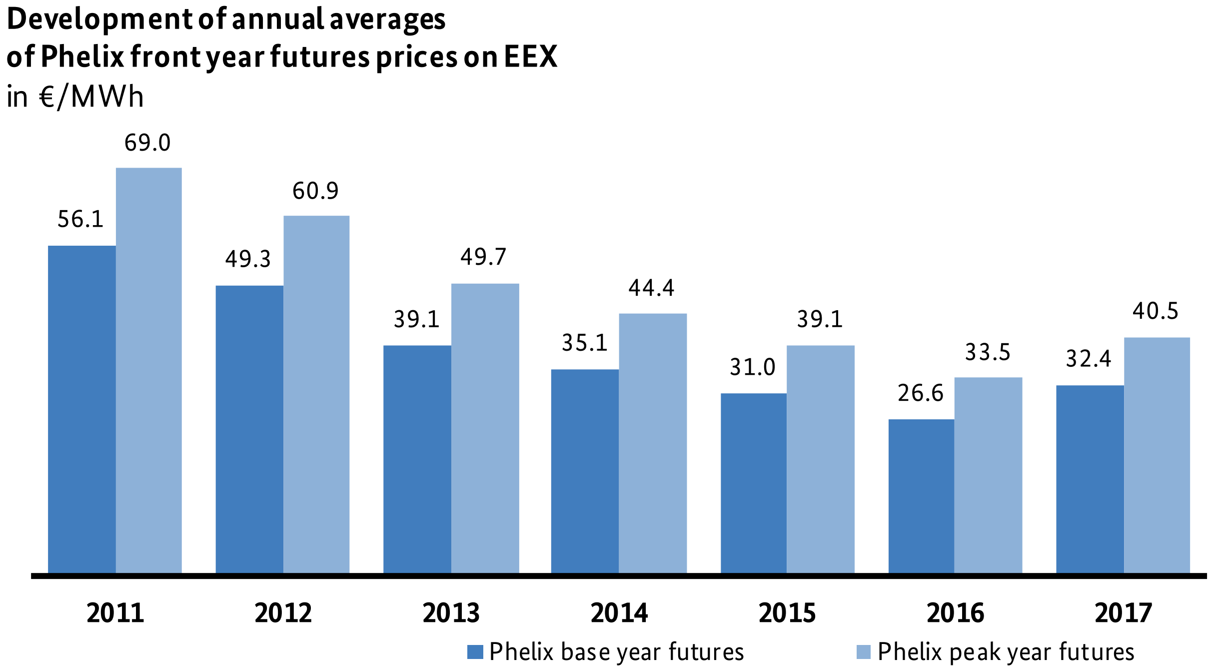

Figure 102: Development of annual averages of Phelix-DE/AT front year futures prices on EEX

The annual average price difference between base and peak products was €8.13/MWh (2016: €6.93/MWh). The peak price was therefore around 25% higher than the base price, as in the previous year.

1.2.4 Price level of Phelix-DE

Since the launch of Phelix-DE on 25 April 2017, base and peak year future prices have come into line with those of the "old" Phelix-DE/AT. The annual average of the Phelix-DE base year future from 25 April up to the end of 2017 was €33.46/MWh, whereas the average of the Phelix-DE/AT base year future over the same period was approximately €33.51/MWh. The price of the Phelix-DE peak year future was €41.65/MWh, also approximately €0.05/MWh less than the Phelix-DE/AT peak year future.

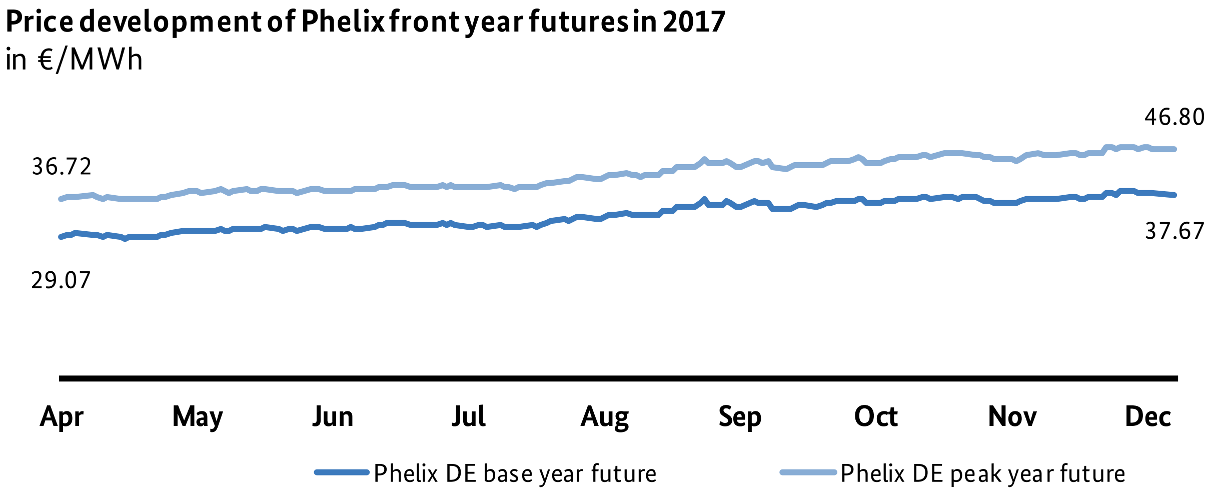

Figure 103: Price development of Phelix-DE base front year and Phelix-DE peak front year futures in 2017

1.3 Trading volumes by exchange participants

1.3.1 Share of market makers

An exchange participant who has undertaken to publish binding purchase and sale prices (quotations) at the same time is referred to as a market maker. The role of market makers is to increase the liquidity of the market place. The specific conditions are agreed between the market makers and the exchange in market maker agreements, which include provisions on quotation times, the quotation period, the minimum number of contracts and maximum spread. The companies involved are not prevented from engaging in additional transactions (that are not part of their role as market maker) as exchange participants.

Only three companies (four in 2016) acted as market makers on the EEX futures market for Phelix Futures (DE-AT) in the reporting period: Uniper Global Commodities SE, RWE Supply & Trading GmbH and Vattenfall Energy Trading GmbH. However the market makers were not active during the entire reporting period but only for two or three quarters. The market makers' share of the purchase volume was therefore only 9%, down from 20% in the previous year. On the sales side, the volume also fell to 8% from 20% in the previous year. The figure refers to the turnover the companies generated when acting as market makers, i.e. it does not include the volumes which the companies may have traded outside their role as market makers.

The decline mentioned above is partly due to the newly launched product for electricity contracts, Phelix-DE. Two market makers were active in the trading of this product, with a share of approximately 31% of the purchase volume and 31% cent of the sales volume.

In addition to agreements with market makers, EEX maintains contracts with trading participants who are committed to strengthening liquidity to an individually agreed extent. These companies accounted for approximately 7% of the total trading volume (sales and purchases) in 2017, exactly the same amount as the previous year.

Five market makers were active on the day-ahead market of EXAA in the reporting period. In 2017, the cumulative share of transactions carried out by companies in their role as market makers was 1.9% of the purchase volume of the day-ahead auction (3.3% in 2016) and 5.5% of the sales volume (9.4% in 2016).

1.3.2 Share of transmission system operators

In accordance with the Equalisation Mechanism Ordinance (AusglMechV), the transmission system operators (TSOs) are obliged to sell renewable energy volumes passed on to them in accordance with the fixed feed-in electricity tariffs under the Renewable Energy Sources Act on the spot market of an electricity exchange. For this reason, the TSOs account for a large but steadily declining share of the spot market volume on the seller side, due to the growing importance of direct marketing.

The share of TSOs in the day-ahead sales volume of EPEX SPOT has been declining for a number of years, and, as in the previous year, was only around 17% in 2017. By comparison, their share was still 28% in 2012. The volumes marketed by the TSOs also declined in absolute terms. The on-exchange day-ahead sales volume marketed by TSOs was approximately 38.6 TWh in 2017; in 2016, this value was still around 41.7 TWh and in 2012 around 69.5 TWh. TSOs generated a very small spot market volume of about 0.5% on the buyer side.

1.3.3 Share of participants with the highest turnover

An analysis of the trading volume generated by the participants with the highest turnover gives an insight into the extent to which exchange trading is concentrated. The participants with the highest turnover include the large electricity producers, financial institutions and – on the spot market – the TSOs. In order to compare the figures over time, it is important to note that the group of participants with the highest turnover can change over the years, so that the cumulative share of turnover does not necessarily relate to the same companies. Also, this report does not provide group values, i.e. the turnover of a group of companies is not aggregated if that group has several participant registrations.[87]

The share of the five purchasers with the highest turnover in the day-ahead trading volume on EPEX SPOT fell from 41% in 2016 to 33%. The corresponding share on the seller side did not change noticeably compared to the previous year. The cumulative share of the five sellers with the highest turnover was approximately 32% in 2017 as in the previous year. The previously higher shares on the seller side are primarily due to the TSO's higher sales volumes at that time.

Share of the five buyers and five sellers with the highest turnover in the day-ahead volume of EPEX SPOT in per cent

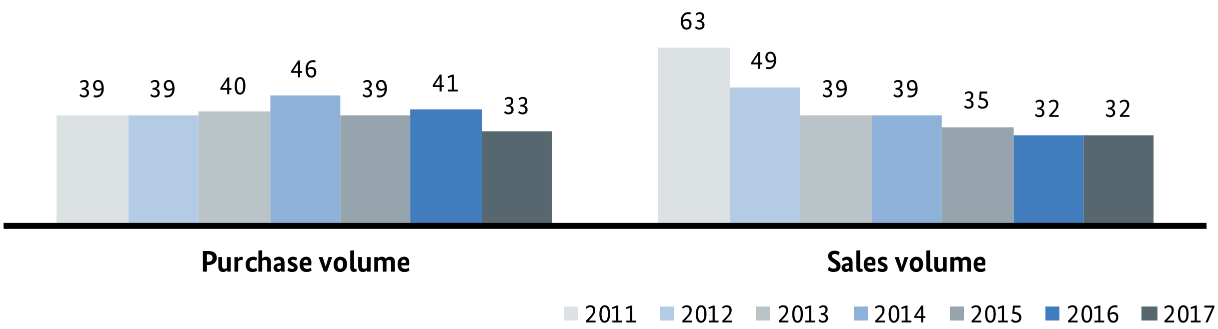

Figure 104: Share of the five sellers and five buyers with the highest turnover in the day-ahead volume of EPEX SPOT

EXAA as another exchange for day-ahead auctions experienced a slight increase in concentration. The share of the five buyers with the highest turnover increased from 37% in 2016 to 38% in 2017. The share of the five sellers with the highest turnover rose in 2017 to 37% (2016: approximately 35%).

The share of the five buyers of Phelix-DE/At futures with the highest turnover on EEX (excluding OTC clearing) declined from around 30% in 2016 to 29% in 2017. The share of the five sellers with the highest turnover rose from around 30% in 2016 to 32% in 2017.

The share of the five buyers of only Phelix-DE futures with the highest turnover on EEX was around 47%. On the seller side this was 49%.

[87] Generally speaking, groups only have one participant registration.

2. Bilateral wholesale trading

Bilateral wholesale trading ("OTC trading", "over the counter") is characterised by the fact that the contracting parties are known to each other (or become known to each other no later than on conclusion of the transaction) and that the parties can make flexible and individual arrangements regarding the details of the contract. The surveys carried out for the monitoring of OTC trading aim to record the amount, structure and development of bilateral trading volumes. Unlike exchange trading, however, it is impossible to provide a complete picture of bilateral wholesale trading since off-exchange there are no clearly definable market places nor is there a standard set of contract types.

Brokers play a major role in bilateral wholesale trading. They act as intermediaries between buyers and sellers and pool information on the supply and demand of electricity transactions. Electronic broker platforms are used to bring interested parties on the supply and demand sides together and so increase the chances of the two parties reaching an agreement.

On-exchange OTC clearing plays a special role. OTC trading transactions can be registered on the exchange to hedge the parties' trading risk.[88] OTC clearing provides an interface between on-exchange and off-exchange electricity wholesale trading.

In 2017 different broker platforms were once again surveyed with regard to bilateral wholesale trading (see sections below). Data on OTC clearing on EEX was also collected. The surveys revealed a stable high level of liquidity in bilateral electricity wholesale trading in 2017.

2.1 Broker platforms

During monitoring, operators of broker platforms are also asked to answer questions on the contracts they have brokered. Many brokers provide an electronic platform to conduct their brokerage services.

As in the previous year eleven brokers who brokered electricity trading transactions with Germany as a supply area took part in this year's collection of wholesale trading data. The total volume brokered by them was around 5,671 TWh in 2017 compared to 5,759 TWh in 2016, a decrease of around two per cent. Data from the London Energy Brokers' Association (LEBA), which, however, does not include all broker platforms, also showed that the volume of trading transactions had fallen. The trading volume for German power brokered by LEBA members fell from 5.518 TWh to 5.263 TWh, or by around five per cent year-on-year.[89]

Contracts for the year ahead continue to make up the majority of electricity transactions brokered on broker platforms with 64% (63% in the previous year), followed by the activities for the current year with 19% (18% in the previous year). Short-term transactions with a fulfilment period of less than one week generated only

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[88] EEX no longer refers to this service as "OTC clearing", but as "trade registration". The original designation has been retained in this Monitoring Report.

[89] See London Energy Brokers' Association, OTC Volume Report: https://cdn.evia.org.uk/content/monthly_vol_reports/ https://cdn.evia.org.uk/content/monthly_vol_reports/LEBA%20Energy%20Volume%20Report%20December%202017.pdf (retrieved on 19 June 2018).

small volumes. Compared to the previous year, the distribution of the fulfilment periods has only minimally shifted.

Volume of electricity traded via eleven broker platforms in 2017 by fulfilment period

Fulfilment period	Volume traded in TWh	Percentage
Intraday	0	-
Day ahead	80	0.01
Less than one week	65	0.01
More than one week	1,100	0.19
2018	3,611	0.64
2019	578	0.1
2020	220	0.04
2021	17	0
Total	**5,671**	**1**

Table 66: Volume of electricity traded via broker platforms in 2017 by fulfilment period

2.2 OTC Clearing

Alongside the on-exchange EEX order book trade, on-exchange OTC clearing played a special role in bilateral wholesale trading. In OTC clearing, the exchange, or its clearing house, is the contracting party of the trading participants in on-exchange trading so that the exchange bears the counterparty default risk. While the default risk in bilateral trading can be reduced or hedged by various means without applying this method, it cannot be eliminated altogether. Another factor is that the inclusion of OTC transactions can in some cases reduce the amount of the collateral necessary for exchange trading, e.g. futures, that has to be deposited with the clearing bank.

By registering on the exchanges, the contracting parties ensure that their contract is subsequently traded as a transaction originating on the exchange, i.e. both parties act as though they had each bought or sold a corresponding futures market product on the exchange. OTC clearing therefore represents an interface between on-exchange and off-exchange electricity wholesale trading.

EEX, or its clearing house European Commodity Clearing AG (ECC), provides OTC clearing (or trade registration, s.a.) for all futures market products that are also approved for exchange trading on EEX.

The volume of OTC clearing of Phelix futures on EEX was 905 TWh in 2017. The volume was still 1,367 TWh in 2016. Since OTC clearing is used to “retrospectively” offset futures concluded on the exchange, the development of the OTC clearing volume should be considered in the context of the on-exchange futures market volume. The total volumes of on-exchange futures trading and OTC clearing remained relatively stable for a long time. The volume has increased slightly since 2012. Compared to 2016, the volume significantly declined in 2017, both in OTC and on-exchange trading. There was a significant year-on-year decline in the OTC clearing volume (approx. 46%) and in exchange trading (approx. 34%). This was also due to the launch of the new Phelix-DE, futures which takes over the trading volumes of the old Phelix-DE/AT.

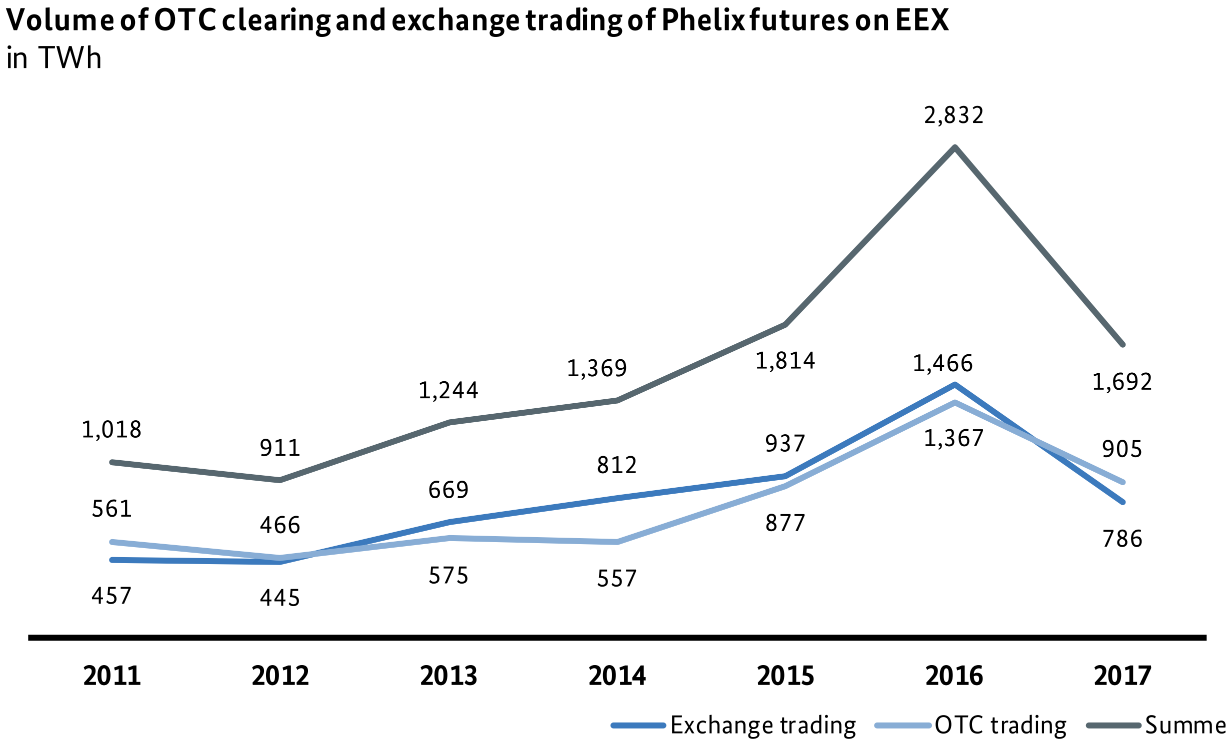

Figure 105: Volume of OTC clearing and exchange trading of Phelix-DE/AT futures on EEX

According to LEBA, the volume for German power registered by LEBA members for clearing was approx. 859 TWh in 2017, which is equivalent to a share of about 16% of the total OTC contracts brokered by LEBA members. By contrast, the corresponding figures were around 22% with a volume of approx. 1,183 in 2016.[90]

Phelix options had no bearing on exchange trading on EEX. As in the previous year there were no such transactions in 2017. By contrast, OTC clearing of Phelix options agreed off the exchange has practical significance: Phelix options accounted for a share of 118 TWh or 13% of OTC clearing in 2017 while the remaining 787 TWh or 87% of OTC clearing consisted of Phelix futures. The OTC clearing volume for options fell significantly compared to the previous year. The distribution of the volumes registered on EEX for OTC clearing across the various fulfilment periods in 2017 shifted slightly compared to the previous year. While in 2016 more than half of the volume (59%) consisted of contracts for the year ahead, the figure had risen to 64% in 2017 (581 TWh). Only around 23% (216 TWh) related to 2017 itself. Around 10% related to the year after next (trading for 2019). Later fulfilment periods made up only a small share of 2%.

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[90] Cf. https:/www.leba.org.uk/pages/index.cfm?page_id=59 (retrieved on 2 June 2017). The total volume of German power brokered by LEBA members was 5,262 TWh for the whole of 2016, approx. 5,517 TWh.

OTC clearing volume of Phelix futures on EEX by fulfilment year in TWh

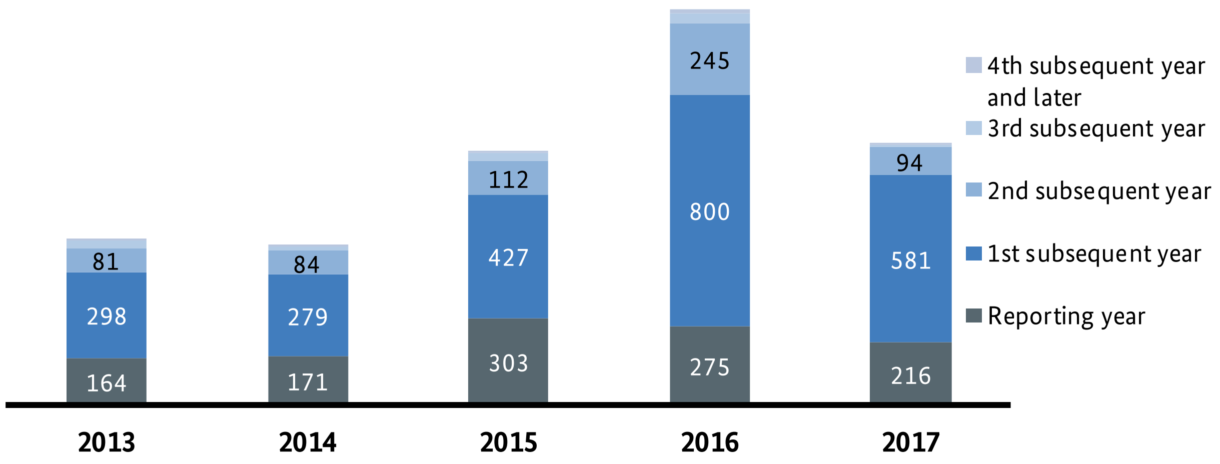


Figure 106: OTC clearing volume for Phelix futures on EEX by fulfilment year

The majority of the OTC clearing volume of Phelix futures on EEX is generated by just a few broker platforms. The five companies that registered the largest volumes for OTC clearing in 2017 accounted for about 55% of all purchases and 60% of all sales (the figures for 2016 were around 62% of all purchases and 62% of all sales). EPEX SPOT offers OTC clearing for intraday contracts. However, the practical significance of this supply continues to be quite small. The volume attributed to this in 2017 was only around 0.05 TWh. In the previous year, it was also a mere 0.03 TWh.

OTC Clearing of Phelix-DE

EEX also offers OTC clearing for the new Phelix-DE futures which were launched in 2017. The volume of OTC clearing of Phelix-DE futures on EEX was 93 TWh in 2017. As this was the first survey on the OTC clearing of this new product, no year-on-year comparison was available. However, the volume of OTC clearing of Phelix-DE/AT over the same period (April to December 2017) was 511 TWh. As mentioned in the trading volumes subsection, since the launch of Phelix-DE there has been a clear shift in liquidity from Phelix-DE/AT to Phelix-DE. However, exchange trading and OTC clearing in the old product Phelix-DE/AT continued to prevail in the above period.

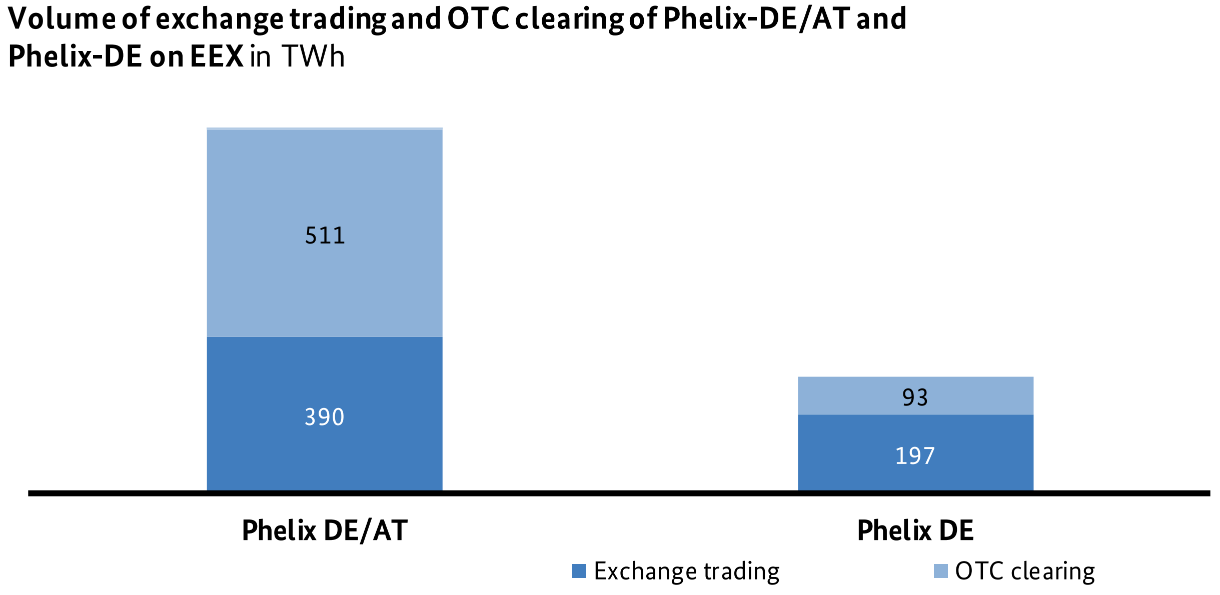


Figure 107: Volume of OTC clearing and exchange trading of Phelix DE/AT and Phelix DE on EEX

The largest share of the OTC clearing volume for Phelix-DE futures on EEX in 2017 consisted of contracts for the year ahead – around 50%. Around 39% related to the year after next. Only very small amounts were cleared in the current year (around 4%) and around 5% for the third year ahead (trading for 2020).

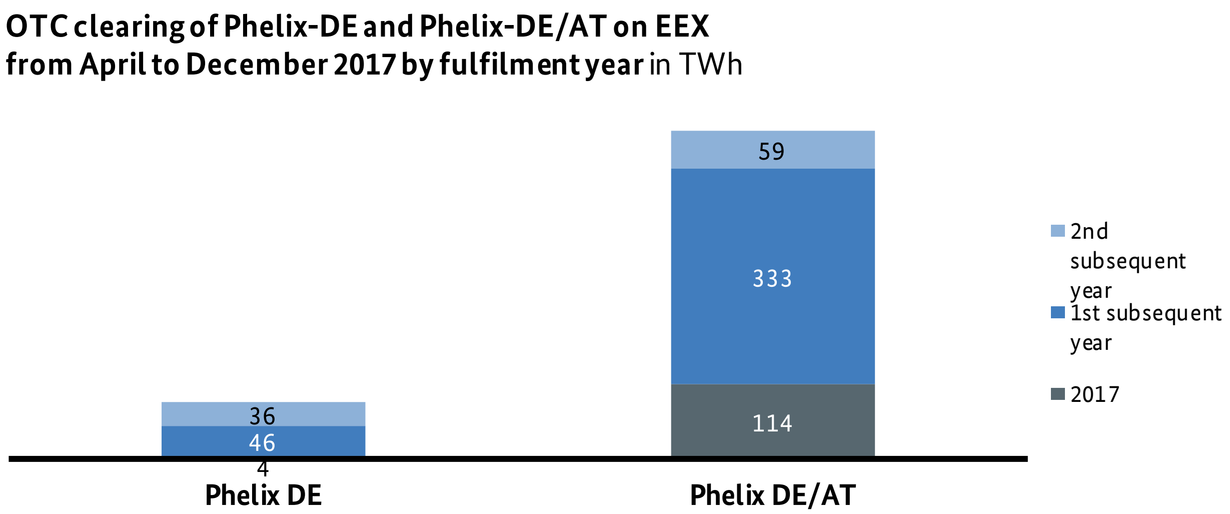


Figure 108: OTC clearing volume of Phelix-DE and Phelix-DE/AT on EEX from April to December 2017 by fulfilment year

After the launch of Phelix-DE, it was found that the distribution of contracts was similar to that with the “old” Phelix-DE-AT. In the case of Phelix-DE-AT, around 65% of the volume consisted of contracts for the year ahead, followed by 22% for the current year, around 12% for the year after next and only very small quantities for the remaining years.

G Retail

The number of suppliers reflects the diversity of companies that are active in the market. Not every supplier offers contracts in all network areas. However, there has been a steady increase in the number of companies active at supra-regional level, thereby increasing the possibilities for consumers to switch supplier.

Consumers should bear the following advice in mind when switching supplier:

Tariffs involving prepayment or a deposit should be avoided, because if the supplier were to become insolvent the prepayments made in advance could be lost.

It should be remembered that bonus payments are a one-off payment and not paid in subsequent years.

The new contract should not have a duration of more than one year.

Check if the tariff has a fixed price; when the fixed price period is over, however, there could be a significant jump in price.

Long notice periods of over three months should be avoided.

An average household customer with a default supply contract was able to save an average of €68 per year upon switching contract and €85 per year upon switching supplier.

Further information regarding switching suppliers is available at https://www.bnetza.de/lieferantenwechsel.

For night storage and heat pump electricity, the increasing number of electric heating suppliers makes it easier for consumers to compare locally available suppliers, for example through internet portals, consumer magazines or obtaining information from consumer advice centres.

1. Supplier structure and number of providers

The analysis of data from 1,404 suppliers for the year 2017 shows that the electricity retail market is still undergoing a process of change. For the data analysis, the information provided by the suppliers was considered to be submitted by individual legal entities without taking company affiliations and links into account.

1,289 suppliers registered a total of 50.4 million meter points of final consumers supplied. As Figure 109 shows, approximately 84% of all suppliers taking part in monitoring serve less than 30,000 meter points. This group covers nearly 7.9m, or 16% of all registered meters. Some 7% of all suppliers serve over 100,000 meter points each. In absolute terms this amounts to around 36m meter points and therefore approximately 72% of all the meter points registered by suppliers, which is a similar figure to the previous year. Hence the majority of companies operating as suppliers have a customer base made up of a relatively small number of meter points, whereas 88 large suppliers (individual legal entities) serve the largest number of meters in absolute terms.

Number and percentage of suppliers that supply the number of meter points shown
not taking account of company affiliations

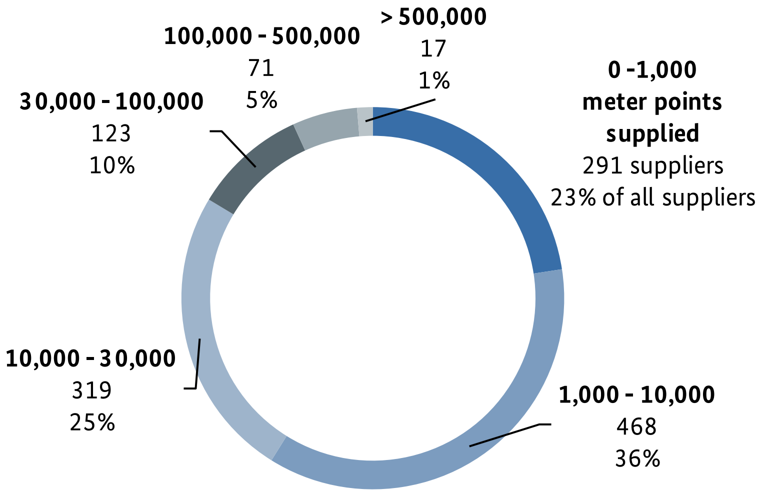


Figure 109: Number of suppliers by number of meter points supplied

A large number of suppliers does not automatically translate into a high level of competition. Suppliers were therefore also asked about the number of network areas in which they supply final consumers with electricity. The analysis of the data submitted by 1,187 suppliers shows that half of them only operate regionally. Around 50% of suppliers serve a maximum of 10 network areas, while 13% serve only one network area. This figure has been declining steadily (2016: 17%). 23% of companies operate in 11-50 network areas, with 14% operating in 51-250 network areas and 4% in 251-500 network areas. 88 suppliers, or around 7%, supply customers in more than 500 network areas (see Figure 110). This figure can be taken as the approximate number of suppliers that operate throughout the whole of Germany. Another figure that depicts the nationwide activity of suppliers is the number of federal states supplied: 182 suppliers have concluded contracts in all 16 federal states.

On a national average, a supplier has customers in 92 network areas (2016: 80).

Number and percentage of suppliers that supply customers in the number of network areas shown
not taking account of company affiliations

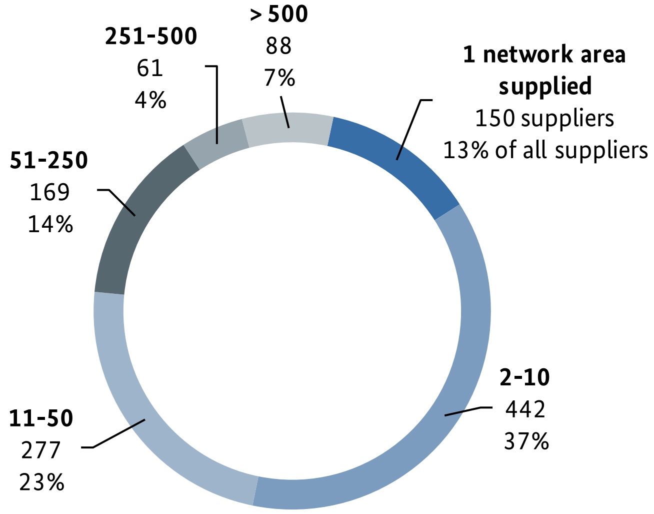


Figure 110: Number of suppliers by number of network areas supplied

Although the majority of suppliers continue to operate regionally, the number of suppliers that electricity customers could choose from increased once again in 2016. An evaluation of the data supplied by 808 distribution system operators on the number of suppliers that supply consumers in each network area produced the following results (see Figure 111): In 2017 more than 50 suppliers operated in over 89% of network areas (720 network areas). In the year 2007 this number barely covered one quarter of the network areas (165 network areas). Today more than 100 suppliers operate in around 71% of the network areas, whereas five years ago it was only 33% (259 network areas). On average, final consumers in Germany were able to choose between 143 suppliers (2016: 130); household customers were able to choose between 124 suppliers (2016: 112).

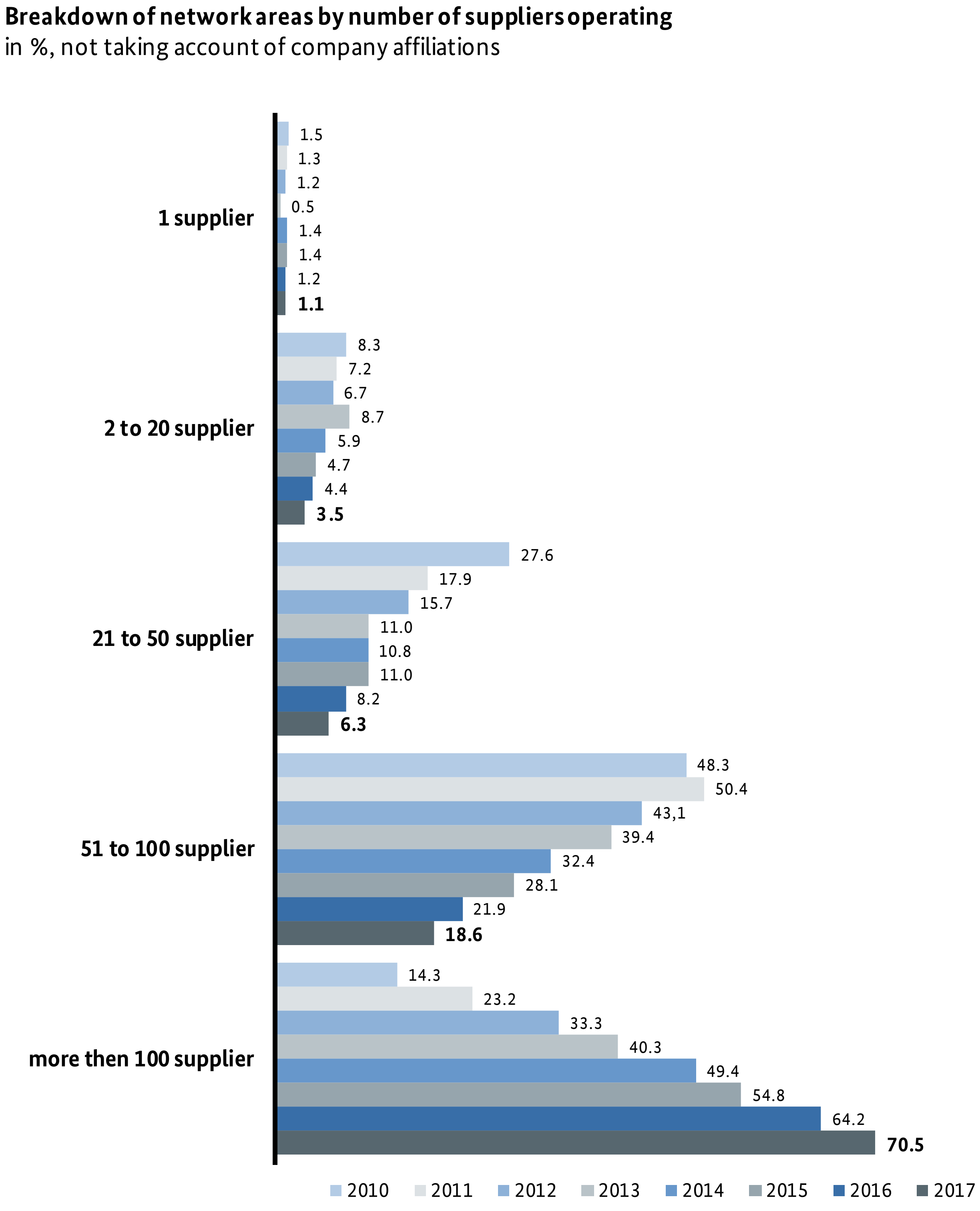


Figure 111: Breakdown of network areas by number of suppliers operating

2. Contract structure and supplier switching

Switching rates and processes are important indicators of the level of competition. The annual switching rates in the electricity retail sector have increased steadily in recent years. In 2017 this figure has stabilised, with no notable increase in the number of supplier switches. One reason for this could be the increased retail price in 2017, which reduces the incentive to switch supplier. In summary, the rate of supplier switches is at 11.8% for household customers (2016: 11.4%) and 13% (2016: 12.7%) for non-household customers with over 10 MWh of annual consumption. The collection of the key figures for supplier switches is based on relevant indicators that best reflect the actual switching behaviour.

As part of the monitoring, network operators (TSOs and DSOs) and suppliers collect data on contract structures and supplier switches for each specific customer group. Final consumers of electricity can be grouped, according to their meter profile, into customers with and without interval metering. For customers without interval metering, consumption over a set period of time is estimated using a standard load profile (SLP).

Final consumers can also be divided into household, commercial and industrial customers. Household customers are defined in the German Energy Industry Act (EnWG) primarily according to qualitative characteristics.[91] Non-household customers are also referred to in the monitoring report as commercial and industrial customers. There is so far no recognised definition of commercial customers[92] on the one hand and industrial customers on the other. For monitoring purposes as well, a strict separation of these two customer groups is not undertaken.

According to the supplier data, the volume of electricity sold to all final consumers in 2017 reached approximately 445 TWh. Of this, around 261 TWh was supplied to interval-metered customers and 163 TWh to SLP customers (including 14 TWh of electricity for night storage heating and heat pumps). The majority of SLP customers are household customers. In 2017, household customers were supplied with around 121 TWh, including night storage and heating electricity.

As part of the monitoring, data is collected on the volume of electricity sold to various final consumer groups, broken down into the following three contract categories:

- default supply contract,
- contract with a default supplier outside of default supply contracts and
- contract with a supplier who is not the local default supplier.

For the purposes of this analysis, the default supply contract category also includes fallback supply (section 38 EnWG) and doubtful cases.[93] Delivery outside the default supply contract is referred to either as a contract outside of default supply or is defined specifically ("contract with a default supplier outside of default supply contracts" or "contract with a supplier who is not the local default supplier"). An analysis on the basis

[91] Section 3(22) EnWG defines household customers as final consumers who purchase energy primarily for their own household consumption or for their own consumption for professional, agricultural and commercial purposes not exceeding an annual consumption of 10,000 kilowatt hours.

[92] The category "commercial customers" usually also includes customers from the liberal professions, agriculture, services and public administration, if their annual consumption does not exceed 10,000 kilowatt hours.

[93] In addition to household customers, final consumers served by fallback supply are usually included under the default supply tariff, section 38 EnWG. For monitoring purposes, suppliers were asked to allocate cases that could not be clearly categorised to default supply.

of these three categories makes it possible to draw conclusions as to the extent of the decline in the importance of default supply and the role of the default supplier since the liberalisation of the energy market. The corresponding figures, however, should not be directly interpreted as "cumulative net switching figures since liberalisation". It must be noted that for monitoring purposes the legal entity is taken to be the contracting party; thus a contract with a company affiliated with the default supplier falls under the category "contract with a supplier who is not the local default supplier".[94]

This year again, electricity suppliers provided information as to how many household customers switched supplier or adjusted their supply contract in 2017 (contract switch).

Furthermore, the TSOs and DSOs supplied information on the number of "supplier switches" in 2017, according to the different customer groups. In the monitoring report, the term "supplier switch" refers to the process by which a final consumer's meter point is assigned to a new supplier. As a rule, moving into or out of premises is not considered a supplier switch.[95] In this analysis, too, it must be noted that the change of supplier refers to a change in the supplying legal entity. According to this definition, a "change of supplier" can thus be brought about by an internal reallocation of supply to another group company, the insolvency of the former supplier or in the event that the supplier terminates the contract. The actual scope of supplier switches can therefore deviate from the figures reported. In addition to supplier switches, the monitoring report also analysed household customers' choice of supplier upon moving house.

2.1 Non-household customers

2.1.1 Contract structure

Electricity volumes for non-household customers are predominantly supplied to interval-metered customers whose electricity consumption is recorded at short intervals ("consumption profile"). Interval-metered customers are characterised by high consumption[96], the majority are industrial or high-consumption non-household customers.

In the reporting year 2017, approximately 1,200 electricity suppliers (individual legal entities) provided data on the meter points supplied and on the consumption of interval-metered customers (1,150 in the previous year). The 1,200 electricity suppliers include many affiliated companies, so that the number of suppliers does not equal the number of competitors.

The companies supplied just under 261 TWh of electricity to the approximately 372,100 meter points of interval-metered customers in 2017 (266 TWH was supplied to 370,600 meter points in the previous year). 99.7% of this was supplied under contracts outside of default supply[97]. It is unusual, but not impossible, for

[94] It is also possible that further ambiguities may arise, for example if the local default supplier changes. In these cases, no automatic switch of contract takes place (section 36(3) EnWG).

[95] If the supplier upon moving house is not the local default supplier, this is considered a "switch of supplier". Transfers of supply contracts as the result of concession switch are not considered to be a supplier switch.

[96] In accordance with section 12 of the Electricity Network Access Ordinance (StromNZV), interval metering is generally required if annual consumption exceeds 100 MWh.

[97] Under Section 36 EnWG, default supply only applies to household customers. Any mention in the following of default supply of non-household customers refers to fallback supply.

interval-metered customers to be supplied under default or fallback supply contracts. A total of 0.7 TWh of electricity was supplied to interval-metered customers with a default or fallback supply, which is 0.3% of the total electricity supplied to interval-metered customers.

27% of the total electricity for interval-metered customers was supplied under a special contract with the default supplier (divided between around 42% of all interval meter points). Approximately 72% of the total electricity was supplied under a contract with a legal entity other than the local default supplier (divided between approximately 57% of all meter points). In the previous year, 30% of the volume was sold under special contracts with the default supplier and 70% under special contracts with other suppliers. These figures again show that with regard to the volume sold, default supply and special contracts with the default supplier outside the default supply are of secondary importance for the acquisition of interval-metered electricity customers. In contrast, the volumes sold and the number of meter points supplied under special contracts outside the default supply are steadily increasing.

Contract structure for interval-metered customers in 2017
Volume and distribution

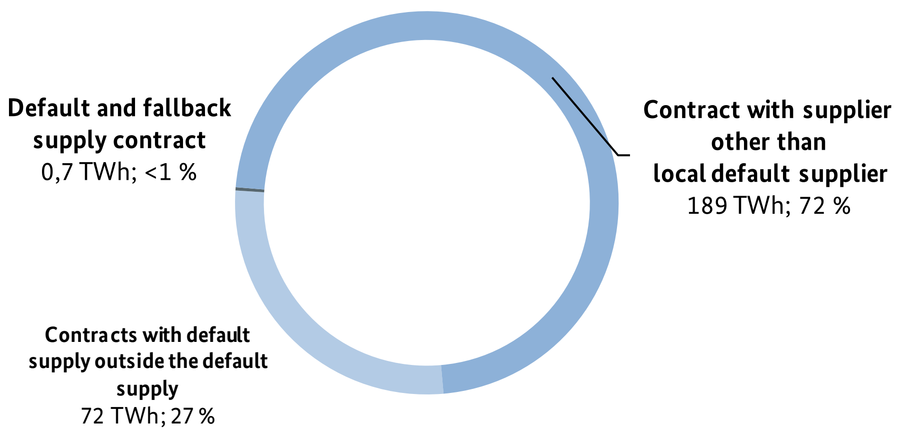


Figure 112: Contract structure for interval-metered customers in 2017

2.1.2 Supplier switching

Data on the supplier switching rates among different customer groups in 2017 and the consumption volumes attributed to these customers was collected in the TSO and DSO surveys. The surveys differentiated between the following consumption categories: Large industrial customers typically fall into the >2 GWh/year category, and a wide range of non-household customers such as restaurants, office buildings, hospitals and small companies, fall into the 10 MWh/year to 2 GWh/year category. The survey produced the following results:

Supplier switching rates by consumer category in 2017

Final consumer category	Number of meter points where the supplier changed	Share in all meter points of the consumption category	Consumption at meter points where the supplier changed in TWh	Percentage of total consumption by consumer category
>10 MWh/year – 2 GWh/year	223,941	10.4%	17.1	13.7%
> 2 GWh/year	2,865	16.2%	28.7	12.6%
Total non-household consumers	**226,806**	**10.5%**	**45.8**	**13.0%**

Table 67: Supplier switches by consumer category in 2017

The volume-based switching rate for the categories with a consumption exceeding 10 MWh/year was 13% in 2017. The switching rate in the previous year was 12.7%. Switching rates in the non-household customer category have remained more or less constant since 2009. The survey does not examine what percentage of non-household customers have switched supplier once, more than once or not at all during a period of several years.

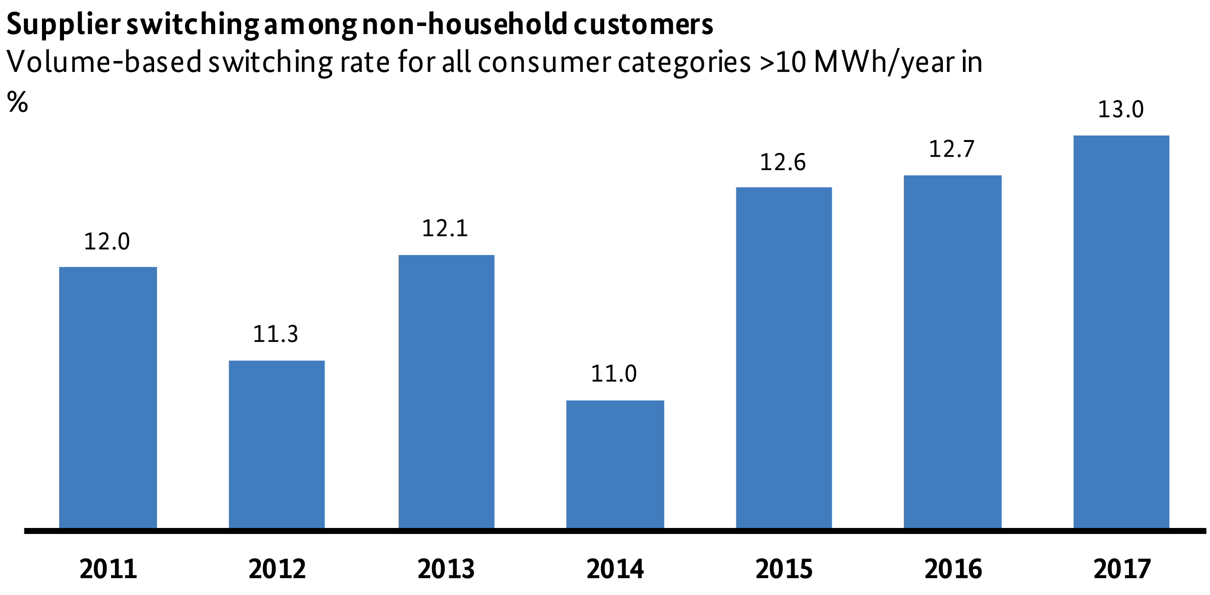


Figure 113: Supplier switching among non-household customers

2.2 Household customers

2.2.1 Contract structure

The data from the monitoring report shows that in 2017 a relative majority of 41.2% of household customers concluded a special contract with the local default supplier (2016: 40.9%). The percentage of household customers with a standard default supply contract is 27.8% (2016: 30.6%). Thus the percentage of default supply customers has fallen this year, whereas the percentage of customers who concluded a special contract with a local default supplier has increased when compared to the previous year. Meanwhile, 31% of all household customers are served by a company other than the default supplier (2016: 28.6%). Consequently, there has been a further increase in the percentage of customers who no longer have a contract with their default supplier. Overall, 69% of all households are still served by the default supplier (by way of default supply or special contract). Thus the strong position that default suppliers still have in their respective service areas has weakened slightly when compared to the previous year.

Contract structure of household customers in 2017
TWh and percentage

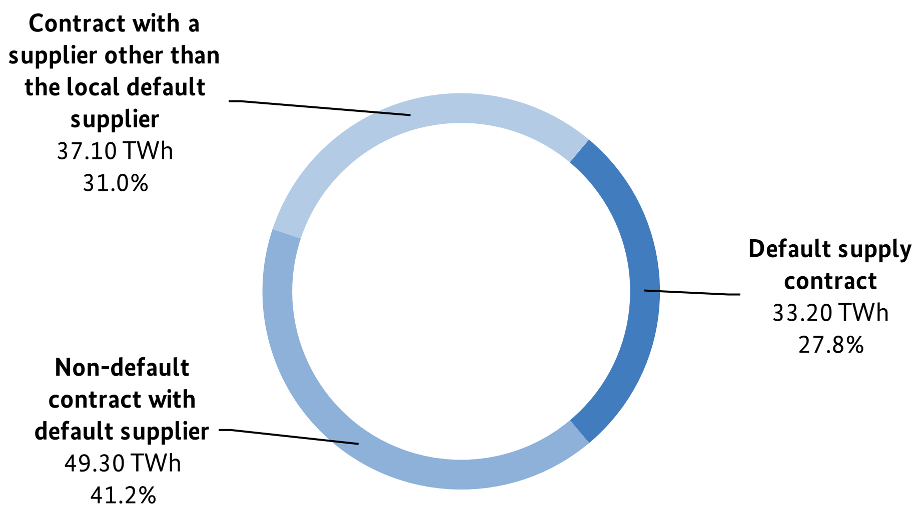


Figure 114: Contract structure of household customers

2.2.2 Switch of contract

Contract switches by household customers in 2017

Category	Contract switches in TWh	Percentage of total consumption (120.3 TWh)	Number of contract switches	Percentage of total number of household customers (46.1m)
Household customers who switched their existing energy supply contracts with their supplier	7.9	6.6	2,632,438	5.7

Table 68: Contract switches by household customers (based on survey of electricity suppliers)

For the third time, this year's monitoring report collected data from suppliers on household customers who changed their existing supply contract within a company (switch of contract). Suppliers were only required to register contract switches that were initiated by the customer. The total number of contract switches was around 2.6m, which is slightly higher than the previous year's figure (2016: 2.4m contract switches). The volume of electricity involved in the contract switches amounted to approximately 7.9 TWh. This results in a number and volume-based contract switching rate of 5.7% and 6.6% respectively.

The consistently high number of household customers who are supplied with electricity under a default supply contract or another contract with the default supplier shows that not all consumers are making use of their switching potential yet.

It is recommended that consumers inform themselves about their contract status (default supply etc.) and about their supplier's current prices, and that they compare these prices with those of other suppliers. Many customers can achieve savings through a change of contract or a switch of supplier.

2.2.3 Supplier switch

To determine the number of supplier switches by household customers, the DSOs were questioned as to the number of supplier switches at the meter points, as well as the choice of supplier when moving home in their network area. At 4.7m the total number of household customers switching supplier (including switches made due to moving home) is at a similar level to the previous year. The number of supplier switches not related to moving home has declined for the first time (-70,078). There was an increase in supplier selection due to moving home (+87,565); that figure, however, has remained relatively constant since 2013.

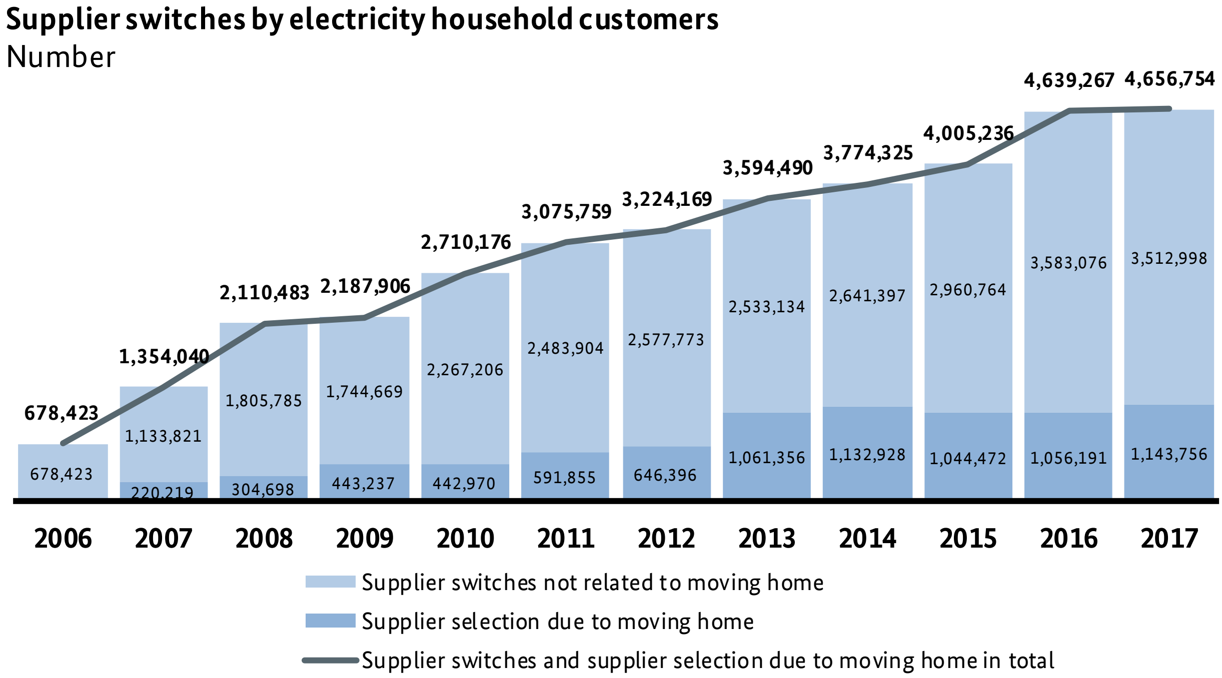


Figure 115: Supplier switches by household customers in the electricity sector

When viewing the trend in supplier switches from 2006 to 2017, one-off effects have to be taken into account as a consequence of the insolvency of two large cut-price electricity suppliers. The customers affected were initially switched to fallback supply and subsequently, provided they had not switched to another supplier themselves, were transferred to the default supply of the local default supplier. An estimated 500,000 customers were affected (also based on the figures of the monitoring report). By definition, such an atypical procedure is recorded as a switch, despite the fact that it is not based on a customer deciding to make the switch. It is therefore appropriate to remove the estimated portion of "switches brought on" by the insolvency. An adjustment of the figures from 2011 and 2013 by removing the 500,000 switches brought on by insolvency thus provides a more accurate picture of the rise in the number of switches, not including switches made for moving home. This is shown in the Figure above, already in adjusted form.

A total of 3,512,998 switches were determined for 2017, excluding for moving home. This amounts to around 7.2% of household customers and corresponds to a decrease by about 70,078 relative to the previous year. These switches entail an electricity volume of about 11.2 TWh, which is roughly at the same level as the previous year's figure (2016: 11.1 TWh). The switching rate based on total electricity consumed by household customers (excluding heating electricity) in 2017 was at around 9.4%.

In addition to the switching figures shown for household customers that excluded switches when moving home, the number of household customers who immediately chose an alternative supplier over the default supplier when moving into new premises increased by around 88,000, to 1,143,756. At just under 3.0 TWh, the electricity amount registered for supplier switches is also above the previous year's amount.

Supplier switches by household customers, including switches when moving home

Category	2017: Supplier switches in TWh	Percentage of total consumption[1] (119.9 TWh)	2017: Number of supplier switches	Percentage of total household customers
Household customers switching supplier without moving home	11.2	9.4	3,512,998	7.2
Household customers who switched to a supplier other than the default supplier when moving home	3.0	2.5	1,143,756	2.4
Total	14.2	11.8	4,656,754	9.6

[1] Not including heating electricity

Table 69: Supplier switches by household customers including switches when moving home

A joint view of household customer supplier switches that includes switches when moving home shows a total of around 4.7m switches for 2017, with a total electricity volume of 14.2 TWh. This corresponds to a switching rate based on volume and number of switches of 11.8% and 9.6% respectively. Thus the volume-based rate was again above the number-based rate. This suggests that a household customer's high level of electricity consumption has a positive influence on his/her decision to switch supplier. The average volume of electricity consumed by a household customer that made a switch was approximately 3,000 kWh in 2017. In contrast to this, household customers with a default supply contract consumed only about 2,100 kWh on average.

A joint view of the contract and supplier switches in 2017 makes it possible to calculate the number of household customers who undertook a change in their energy supply contract. A total of around 7.3m switches were made, with the volume of electricity involved in contract and supplier switches totalling 21.2 TWh.

3. Disconnections, cash or smart card readers, tariffs and terminations

A customer who fails to make a payment to the electricity supplier will receive a chargeable reminder, accompanied, or followed, by a disconnection notice.

The starting date of the disconnection period must be announced to the customer three working days prior to the disconnection date. Disconnection (interruption) of supply is carried out at the earliest four weeks after the disconnection notice and three days after the final disconnection notice.

The interruption of the electricity supply may only be carried out if the customer is €100 or more in arrears.

The supplier may charge the customer a fee for issuing notices, disconnecting supply and reinstating service. These fees can vary considerably, depending on supplier. In many cases, customers can demand verifiable documentation of the basis for calculation.

What can consumers do?

Consumers who receive benefits from the job centre, for example, can have their payments to the energy supplier made directly by the social benefit agency; this can be achieved by way of informal application with the pertinent office. Consumers should monitor their energy consumption and adjust their advance payments as necessary. By changing tariff or supplier, consumers can lower their energy costs. They can also receive energy cost counselling from consumer advice centres, for example.

3.1 Disconnection of supply and terminations

In 2017, the Bundesnetzagentur questioned network operators and electricity suppliers about disconnection notices and disconnection requests, as well as the number of actual disconnections carried out, along with the associated costs. In the 2011 to 2014 monitoring reports, the survey on disconnections focused solely on disconnection notices and requests relating to default supply customers, as well as on disconnections carried out on behalf of the local default supplier.

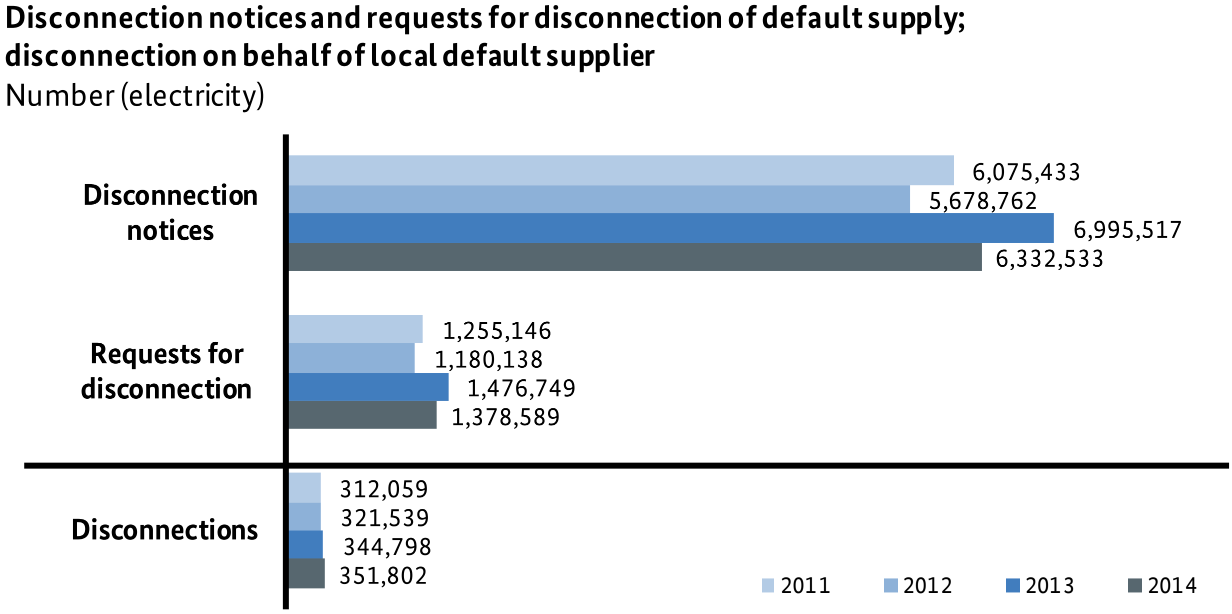


Figure 116: Disconnection notices and requests for disconnection of default supply; disconnection on behalf of the local default supplier

Starting in 2015, the data requested from electricity suppliers was further differentiated. The survey of disconnection notices and requests is now directed at all suppliers. At the same time, the suppliers were asked about disconnections under default supply as well as non-default supply contracts. In 2016 the survey was expanded to include DSOs, so that it now includes disconnections carried out by DSOs on behalf of a supplier other than the local default supplier.

The background of the modified survey is, on the one hand, the practice of some suppliers of stipulating provisions for the disconnection of non-default supply customers as well. DSOs, however, had in many cases not offered disconnections within the framework of their supply contracts at all, or had only offered them for the default supplier. In 2015 the Federal Court of Justice confirmed the Bundesnetzagentur's position that a network operator is in violation of his obligation to grant non-discriminatory network access if he rejects an electricity supplier's request for disconnection of electricity supply solely on the grounds that the delivery does not fall under a default supply contract.[98] Since 1 January 2016, the rights and obligations that are in effect between network operator and network user are now regulated in the network usage contract/supplier framework agreement for electricity, which is specified by the Bundesnetzagentur and regulates the possibility to disconnect supply at the request of any supplier.

On the other hand, network operators had until now been unable to tell whether a disconnection request by the default supplier was occurring within the framework of a default supply contract or a non-default supply contract. To request a disconnection under section 24(3) of the Low Voltage Network Connection Ordinance (NAV), the supplier must only credibly show that the contractual prerequisites for disconnection between supplier and customer are met. The supplier is not, however, required to disclose the contractual terms. Nor is a supplier obligated to effect a modification of his network registration with the network operator if he

[98] Federal Court of Justice, EnZR 13/14, 14 April 2015

changes the contractual terms with the customer. Network operators therefore have no way of knowing whether a customer who was originally supplied under a default supply contract is actually still under default supply or has switched to a household customer contract with the default supplier.

Under the Electricity Default Supply Ordinance (StromGVV), default suppliers have the right to disconnect supplies to customers, in particular upon failure to fulfil payment obligations of at least €100 and after appropriate notice has been given. The figures provided by the DSOs and suppliers show a slight increase in the overall number of disconnections in 2017.

Compared with the previous year, the number of disconnections reported to the Bundesnetzagentur that were carried out on behalf of the local default supplier has increased to 330,242, with roughly 11,773 more disconnections carried out at meter points than in the previous year. In addition, there were 13,623 reported disconnections carried out on behalf of a supplier other than the local default supplier. This figure is based on information from the DSOs, who ultimately carry out the disconnections on behalf of the suppliers.

For the first time, network operators have broken down the number of disconnections by federal state. Of the 330,242 disconnections carried out on behalf of the local default supplier, 99% could be attributed to individual federal states. Based on the total number of meter points, 0.66% of meter points were affected by disconnections. The federal states of Bremen, Hessen, North Rhine-Westphalia, Hamburg, Saxony-Anhalt, Schleswig-Holstein and Berlin were above this average figure, with over 0.66% of meter points affected by disconnections. The following table shows the breakdown by individual federal state:

Number of disconnections by federal state in 2017

	Number of disconnections	Percentage of meter points of final consumers in a federal state
Bremen	4,609	1.04
Hessen	34,351	0.92
North Rhine-Westfalia	98,177	0.89
Hamburg	9,581	0.83
Saxony-Anhalt	12,050	0.79
Schleswig-Holstein	12,424	0.72
Berlin	15,806	0.67
Saxony	17,691	0.63
Mecklenburg-Western Pomerania	6,078	0.61
Saarland	3,576	0.58
Lower Saxony	25,680	0.55
Thuringia	7,412	0.53
Rhineland-Palatinate	13,208	0.53
Brandenburg	7,908	0.48
Bavaria	35,057	0.46
Baden-Württemberg	22,624	0.36
total in Germany	**326,232**	**0.66**

Table 70: Number of disconnections by federal state in 2017

In 2017, the DSOs reinstated electricity supply for around 282,000 meter points that had been disconnected on behalf of the local default supplier, compared to 293,000 meter points where supply was reinstated in the previous year. In addition, electricity supply was reinstated for approximately 19,500 meter points on behalf of a supplier other than the local default supplier.

The network operators charged the electricity suppliers an average fee of €47 (excluding VAT) for disconnecting supply, with the actual costs charged ranging between €13 and €180. The average fee charged to household customers for reinstating supply to a meter point was €50 (excluding VAT), with the actual fees varying from €15 to €150.

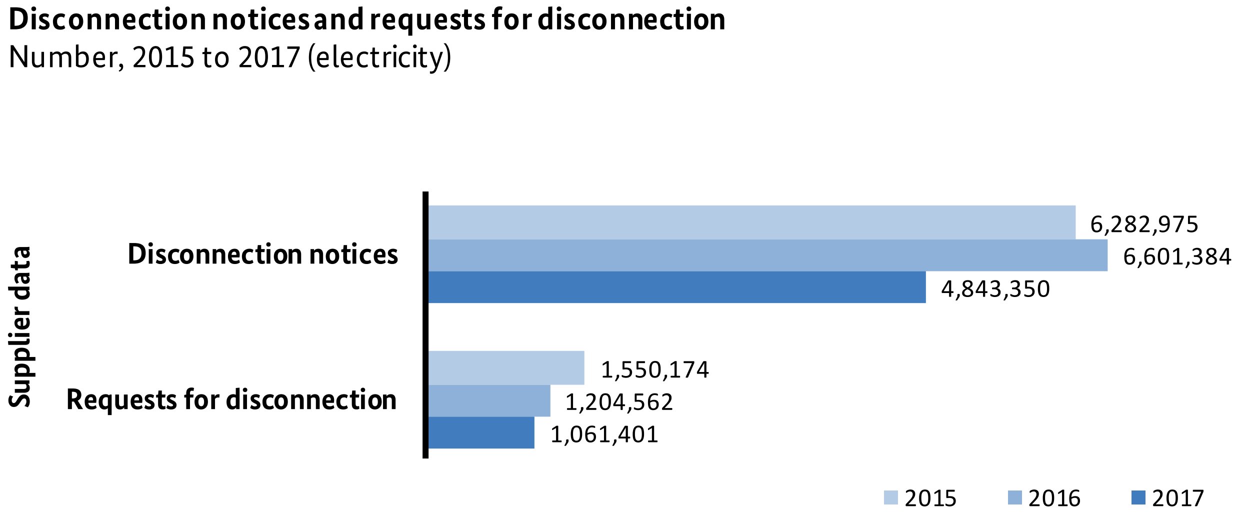
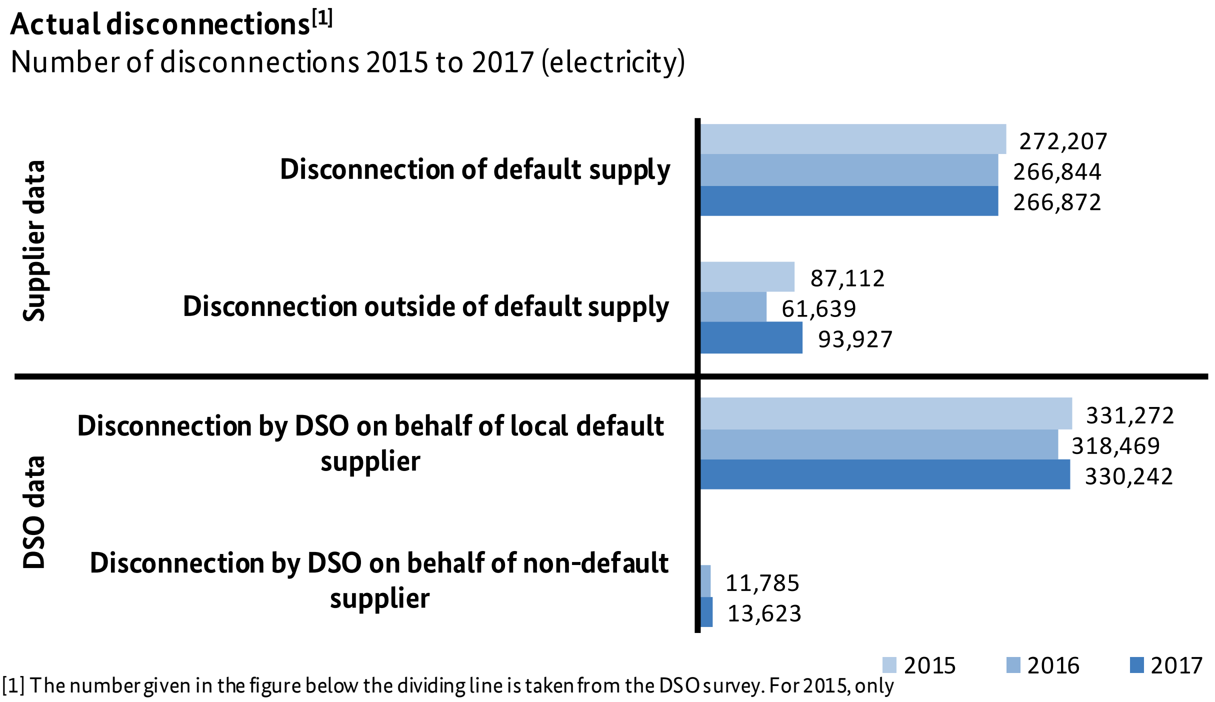


Figure 117: Disconnection notices and disconnection requests based on survey of electricity suppliers



[1] The number given in the figure below the dividing line is taken from the DSO survey. For 2015, only disconnections carried out by the DSOs on behalf of the local default supplier were recorded. Disconnections carried out on behalf of non-default suppliers are explicitly included in the survey as of 2016. The DSOs do not have information regarding the contractual relationships for the individual disconnections. All of the data above the dividing line has been taken from the supplier survey. Here, the disconnections carried out are broken down according to contractual relationships (default supply and non-default supply). For this reason, the disconnection numbers shown here are not directly comparable.

Figure 118: Actual disconnections based on survey of electricity suppliers and electricity DSOs

At the same time, the suppliers were asked how often in 2017 they had issued disconnection notices to customers who had failed to meet payment obligations, and how often they had requested the network operator responsible to disconnect supply. The companies responded that they had issued around 4.8m disconnection notices to household customers. According to the data provided by the companies, disconnection notices threatening to cut off customers are sent off when the statutory requirements of section 19 StromGVV are met and when, on average, a customer is €117 in arrears (2016: €119). Of the nearly 4.8m disconnection notices issued, approximately 1.0m resulted in electricity being disconnected by the pertinent network operator. The suppliers also responded that there were around 267,000 cases of disconnections carried out within the framework of a default supply contract, which is similar to the 2016 figure. The average percentage of actual disconnections relative to the respective overall number of customers under default supply was 1.7%. Disconnection outside of a default supply contract was carried out in approximately 94,000 cases (an increase of 22,000 relative to the previous year). Ultimately, network operators thus carried out a total of 361,000 disconnections (of customers with default and non-default supply contracts), which is roughly 22,000 more disconnections than were carried out in 2016.

Of the nearly 4.8m disconnection notices issued by suppliers, around 21% led to a disconnection request. In just under 7% of the 4.8m cases of disconnection notices did the respective network operator actually cut off the supply. This corresponds to a rate of 0.8% of all meter points of household customers in Germany.

There are various reasons for this difference. One assumption is that in many cases a disconnection notice leads to a payment. In other cases, customers might not allow the person charged with carrying out the disconnection onto their premises. In order to ultimately disconnect the electricity supply, judicial enforcement is required, which in turn costs time and money.

According to information provided by the suppliers, in 2017 the ratio between total disconnections and the number of household customers affected (with default and non-default supply contracts) was 1 to 0.87. This means that an estimated 13% of disconnections involve repeat disconnections of the same customers.

While some suppliers pass on only the costs charged by the network operator commissioned with carrying out the disconnection or reinstatement of supply, a number of electricity suppliers charged customers an additional fee of their own. For the first time, the electricity suppliers were asked whether they charge the flat rate fee according to section 19(4) StromGVV. Using this flat rate calculation, suppliers charged their customers an additional average fee of around €39 (including VAT),[99] with the actual fee ranging between €2 and €199. It is interesting to note that the average fee charged by suppliers without a flat rate calculation tends to be lower. Suppliers who did not carry out a flat rate calculation charged their customers an average fee of €33 (including VAT), with the actual fee ranging between €4 and €140. For reinstating supply, electricity suppliers using the flat rate fee model charged their customers an average of €41 (including VAT), with the actual cost ranging between €2 and €135, while suppliers who did not use the flat rate model charged an average of €31 (including VAT), with the actual fees varying from around €3 to €135.

For the first time, the Bundesnetzagentur asked suppliers in the 2018 monitoring survey how much they charge household customers for issuing a reminder because of arrears in payment. The average cost of issuing such a reminder was €3.70.

Despite issuing a disconnection notice and disconnection request, very few suppliers actually terminate services with their customers. Termination of a default supply contract is only permitted under stringent conditions: There must be no obligation to provide basic services or the requirements to disconnect supply must have been met repeatedly; also, the customer must have been warned of contract termination because of

[99] Supplier's own costs, not including costs incurred with the commissioned network operator.

arrears in payment. In 2017, suppliers terminated nearly 158,461 contracts with their customers overall (2016: approximately 171,647). The average customer arrears upon a termination of the energy supply contract in 2017 was €164.

3.2 Cash meters and smart card readers

In the 2017 monitoring survey, metering operators and suppliers were again surveyed on prepayment systems in accordance with 14 StromGVV, such as cash meters or smart card readers. Over the course of 2017, such prepayment systems were installed on behalf of the default supplier at about 19,500 household customers' points of consumption. This corresponds to 0.04% of all meter points of household customers in Germany. In just under 4,000 cases, a cash meter or smart card reader was newly installed in the 2017 calendar year, with about 3,000 such meters being removed again.

3.3 Tariffs and billing cycles of less than one year

Suppliers are required to offer load-based tariffs or time-of-use tariffs to final consumers of electricity, insofar as this is technically feasible and economically reasonable (section 40(5) EnWG). In 2017, as in the previous year, nearly 10% of suppliers offered load-based tariffs, while some 64% of suppliers offered time-of-use tariffs in 2017 (2016: 63%).

For the first time, suppliers were asked if they offer online tariffs and tariffs with dynamic pricing.

Only 25% of all suppliers offer online tariffs, which both can be concluded online (e.g. on the company's website or through a price comparison platform) and for which bills are available online. However, of the biggest suppliers, which account for 80% of electricity supply to household customers, 70% offer an online tariff.

Just under 3% of suppliers offered their household customers tariffs with dynamic pricing that reflect the interval-based price on the spot market, including the day-ahead market.

Around 12% of suppliers offered other tariffs as well (2016: 11%).

Section 40(3) EnWG also requires suppliers to offer final consumers monthly, quarterly or semi-annual bills. Customer demand for such billing cycles increased slightly in 2017. With a total of around 16,700 customers choosing billing cycles of less than one year (2016: around 14,000), customer demand for such billing cycles remains very low.

Moreover, in 2017, 135 suppliers stated that they carry out other forms of billing for household customers. In approximately 39,900 cases in total, suppliers carried out monthly, quarterly or semi-annual billing (2016: 27,000). The average charge (including VAT) for each additional billing was around €8 with customer reading and €11 without customer reading.

Although load-based and time-variable tariffs are available today, they are not very widespread.

Dynamic prices that are oriented to electricity prices at the exchange are still a niche product.

By contrast, there seems to be an increase in so-called online tariffs, especially among large suppliers. The online component, however, refers to the tariff billing and not to the contract arrangements.

4. Price level

Suppliers that provide final consumers with electricity in Germany submit information in the monitoring survey about the retail prices their companies charged on 1 April 2018 for various consumption levels. Suppliers are asked to provide price data on the consumption level for household customers for six different consumption bands. The lowest level covers an annual electricity consumption of under 1,000 kWh, while the highest level covers an annual electricity consumption of over 15,000 kWh. The standard case for household customers is in the 2,500 kWh to 5,000 kWh consumption band.

Furthermore, as in previous years, two different consumption levels for non-household customers with an annual consumption of 50 MWh and 24 GWh were analysed.

The companies give the overall price in cents per kilowatt hour (ct/kWh), including the non-variable price components such as the service price, base price and internal price in the overall price. The final price is broken down into individual price components. This includes components that the suppliers cannot control but that may vary from one network area to another, such as network charges, concession fees and charges for meter operations. Furthermore, the state-controlled surcharges and taxes are taken into account, i.e. value added and electricity taxes, surcharges under the EEG, KWKG and section 19(2) StromNEV, and surcharges for offshore liability and interruptible loads. After deducting these transitory items from the overall price, the amount remaining is the amount controlled by the supplier, which includes the energy and supply costs and the margin.

Both with regard to the overall price and the individual price components, the suppliers provided their "average" overall prices for the six consumption levels of household customers for each of the three different contract types (see below).100

For household customers, companies were asked to provide data on the individual price components for the six consumption bands for the following three contract types:

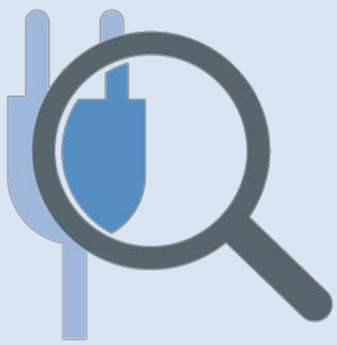
[100] If a company cannot calculate an average price due to the many different tariffs they offer, one representative tariff is chosen.

– default supply contract,

– non-default contract with a default supplier (after switch of contract) and

– contract with a supplier who is not the local default supplier (after switch of supplier).

The findings of the supplier survey are presented in the following by contract type per consumption level. To better illustrate any long-term trends, a comparison is made in each case with the previous year's figures – insofar as they correspond to the consumption level. When comparing the figures as at 1 April 2018 and 1 April 2017, it should be noted that minor changes in the calculated averages do not necessarily indicate a trend, but could instead come about through the participation of different suppliers in the survey.



The electricity price that customers pay to their supplier is made up of a number of price components: In addition to the energy and supply costs and the margin, the main components are the network charge, the concession fee and various surcharges and taxes. There is usually a monthly non-variable base price and a kilowatt-hour price. Consumers with a low consumption level tend to profit from a contract with a low base rate, while those with a high consumption level profit from a contract with a low kilowatt-hour price. There is no electricity price regulation in Germany.

4.1 Non-household customers

24 GWh/year consumption category ("industrial customers")

The customer group with an annual consumption in the 24 GWh range consists entirely of interval-metered customers, i.e. generally industrial customers. The wide range of options with regard to contractual arrangements is very important to this customer group. Suppliers generally do not use specific tariff groups for consumers who fall into the 24 GWh/year category, but offer customer-specific deals. Their customers include those with a full supply and those whose negotiated consumption represents only part of their procurement portfolio. Supply prices are often indexed against wholesale prices. In some cases, customers themselves are responsible for settling network charges with the network operator. In extreme cases, these types of contracts even go so far as to require suppliers to merely provide balancing group management services for customers in terms of the economic result. For high-consumption customers, the distinction between retail and wholesale trading can be quite fluid.

Special statutory regulations on the potential reduction of specific price components have a significant impact on individual prices for industrial customers. The main aim of these regulations is to reduce prices for businesses with high electricity consumption. The scale of the charges resulting from price components outside the supplier's control and the corresponding impact on individual prices depend on the maximum possible reduction available to companies in the 24 GWh/year consumption category. However, the price query was based on the assumption that none of the possible reductions applied to the customers concerned (sections 63 ff. EEG, section 19(2) StromNEV, section 36 KWKG, section 17f. EnWG).

The 24 GWh/year consumption category was defined as an annual usage period of 6,000 hours (annual peak load of 4,000 kW; medium voltage supply of 10 or 20 kV). Data was collected only from suppliers with at least one customer with an annual consumption between 10 GWh and 50 GWh. This customer profile essentially applied to only a limited number of suppliers. The following price analysis of the consumption category was based on data from 214 suppliers (212 suppliers in the previous year).

This data was used to calculate the (arithmetic mean) of the total price and the individual price components. The data spread for each price component was also analysed in terms of ranges. The 10th percentile represents the lower limit and the 90th percentile the upper limit of each reported range. This means that the middle 80% of the figures provided by the suppliers are within the stated range. The analysis produced the following results:

Price level for the 24 GWh/year consumption category without reductions on 1 April 2018

	Spread between 10 and 90 percentile range of the supplier data sorted by size in ct/kWh	**Average** (arithmetic) in ct/kWh
Price components outside of supplier's control		
Net network charge	1.55 - 3.27	2.33
Metering, meter operation	0.00 - 0.03	0.03
Concession fee	0.11 - 0.11	0.10[1]
EEG surcharge		6.79
Other surcharges[2]		0.29
Electricity tax		2.05
Price component controlled by the supplier (remaining balance)	2.85 - 4.50	3.71
Total price (excluding VAT)	**14.01 - 16.49**	**15.30**

[1] Over 90% of suppliers quozed a concession fee of 0.11 ct/kWh. Fewer than 20 suppliers quoted a lower figure.
[2] KWKG (0-168 ct/kWh), StromNEV (0.063 ct/kWh), section 18 AbLaV surcharge (0.011 ct/kWh), offshore liability (0.049 ct/kWh)

Table 71: Price level for the 24 GWh/year consumption category without reductions on 1 April 2018

The arithmetic mean of the price component controllable by the supplier rose from 3.41 ct/kWH in the previous year to 3.71 ct/kWh. The surcharges totalled 7.08 ct/kWh (including an EEG surcharge of 6.79 ct/kWh), which corresponds to the value from the previous year. The average net network charge also rose slightly from 2.23 ct/kWh in the previous year to 2.33 ct/kWh. As the spread of net network charges is very high, the average charge does not necessarily represent the actual development.[101] The average overall price (excluding VAT and excluding possible reductions) of 15.30 ct/kWh was 0.40 ct/kWh above the arithmetic mean of the figures collected in the previous year. Due to the alignment of tariffs for industrial customers to wholesale prices described above, price increases can be passed on more quickly to these customers than to household customers. In particular, the price component which is controllable by the supplier rose accordingly.

By definition, these prices were based on the assumption that (industrial) customers with an annual consumption of 24 GWh were not eligible for any of the statutory reductions available. In the consumption category thus defined, cost items outside the supplier's control accounted for a total of 11.59 ct/kWh, or about 76%, of the overall price. However, electricity consumers who meet the requirements of applicable laws and regulations can take advantage of reductions in network charges, concession fees, electricity tax and the surcharges under the EEG, KWKG, section 19 of the StromNEV and section 17f. of the EnWG. If all of these possible reductions are applied, the price component outside the supplier's control could be reduced from over 11 ct/kWh to below 1 ct/kWh.[102]

The EEG surcharge offers the greatest scope for possible reductions. It can be reduced by up to 95% for customers with an annual consumption of 24 GWh – depending on the specific case – the actual level of possible reduction depends on several factors in accordance with section 64 of the EEG. Under section 19(2) first sentence of the StromNEV, the net network charge may be reduced by up to 80%.[103] Electricity tax may be waived, refunded or reimbursed in full in accordance with section 9a of the StromStG. The concession fees under section 2(4) first sentence of the KAV and the surcharges under section 36 of the KWKG and section 17f of the EnWG offer significantly less scope for a reduction of the overall price in quantitative terms. No monitoring data was collected on the actual extent to which industrial customers make use of each of the possible reductions. As a result, the monitoring data cannot be used to draw conclusions on the "correct" average price for industrial customers.

[101] It should be noted that the arithmetic mean does not reflect the wide spread of network charges and the heterogeneous nature of the network operators in these consumption categories.

[102] There are different eligibility requirements for the various possible reductions. During monitoring, no data was collected on whether there are any cases in practice where all the possible maximum reductions are, or can be, fully exploited.

[103] The even greater reductions possible under Section 19(2) sentence 2 of the StromNEV are not relevant to the 24 GWh/year consumption category since this has been defined as comprising 6,000 hours of use.

Possible reductions for the 24 GWh/year consumption category

Based on price query as of 1 April 2018	Anticipated figure in the price query in ct/kWh	Amount of possible reduction in ct/kWh	Remaining balance in ct/kWh
EEG surcharge	6.79	-6.46	0.33
Electricity tax	2.05	-2.05	0.00
Net network charge	2.33	-1.86	0.47
Other surcharges	0.29	-0.10	0.19
Concession fee	0.10	-0.10	0.00
Total	**11.56**	**-10.57**	**0.99**

Table 72: Possible reductions for the 24 GWh/year consumption category on 1 April 2018

50 MWh/year consumption category ("commercial customers")

The 50 MWh/year consumption category described below was defined as an annual usage period of 1,000 hours (annual peak load of 50 kW; low voltage supply of 0.4 kV), which corresponds to the consumption profile of a commercial customer. An annual consumption of 50 MWh is 14 times higher than the 3,500 kWh category ("household customers") and is also two thousandths of the 24 GWh/year consumption category. Given the moderate level of consumption, individual contract arrangements play a significantly smaller role than in the 24 GWh/year consumption category. Suppliers were asked to make a plausible estimate of the charges for customers whose consumption profile is similar to that of the consumption category based on the terms and conditions that applied on 1 April 2018. Data was requested from suppliers that had at least one customer with an annual consumption between 10 MWh and 100 MWh. Since this consumption is below the 100 MWh threshold above which network operators are required to use interval metering, it is safe to assume that in this category consumption is measured using a standard load profile.

The following price analysis of the consumption category was based on data from 888 suppliers (959 in the previous year). This data was used to calculate the (arithmetic mean) of the total price and of the individual price components. The data spread for each price component was also analysed in terms of ranges that included the middle 80% of the figures provided by the suppliers. The analysis produced the following results:

Price level for the 50 GWh/year consumption category on 1 April 2018

	Spread between 10 and 90 percentile range of the supplier data sorted by size in ct/kWh	Average (arithmetic) in ct/kWh	Percentage of total price
Price components outside of supplier's control			
Net network charge	4.33 - 7.73	5.95	28%
Metering, meter operation	0.02 - 0.99	0.32	1%
Concession fee	0.11 - 1.59	0.54	3%
EEG surcharge		6.79	32%
Other surcharges[2]		0.76	4%
Electricity tax		2.05	9%
Price component controlled by the supplier (remaining balance)	3.32 - 7.32	5.14	24%
Total price (excluding VAT)	**19.12 - 23.84**	**21.56**	**100%**

[1] KWKG (0.345 ct/kWh), StromNEV (0.370 ct/kWh), section 18 AbLaV surcharge (0.011 ct/kWh), offshore liability (0.037 ct/kWh)

Table 73: Price level for the 50 MWh/year consumption category on 1 April 2018

The remaining balance that can be controlled by the supplier increased for the first time. Whereas in April 2017 this value was at 4.82 ct/kWh, by April 2018 it had risen to 5.14 ct/kWh – an increase of 0.32 ct/kWh. By contrast, in the previous reporting year, this price had fallen in 2017 by around 0.33 ct/kWh compared with the previous year.

The renewable energy surcharge fell from 6.88ct/kWh in the previous year to 6.79 ct/kWh. The other surcharges fell from 0.80 ct/kWh to 0.76 ct/kWh. Overall the renewable energy surcharge and other surcharges decreased by 0.13 ct/kWh. The average net network charge rose by 0.04 ct/kWh to 5.95 ct/kWh. As the spread of net network charges is very high, the average charge does not necessarily represent the actual development.[104]

The average overall price excluding VAT) of 21.56 ct/kWh in April 2018 fell by 0.14 ct/kWh compared to the previous year's figure. This decrease is in large part due to both the lower renewable energy surcharge and lower other surcharges. This is also reflected in the percentage of these price components in the overall price. The renewable energy surcharge now makes up 32% of the overall price, while the net network charge makes up 28% of the overall price. Therefore, an average of about 76% of the overall price in this consumption category relates to cost items outside of the supplier's control (network charges, metering, surcharges, electricity tax and concession fee). Only about 24% (22% in the previous year) relates to price elements that provide scope for commercial decisions.

4.2 Household customers

In this section, retail prices and price components for household customers are examined and set out in tabular form as the volume-weighted averages for the three different types of tariffs in six consumption bands. The suppliers of electricity to final consumers in Germany provided data for the following consumption bands for low-voltage supply (0.4 kV):

- band I (DA[105][106]): annual electricity consumption below 1,000 kWh
- band II (DB): annual electricity consumption between 1,000 and 2,500 kWh
- band III (DC): annual electricity consumption between 2,500 and 5,000 kWh
- band IV: annual electricity consumption between 5,000 and 10,000 kWh
- band V: annual electricity consumption between 10,000 and 15,000 kWh
- band VI (DE): annual electricity consumption above 15,000 kWh

First the volume-weighted average price across all types of contracts for household customers was looked at in the representative consumption band between 2,500 kWh and 5,000 kWh per year (band III). In section I.G.4.2.2, individual consumption bands are subsequently analysed, with the focus on the consumption band of a typical household customer in band III.

4.2.1 Volume-weighted price across all contract categories for household customers (band III)

In the following tables and figures, the volume-weighted overall price across all contract categories for band III is examined. The average price for all household customers in consumption band III is taken as an indicator, which is calculated by weighing the individual prices for the three types of contract (default supply; non-default supply; contract with a supplier other than the local default supplier) using the respective

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[104] It should be noted that the arithmetic mean does not reflect the wide spread of network charges and the heterogeneous nature of the network operators in these consumption categories.

[105] "DA", "DB", "DC" and "DE" refer to the consumption bands defined by EUROSTAT.

[106] The charge for billing is now part of the net network charge, in accordance with section 7(2) of the Metering Act and section 17(7) third sentence of the StromNEV. With regard to the other price components, section 17(7) first sentence of the StromNEV specifies that as from 1 January 2017 the charge for meter operations must also include the charge for metering. This year's Monitoring Report does not yet make this differentiation [see BNetzA section on metering operation].

consumption volumes. The average price calculated as at 1 April 2018 was 29.88 ct/kWh, which has remained largely unchanged from the previous year (2017: 29.86 ct/kWh). Table 74 provides a detailed breakdown of the individual price components of the volume-weighted average price. The change relative to the previous year is shown in Table 75.

Average volume-weighted prices across all types of contract for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat band DC) as at 1 April 2018 (ct/kWh)

Price component	Volume-weighted average across all types of contract (ct/kWh)	Percentage of total price
Energy and supply, margin	6.70	22.4
Net network charge	6.88	23.0
Meter operation charge	0.31	1.0
Concession fee	1.61	5.4
EEG surcharge	6.79	22.7
KWKG surcharge	0.35	1.2
Section 19 StromNEV surcharge	0.37	1.2
Section 18 AbLaV surcharge	0.01	0.0
Offshore liability surcharge	0.04	0.1
Electricity tax	2.05	6.9
VAT	4.77	16.0
Total	**29.88**	**100.0**

Table 74: Average volume-weighted prices across all types of contracts for household customers in consumption band III as at 1 April 2018

Change in volume-weighted price level across all types of contract from 1 April 2017 to 1 April 2018 for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat band DC)

Price component	Volume-weighted average across all types of contract (ct/kWh)	Change in level of price component	
		in ct/kWh	(%)
Energy and supply, margin	6.70	0.28	4.2
Net network charge	6.88	-0.11	-1.6
Meter operation charge	0.31	-0.01	-3.2
Concession fee	1.61	-0.01	-0.6
EEG surcharge	6.79	-0.09	-1.3
KWKG surcharge	0.35	-0.09	-25.7
Section 19 StromNEV surcharge	0.37	-0.02	-5.4
Section 18 AbLaV surcharge	0.01	0.00	0.0
Offshore liability surcharge	0.04	0.07	k.A.
Electricity tax	2.05	0.00	0.0
VAT	4.77	0.00	0.0
Total	**29.88**	**0.02**	**0.1**

Table 75: Change in volume-weighted price level for household customers across all types of contract from 1 April 2017 to 1 April 2018 (consumption band between 2,500 kWh and 5,000 kWh)

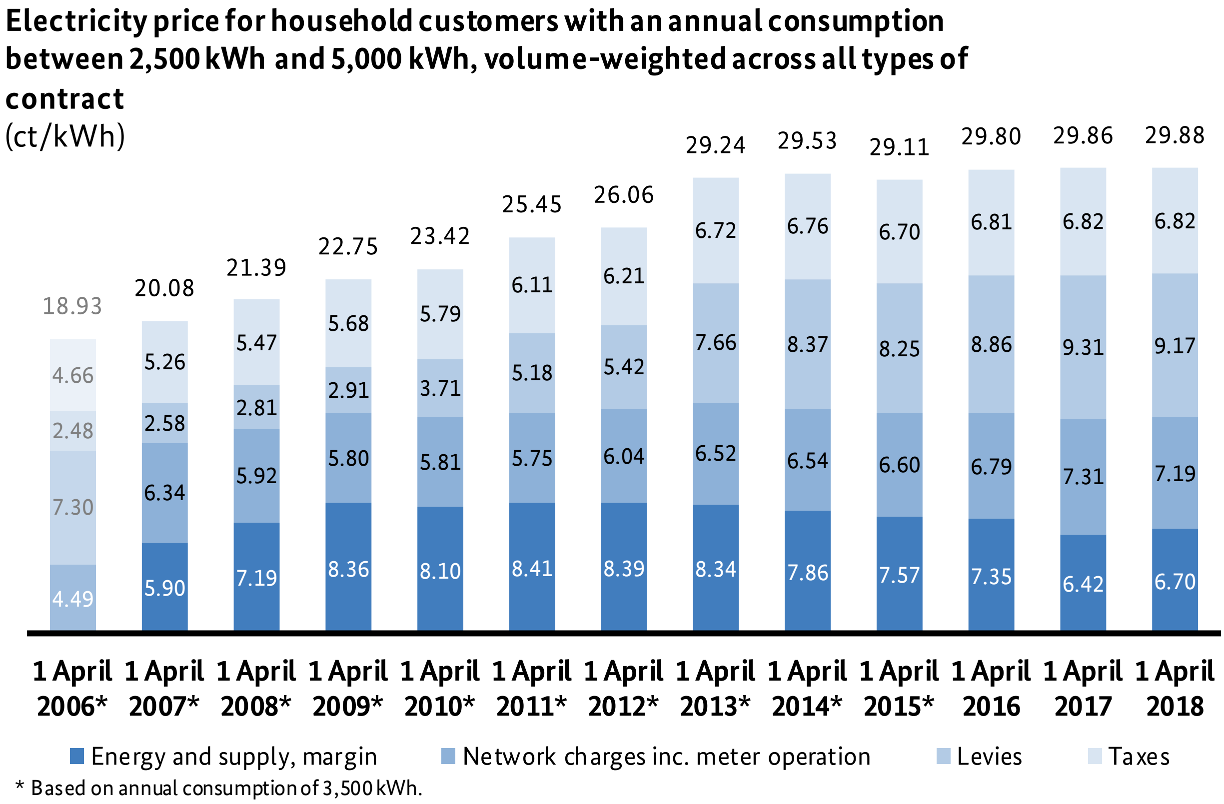


Figure 119: Development of volume-weighted electricity price for household customers across all types of contracts

Figure 119 shows the development of the average price for household customers. While the overall price since 2016 has changed only minimally, there has been a shift in the price components. The following section therefore takes a closer look at the price components.

Figure 120 shows that surcharges, taxes and levies account for around 54% of the average electricity price for household customers. The net network charge including meter operations accounts for a share of around 24%. The share of the electricity price that the supplier can control (energy and supply costs and the margin) accounts for around 22.4% in 2018 (previous year: 21.5%). The following section presents the development of these essential price components of the volume-weighted electricity price for household customers.

Breakdown of the retail price for household customers with annual consumption between 2,500 kWh and 5,000 kWh as at 1 April 2018 (volume-wighted across all types of contract, band III, Eurostat band DC)
(%)

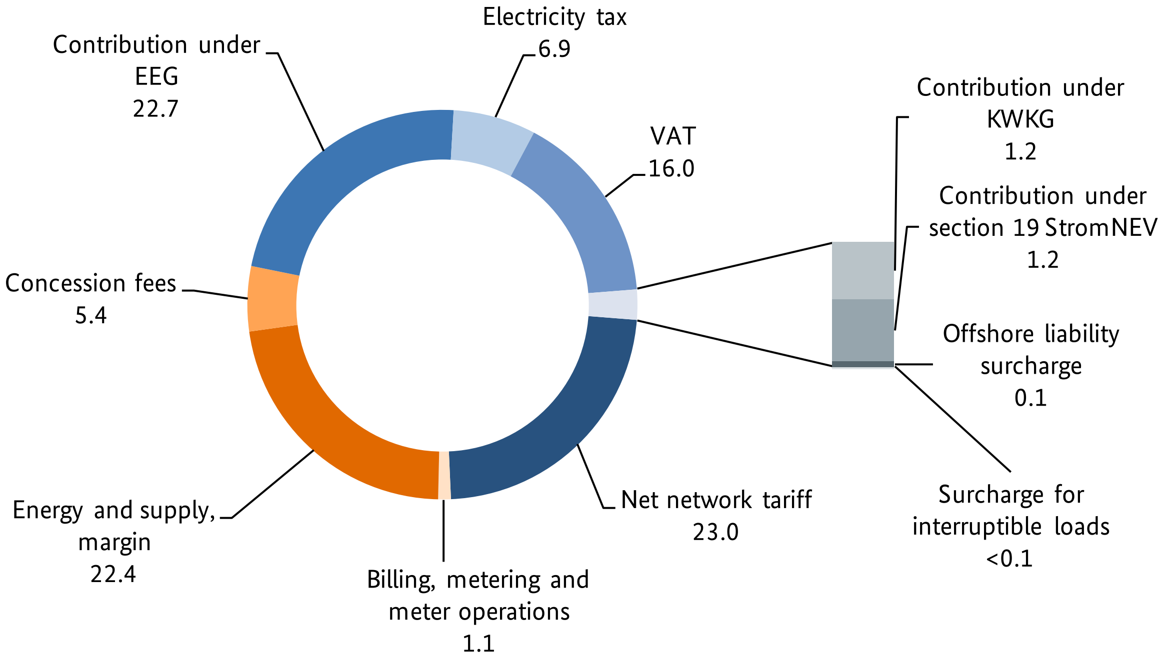


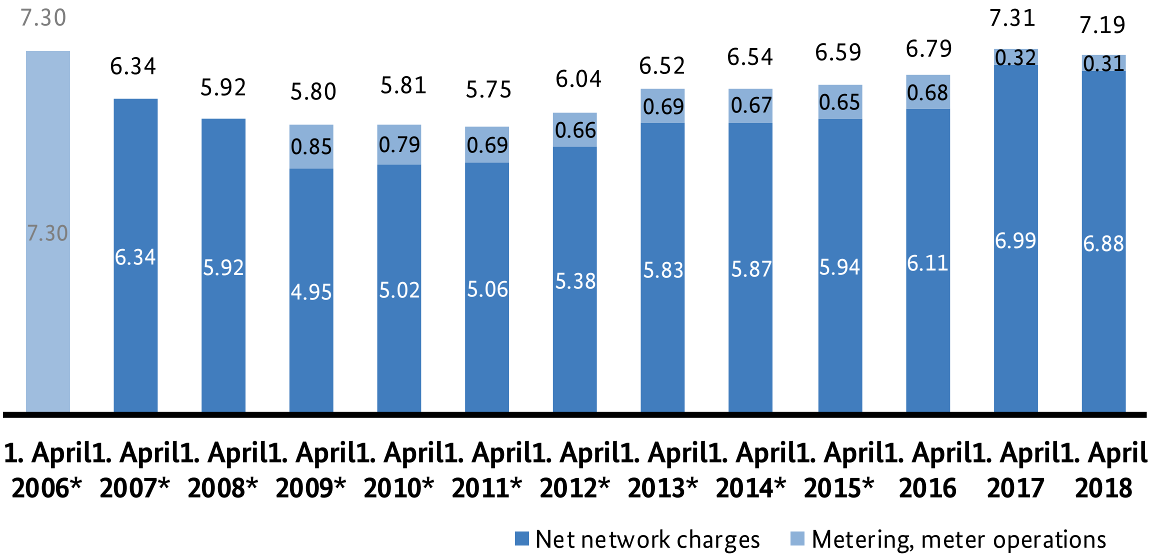
Figure 120: Breakdown of average volume-weighted price for household customers in consumption band III as at 1 April 2018 (volume-weighted average across all types of contract)[107]

First, a look at the network charges shows a relatively sharp increase until 2017,[108] following successive decreases in the period up to 2011. In 2018, the average network charge fell for the first time since 2011. That amounts to a decrease of 1.6% (-0.11 ct/kWh) relative to 2017. Thus, while the network charge continues to be high, for the first time in eight years it has fallen compared to the previous year.

[107] The value added tax makes up 16% of the total gross price, since the statutory 19% VAT is charged on and added to the net price (100%). Thus the VAT at 19% is the dividend and the total price at 119% is the divisor.

[108] Net network charge includes charges for meter operations.

Development of network charges for household customers with an annual consumption of 2,500 to 5,000 kWh (volume-weighted across all types of contract)
in ct/kWh



* Based on an annual consumption of 3,500 kWh.

Figure 121: Network charges for household customers, including charges for billing, metering and meter operations

For the first time, there has also been a noticeable decrease in the other taxes and levies. These include in particular the renewable energy surcharge (EEG surcharge) and the surcharge as regulated under the KWKG (see chapter I.G.4.3 "Surcharges"). The EEG surcharge is used to balance out the renewable energy costs incurred by the TSOs (in particular the payments to installation operators) and the income generated from selling renewable energy on the spot market. The surcharge is announced by the TSOs on 15 October each year for the following calendar year. The Bundesnetzagentur ensures that the surcharge has been determined properly. The renewable energy surcharge for 2018 fell to 6.79 ct/kWh, thus accounting for around 23% of the total electricity price. Figure 122 shows the changes in the surcharge in more detail.

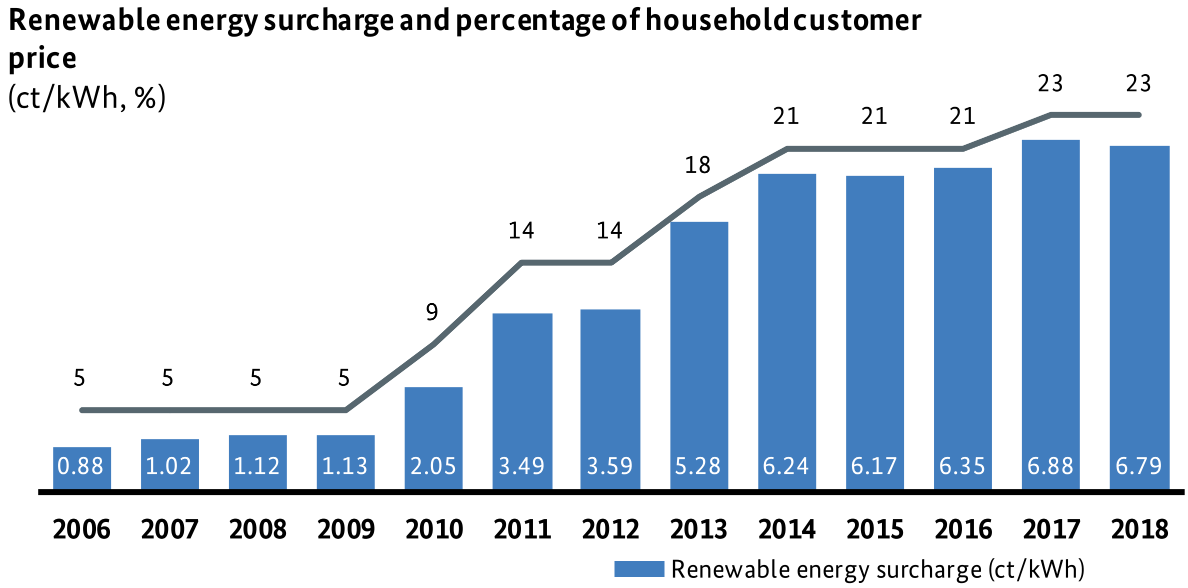


Figure 122: Renewable energy surcharge and percentage of household customer price

The price component for "Energy and supply costs and the margin" (see Figure 123) remained largely stable in the period from 2009 to 2013. While since 2011 this price component controlled by the supplier has fallen steadily, in 2018 it increased by 0.28 ct/kWh, or nearly 5% (2017: 6.42 ct/kWh). This increase could be attributable in particular to the increase in wholesale prices in 2017 (see chapter I.F. "Wholesale", page 226 ff.). These higher prices are gradually being passed on to household customers.

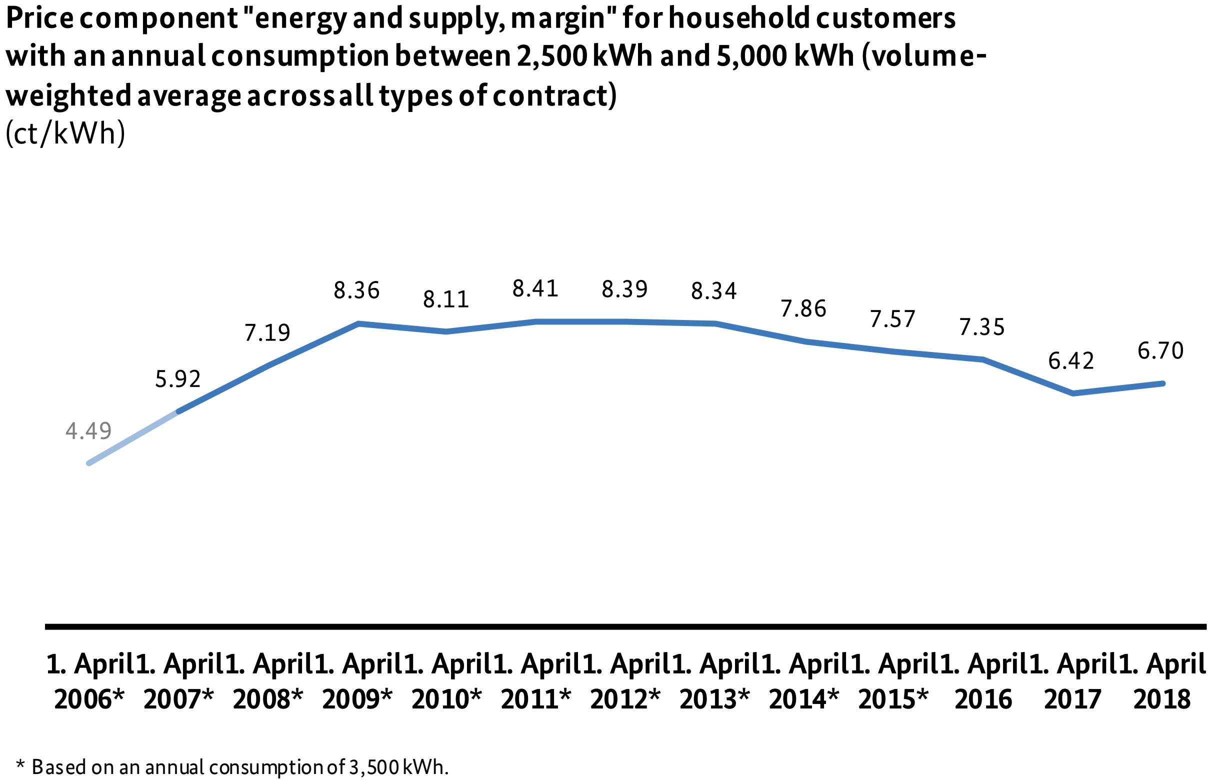


Figure 123: Development of the price component “energy and supply costs and margin” for household customers

4.2.2 Household customer prices by consumption band

Using the figures provided by the suppliers, average prices are calculated for default supply contracts, for non-default contracts with the default supplier and for contracts with a supplier other than the local default supplier. The following section examines the prices for the six consumption bands of household customers.

It is important to note that the average network charges listed for each type of tariff are calculated using the figures provided by the suppliers, which in turn are the charges averaged over all the networks supplied. This results in a different network charge for each tariff. The large number of network areas leads to considerable heterogeneity in both the supplier structure and the contract structure of customers supplied. For example, suppliers can supply electricity to a majority of their customers with particularly high or particularly low network charges, regardless of whether they are customers with default supply contracts or not. The opposite case is also possible. Based on this distribution of customers in the various network areas according to each contract type, the three types of supply result in different volume-weighted average network charges. In each network area, the network charge is independent of the contract type. The following tables should therefore not be taken to mean, for example, that the default supply is the contract type with the highest network charge.

The volume-weighted prices were calculated using the consumption volumes for 2017 and the prices as at 1 April 2018. The use of new consumption bands since 2016 is due to a change in the methodology used by Eurostat to collect price data. This monitoring report shows the results for six consumption bands.

Band I: Annual electricity consumption below 1,000 kWh

Average volume-weighted prices per contract category for household customers with an annual consumption below 1,000 kWh (band I; Eurostat band DA) as at 1 April 2018 (ct/kWh)

Price component	Default supply contract	Non-default contract with the default supplier	Contract with supplier other than the default supplier
Energy and supply, margin	12.14	9.72	6.73
Net network charge	13.95	11.79	10.27
Meter operation charge	1.95	1.72	1.27
Concession fee	1.65	1.77	1.79
EEG surcharge	6.79	6.79	6.79
KWKG surcharge	0.35	0.35	0.35
Section 19 StromNEV surcharge	0.37	0.37	0.37
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore liability surcharge	0.04	0.04	0.04
Electricity tax	2.05	2.05	2.05
VAT	7.48	6.57	4.97
Total	**46.78**	**41.18**	**34.64**

Table 76: Average volume-weighted price per type of contract for household customers in consumption band I as at 1 April 2018

It is important to note that for customers with a relatively low consumption, suppliers are asked to give prices including non-variable price components, such as the service price, base price and internal price. The combination of lower consumption levels with the non-variable price components such as the base price results in a higher kilowatt-hour rate.

Band II: Annual electricity consumption between 1,000 and 2,500 kWh

Average volume-weighted prices per contract category for household customers with an annual consumption between 1,000 kWh and 2,500 kWh (band II; Eurostat band DB) as at 1 April 2018 (ct/kWh)

Price component	Default supply contract	Non-default contract with the default supplier	Contract with supplier other than the default supplier
Energy and supply, margin	8.82	7.10	6.08
Net network charge	8.17	7.46	8.08
Meter operation charge	0.64	0.64	0.66
Concession fee	1.64	1.73	1.69
EEG surcharge	6.79	6.79	6.79
KWKG surcharge	0.35	0.35	0.35
Section 19 StromNEV surcharge	0.37	0.37	0.37
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore liability surcharge	0.04	0.04	0.04
Electricity tax	2.05	2.05	2.05
VAT	5.49	5.04	4.94
Total	**34.37**	**31.58**	**31.06**

Table 77: Average volume-weighted price per type of contract for household customers in consumption band II as at 1 April 2018

Band III: Annual electricity consumption between 2,500 kWh and 5,000 kWh

Band III covers the majority of typical household customers in Germany and is comparable to the 3,500 kWh annual consumption band used until 2015. The following tables show the results of the data analysis for band III, with the individual price components analysed in more detail and shown in time series.

Average volume-weighted prices per contract category for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat band DC) as at 1 April 2018 (ct/kWh)

Price component	Default supply contract	Non-default contract with the default supplier	Contract with supplier other than the default supplier
Energy and supply, margin	8.06	6.61	5.69
Net network charge	6.79	6.76	7.01
Meter operation charge	0.32	0.31	0.34
Concession fee	1.67	1.61	1.57
EEG surcharge	6.79	6.79	6.79
KWKG surcharge	0.35	0.35	0.35
Section 19 StromNEV surcharge	0.37	0.37	0.37
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore liability surcharge	0.04	0.04	0.04
Electricity tax	2.05	2.05	2.05
VAT	5.02	4.73	4.58
Total	**31.47**	**29.63**	**28.80**

Table 78: Average volume-weighted price per type of contract for household customers in consumption band III as at 1 April 2018

A comparison of the three types of contract – default, non-default contract with the local default supplier (usually after switching contract) and contract with a supplier other than the local default supplier (usually after switching supplier) – makes it clear that default tariffs are still the most expensive option for customers with an annual consumption of between 2,500 kWh and 5,000 kWh. At the same time, a comparison is only possible to a limited extent. While the average consumption in 2017 for customers on default tariffs was around 2,100 kWh, the average for customers on non-default tariffs with the default supplier and customers who had switched from their default supplier was about 38% higher, at around 2,899 kWh.

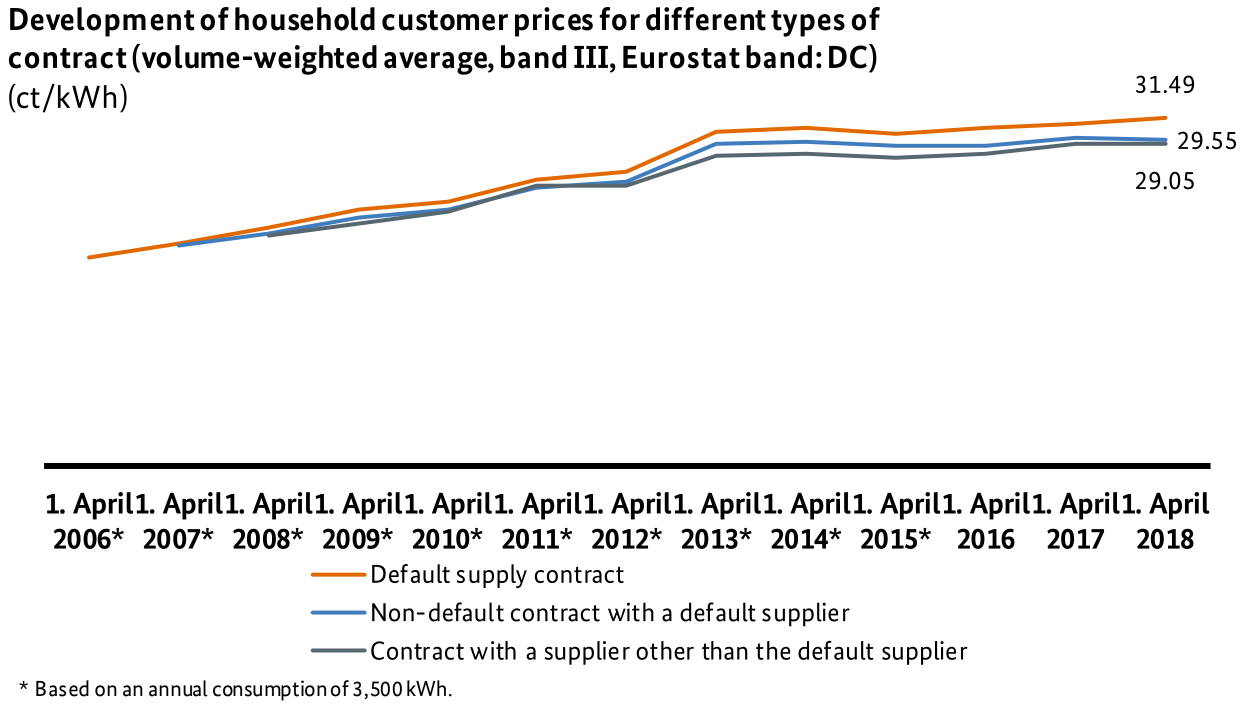


Figure 124: Household customer prices for the different types of contract

A comparison of the average prices for the three types of contract shows that throughout the period since 2008, default tariffs were the most expensive option for household customers. Prices for customers on non-default contracts with the default supplier were consistently cheaper over the same period of time than for those on default tariffs. On average, prices for customers who switched from the local default supplier to a new supplier are the cheapest. In ten out of the eleven years in the period under review, average prices for customers who had switched from their local default supplier were – to a greater or lesser extent – lower than those for customers who had switched tariff with their default supplier.

Household customers can achieve additional savings compared to a default supply contract by switching the tariff with the default supplier (-1.94 ct/kWh) and, to an even greater extent, by switching supplier (-2.44 ct/kWh).[109] For a household customer with an annual consumption of 3,500 kWh, this amounts to savings in energy costs of around €68 and €85 per year respectively.

At 8.03 ct/kWh, the price component that can be controlled by the supplier, including energy and supply costs, was nearly 38% higher for customers on default tariffs than for customers who had switched from their default supplier; the average price component for the latter group was 5.83 ct/kWh. In 2017, the difference between the two groups was only 29%. The average price component for energy and supply costs and the margin for customers on non-default contracts with their default supplier was 6.57 ct/kWh (2017: 6.34 ct/kWh), and thus around 22% lower than that for customers on default tariffs. Any direct comparison of these figures must take into account further differences between the customer groups other than their different consumption levels. For instance, default contracts have shorter notice periods and on average a

[109] The cost savings apply to the consumption band between 2,500 kWh and 5,000 kWh/year.

higher risk of non-payment. These risk costs are also included in the price component that can be controlled by the supplier. Figure 125 provides a detailed overview of the trend.

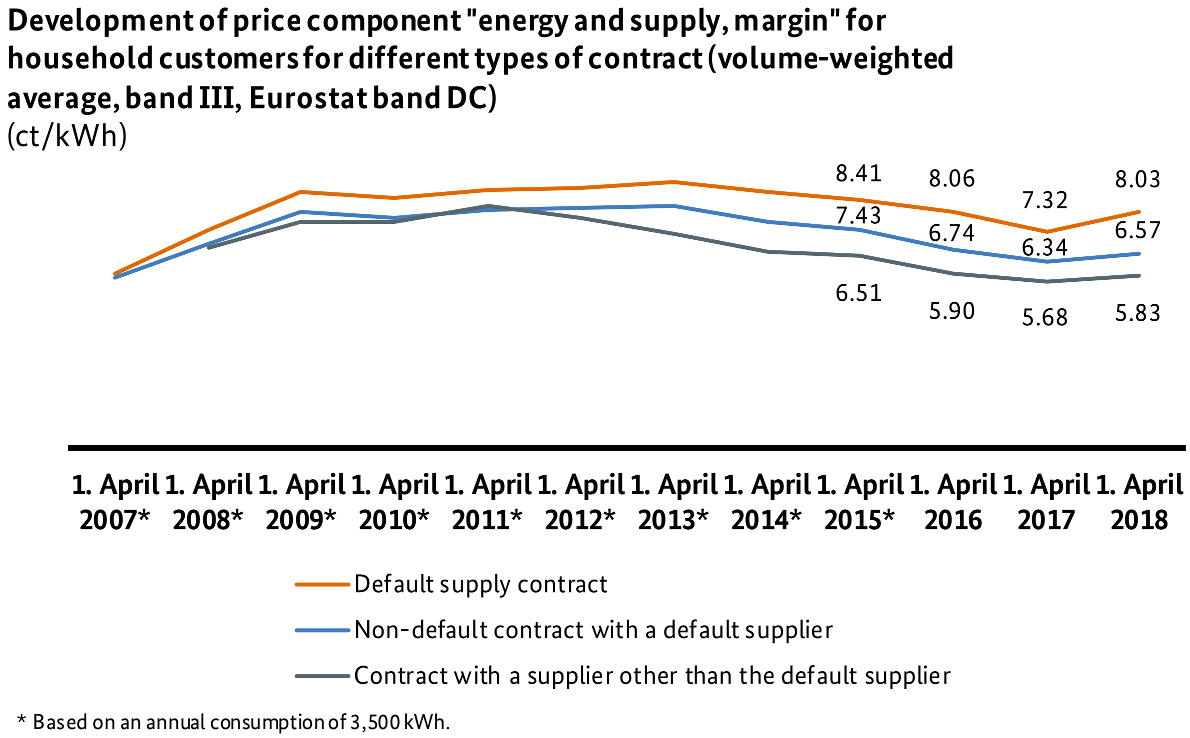


Figure 125: Development of the price component “energy and supply costs and margin” for household customers

Special bonuses and schemes

Non-default supply contracts can have a range of further features that suppliers use to compete for customers. These features may offer greater security either to the customer (e.g. price stability) or to the supplier (e.g. prepayment, minimum contract period), which is then compensated for between the parties elsewhere (overall price).

The suppliers were questioned specifically about such features. Minimum contract periods and price stability were found to be especially common. Minimum contract periods for special tariffs with the local default supplier are 15 months on average, while price stability with a supplier other than the local default supplier is offered for an average period of 15 months.

One-off bonus payments offered in conjunction with non-default contracts with the default supplier range between €5 and €232, with an average payment of €55, whereas contracts with a supplier other than the local default supplier offer one-off payments also ranging from €5 to €232, with an average payment of €63.

The following table provides an overview of the various special bonuses and schemes that are offered by electricity suppliers.

Special bonuses and schemes for household customers

As at 1 April 2018	Household customers			
	Non-default contract with the default supllier		Contract with supplier other than the default supplier	
	No. of tariffs	Average scope	No. of tariffs	Average scope
Minimum contract period	344	11 months	430	11 months
Price stability	301	15 months	380	15 months
Advance payment	62	10 months	48	10 months
One-off bonus payment	123	€ 55	211	€ 63
Free kilowatt hours	4	267 kWh	6	220 kWh
Deposit	8	-	6	-
Other bonuses and special arrangements	105	-	121	-

Table 79: Special bonuses and schemes for household customers

Band IV: Annual electricity consumption between 5,000 kWh and 10.000 kWh

Band IV as used in the monitoring survey represents household customers with an above-average annual consumption of between 5,000 kWh and 10,000 kWh. The following table shows the results of the survey.

Average volume-weighted prices per contract category for household customers with an annual consumption between 5,000 kWh and 10,000 kWh (band IV) as at 1 April 2018 (ct/kWh)

Price component	Default supply contract	Non-default contract with the default supplier	Contract with supplier other than the default supplier
Energy and supply, margin	7.94	6.43	4.87
Net network charge	6.39	6.07	6.32
Meter operation charge	0.18	0.17	0.20
Concession fee	1.53	1.58	1.55
EEG surcharge	6.79	6.79	6.79
KWKG surcharge	0.35	0.35	0.35
Section 19 StromNEV surcharge	0.37	0.37	0.37
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore liability surcharge	0.04	0.04	0.04
Electricity tax	2.05	2.05	2.05
VAT	4.87	4.53	4.25
Total	**30.52**	**28.39**	**26.80**

Table 80: Average volume-weighted prices per type of contract for household customers in consumption band IV as at 1 April 2018

Band V and band VI: Annual electricity consumption between 10,000 kWh and 15,000 kWh and annual electricity consumption above 15,000 kWh

For the first time, this monitoring report includes information provided by suppliers on bands V and VI. Bands V and VI consist of household customers with a very high annual consumption of between 10,000 kWh and 15,000 kWh and above 15,000 kWh. The following tables show the results of the survey.

Average volume-weighted prices per contract category for household customers with an annual consumption between 10,000 kWh and 15,000 kWh (band V) as at 1 April 2018 (ct/kWh)

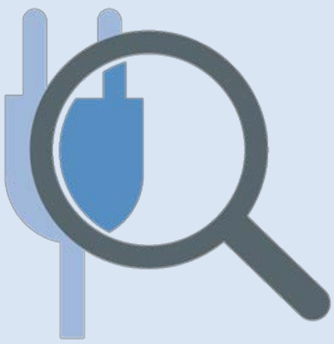
Price component	Default supply contract	Non-default contract with the default supplier	Contract with supplier other than the default supplier
Energy and supply, margin	8.32	5.48	4.58
Net network charge	5.96	5.59	5.82
Meter operation charge	0.09	0.10	0.13
Concession fee	1.55	1.57	1.47
EEG surcharge	6.79	6.79	6.79
KWKG surcharge	0.35	0.35	0.35
Section 19 StromNEV surcharge	0.37	0.37	0.37
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore liability surcharge	0.04	0.04	0.04
Electricity tax	2.05	2.05	2.05
VAT	4.85	4.24	4.09
Total	**30.38**	**26.59**	**25.70**

Table 81: Average volume-weighted price per type of contract for household customers in consumption band V as at 1 April 2018

Average volume-weighted prices per contract category for household customers with an annual consumption above 15,000 kWh (band VI) as at 1 April 2018 (ct/kWh)

Price component	Default supply contract	Non-default contract with the default supplier	Contract with supplier other than the default supplier
Energy and supply, margin	8.58	4.97	4.57
Net network charge	5.92	5.25	5.80
Meter operation charge	0.05	0.06	0.11
Concession fee	1.53	1.70	1.60
EEG surcharge	6.79	6.79	6.79
KWKG surcharge	0.35	0.35	0.35
Section 19 StromNEV surcharge	0.37	0.37	0.37
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore liability surcharge	0.04	0.04	0.04
Electricity tax	2.05	2.05	2.05
VAT	4.88	4.10	4.12
Total	**30.57**	**25.69**	**25.81**

Table 82: Average volume-weighted price per type of contract for household customers in consumption band VI as at 1 April 2018



In band III, which covers the majority of typical household customers in Germany, default tariffs are the most expensive type of supply. If a customer switches to a less expensive tariff with the default supplier (such as an online tariff), the average electricity price is 29.55 ct/kWh. If a customer switches to another electricity supplier, who may be active across all of Germany, the average electricity price is 29.05 ct/kWh. The average household customer with an annual electricity consumption of between 2,500 kWh and 5,000 kWh could achieve savings of an average of €68 a year as at 1 April 2018 by switching the tariff with the default supplier and €85 a year as at 1 April 2018 by switching supplier.

4.3 Surcharges

In the electricity sector, surcharges currently outweigh all other electricity price components. In the following section, the surcharges are listed according to volume.

EEG surcharge

Transmission system operators are entitled and obliged under section 60(1) EEG to receive compensation for their expenditures associated with the supply of electricity to final consumers, after deduction of revenue, according to the provisions of the Renewable Energy Sources Ordinance (EEG surcharge).

The EEG surcharge payments cover the difference between the TSOs' revenue and expenditures in implementing the EEG in accordance with section 3(3) and 3(4) of the Renewable Energy Sources Ordinance (EEV), as well as section 6 of the Renewable Energy Sources Implementing Ordinance (EEAV).

The surcharge is determined and announced by 15 October of each year for the following calendar year by the transmission system operators. Chapter I.B.2.2. provides a detailed look at the development of the EEG surcharge over the past years.

KWKG surcharge

Under sections 26a and 26b of the Combined Heat and Power Act (KWKG), the German transmission system operators are obliged to determine the KWKG surcharge for the following calendar year in a transparent way. The annual accounts from previous calendar years serve as the basis for the determination of the KWKG surcharge.

Revenue from the KWKG surcharge is used to cover costs associated with the financing of combined heat and power plants.

The KWKG surcharge is determined and announced by 25 October for the following calendar year by the TSOs. The following table shows the development of the KWKG surcharge over the past years.

Total amount of KWKG surcharge
€ million

2010	2011	2012	2013	2014	2015	2016	2017	2018
411.5	192.4	256.6	363.7	488.9	456.9	984.4	1,167.6	969.2

Table 83: Total amount of KWKG surcharge

Offshore liability surcharge for 2018 according to section 17f EnWG

Under section 17f(5) EnWG, network operators are entitled to pass on the costs for compensation payments to final consumers in the form of a surcharge on network charges. The mark-up on the network charges is calculated on the basis of the forecasted costs resulting from, on the one hand, the recoverable costs from compensation payments to operators of offshore wind farms for 2018, and, on the other hand, on the difference between the actual recoverable costs from the previous year and the predicted recoverable costs from compensation payments to operators of offshore wind farms for the subsequent year.

The revenue from the so-called offshore liability surcharge is used to cover the costs incurred by the compensation of offshore wind farms resulting from rejected feed-in.

The offshore liability surcharge is determined and announced by 15 October of each year for the following calendar year by the transmission system operators. The following table shows the development of the offshore liability surcharge in recent years.

Total amount of offshore liability surcharge
€ million

2010	2011	2012	2013	2014	2015	2016	2017	2018
				764.5	421.6	162.7	243.6	115.0

Table 84: Total amount of offshore liability surcharge

Section 19 StromNEV surcharge

Under the Electricity Network Charges Ordinance (StromNEV), final consumers can request an individual network charge as provided for by section 19(2) StromNEV. TSOs are obliged to reimburse downstream DSOs for lost revenues resulting from individual network charges. TSOs must balance these payments as well as their own lost revenue among themselves. The resulting lost revenues are thus passed on to all final consumers as a portion of the network charges.

The revenue from the surcharge under section 19 StromNEV is used to cover lost network charge proceeds brought on by reductions of the network charge.

The section 19 StromNEV surcharge is determined and announced by 25 October of each year for the following calendar year by the TSOs. The following table shows the development of the section 19 StromNEV surcharge in recent years.

Total amount of section19 StromNEV surcharge
€ million

2010	2011	2012	2013	2014	2015	2016	2017	2018
		440.0	805.2	629.8	797.7	897.5	115.9	1,181.8

Table 85: Total amount of section 19 StromNEV surcharge

Interruptible loads surcharge

Each year the German TSOs calculate the interruptible loads surcharge based on section 18 of the Ordinance on Interruptible Loads Agreements (AbLaV). For 2016, final consumers were not subject to this charge due to the fact that the amendment of the AbLaV ordinance had not yet been competed at the time the surcharge was determined.

The interruptible loads surcharge covers the costs for the provision and interruption of loads for the purpose of adjusting consumption according to the needs of TSOs.

The interruptible loads surcharge is determined and announced by 25 October of each year for the following calendar year by the transmission system operators. The following table shows the development of the interruptible loads surcharge in recent years.

Total amount of interruptible loads surcharge
€ million

2010	2011	2012	2013	2014	2015	2016	2017	2018
			11.7	34.7	31.9	18.5	33.9	34.8

Table 86: Total amount of interruptible loads surcharge

5. Electricity for heating

In this year's monitoring, data on contract arrangements, supplier switching and price levels for heating electricity – here the distinction is made between night storage heating and heat pumps – was once again collected from suppliers and distribution system operators.

Compared to the previous year, heating electricity consumption increased slightly in 2017. According to the volumes reported by around 1,069 heating electricity suppliers, about 14.47 TWh of heating electricity was supplied to just under 2.03 million meter points during the reporting period. This corresponds to an average supply of just under 7,150 kWh per meter point in 2017. The previous year's figure was just under 7,000 kWh per meter point, with a total volume of 14.48 TWh at 2.07 million meter points.

According to the data provided by the suppliers, just under 11.74 TWh of electricity was supplied for night storage heating at 1.59 million night storage meter points, resulting in an average of about 7,400 kWh per meter point in 2017. The volume of electricity supplied to the approximately 439,600 meter points for heat pumps amounted to just over 2.72 TWh, or an average of about 6,200 kWh/year. Night storage heating accounts for the largest share of consumption (81% in terms of volume and 78% of meter points). There is a slight increase in the share of heat pumps, accounting for 19% in terms of volume and 22% of meter points in 2017. This corresponds to an increase of 1% relative to the previous year, when heat pumps accounted for 18% in terms of volume and 21% of meter points in 2016. Almost all heating electricity suppliers serve both night storage customers and heat pump customers. Several suppliers explained that they were not able to provide an accurate breakdown of the volumes and meter points by night storage heating or heat pumps, and therefore gave an estimate of the breakdown or entered the total in only one of the two categories. 845 of the 1,069 electric heating suppliers provided data on volume and meter points for both night storage heating and heat pumps.

The data on consumption volumes and number of meter points collected from the DSOs during the monitoring survey roughly corresponds to the results of the supplier survey. According to the data provided by 811 DSOs, a total of 13.86 TWh of heating electricity was supplied to just under 2.06 million meter points (night storage heating and heat pumps) in 2017. The DSOs, however, are not asked to differentiate between night storage heating and heat pumps.

5.1 Contract structure and supplier switching

As in previous years, suppliers were asked how their heating electricity supply was distributed across network areas where they were the default supplier and network areas where they were not the default supplier. The survey refers to the default supplier status of the legal entity supplying electricity, which excludes company affiliations (for more detail see section "Contract structure and supplier switching"). The evaluation of the heating electricity supplied by the regional default supplier does not differentiate between "default supply contracts" and "non-default supply contracts with the default supplier" because in the Bundeskartellamt's view, heating electricity is sui generis always supplied under special contracts.[110]

The percentage of heating electricity supplied in 2017 by a legal entity other than the regional default supplier has increased by around 34%, to over 1.71 TWh (2016:1.28 TWh). About 11.9% of the entire heating electricity supply in 2017 came from suppliers other than the default supplier. The number of heating electricity meter points not served by the default supplier also increased, from 8.6% to 11.6%. The decisive factor in this increase is the fact that the number of night storage heating systems not supplied by the regional default supplier rose from around 131,050 meter points in 2016 to over 164,250 meter points in 2017. The number of heat pumps not supplied by the regional default supply also rose from around 48,100 meter points to over 70,500 in 2017. Altogether, 16% of heat pump meter points were supplied by a legal entity other than the default supplier.

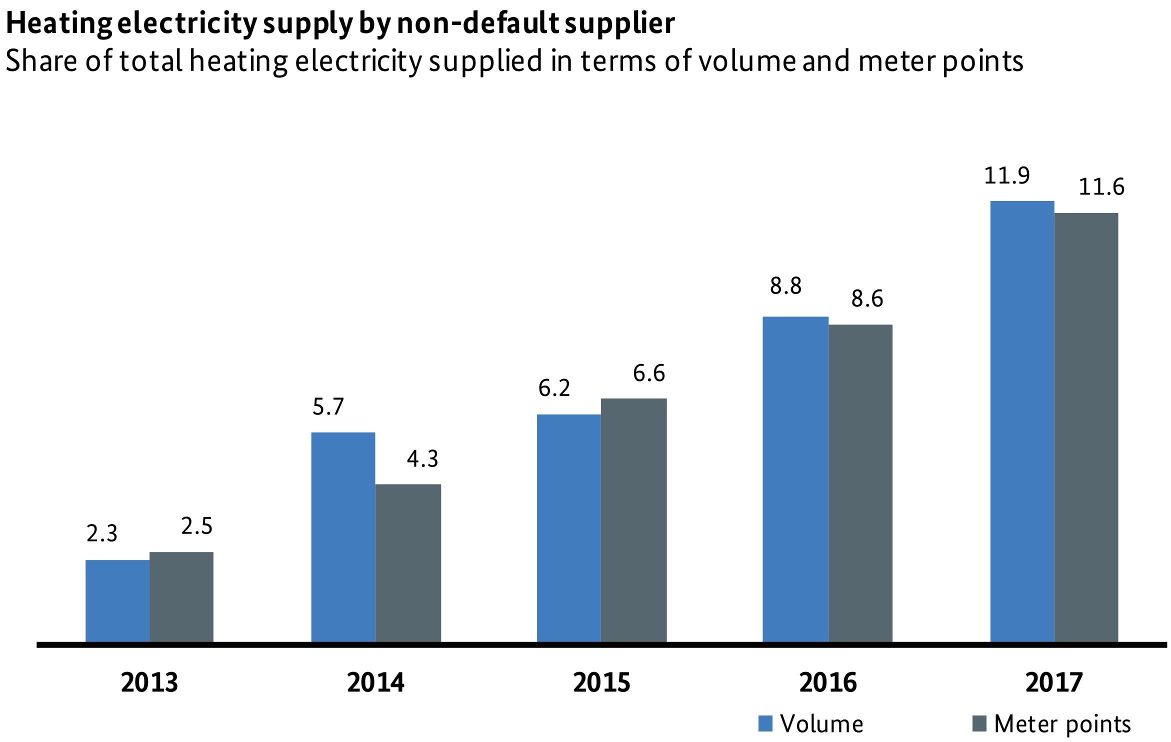


Figure 126: Percentage of heating electricity volume and meter points supplied by a supplier other than the regional default supplier

[110] Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren (Electric Heating – overview and proceedings), September 2010, pp. 9-10.

According to the data provided by the DSOs, supplier switching rates have remained constant in the heating electricity sector. The data shows that there was a change of supplier at about 87,550 heating electricity meter points. These meter points accounted for about 550 GWh of heating electricity in 2017; which represents a switching rate of 4% in terms of consumption volume and 4.3% of meter points.

In the previous year, there was a change of supplier at just under 91,350 meter points, accounting for a volume of around 583 GWh. This corresponds to a switching rate of 4.2% in terms of consumption volume and 4.4% of meter points. The trend over the years shows that switching rates for heating electricity have continuously risen – with a strong increase from 2015 to 2016. The switching rate in 2017 remained at the same level as in the previous year.

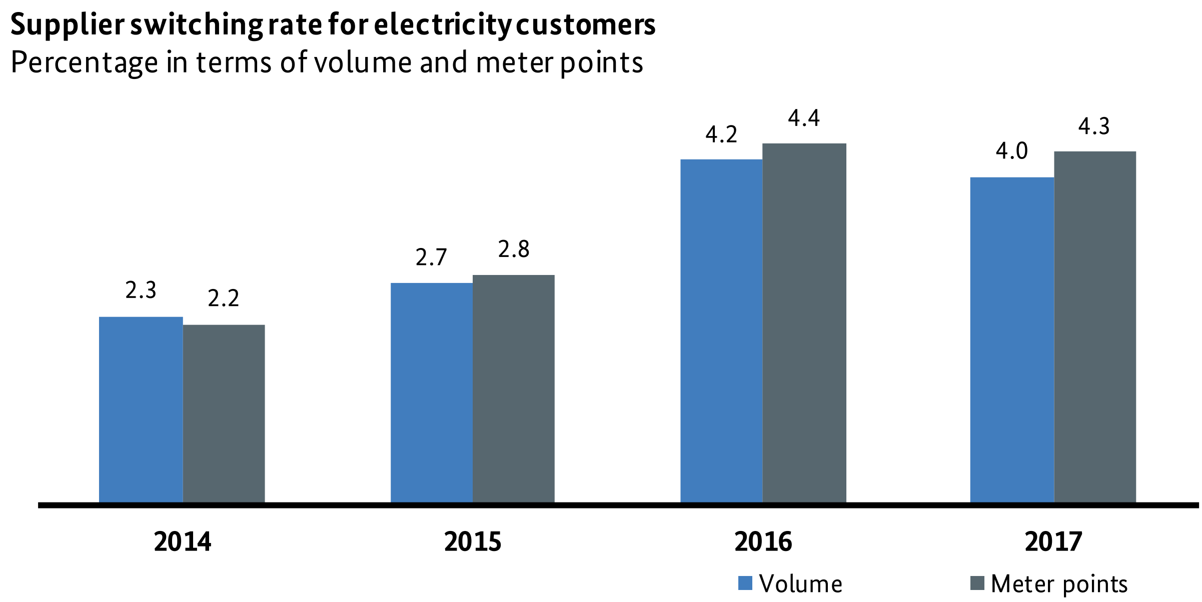


Figure 127: Supplier switching rate for heating electricity customers

582 of the 746 DSOs that provided data on heating electricity volumes also reported figures on supplier switching[111]. These 582 DSOs represent around 98% of the heating electricity volume and meter points of all 746 DSOs that provided data on heating electricity. This means that only a few, mainly small DSOs could not report figures on supplier switching. The reasons for this are generally insufficient evaluation possibilities or limited resources for survey purposes. The switching rates varied depending on the network area. The middle 80% of the graded figures for the quantitative switching rate per DSO that reported supplier switches were between 0.8% and 9.4%.

The percentage of heating electricity and meter points supplied by a legal entity other than the regional default supplier is steadily increasing. This is evidence of a boost in competition. The level of transparency for end customers has improved and the range of services provided by national suppliers of heating electricity has been expanded over the last two years. Consumers are now able to find local suppliers more easily, e.g. through websites, consumer magazines or information from consumer advice centres. However, switching

[111]Several DSOs also pointed out that they had no data, or only individual data, in the electric heating sector for analysis.

rates in the heating electricity sector are still far below the switching rates of household and non-household electricity customers.

5.2 Price level

As in the previous year, price data was collected on night storage tariffs and heat pump tariffs as at 1 April 2018. Suppliers were asked to base their figures on an annual consumption of 7,500 kWh/year. The following analysis is based on the price data for night storage heating provided by 774 suppliers (843 in the previous year) and the price data for heat pumps provided by 758 suppliers (816 in the previous year).

According to the results of the survey, the arithmetic mean of the total gross price for night storage heating was 21.08 ct/kWh (including VAT) on 1 April 2018, which is slightly above the previous year's level of 1 April 2017 (20.94 ct/kWh). The arithmetic mean of the total gross price for heat pump electricity was 21.71 ct/kWh, which is also slightly above the previous year's level (21.65ct/kWh).

Price level on 1 April 2018 for night storage heating with a consumption of 7,500 kWh/year

	Spread in the 10 to 90 percentile range of the supplier data sorted by size in ct/kWh	**Average** (arithmetic) in ct/kWh	**Percentage of total price**
Price components outside the supplier's control			
Net network charge[1]	1,50 - 3,92	2.66	13%
Metering, billing, meter operation	0,11 - 0,48	0.30	1%
Concession fee	0,11 - 1,17	0.44	2%
EEG surcharge	6.88	6.88	33%
Other surcharges[2]	0.80	0.80	4%
Electricity tax	2.05	2.05	10%
VAT	2,97 - 3,77	3.34	16%
Price components controlled by the supplier (remaining balance)	2,79 - 6,37	4.45	21%
Total price (excluding VAT)	18,58 - 23,62	20.94	100%

[1] Due to legislative changes, as of 1 January 2017 the price component "billing" is included in the net network charge and is no longer part of the category "Metering, billing meter operation"; for the next Monitoring Report, the survey will therefore be adjusted to reflect the respective price components.
[2] KWKG (0.438 ct/kWh), section 19(2) Strom NEV surcharge (0.388 ct/kWh), surcharche for interruptible loads under section 18 AbLaV (0.006 ct/kWh), offshore liability (-0.028 ct/kWh)

Table 87: Price level on 1 April 2018 for night storage heating with a consumption of 7,500 kWh/year

The amount that can be controlled by the supplier, which includes energy and supply costs and the margin, was 4.73 ct/kWh for night storage heating, which rose slightly for the first time (2017:4.45 ct/kWh). However, this amount is still smaller than in 2012 and 2013, when the price component controlled by the supplier averaged 5.72 ct/kWh in 2012 and 5.80 ct/kWh in 2013. The trend over the years shows that this price component has been falling steadily in the heating electricity sector. The remaining share controlled by the supplier, which includes energy and supply costs and the margin also rose slightly again in the heat pump sector, to 5.08 ct/kWh as at 1 April 2018, compared to 4.81 ct/kWh in the previous year. The price component controlled by the supplier makes up only about 22% of the total price, including VAT, for night storage heating (23% in the previous year), and about 23% of the total price, including VAT, for heat pumps. About

66% of the price for night storage heating consists of taxes, surcharges and concession fees. Compared to last year, the total of all fixed surcharges, in this case the renewable energy surcharge and the CHP surcharge, fell slightly. Nevertheless the suppliers did not appear to have passed on this reduction to their customers. The Bundeskartellamt has set the concession fee at 0.11 ct/kWh because heating electricity is supplied under special contracts.[112] Nevertheless, some suppliers quoted figures of more than 0.11 ct/kWh in this year's survey. This may be the result of summary invoices where heating electricity and household electricity are not metered separately, or due to incorrect data entries or incorrect assessments. The average figure obtained in the survey for network charges and metering was 2.96 ct/kWh in the night storage heating category, which has remained constant compared to the previous year's figure of 2.96 ct/kWh.

[112] Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren (Electric Heating – overview and proceedings), September 2010, pp. 9-10.

Price level on 1 April 2018 for heat pumps with a consumption of 7,500 kWh/year

	Spread in the 10 to 90 percentile range of the supplier data sorted by size in ct/kWh	**Average** (arithmetic) in ct/kWh	**Percentage of total price**
Price components outside the supplier's control			
Net network charge [1]	1,50 - 4,43	2.85	13%
Metering billing, meter operation	0,11 - 0,50	0.30	1%
Concession fee	0,11 - 1,32	0.51	2%
EEG surcharge	6.88	6.88	32%
Other surcharges[2]	0.80	0.80	4%
Electricity tax	2.05	2.05	9%
VAT	3,08 - 3,90	3.46	16%
Price components controlled by the supplier (remaining balance)	2,88 - 6,84	4.81	22%
Total price (excluding VAT)	19,28 - 24,41	21.65	100%

[1] Due to legislative changes, as of 1 January 2017 the price component "billing" is included in the net network charge and is no longer part of the category "Metering, billing, meter operation"; for the next Monitoring Report, the survey will therefore be adjusted to reflect the respective price components.
[2] KWKG (0.438 ct/kWh), section 19(2) StromNEV surcharge (0.388 ct/kWh), surcharge for interruptible loads under section 18 AbLaV (0.006 ct/kWh), offshore liability surcharge (-0.028 ct/kWh)

Table 88: Price level on 1 April 2018 for heat pumps with a consumption of 7,500 kWh/year

6. Green electricity segment

In the 2018 survey, information was also collected from suppliers on the volume of green electricity delivered to final consumers. For the purposes of this monitoring survey, a green electricity tariff is a tariff for electricity that, on account of green electricity labelling or other marking, is shown to have been produced with a high share/high promotion of efficient or regenerative production technologies and which is offered/traded at a separate tariff. The volumes of green electricity supplied to household customers and other final consumers in 2017 and the share of green electricity in the total volume of electricity supplied in 2017 are presented below.

Green electricity supplied to household customers in 2017

	Category	Total electricity supplied	Total green electricity supplied	Share of green electricity and meter points supplied in total
Household customers	TWh	120.3	29.3	24.4%
	Number of meter points	46,133,521.0	10,949,264.0	23.7%
Other final consumers	TWh	301.8	33.7	11.2%
	Number of meter points	4,245,926.0	475,700.0	11.2%
Total	TWh	422.1	63.0	14.9%
	Number of meter points	50,379,447.0	11,424,964.0	22.7%

Table 89: Green electricity supplied to household customers in 2017

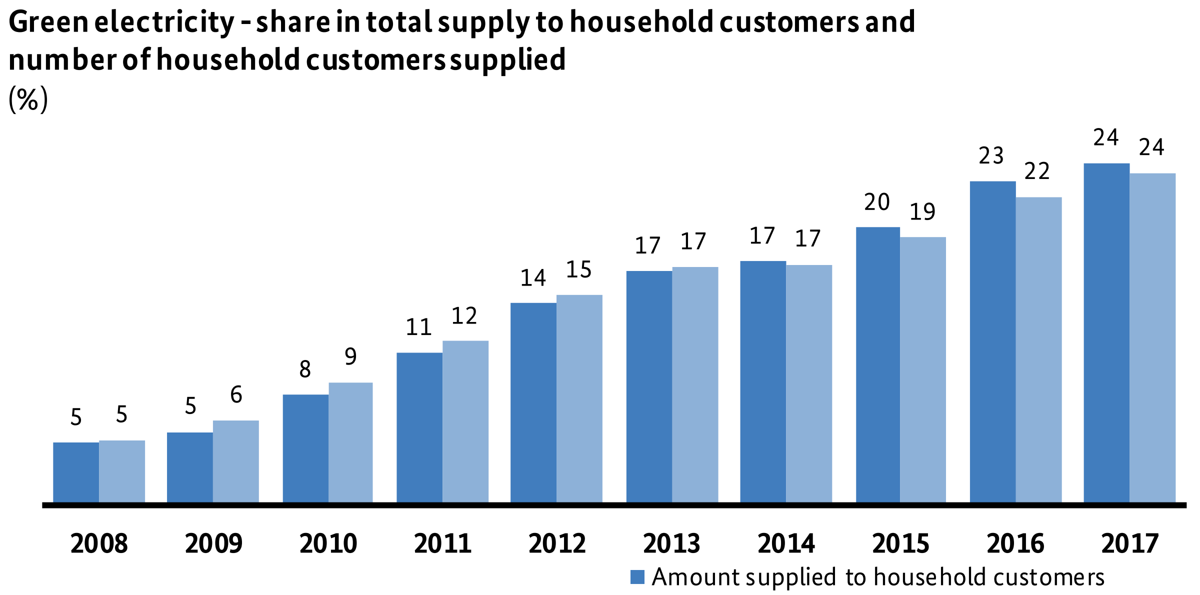


Figure 128: Green electricity volumes and number of household customers supplied

There was a further increase in 2017 in the share of green electricity in the total volume supplied to household customers and in the number of households supplied with green electricity. In 2017 the share of green electricity in total consumption increased by 1.3%. The percentage of household customers supplied with green electricity also rose by almost 2%, to over 10m meter points.

The following table shows the average volume-weighted prices and the individual price components for green electricity supplied to household customers, as well as their percentage of the total price.

Average volume-weighted prices for green electricity for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat band DC) as at 1 April 2018 (ct/kWh)

Price component	Volume-weighted average (ct/kWh)	Percentage of total price
Energy and supply, margin	6.06	20.7
Net network charge	6.95	23.8
Meter operation charge	0.36	1.2
Concession fee	1.60	5.5
EEG surcharge	6.79	23.2
KWKG surcharge	0.35	1.2
Section 19 StromNEV surcharge	0.37	1.3
Section 18 AbLaV surcharge	0.01	0.0
Offshore liability surcharge	0.04	0.1
Electricity tax	2.05	7.0
VAT	4.66	15.9
Total	**29.24**	**100.0**

Table 90: Average volume-weighted prices for green electricity for household customers in consumption band III as at 1 April 2018

The average volume-weighted retail price for household customers with an annual consumption between 2,500 kWh and 5,000 kWh declined slightly, to 29.24 ct/kWh as at 1 April 2018 (previous year: 29.42 ct/kWh). Household customers thus pay around 0.6% less for green electricity than they did in the previous year.

The following diagram shows the percentage distribution of the individual price components for green electricity:

Breakdown of the retail price for household customers with annual consumption between 2,500 kWh and 5,000 kWh (DC) for green electricity, as at 1 April 2018
(%)

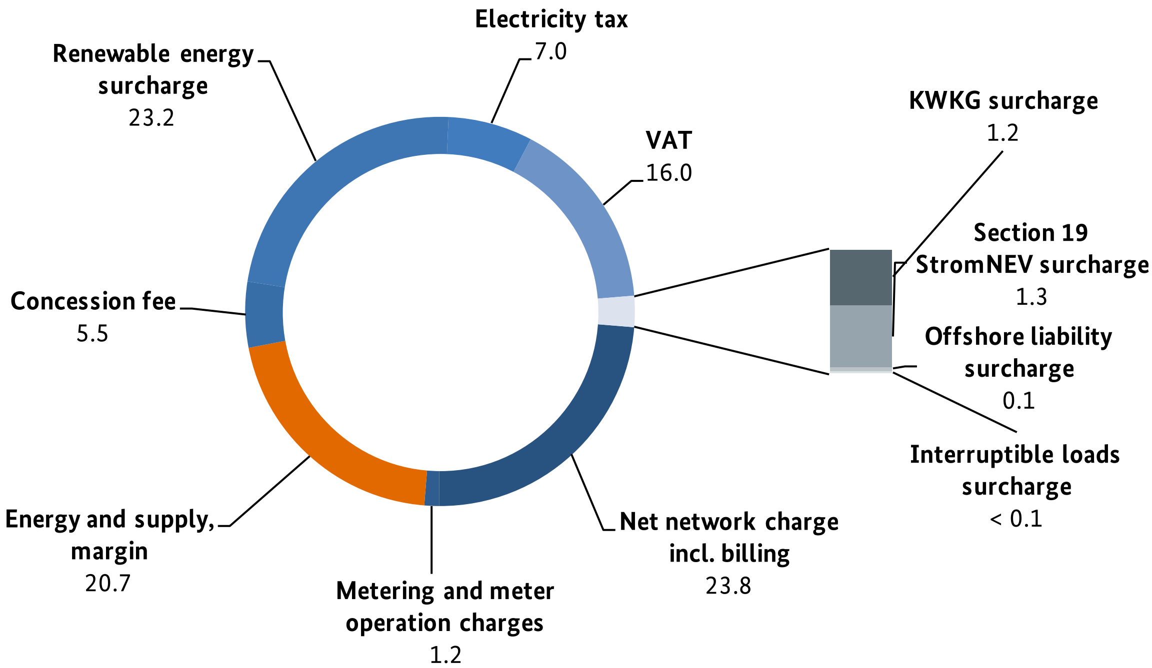


Figure 129: Breakdown of the retail price for household customers in consumption band III as at 1 April 2018[113]

As with conventional electricity, many suppliers offer their customers a range of special bonuses and schemes that can have a further effect on prices under various tariffs. The number and various possible combinations of the elements that make up the prices make it difficult to compare the wide range of competitive tariffs. One-off bonus payments for household customers for green electricity range from €5 to €232, with an average payment of €58. The following table provides an overview of the various special bonuses and schemes that are offered by electricity suppliers to customers on green electricity tariffs.

[113] The value added tax makes up 16% of the total gross price, since the statutory 19% VAT is charged on and added to the net price (100%). Thus the VAT at 19% is the dividend and the total price at 119% is the divisor.

Special bonuses and schemes for household customers (green electricity)

As at 1 April 2018	Household cusomers (green electricity)	
	No. of tarifs	Average scope
Minimum contract period	441	11 months
Price stability	375	14 months
Advance payment	58	10 months
One-off bonus payment	166	€ 58
Free kilowatt hours	6	233 kWh
Deposit	6	-
Other bonuses and special arrangements	117	-

Table 91: Special bonuses and schemes for household customers on green electricity tariffs

As is the case with conventional electricity tariffs, the most common bonuses and schemes offered with green electricity tariffs pertain to minimum contract term, price stability and one-off payments.

7. Comparison of European electricity prices

Eurostat, the statistical office of the European Union, publishes end consumer electricity prices for each six-month period that show the average payments made by household customers and non-household customers in EU Member States. The figures published for each consumer group include (i) the price including all taxes, levies and surcharges, (ii) the price excluding recoverable taxes, levies and surcharges ("net price") and (iii) the price excluding all taxes, levies and surcharges ("adjusted price"). Eurostat also publishes a breakdown of the adjusted price into network costs and the remaining balance controlled by the supplier ("energy and supply"), which includes electricity procurement costs, supply costs and the margin. Eurostat does not collect the data itself, but relies on data from national bodies; until now it has used data supplied by the Federal Statistical Office that is based on figures provided by the German Association of Energy and Water Industries. Rules on the classification, analysis and presentation of the price data aim to ensure European-wide comparability.[114] However, the survey method is set by the individual Member States (cf. Directive 2008/92/EC, Annex I h), which leads to national differences.

7.1 Non-household customers

Eurostat publishes price statistics for seven different consumer groups in the non-household sector that differ according to annual consumption ("consumption bands"). The following section describes the 20 to 70 GWh/year consumption band as an example. The 24 GWh/year category ("industrial customers"), for which specific price data is collected, falls into this consumption band.

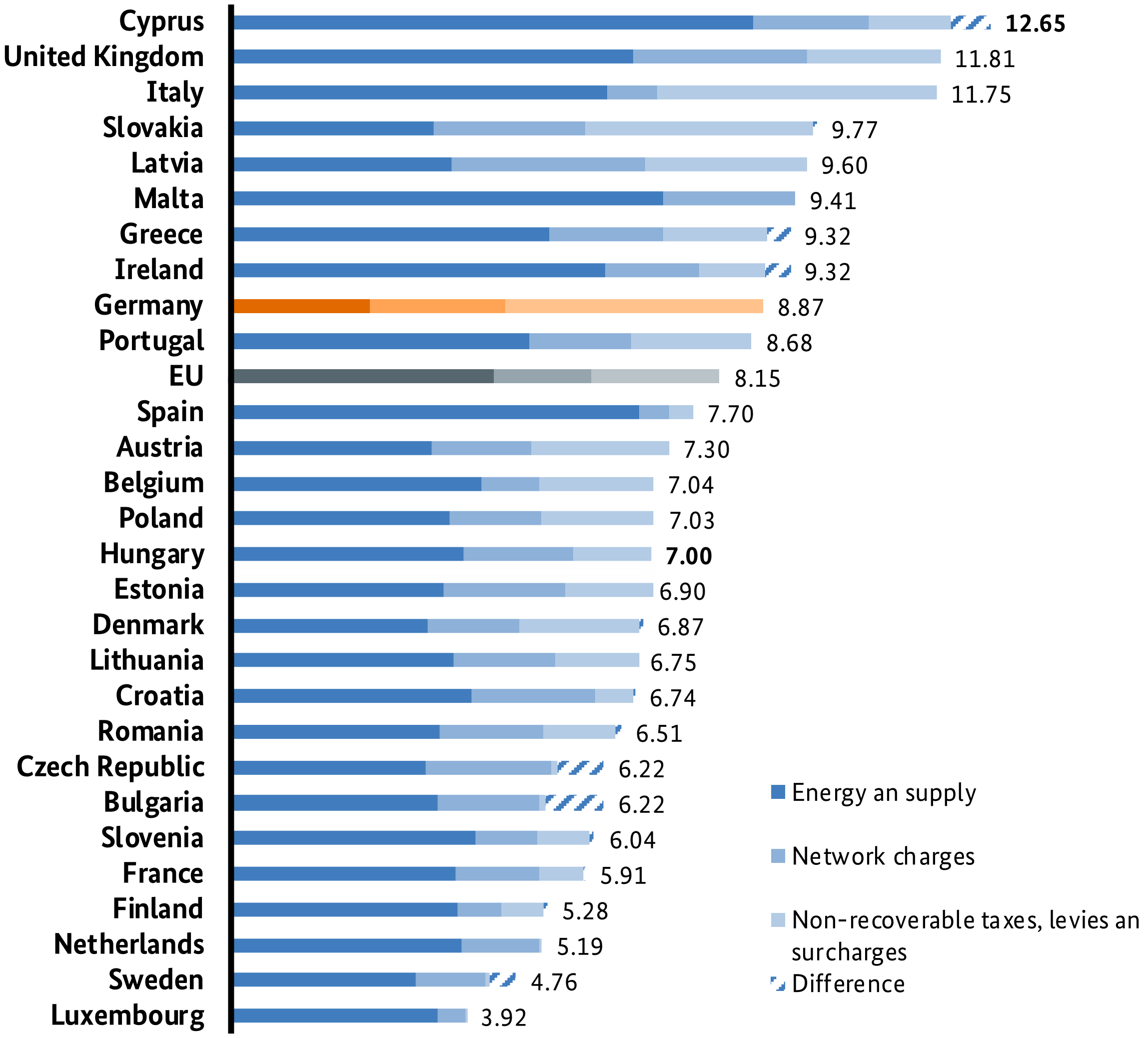
[114] For details see: https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2008:298:0009:0019:DE:PDF (retrieved on 26 July 2017).

The customer group with an annual consumption of 20 to 70 GWh consists of mainly industrial customers, who can deduct national VAT on a regular basis. As a result, the total price has been adjusted for VAT for the purpose of a European-wide comparison. Besides VAT, there are various other taxes, levies and surcharges resulting from specific national factors. These costs can be recovered by this customer group and – like the VAT – have also been deducted from the gross price. These possible reductions are a very important factor for individual net electricity prices, especially for industrial customers in Germany (for more details see section "Price level" I.G.4.1).

According to Eurostat data, there are significant differences in the price of electricity for industrial customers across Europe. Cyprus has the highest net price at 12.65 ct/kWh, while Luxembourg has the lowest, at 3.92 ct/kWh. The European average is 8.15 ct/kWh, of which 2.15 ct/kWh consists of non-recoverable taxes, levies and surcharges and 6.00 ct/kWh is made up of network charges and the remaining balance controlled by the supplier ("energy and supply"). At 4.59 ct/kWh, the adjusted net price in Germany is just under 1.4 ct/kWh below the European average of 6.00 ct/kWh. The German net price is comprised of 2.29ct/kWh network charges and 2.3 ct/kWh "energy and supply". The answer to the question as to whether the net price paid by German industrial customers in the 20-70 GWh/year consumption band is higher or lower than the European average essentially depends on the specific amount of the non-recoverable surcharges, taxes and levies. In the relevant consumption band this amount can vary between 0.54 ct/kWh and 9.23 ct/kWh (see section "Price level" I.G.4.1). In order to determine the average of the net prices actually paid in the relevant consumption band on the basis of a sample survey, numerous assumptions have to be made regarding the amount of possible reductions claimed on average. The documentation published by Eurostat, however, does not list the relevant assumptions concerning the price paid by industrial customers in Germany.[115] The figure relating to the average amount of non-recoverable surcharges, taxes and levies in the 20 to 70 GWh/year consumption band in Germany is 4.28 ct/kWh, or almost twice as much as the European average of 2.15 ct/kWh. The resulting net price for Germany is 8.87 ct/kWh, which is slightly higher than the European average of 8.15 ct/kWh.

[115] Cf. Eurostat, Electricity Prices – Price Systems 2014, 2015 Edition: https://ec.europa.eu/eurostat/documents/38154/42201/Electricity-prices-Price-systems-2014.pdf/7291df5a-dff1-40fb-bd49-544117dd1c10 (retrieved on 7 August 2018).

Comparison of European electricity prices in the second half of 2017 for non-household customers with an annual consumption between 20 GWh an 70 GWh
in ct/kWh ; excl. recoverable taxes, levies and surcharges



Source: Eurostat
Remark: For Greece there is no differentiation of network charges and energy and supply.
Some countries are marked with a hatched difference. This difference results from the fact that electricity prices are collected every six months by Eurostat, but the different price components of the electricity price are only queried throughout the year.

Figure 130: Comparison of European electricity prices in the second half of 2017 for non-household consumers with an annual consumption between 20 GWh and 70 GWh

7.2 Household consumers

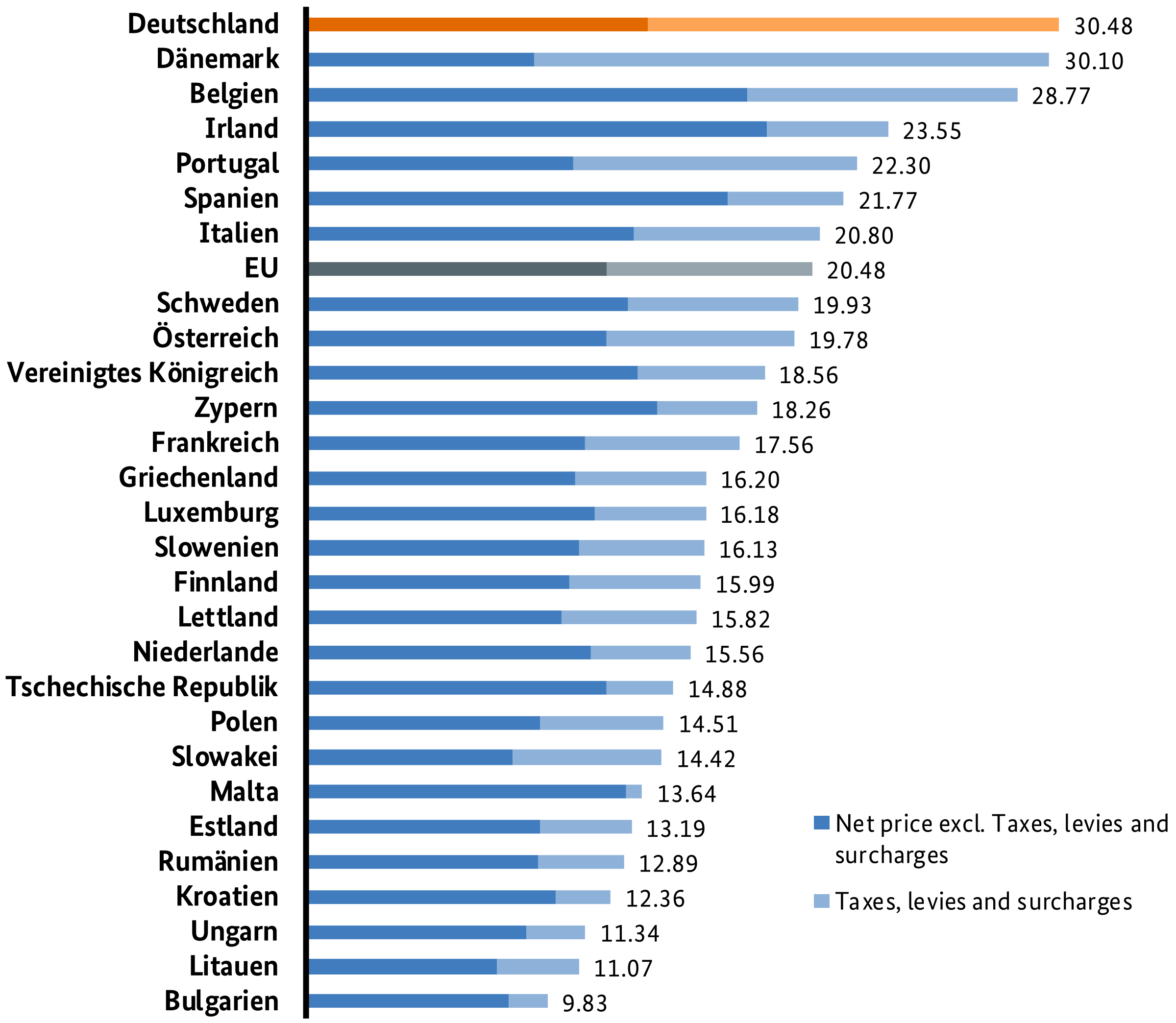
Eurostat takes five different consumption bands into consideration when comparing household customer prices. The volumes consumed by household customers in Germany are mostly in the middle category, with an annual consumption between 2,500 kWh and 5,000 kWh. The following shows a European comparison of the medium consumption band. Household consumers generally cannot have surcharges, taxes and levies refunded, which is why the total price including VAT is relevant to these customers.

Electricity prices for household consumers vary greatly in Europe. Based on the calculation method used by the German Association of Energy and Water Industries, Germany has the highest price among the 28 EU

Member States, with 30.48 ct/kWh. Prices in Germany are about 48% higher than the EU average of 20.48 ct/kWh.

The high price paid in Germany compared to other Member States is due to a higher proportion of surcharges, taxes and levies. In the EU, 8.28 ct/kWh on average consist of surcharges, taxes and levies, whereas in Germany these components account for more than twice as much, with 16.65 ct/kWh. By contrast, at 13.83 ct/kWh, the net price adjusted for all taxes, surcharges and levies in Germany is slightly above the EU average of 12.20 ct/kWh.

Comparison of European electricity prices in the second half of 2017 for household customers with an annual consumption between 2.500 kWh and 5.000 kWh
in ct/kWh ; incl. VAT and all other taxes



Quelle: Eurostat

Figure 131: Comparison of European electricity prices in the second half of 2017 for household customers with an annual consumption between 2,500 kWh and 5,000 kWh

H Metering

1. Digitisation of metering

The entry into force of the Metering Act (MsbG) in September 2016 triggered significant changes in metering. The Metering Act requires the comprehensive rollout of modern metering equipment and smart metering systems. However, the implementation of the rollout and the related legal deadlines depend on many different factors, a key one of which is the technical availability of modern metering equipment and smart metering systems.

Since the beginning of 2017, the first modern metering systems have been available on the market and have been installed by the first default meter operators on a large scale.

It was still not possible to start the rollout of smart metering systems in 2017, since no smart meter gateways certified by the Federal Office for Information Security (BSI) were yet available on the market. The BSI was unable to establish technical feasibility, which requires that at least three smart meters made by independent manufacturers are available on the market. It is unlikely that a rollout of smart metering devices will occur before the end of 2018.

Default meter operators had until 30 June 2017 to notify the Bundesnetzagentur of their metering operations. The notifications covered a total of 50.9m meter points of 899 operators of general supply networks and closed distribution systems pursuant to section 110 of the Energy Industry Act. Just seven of these operators did not intend to continue as default meter operators for smart metering technology in their networks. 892 of them stated their intention to carry out the mandatory installation of smart meters in 6.5m cases in their role as default meter operators. The tables below show when rollout is planned for which groups of customers at what time.

Price caps for mandatory installations

Price caps (per year)	Consumers		Generators	
	Annual consumption (kWh)	Installation as of/no later than	Installed capacity (kW)	Installation as of/no later than
€ 100	> 6,000 ≤ 10,000	2020 / 2028	> 7 ≤ 15	2017 / 2025
€ 100	controllable load[1]	2017	-	-
€ 130	> 10,000 ≤ 20,000	2017 / 2025	> 15 ≤ 30	2017 / 2025
€ 170	> 20,000 ≤ 50,000	2017 / 2025	-	-
€ 200	> 50,000 ≤ 100,000	2017 / 2025	> 30 ≤ 100	2017 / 2025
appropriate	> 100,000	2017 / 2032	> 100	2020 / 2028

[1] eg heat pumps

Table 92: Price caps for mandatory installations

Price caps for voluntary installations

Price caps (per year)	Consumers		Generators	
	Annual consumption (kWh)	Installation as of	Installed capacity (kW)	Installation as of/no later than
€ 23	≤ 2,000	2020	-	-
€ 30	> 2,000 ≤ 3,000	2020	-	-
€ 40	> 3,000 ≤ 4,000	2020	-	-
€ 60	> 4,000 ≤ 6,000	2020	≤ 7	2018

Table 93: Price caps for voluntary installations

Price caps for the installation and operation of modern metering equipment

Price caps (per year)	Consumers		Generators	
	Annual consumption (kWh)	Installation as of	Installed capacity (kW)	Installation as of/no later than
€ 20	regardless of consumption	now	regardless of capacity	now

Table 94: Price caps for the installation and operation of modern metering equipment

The Metering Act, which regulates the introduction of modern metering equipment and smart metering systems, has been in force since September 2016. Smart metering equipment can send the electricity consumption data it collects directly to those that need it, ie to parties authorised to receive data within the meaning of the Act. The Act specifies exactly which parties receive which data. By 2032, every household will receive either a smart metering system or at least modern metering equipment, depending on its annual consumption. The installation of digital meters is mandatory for consumers, so they can't refuse to have one.

2. The network operator as the default meter operator and independent meter operators

893 companies operating a total of 51,434,914 meters responded to the questions about electricity metering for the monitoring survey 2018.

Metering operations are generally carried out by network operators as default meter operators, although this default operation may also be outsourced to another company, either in a transfer or an in-house process. Companies wishing to take over the default metering operations and not already in possession of an approval as a network operator under section 4 of the Energy Industry Act must obtain approval from the Bundesnetzagentur under section 4 of the Metering Act. Two applications from companies wishing to take on metering operations as a joint service for multiple companies were approved in 2017. One application has so far been received in 2018.

The 893 meter operators had the following roles in 2017 (some of them were active in more than one market role).

Meter operator roles within the meaning of the Metering Act

	Number	
	Conventional metering operations	Metering operations of modern metering equipment or smart meters
Network operator as default meter operator within the meaning of the MsbG	852	712
Network operator as non-default meter operator offering its (meter) services on the market	35	22
Supplier acting as meter operator	57	36
Third-party, independent meter operator	53	21

Table 95: Meter operator roles within the meaning of the Metering Act

A connection user can choose which company is to be responsible for the installation, operation, maintenance of metering equipment and systems, and metering (in accordance with section 5 MsbG). A competing third party can be responsible instead of the default meter operator. Independent operators take on the activity of metering operations in the network areas of 733 DSOs, according to data received in the monitoring survey. They may be network operators that offer metering operations outside their own networks, they may be suppliers or they may be independent meter operators with no other market role. There is a large variation in the number of meter operators between the different networks. In 105 networks, between 30 and 50 independent meter operators are active, but in 28 networks there is only a choice between the default meter operator and two to four others. The following graph shows the number of independent meter operators regardless of the size of the network.

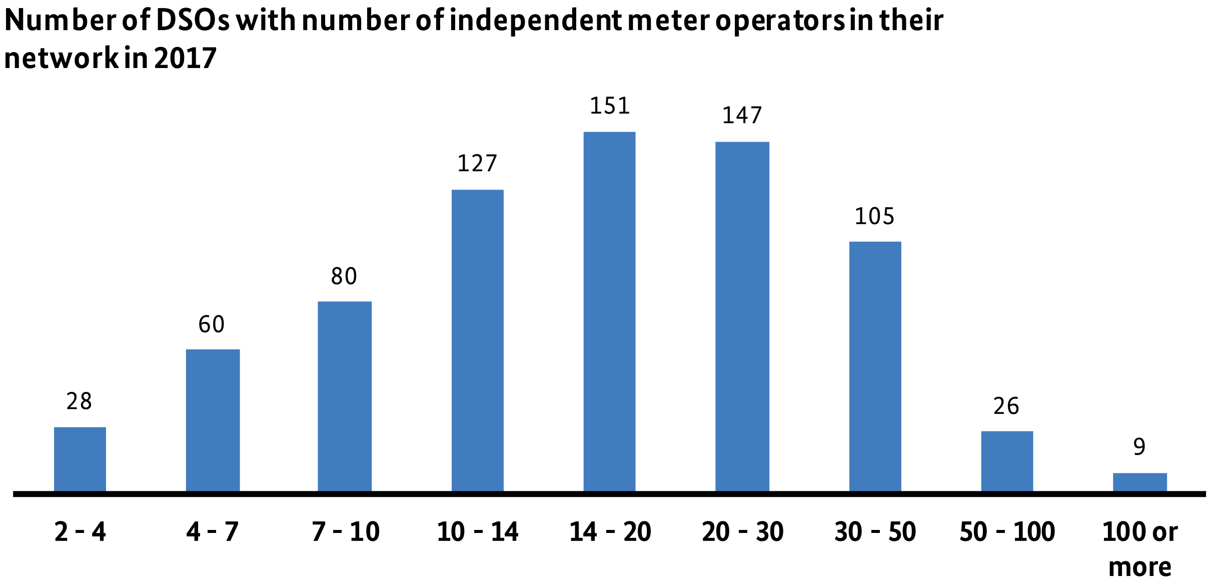


Figure 132: Number of DSOs with number of independent meter operators in their network (grouped)

Regardless of network size, the average number of meter operators active in one distribution system area is about 15. The highest number is 267 independent meter operators in one network area.

Independent meter operators cover about 292,482 meter points in the distribution networks, which equates to a share of less than 1% of the total number of meter points in these networks. This low proportion can be seen in Figure 133. The meter points where independent meter operators are active are shown in proportion to the total meter points of a network area. There are very few networks, only about 6% of the total, where more than 1% of meter points are covered by independent meter operators.

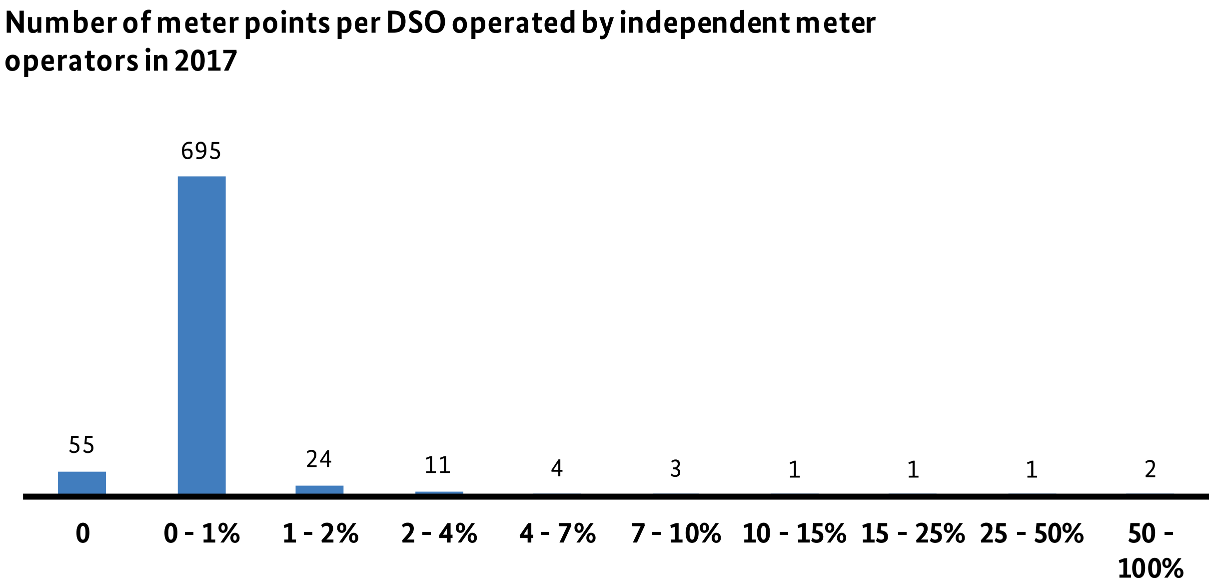


Figure 133: Number of meter points per DSO operated by independent meter operators

The total number of meter points is broken down by federal state as shown in Table 96. It can be seen that North Rhine-Westphalia is the German state with the most meter points – nearly 10m.

Number of meter points by federal state in 2017

	meter points - consumption	meter points - feed-in
Baden-Württemberg	6,172,516	199,204
Bavaria	7,603,507	381,140
Berlin	2,352,468	9,402
Brandenburg	1,580,147	37,601
Bremen	441,709	3,584
Hamburg	1,149,669	4,632
Hesse	3,572,647	114,854
Mecklenburg-Western Pomerania	1,064,241	17,901
Lower Saxony	4,508,513	168,744
North Rhine-Westphalia	10,414,001	227,151
Rhineland-Palatinate	2,195,379	73,252
Saarland	632,320	147,282
Saxony	2,839,980	38,182
Saxony-Anhalt	1,495,811	53,262
Schleswig-Holstein	1,703,679	47,840
Thuringia	1,355,270	35,991

Table 96: Number of meter points by federal state

3. Requirements of section 29 et seq of the Metering Act

Under the Metering Act, meters with an annual electricity consumption of over 6,000 kWh must be included in the rollout of smart metering systems. Around five million final consumers in various consumption categories are affected by the mandatory installation within the meaning of section 29 in conjunction with sections 31 and 32 of the Metering Act. The majority of these – nearly 2.1m meter points – are final consumers with annual consumption of between 6,000 and 10,000 kWh. In the tables below, the number of meter points with mandatory installation of smart meters is shown broken down by the consumption groups used in the Metering Act. The grey columns in the tables show the future rollout of smart metering systems. Since no smart metering systems are yet available on the market, companies were not able to provide data about them. On the other hand, it is possible to see a sharp rise in modern metering equipment, which has been on the market since early 2017. Consequently, the number of installed Ferraris meters is falling, as they are being replaced by modern metering equipment.

Meter points requiring smart meters under section 29 in conj. with sections 31 and 32 of the Metering Act in 2017

	Number of meter points			
	Total	of which have been equipped with metering systems in acc. with section 19 (5) of the Metering Act	of which have been equipped with modern metering devices as defined in the Metering Act	of which have been equipped with smart metering systems as defined in the Metering Act
Final consumers with annual power consumption				
> 6,000 kWh & ≤ 10,000 kWh	2,097,961	263,461	24,136	
> 10,000 kWh & ≤ 20,000 kWh	1,015,859	142,172	9,139	
> 20,000 kWh & ≤ 50,000 kWh	498,631	79,431	3,577	
> 50,000 kWh & ≤ 100,000 kWh	149,376	39,300	834	
> 100,000 kWh	265,322	144,050	1,561	
Consumer devices in accordance with section 14a EnWG	1,060,240	118,961	5,455	
of which meter points at charging stations for electric vehicles	1,954	335	119	
Installed capacity at plant operators in accordance with section 2 para 1 of the Metering Act				
> 7 kW & ≤ 15 kW	498,721	72,312	4,725	
> 15 kW & ≤ 30 kW	272,427	38,628	1,455	
> 30 kW & ≤ 100 kW	308,818	25,014	684	
> 100 kW	380,382	20,639	1,450	

Table 97: Mandatory installation within the meaning of section 29 in conjunction with sections 31 and 32 MsbG

For final consumers with annual consumption of 6,000 kWh or less, section 29 in conjunction with section 31 of the Metering Act gives the default meter operator the right to decide whether to install smart metering systems (voluntary installation) or just to install modern metering equipment. Meter operators reported about 39m final consumers for optional installation, of which the largest group is made up of final consumers with annual consumption of less than 2,000 kWh.

Optional installation within the meaning of section 29 in conj. with section 31 of the Metering Act in 2017

	Number of meter points			
	Total	of which have been equipped with metering systems in accordance with section 19(5) of the Metering Act	of which have been equipped with modern metering devices as defined in the Metering Act	of which have been equipped with smart metering systems as defined in the Metering Act
Final consumers with annual power consumption of:				
≤ 2,000 kWh	20,080,686	2,650,025	237,487	
> 2,000 kWh & ≤ 3,000 kWh	8,410,896	1,035,150	91,557	
> 3,000 kWh & ≤ 4,000 kWh	5,567,234	632,529	57,330	
> 4,000 kWh & ≤ 6,000 kWh	5,226,506	546,820	49,294	
Installed capacity at plant operators in accordance with section 2 para 1 of the Metering Act				
> 1 kW & ≤ 7 kW	423,076	72,006	5,064	

Table 98: Voluntary installation within the meaning of section 29 in conjunction with sections 31 and 32 MsbG

In response to the question in the monitoring survey about whether the default meter operator is planning on equipping final consumers with annual consumption below 6,000 kWh with a smart metering system, 70 companies said "Yes" and 358 companies said "No". 392 companies remain undecided.

4. Organisation of metering operations

As well as the installation of metering equipment, metering operations include the operation, maintenance and billing of metering operations and smart meter gateway administration. Companies have the choice between fulfilling these functions themselves or transferring some of them to service providers. The answers to the questions in the monitoring survey indicate that the majority of meter operators perform these tasks themselves. One exception is smart meter gateway administration, where there is a growing tendency to employ external service providers. Companies carrying out gateway administration have to be certified by the BSI, which has so far certified 26 administrators. The strict security requirements make gateway administration an area where service providers are likely to continue to specialise in the future, rather than companies doing it themselves. It is only likely to be worth companies doing their own gateway administration if they have above a certain number of meter points under their responsibility.

Figure 97 shows the individual types of activities.

Type of activities related to meter operations in 2017
number/distribution

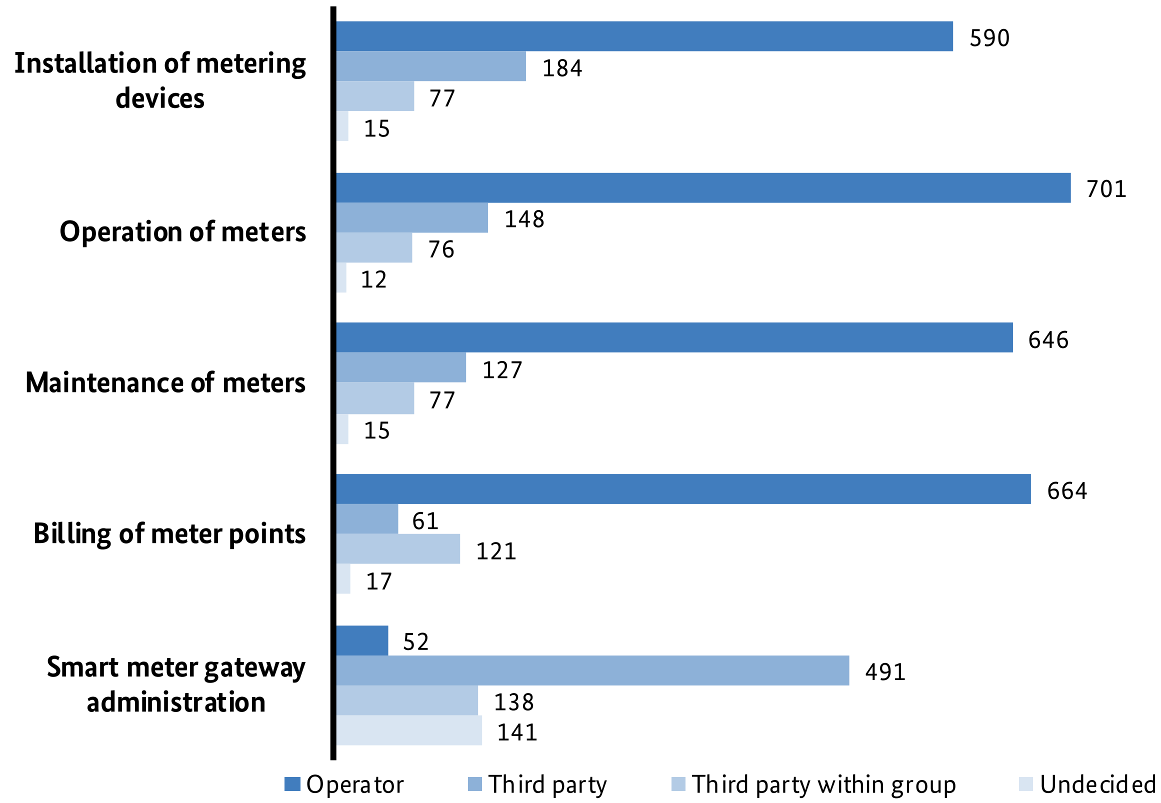


Figure 134: Performance of the activities related to metering operations

The Metering Act only regulates the nationwide rollout of modern metering equipment and smart metering systems for electricity. New gas meters can only be legally installed if they can be securely connected with a smart meter gateway. If meters have a smart meter gateway, default meter operators are obliged to connect it if it is technically possible to do so. However, since no smart metering systems are yet available on the market, it is not currently possible to comply with the obligations laid down in the law. Therefore, most companies do not offer metering via the smart meter gateway for sectors other than electricity, such as gas, heating and district heating, or water. Between 5% and 8% of companies offer metering operations for other sectors, with just gas showing a slightly higher figure at 119 providers (see Figure 135).

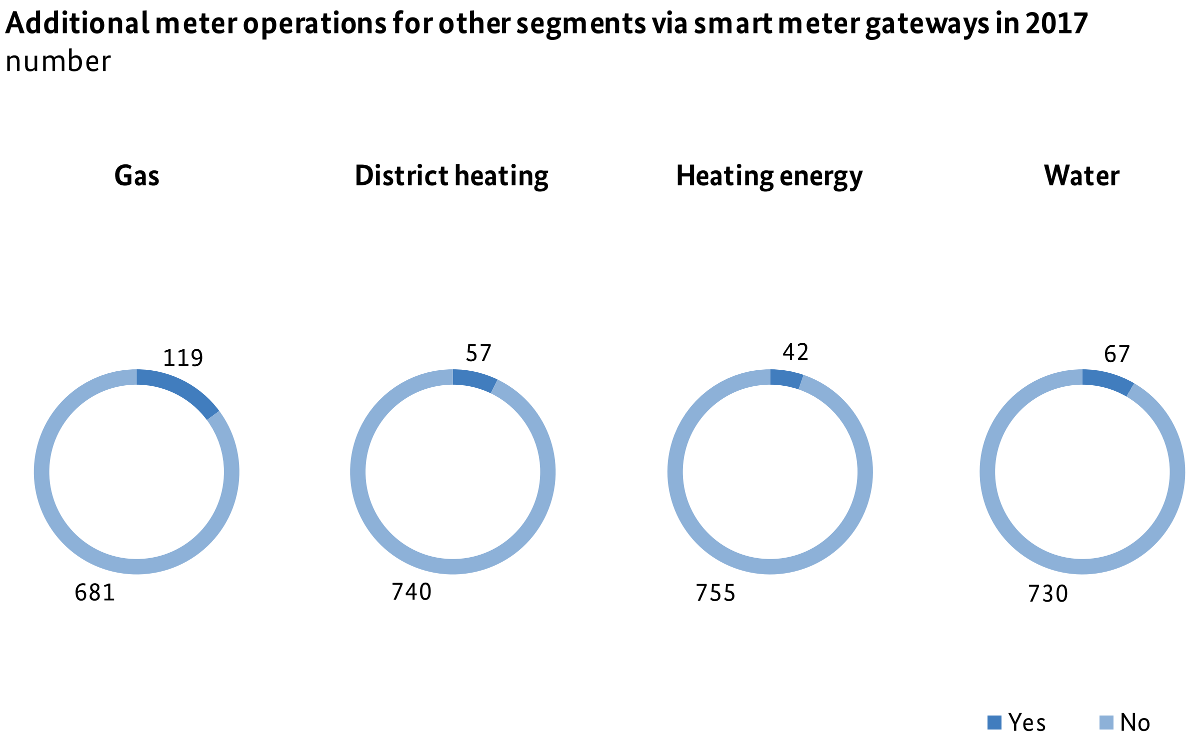


Figure 135: Additional metering operations for other sectors using the smart meter gateway

Both default meter operators and their competitors have the option of offering additional metering services for smart metering systems within the meaning of section 35(2) of the Metering Act. Although the majority of companies additionally provide current and voltage transformers, up to now only a very few of them offer other services such as using smart metering systems for prepayment (see chapter I.G.3.2), setting up or using smart metering systems for load control, or making smart meter gateways available and technically operating them for value-added services. A high number of meter operators in all categories have not yet made a decision on additional services, which could be related to the fact that the smart metering systems are not yet available. Without the systems in place, it is not yet possible to offer many services. Figure 136 shows the evaluation of additional services.

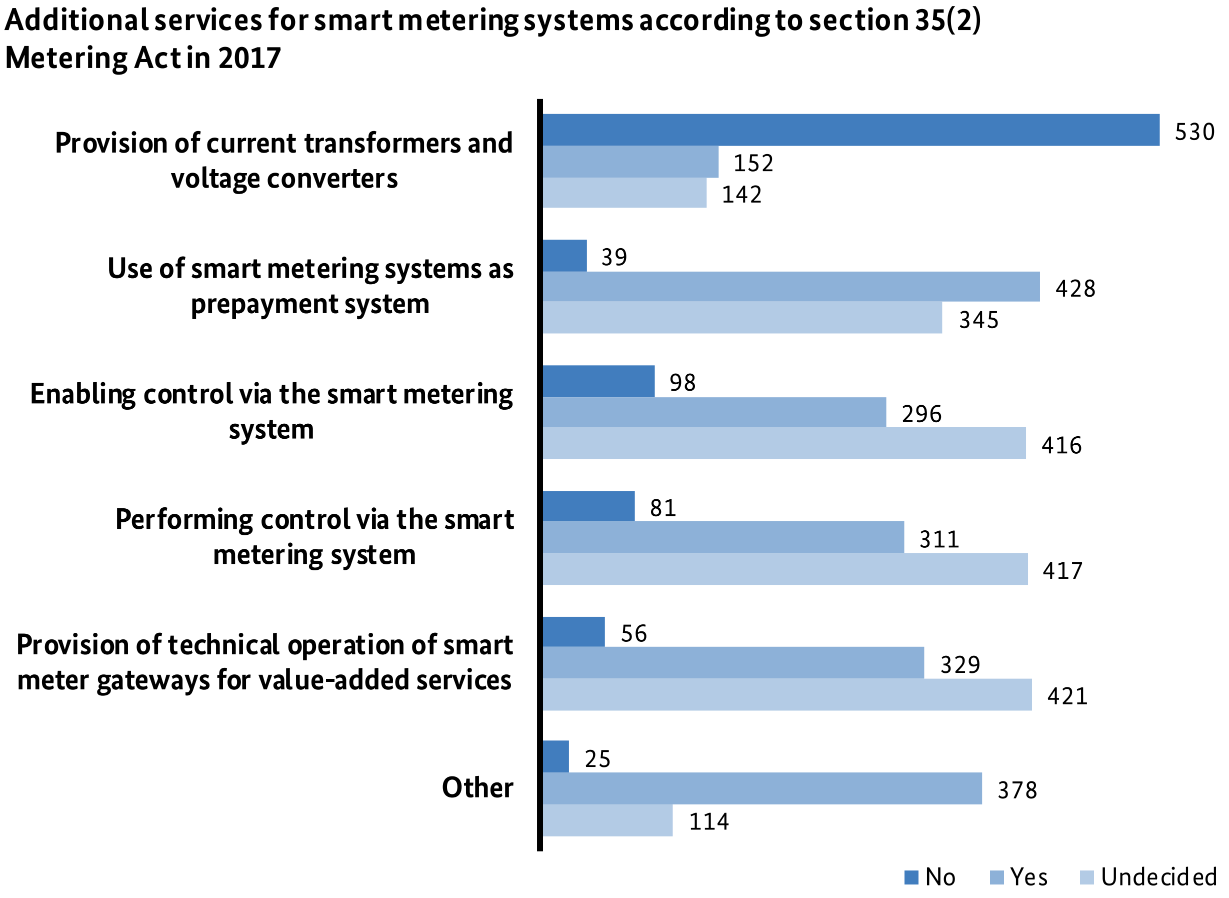


Figure 136: Additional services for smart metering systems

A large majority (81%) of meter operators do not sell products that combine electricity supply and meter operation (see Figure 137).

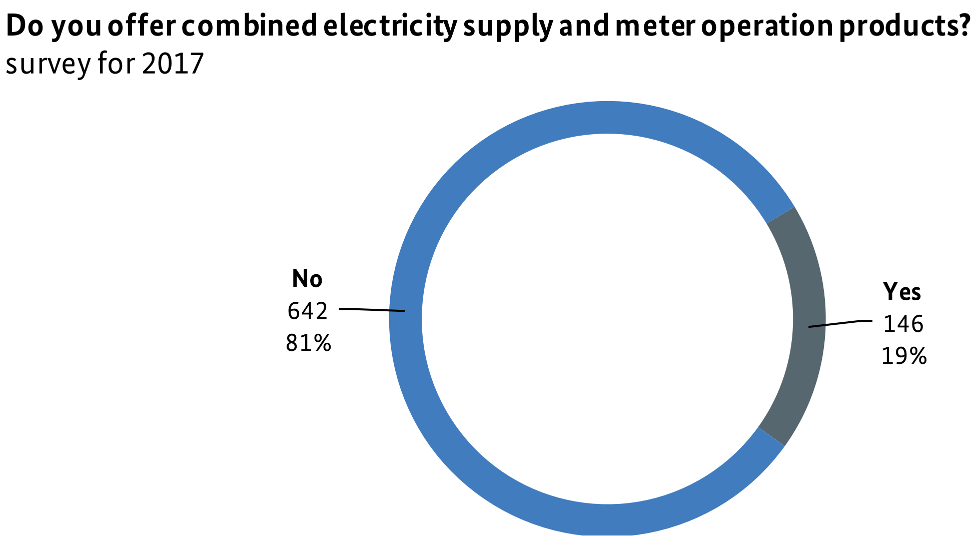


Figure 137: Combined products for electricity supply and meter operation

It is no longer mandatory for the billing of the connection user/owner for meter operation to take place via the supplier, but this is still usually the case. Presumably suppliers and meter operators have made agreements to continue to bill meter operation jointly as part of the electricity bill. There has been some increase in mixed billing models – where billing sometimes occurs separately and sometimes via the suppler – but this is still far less common than billing via the supplier (see graph below).

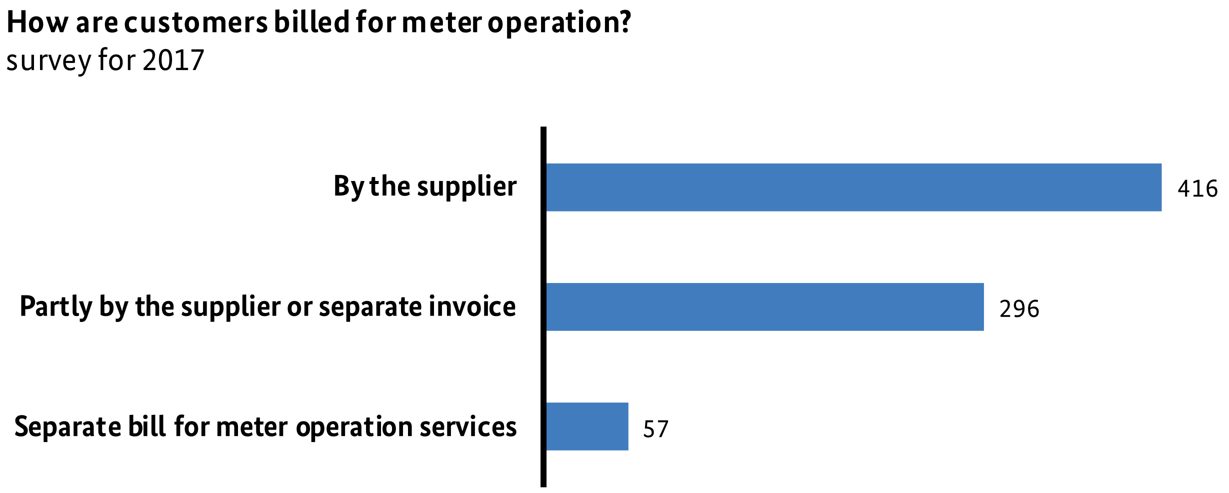
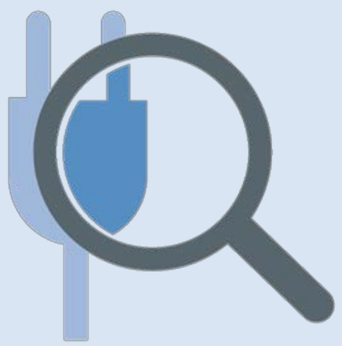


Figure 138: Billing the connection user/owner for meter operation



Before the Metering Act entered into force in September 2016, suppliers had to include meter operation in their electricity bills. Under the new law, the supplier is no longer required to send a combined bill if modern metering equipment or smart metering systems are used. If conventional meters are still used, however, the billing for them must still be carried out by the supplier.

It is therefore possible that consumers will receive a bill from the meter operator for the meter operation and another one from their supplier for the electricity itself. Under such circumstances, it is advisable for them to check that the meter operation is really no longer included in the supplier's bill.

5. Metering technology used for household customers

Meter operators provided the following information on the type of technology used in meters and metering systems for standard load profile (SLP) customers in Germany:

Meter technology employed for standard load profile (SLP) customers

Requirement	Meter points 2016	Meter points 2017
Electromechanical metering systems (with current transformers and three-phase meters based on the Ferraris principle)	43,413,117	41,225,392
of which two-tariff and multiple-tariff meters (Ferraris principle)	2,794,792	2,624,019
Electronic meter device (basic meter not connected to a communication network) in accordance with section 2 para 15 of the Metering Act	6,945,610	6,967,445
Modern measuring device (not connected to a communication network) in accordance with section 2 para 15 of the Metering Act	50,251	558,574
Metering systems in accordance with section 2 para 13 of the Metering Act that are not smart metering systems pursuant to section 2 para 7 of the Metering Act (e.g. EDL40)	453,797	462,026
Smart metering systems in accordance with section 2 para 7 of the Metering Act		

Table 99: Meter technology employed for standard load profile (SLP) customers

The availability of modern metering equipment from the start of 2017 led to a clear move away from electromechanical meters during the year for SLP customers, including all household customers. It may be assumed that the installation of about 50,000 meters in 2016 only covered small-scale projects. There was therefore a jump in 2017 in the number of modern metering devices pursuant to section 2 para 15 of the Metering Act that are not connected to a smart metering system. Modern metering equipment is now fitted at about 560,000 meter points. The total number of electromechanical metering systems has dropped by about 2.2m meter points. However, the number of electronic meters has only risen slightly over the previous year to about seven million meter points. There has been another small drop in the use of two-tariff and multiple-tariff meters to 2.6m. Metering systems pursuant to section 2 para 13 of the Metering Act, which are not smart metering systems, are installed at nearly half a million meter points of SLP customers.

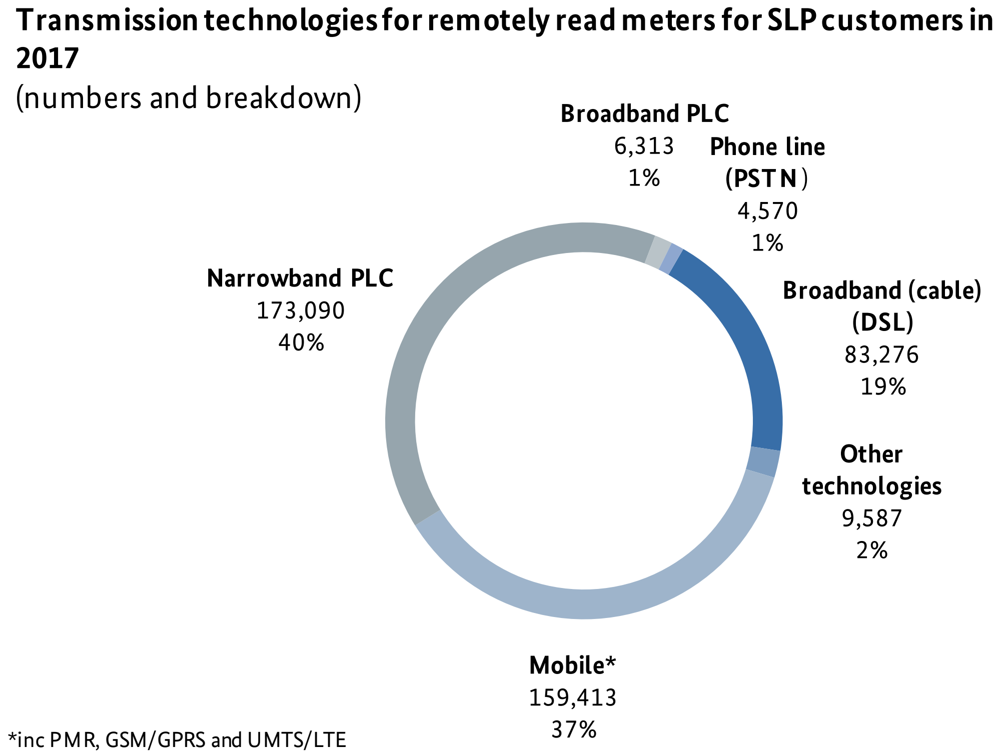
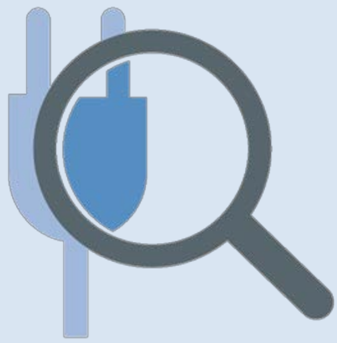


Figure 139: Transmission technologies for remotely read meters for SLP customers

Only about 436,000 of the total nearly 49.2m meter points for household customers are read remotely. Most meters still have to be read manually once a year. The proportion of transmissions via power line communication (PLC) was around 8,000 meter points lower than last year due to the strong decline in broadband PLC technology. Narrowband PLC technology, on the other hand, is growing in importance. The overall decline in PLC technology is in contrast to the sharp rise in transmission via mobile communications and other technologies. PLC transmission technology is now being used in just 41% of cases, while mobile transmissions are used in 37%. There was a further small decline in transmissions via telephones lines (PSTN) and broadband (DSL).



The Metering Act includes an obligation to install smart metering systems for consumers with annual consumption of over 6,000 kWh. Meters with smart metering systems process the meter data and transmit it directly to authorised parties via a smart meter gateway.

The default meter operator can also install smart metering systems for customers with less than 6,000 kWh of annual consumption, but it does not have to do so. If it decides not to, however, it must at least fit modern metering equipment. This equipment does not transit data automatically but has to be physically read like conventional meters.

6. Metering technology used for interval-metered customers

According to the information provided by meter operators, the number of meter points of interval-metered final consumers reached about 450,000, with non-household customers from the industrial and commercial segment accounting for all interval-metered customers.

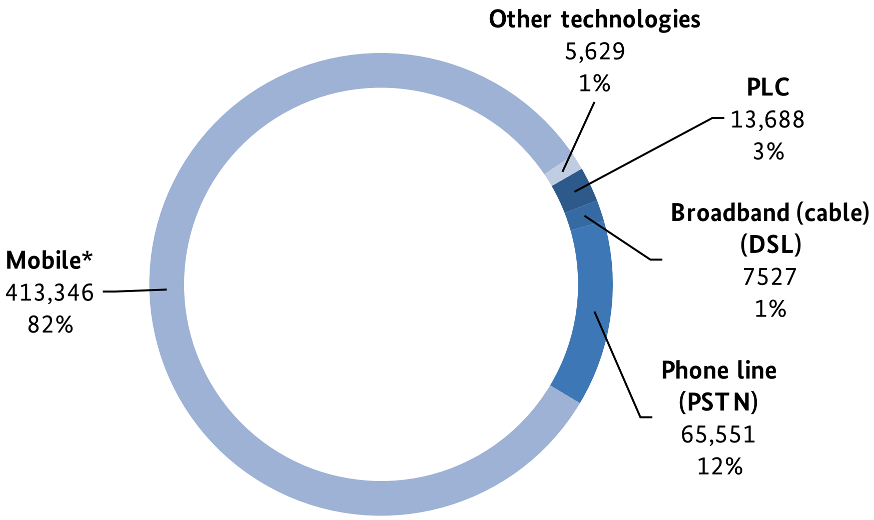
Meter technology employed for interval-metered customers

Requirement	Meter points 2017
Metering equipment in the interval-metered segment	451,085
Metering systems in accordance with sections 21d and 21e EnWG	242,537
Other	78,775

Table 100: Meter technology employed for interval-metered customers

The following diagram shows the number and breakdown of transmission technologies used.

Transmission technologies for remotely read meters for interval-metered customers in 2017
(numbers and breakdown)



*inc PMR, GSM/GPRS and UMTS/LTE

Figure 140: Transmission technologies for interval-metered customers

There were some changes in the transmission technology landscape for interval-metered customers compared with 2016, with remote meter readings transmitted via mobile communication rising by about seven percentage points, in particular. Phone line connections, meanwhile, were down by about six percentage points. As in the previous year, the diagram above shows that in the interval-metered segment, transmission technologies other than by radio (GSM, GPRS, UMTS, LTE) and telephone line (PSTN) are rarely used. The prevailing trend of telephone-line transmission falling and mobile transmission rising by a comparable amount is also apparent for interval-metered customers. 82% of remote read meters now communicate by mobile transmission.

7. Metering investment and expenditure

Total investment and expenditure[116] on metering was up about €66m to €575m in 2017, with distribution again shifting somewhat. There was a slight year-on-year rise in investments in maintenance and renewal and in expenditure, but a fall in investments in new installations, upgrades and expansion.

Investment in new installations, upgrades and expansion made in 2017 lagged around 51% behind projected figures for the year. Investment made in maintenance and renewal was around 23% below what was planned. The volume of expenditure, by contrast, was only around 2% less than the projected values. Plans for 2018 suggest there will be a sharp increase in investments, while expenditure will remain stable.

About €52m of the total investment volume of €575m in 2017 was for smart metering systems and modern metering equipment. There is projected to be a significant rise in this proportion to about €206m in 2018.

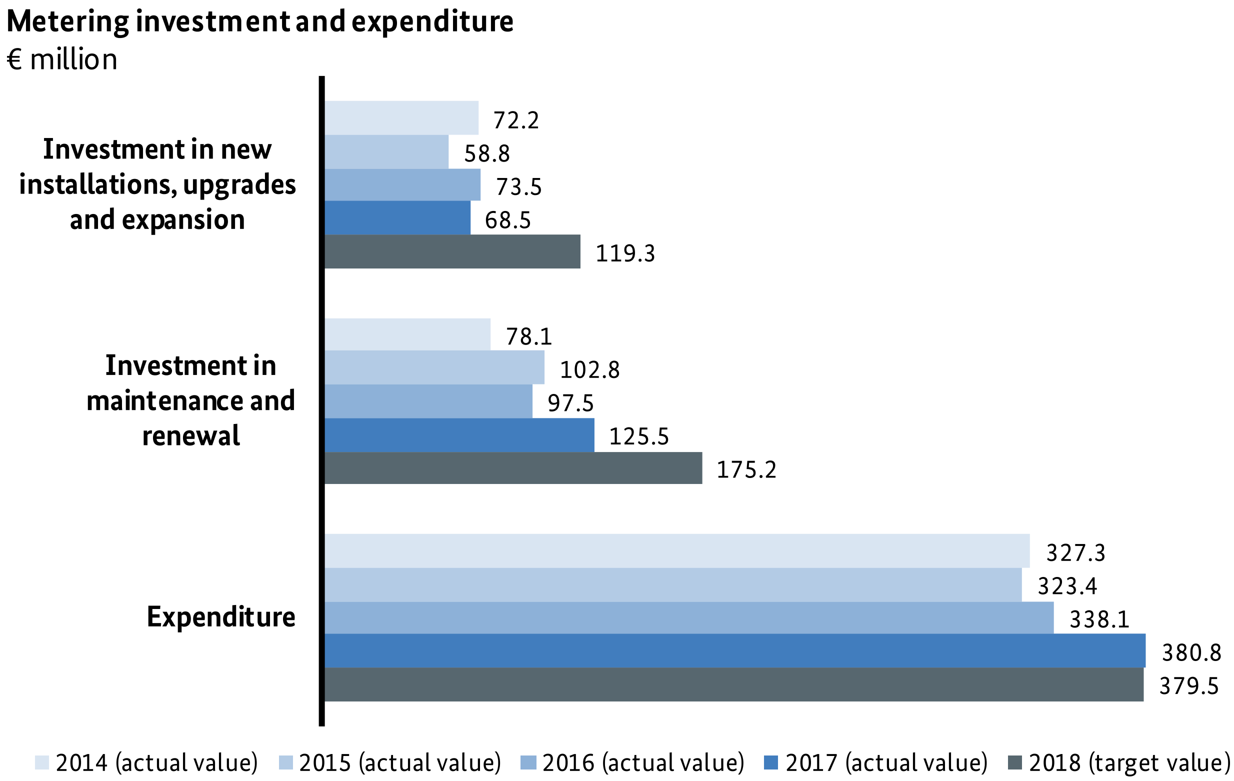


Figure 141: Metering investment and expenditure

[116] Definitions are provided in the section 0 "Investments" in the Networks chapter (starting on page 112).

8. Final consumer prices for metering equipment

For the second time, meter operators were asked about the prices final consumers were charged for metering systems. The arithmetic average values of the prices indicated are outlined in Table 101. The prices for standard services as defined in section 35(1) of the Metering Act range on average between €90.36 and €446.61 per year depending on the final consumer group and installed capacity of installation operators. The prices for voluntary installation within the meaning of section 29 in conjunction with section 31 of the Metering Act are also shown in Table 101. Depending on the final consumer group, they vary, on average, between €21.72 and €51.88 per year. Table 102 shows that final consumers are charged on average €19.74 per year for modern metering equipment within the meaning of section 29 in conjunction with section 32 of the Metering Act. Both tables make clear that average prices for meter operation are very close to the legal maximums.

Prices for standard services within the meaning of section 35 (1) of the Metering Act for carrying out metering operations in 2017
(€/year)

	Average price	Price cap
Final consumers with annual power consumption		
≤ 2,000 kWh**	21.72	23.00
> 2,000 kWh & ≤ 3,000**	27.53	30.00
> 3,000 kWh & ≤ 4,000**	35.66	40.00
> 4,000 kWh & ≤ 6,000**	51.76	60.00
> 6,000 kWh & ≤ 10,000	90.36	100.00
> 10,000 kWh & ≤ 20,000 kWh	118.63	130.00
> 20,000 kWh & ≤ 50,000 kWh	155.11	170.00
> 50,000 kWh & ≤ 10,000 kWh	183.78	200.00
> 100,000 kWh	446.61	
Consumer devices within the meaning of section 14a EnWG	94.92	100.00
Installed capacity at plant operators in accordance with section 2 para 1 of the Metering Act		
> 1 kW & ≤ 7 kW**	51.88	60.00
> 7 kW & ≤ 15 kW	93.73	100.00
> 15 kW & ≤ 30 kW	121.96	130.00
> 30 kW & ≤ 100 kW	186.83	200.00
> 100 kW	434.63	

*in accordance with section 35(1) of the Metering Act

**voluntary installation in accordance with section 29 in conjunction with sections 31 MsbG

Table 101: Prices for standard services within the meaning of section 35(1) of the Metering Act for carrying out metering operations

Prices for voluntary installation within the meaning of section 29 in conjunction with section 32 of the Metering Act in 2017
(€/year)

	Average price	Price cap
Modern metering device as defined in the Metering Act	19.74	20.00

Table 102: Prices for voluntary installation within the meaning of the Metering Act

Installing modern metering equipment and smart metering systems generally leads to higher costs for consumers. In order to limit these, a price cap has been laid down by law for the operation of modern metering equipment and smart metering systems. The costs depend on the consumer's annual consumption level. Households with an annual consumption of 2,500 kWh have to pay no more than €30 a year, while those with an annual consumption of 5,000 kWh can pay up to €60 a year.

II Gas market

A Developments in the gas markets

1. Summary

1.1 Production, imports and exports, and storage

In 2017, natural gas production in Germany fell by 0.6bn m^3 to 7.2bn m^3 of gas (with calorific adjustment). This corresponds to a decline of 8.1% compared to the previous year. The decline in production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output. The reserves-to-production ratio of proven and probable natural gas reserves, calculated on the basis of the previous year's production and reserves, was 8.0 years as at 1 January 2018 (2017: 8 years).

The total volume of natural gas imported into Germany in 2017 was 1,676 TWh. Based on the previous year's figure of 1,641 TWh, imports to Germany increased by 35 TWh or just over 2%. Imports from Norway dropped by just over 9%, while imports from Russia through the Nord Stream pipeline rose by 16.6%.

In 2017, Germany exported a total of 743.5 TWh of natural gas. Compared to the previous year's figure of 770.4 TWh, exports from Germany decreased by 27 TWh, a drop of 3.5%. About 50% (2017: 46%) of the natural gas exported by Germany went to Czechia, which is an increase of 5.4% year-on-year. Exports to Belgium and Poland rose sharply by 93.1% and 23.1% respectively, while there was a clear decrease in exports to Luxembourg (-36.2%), the Netherlands (-27.5%) and Austria (-20.5%).

The total maximum usable volume of working gas in underground storage facilities as at 31 December 2017 was 280.1 TWh. Of this, 132.22 TWh was accounted for by cavern storage, 125.86 TWh by pore storage facilities and 22.01 TWh by other storage facilities.

The volume of short-term (up to the beginning of the gas year 2017/2018 on 1 October 2017) freely bookable working gas declined slightly, whereas the capacities bookable for 2019 increased. There was also an increase in the volume of long-term bookable working gas from 2020. Compared with the previous year, the volume of working gas that can be booked five years in advance declined slightly. Overall, customers are tending towards shorter-term bookings in the storage market.

On 1 October 2018, at the beginning of the 2018/2019 gas year, the total storage level of German storage facilities was around 80% compared with 85% in 2017. As at 1 November 2018 the storage level of these storage facilities was over 87%.

The market for the operation of underground natural gas storage facilities is still relatively highly concentrated, although concentration has eased over the past few years. The cumulative market share of the three largest storage facility operators stood at around 68.2% at the end of 2017, remaining the same as in the previous year. The considerable decline in 2016 was largely due to reduced concentration in the storage market resulting from the takeover of VNG AG by EnBW AG.

1.2 Networks

1.2.1 Network expansion

On 1 April 2018, the transmission system operators (TSOs) submitted their draft gas NDP 2018-2028 to the Bundesnetzagentur. Essentially, the results of the gas NDP 2018-2028 confirm the measures set out in the gas NDP 2016-2026. In addition, the TSOs are proposing a further 41 expansion measures up to 2028. The TSOs' proposal includes the expansion of the gas transmission system by an additional 1,390 km and an increase in the capacity of compressor stations by around 499 MW. Investment costs have gone up significantly from €4.5bn in the gas NDP 2016-2026 to €7.0bn in the gas NDP 2018-2028.

This increase is mainly accounted for by the planned European Gas Pipeline Link (EUGAL), which will receive gas from the planned import pipeline Nord Stream 2 to transport it within Germany and to Czechia. The planned pipeline will be 480 km long, running from Lubmin on the Baltic Sea to Deutschneudorf on the German-Czech border. Investment costs for only the EUGAL pipeline amount to around €2.3bn. If all the other expansion measures directly related to the EUGAL pipeline are included, such as connection to the existing network, the total cost of investment will be around €2.7bn. This adds up to an estimated €175m of annual capital cost to be paid by the TSOs Gascade, Fluxys D, Gasunie Deutschland and Ontras in the coming years. Shippers have already made long-term capacity bookings for the incremental capacity created by EUGAL and by other network expansion measures to transport gas from Nord Stream 2. According to the TSOs, these bookings will make an essential contribution to refinancing investments. The total volume of bookings received for incremental capacity related to Nord Stream 2 is equivalent to around €200m per year for the next few years. This does not yet take account of possible changes in the network charges and bookings of further available capacity.

Moreover, the connection of two planned power plants will result in a requirement for further network expansion measures. For the first time, the gas NDP now includes a liquefied natural gas (LNG) terminal at Brunsbüttel on the German coast, which, based on the information from the TSOs, will also create the need for network expansion.

1.2.2 Investments

In 2017, investments in and expenditure on network infrastructure by the 16 German TSOs amounted to €970m compared with €469.9m in 2016 (both values under commercial law).[117] Total investments of €1.49bn are planned for 2018, corresponding to a year-on-year increase of 53%. This relatively high fluctuation is due to investments in large-scale, one-off projects.

Service and maintenance expenses amounted to €1,084m in 2017, based on the data provided by the gas DSOs.

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[117] Investments and expenditure are defined in the glossary. The values under commercial law do not correspond to the implicit values included in the system operators' revenue cap in accordance with the provisions of the Incentive Regulation Ordinance (ARegV). A comparative calculation of the values under commercial law with the values from incentive regulation will be able to be made following the introduction of an index-based investment monitoring pursuant to section 33(5) ARegV. Medium to long-term trends can be derived from the evaluations on the basis of the survey of commercial values. The introduction of an index-based investment monitoring pursuant to section 33(5) ARegV is currently being prepared by the Bundesnetzagentur taking account of the effort required for companies to transmit data.

In the 2018 monitoring, around 645 gas DSOs reported total network infrastructure investments in 2017 of €1,031m in new builds, upgrades and expansion (€623m) and in maintenance and renewal (€408m). For 2018, a total investment of €1,244m is foreseen. Investments of gas distribution system operators (DSOs) declined from €2,315m in 2015 to €1,031m in 2016.

1.2.3 Supply interruptions

As in previous years, the Bundesnetzagentur conducted a comprehensive survey of all gas supply interruptions throughout the Federal Republic of Germany. The System Average Interruption Duration Index (SAIDI) determined from the results of this survey reflects the average duration of supply disruptions experienced by a customer over a period of one year and was 0.99 minutes per year in 2017 compared with 1.03 minutes per year in 2016.

1.2.4 Network charges

The average volume-weighted network charge, including metering and meter operation charges, for default supply of household customers in consumption band II was 1.51 ct/kWh on 1 April 2018, slightly up on the previous year's level.

1.2.5 Network balance

The total quantity of gas provided from general supply networks in Germany slightly decreased by 5.6 TWh or just over 0.5% from 941.3 TWh in 2016 to 935.7 TWh in 2017. The quantity of gas supplied to household customers (as defined in section 3 para 22 EnWG) rose by just over 1% to 278.8 TWh (2016: 275.6 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW increased slightly, reaching 98 TWh in 2017, up just over 4% on the previous year's volume of 94 TWh.

With regard to gas transmission networks, the quantity of gas procured directly from the market by large final consumers amounted to 80.7 TWh, which is equivalent to about 44% of the total quantity of gas supplied by the TSOs. The "large final consumers" referred to here are industrial customers and gas-fired power stations that do not follow a traditional route via a supplier but instead approach the network operator as a shipper and pay the transport charges themselves. As regards gas distribution networks, the amount of gas procured without a conventional supplier contract amounted to 38 TWh, compared with 45.4 TWh in 2016, corresponding to a share of approximately 5% of the DSOs' total gas supplies.

1.2.6 Market area conversion

The conversion of German L-gas networks to H-gas got off to a good start in 2015 with the conversion of smaller network areas. Today, larger network operators such as Westnetz, Avacon and wesernetz Bremen have also started the conversion process.

Gastransport Nord, Gasunie Germany Transport Services, Nowega, Open Grid Europe and Thyssengas are TSOs directly affected by the market area conversion. In 2015, there was a total of 969 L-gas interconnection points that still had to be converted. This figure went down to 950 in 2016 and to 922 in 2017.

The planned conversions by the individual network operators tend to take place in months when less gas is consumed, from April to October. By 2023, a total of 2,982 conversions will be carried out for interval-metered customers and 1,695,250 for standard load profile (SLP) customers.

1.3 Wholesale

Liquid wholesale markets are vital to ensure well-functioning markets along the entire value chain in the natural gas sector, from the procurement of natural gas through to supplying end customers. The greater the variety of options for companies to procure gas for both the short and long term at the wholesale level, the less they are tied to a single supplier long-term. The Bundeskartellamt now defines the wholesale market for natural gas as a national market and no longer defines markets based on their respective network area.

The volume traded on the spot market rose again in 2017 to about 309 TWh compared with about 295 TWh in 2016. As in previous years, the focus of spot trading for both market areas in 2017 was on day-ahead contracts (NCG: 115.8 TWh, 2016: 128.5 TWh; GASPOOL: 69.3 TWh, 2016: 51.1 TWh). The futures trading volume fell from about 130 TWh in 2016 to about about 86 TWh in 2017, corresponding to a decrease of some 34%. When viewing this decline, it must be taken into account that there had been an extraordinary increase in the futures trading volume between 2015 and 2016 from about 97 TWh to about 130 TWh.

In 2017, broker platforms reported having brokered natural gas transactions for delivery to Germany for an amount totalling 2,672 TWh (2016: 3,120 TWh), of which 1,120 TWh was for contracts with delivery in 2017 (delivery time of at least one week).

In contrast to 2016, wholesale gas prices in 2017 showed some significant increases.[118] In 2017, the (unweighted) annual average daily reference prices calculated by EEX amounted to €17.51/MWh for the NCG market area and €17.28/MWh for the GASPOOL market area, up 24% and 22% respectively. The (unweighted) average cross-border price, as calculated by the Federal Office for Economic Affairs and Export Control (BAFA), amounted to €16.98/MWh in 2017, up 12% from €15.23/MWh in 2016.

1.4 Retail

1.4.1 Contract structure and competition

An overall analysis of how household customers were supplied in 2017 in terms of volume shows that the majority of them, some 51% compared with 53% in 2016, were supplied by the local default supplier under a non-default contract and were supplied with 126.4 TWh of gas (2016: 128.3 TWh). Some 19% of household customers had a default supply contract and were supplied with 47.3 TWh of gas, compared with 22% and 52.8 TWh, respectively, in 2016. The percentage of household customers who had a contract with a supplier other than the local default supplier once again increased and was 30% (2016: 25.6%) for 75.5 TWh of gas (2016: 62.4 TWh). Thus supply by the default supplier at a default tariff is the least popular form of supply.

The gas sold to non-household customers is mainly to interval-metered customers. About 27% of the total volume delivered to these customers was supplied under a contract with the default supplier on non-default terms (2016: 29%) and about 73% was supplied under a contract with a legal entity other than the default supplier (2016: 71%). The figures show that default supply is declining and of only minor significance for the supply of non-household customers in the gas sector.

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[118] Influencing factors include the world market prices for oil and LNG, weather and temperatures, the renegotiation of long-term supply contracts on the European gas market, increasing trade at European gas trading points and gas storage capacities.

The total number of household customers changing contract was 891,000. The volume of gas these customers were delivered was approximately 9.5 TWh. The resulting numbers-based and volume-based change of contract rates are 7.2% and 3.8%, respectively.

The number of household customers who switched supplier fell when compared with the previous year by about 4% (down 45,759 supplier switches) to 1,212,553 compared with 1,258,312 in 2016. The number of household customers who decided to immediately switch to a supplier other than the local default supplier when moving home has remained steady (2017: 264,111; 2016: 264,954).

When looking at 12.5m household customers (according to DSO figures), the resulting overall numbers-based supplier switching rate for household customers is 11.8%, down from 12.3% in 2016.

The total volume of gas supplied to customers who switched supplier (including those who switched when moving) fell in 2017 by 3.2 TWh or just under 9% to 34 TWh (2016: 37.2 TWh). Taking into account the slight rise in gas supplied to household customers by network operators in 2017, the volume-based switching rate fell to 12.2% from 13.5% in 2016.

The volume-based supplier switching rate of 12.2% is still above the numbers-based rate of 11.8% because high-consumption household customers exhibit a greater willingness to switch. At around 24,500 kWh, the calculated annual consumption of an average gas customer that switched supplier is above the national average of 20,000 kWh.

There was a strong rise in switching rates among non-household customers between 2006 and 2010. In the following years, from 2010 to 2016, the switching rates remained more or less steady between 11% and 13%, whereas in 2017 there was a clear fall in the switching rate to 8.9% from 11.1% in 2016. Total gas consumption of 88 TWh was affected by supplier switches in all customer categories (2016: 103 TWh in total). This represents a decline of 15 TWh or 15% compared with the previous year.

As in the 2017 Monitoring Report, the present report also deals with the concentration ratio (CR) of the four largest companies in the retail gas market, whereas up until 2016 only three had been considered. The cumulative sales for the four largest companies to customers with a standard load profile (SLP) was about 87 TWh in 2017, of which about 74 TWh was supplied under special contracts. Cumulative sales to interval-metered customers were about 138 TWh. The cumulative market share of the four largest companies (CR4) in 2017 was around 23% for SLP customers and about 30% for interval-metered customers compared with 25% and 28%, respectively, in 2016. Despite a rise in interval-metered customers, the aggregated market shares for both categories of customer remained clearly below the statutory thresholds for presuming market dominance. It must also be noted with respect to the interval-metered customers that the figure refers to the four largest companies, instead of to three companies as was the case up to 2016, and as such the CR4 figure has to be seen in this perspective.

Since market liberalisation and the creation of a legal basis for a well-functioning supplier switch, there has been a steady positive development in the number of active gas suppliers for all final consumers in the different network areas. This positive trend continued in 2017 as well. In 2017, more than 50 gas suppliers were operating in 93% of the network areas. Final consumers in over 56% of network areas had a choice of more than 100 gas suppliers. If viewed separately, the trend for household customers is similarly positive. In about 87% of network areas, household customers have a choice of 50 or more gas suppliers. More than

100 gas suppliers are operating in 40% of network areas. On average, final consumers in Germany can choose between 116 suppliers in their network area; household customers can, on average, choose between 98 suppliers (these figures do not take account of corporate groups).

1.4.2 Gas disconnections

In 2017 the number of disconnections carried out by DSOs on behalf of the local default supplier fell to 37,992 (2016: 38,576), which represents a drop in disconnections of about 600 or well over 1.5% when compared with the previous year. Additionally, 2,056 gas disconnections, up from 1,260 in 2016, were carried out on behalf of a supplier other than the local default supplier. In 2017 the DSOs re-connected the gas supply for about 29,029 (2016: 30,633) of the meters disconnected by DSOs on behalf of the local default supplier.

When compared with the previous year, this is about 1,600 meter points fewer. The decline in re-connected meter points is largely due to a general decrease in gas disconnections. In addition, supply was also restored to about 1,946 meter points (2016: 1,486) on behalf of gas suppliers other than the local default supplier.

Compared with the previous year, the number of disconnection notices issued by all gas suppliers of 1,124,435 was a considerable fall from 1,286,050 in 2016, down some 12.5%. The number of disconnection orders fell by 14.8% to 231,875, down from 272,135 in 2016.

According to the gas suppliers, 37,750 (2016: 38,004) disconnection notices (for customers on a default contract or a non-default contract with the default supplier) ended with an actual disconnection carried out by the network operator responsible. This signifies a decrease of 1,254 disconnections compared with the previous year. A comparison of the number of disconnection notices issued with the number of disconnections actually carried out clearly shows that over 3% of the notices issued actually resulted in a disconnection being carried out by the DSO. Furthermore, the gas suppliers stated that in 25,382 cases (2016: 26,707) they had disconnected customers with a default contract. The disconnection rate of 0.8% with respect to the total number of customers under a default contract was thus less than one percent on average. Disconnection of non-default customers was carried out in 12,368 cases compared with 12,297 disconnections in 2016. The disconnection rate for non-default customers was 0.2%.

1.4.3 Price level

As at 1 April 2018, retail prices for gas had again fallen slightly compared with 1 April 2017.

The average price for household customers across all three contract categories (ie default supply contract, non-default contract with the default supplier, and contract with a supplier other than the local default supplier) decreased by 1.3% to 6.07 ct/kWh (including VAT) as at 1 April 2018 (1 April 2017: 6.15 ct/kWh).

The gas price for default supply dropped 1.3% to 6.64 ct/kWh (including VAT) as at 1 April 2018. The gas price for non-default contracts with the default supplier fell only slightly by 0.2% and was 6.06 ct/kWh (including VAT) as at 1 April 2018. Likewise the gas price for a contract with a supplier other than the local default supplier fell by 1.2% to 5.71 ct/kWh (including VAT) as at 1 April 2018. Gas prices for consumers under contract with a supplier other than the local default supplier thus reached the lowest level they have been since the first survey on 1 April 2008.

With regard to the main component of the gas price for household customers in band II, which is the price component that can be controlled by the supplier: "energy procurement, supply and margin", it is notable that in 2018 this price component for customers with a supplier other than the local default supplier hit the lowest level since the survey started of 2.66 ct/kWh. Moreover, the price component "energy procurement, supply and margin" for default supply customers fell to 3.29 ct/kWh as at 1 April 2018. This price component was steady at 3.01 ct/kWh as at 1 April 2018 for customers with a non-default contract with their default supplier

Customers on default tariffs can make savings by switching tariff or supplier. The average household customer with gas consumption of 23,250 kWh could save an average of €135 a year as at 1 April 2018 by changing contract. The average potential saving for the year through changing supplier was €216.

In addition, special bonuses offered by gas suppliers, including one-off bonus payments, are an added incentive for customers to switch supplier. These one-off bonus payments amount to an average of €70.

Varying developments were recorded in 2017 for gas prices for non-household (industrial and commercial) customers compared with the previous year. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") of 2.82 ct/kWh is 0.13 ct/kWh or around 5% higher than the previous year's figure of 2.69 ct/kWh. Components of the overall price that are not under the control of the supplier (in particular, network charges and levies) fell by a scant 1% compared with the previous year.

By contrast, the arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MW/h ("commercial customer") of 4.40 ct/kWh is 0.1 ct/kWh or around 2% lower than last year's price. The absolute level of the price components that are not controlled by the suppliers (in particular network charges and levies) has remained stable at 1.84 ct/kWh in a year-on-year comparison. By contrast, the residual price component controlled by the supplier decreased by 0.12 ct/kWh (from 2.67 ct/kWh in 2016 to 2.55 ct/kWh in 2017), thus by around 4%.

German household customers paid slightly more than the European average for gas, while non-household customers paid significantly more. The net gas price in the annual consumption range of 27.8 GWh to 278 GWh ("industrial customer") is 2.64 ct/kWh, which is at the upper end of the scale. The EU average is 2.40 ct/kWh. On a European average, the net price is subject to about 10% (0.24 ct/kWh) of non-refundable taxes and levies. In this regard, Germany reports a higher than average figure of about 15% (0.40 ct/kWh). Unlike the industrial customer sector, there are major differences in gas prices for household customers across Europe. The gas price for household customers in Germany (6.42 ct/kWh) is only slightly above the EU average (6.36 ct/kWh).

The prices for industrial customers (annual consumption 116 GWh) show significantly smaller differences in a European comparison than the prices for household customers do. The net gas price in the annual consumption range of 27.8 GWh to 278 GWh is 2.55 ct/kWh, which is at the upper end of the scale. The EU average is 2.31 ct/kWh. On a European average, the net price is subject to about 10% (0.21 ct/kWh) of non-refundable taxes and levies. In this regard, Germany has a higher than average figure of about 18% (0.40 ct/kWh).

2. Network overview

All 16 TSOs took part in the 2018 Monitoring Report data survey. As at 31 December 2017, the length of pipelines in the transmission system was 38,798 km and included 3,489 exit points for delivery to final consumers, redistributors or downstream networks including the points at which gas can be taken off for delivery to storage facilities, hubs and conditioning or conversion plants. The number of final consumer meter points in the transmission system was 545. 183 TWh of gas was delivered to final consumers from the TSO network, which is the same as the previous year.

As of 7 November 2018, a total of 718 gas DSOs were registered with the Bundesnetzagentur, 691 (about 96%) of whom took part in the 2018 monitoring survey as at 31 July 2018. As of 31 December 2017, the total length of pipelines in the gas distribution network was 498,081 km and included 10.8m exit points for delivery to final consumers, redistributors or downstream networks including the points at which gas can be taken off for delivery to storage facilities, hubs and conditioning or conversion plants. As of 31 December 2017, there were 14.3m final customer meter points in the gas distribution network of the DSOs participating in the monitoring survey. The number of meter points for household customers as defined in section 3 para 22 of the EnWG was 12.5m. Total gas supplies from the network of these DSOs amounted to 752.4 TWh in 2017, up by about 6 TWh or around 1% compared to the previous year. The quantity of gas supplied to household customers as defined in section 3 para 22 EnWG rose by just over 3 TWh or 1% to 278.8 TWh.

A simplified comparison between the supply and demand of natural gas in 2017 in Germany is shown below. It must be pointed out, however, that this is based on gas flows, meaning that self-supply and statistical differences have not been accounted for. The total amount of gas entering the German network was about 1,760 TWh in 2017. Around 4% came from domestic sources (70 TWh), the rest (1,676 TWh) was imported. The balance of gas that entered and exited storage in 2017 amounted to 4 TWh, so there was more gas being withdrawn from the storage facilities than injected into them. Moreover, 9.3 TWh of biogas upgraded to natural gas quality was fed into the German natural gas network in the year.

Around 42% (743.5 TWh) of available gas volumes in Germany was transported to neighbouring countries in Europe. Final consumers used 935.7 TWh of gas in Germany.

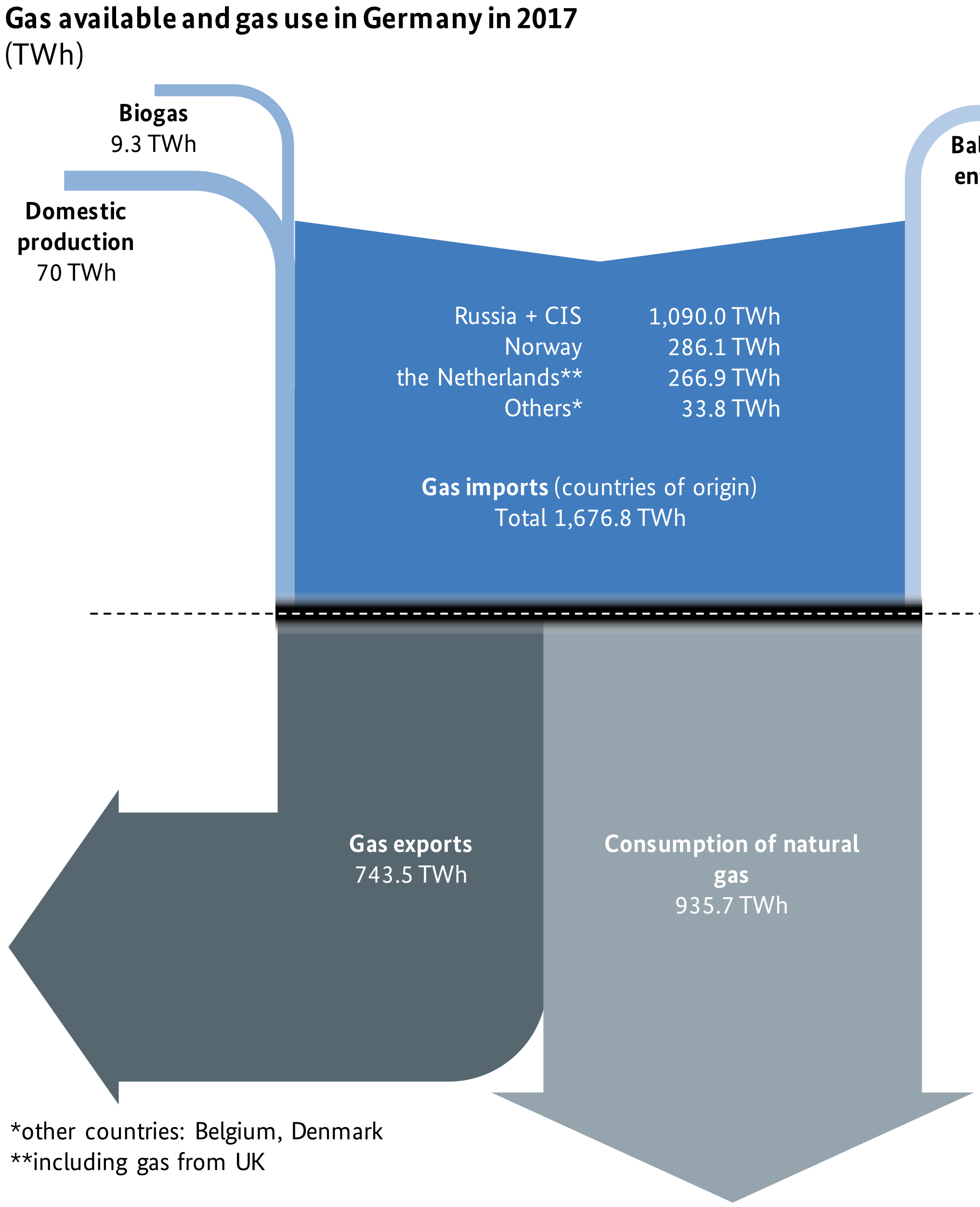

Figure 142: Gas available and gas use in Germany in 2017[119]

[119] Because of the infrastructure in place, recorded import and export volumes may also include transit flows or loop flows (eg volumes of gas that leave Germany at the Olbernhau cross-border transfer point using the GAZELLE gas pipeline and then re-enter the German network at the Waidhaus cross-border transfer point). Transit flows or loop flows are not represented at this point.

Number of gas network operators in Germany registered with the Bundesnetzagentur

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Transmission system operators (TSOs)	18	14	17	17	17	17	16	16	16
Distribution system operators (DSOs)	712	711	739	724	714	714	715	717	718
DSOs with fewer than 100,000 connected customers	671	678	683	686	689	689	690	692	693

Table 103: Number of gas network operators in Germany registered with the Bundesnetzagentur as at 1 November 2018

Gas network operators were asked about the total length of their networks, as well as the length subdivided according to pressure ranges (nominal pressure in bar). The findings from the operators surveyed are shown in the table below.

The majority of gas DSOs (605 operators) have short to medium length networks of up to 1,000 km. Of the remainder, 78 DSOs have gas networks with a total length of more than 1,000 km. The following figure shows a percentage breakdown of DSOs according to network length:

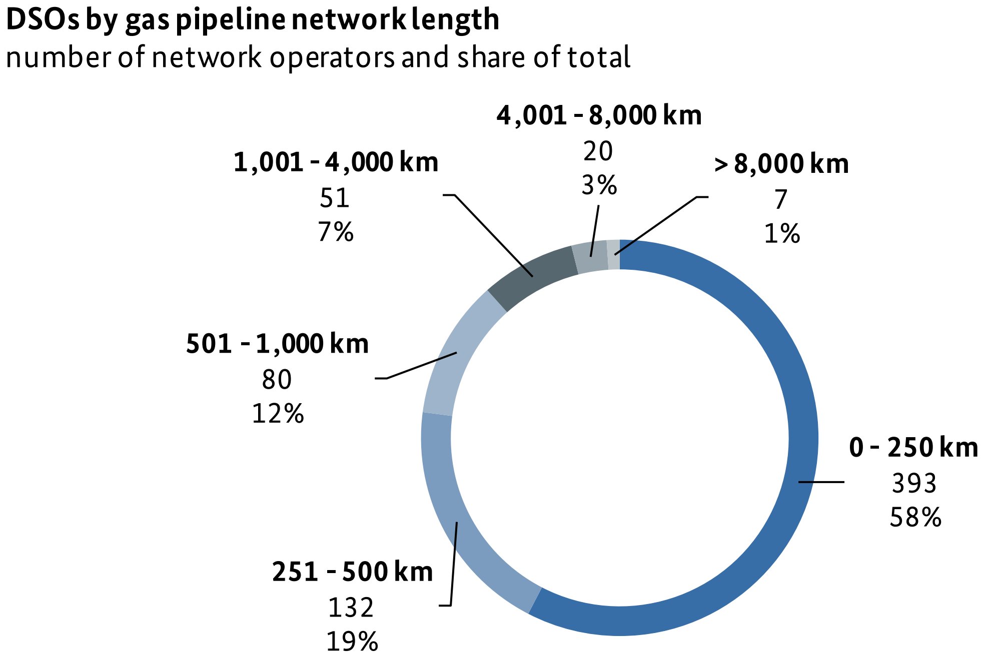

Figure 143: DSOs by gas pipeline network length as stated in the DSO survey – as at 31 December 2017

2017 network structure figures

	TSOs	DSOs	Total no of TSOs and DSOs
Network operators	16	696	712
Network length (in km)	38,798	498,081	536,879
≤ 0.1 bar	0	171,257	171,257
> 0.1 – 1 bar	1	243,357	243,358
> 1 bar	38,797	83,467	122,264
Number of offtake points	3,489	10,834,078	10,837,567
≤ 0.1 bar	1	6,130,546	6,130,547
> 0.1 – 1 bar	13	4,450,234	4,450,247
> 1 bar	3,475	253,298	256,773
Final consumers (meter points)	545	14,240,012	14,240,557
Industrial and commercial customers and other non-household customers	497	1,772,134	1,772,631
Household customers	0	12,467,713	12,467,713
Gas-fired power plants with a net electricity capacity of at least 10 MW	48	165	213

Table 104: 2017 network structure figures according to the TSO and DSO survey – as at 31 December 2017

The table below shows a breakdown of the quantity of gas provided to final customers in the network areas of the TSOs and DSOs surveyed in 2017.

Gas exit volumes in 2017 broken down by final consumer category, according to the survey of gas TSOs and DSOs

	TSO exit volume (TWh)	Share of total amount	DSO exit volume (TWh)	Share of total amount
≤ 300 MWh/year	<0.1	<0.1%	337.2	44.8%
> 300 MWh/year ≤ 10,000 MWh/year	0.6	0.3%	129.3	17.2%
> 10,000 MWh/year ≤ 100,000 MWh/year	5.9	3.2%	104.1	13.8%
> 100,000 MWh/year	127.9	69.8%	132.6	17.6%
Gas-fired power plants with ≥ 10 MW net nominal capacity	48.9	26.7%	49.2	6.5%
Total	183.3	100%	752.4	100.0%

Table 105: Gas exit volumes in 2017 broken down by final consumer category, according to the survey of gas TSOs and DSOs

The following consolidated overview includes the total gas exit volumes of TSOs and DSOs and the quantity of gas provided to final consumers by suppliers for 2017. Once again, gas TSOs and DSOs were asked in the 2017 monitoring survey to provide figures on the volumes that mostly large final consumers (industrial customers and gas-fired power plants) procure directly on the market themselves, ie not using the traditional route via a supplier, and instead approach the network operator as a shipper (paying the transport charges themselves). The quantity of gas procured directly on the market amounted here to 80.7 TWh (2016: 87.5 TWh), equivalent to just over 44% of the total quantity of gas delivered by TSOs to final consumers. As regards gas distribution networks, the amount of gas procured without a conventional supplier contract amounted to 38 TWh, compared with 45.4 TWh in 2016,[120] corresponding to a share of approximately 5% of the DSOs' total gas supplies.

The difference between the exit volumes of the system operators (935.7 TWh) and the gas delivered by gas suppliers (830.1 TWh) is approximately equivalent to the amount of gas procured directly on the market without using a supplier (118.7 TWh).[121]

[120] The figure of 58.1 TWh given for 2016 in the 2017 Monitoring Report had to be adjusted to 45.4 TWh.

[121] Variations in data quality mean that the difference calculated is slightly below the figure calculated for gas procured on the market.

Total gas exit volumes in 2017, according to the survey of gas TSOs and DSOs and total volumes of gas delivered according to gas supplier survey, broken down by final customer category

	TSO and DSO exit volume (TWh)	Share of total amount	Total volume of gas delivered by suppliers in TWh	Share of total amount
≤ 300 MWh/year	337.2	36.0%	324.1	39.0%
> 300 MWh/year ≤ 10,000 MWh/year	129.9	13.9%	119.1	14.3%
> 10,000 MWh/year ≤ 100,000 MWh/year	110.0	11.8%	102.3	12.3%
> 100,000 MWh/year	260.5	27.8%	210.9	25.4%
Gas-fired power plants with ≥ 10 MW net nominal capacity	98.1	10.5%	73.7	8.9%
Total	935.7	100.0%	830.1	100.0%

Table 106: Total gas exit volumes in 2017, according to the survey of gas TSOs and DSOs and total volumes of gas delivered according to gas supplier survey

The total quantity of gas supplied by general supply networks in Germany fell in 2017 by 5.6 TWh or nearly 1% year-on-year to 935.7 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 EnWG) rose by just over 1% to 278.8 TWh (2016: 275.6 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW increased once again. Some 98.1 TWh of gas was supplied to such power stations in 2017, about 4.4% up on the previous year (94 TWh).

The structure of the gas retail market remained for the most part unchanged. There is a total of 5,752 entry points to the gas distribution networks, of which 216 are for emergency entry only. A look at the number of meter points served by the DSOs shows that only 25 DSOs supply more than 100,000 meter points each. Out of a total of 14.3m meter points supplied by the DSOs in Germany, some 43% (6.2m), accounting for just over 44% (328.9 TWh) of the total gas supplies, are served by DSOs that supply more than 100,000 meter points. The majority (58%) of DSOs active in Germany supply between 1,000 and 10,000 gas customers.

DSOs by number of meter points supplied
(number and percentage)

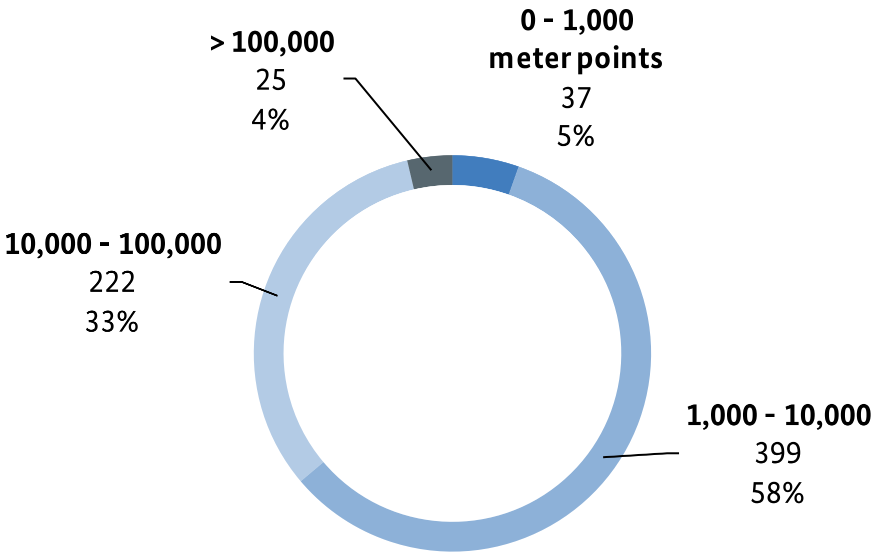

Figure 144: DSOs by number of meter points supplied (data from the gas DSO survey) – as at 31 December 2017

3. Market concentration

The degree of market concentration is an important indicator of the intensity of competition. Market shares are a useful reference point for estimating market power. They represent the extent to which demand in the relevant market was actually satisfied by one company during the reference period.[122] To represent the market share distribution, i.e. the market concentration, this report uses CR3 values or CR4 values (known as "concentration ratio"), i.e. the sum of the market shares of the three or four strongest suppliers. The larger the market share covered by only a few competitors, the higher the market concentration. A key parameter for measuring the degree of market concentration is the working gas volume in underground storage facilities.

3.1 Natural gas storage facilities

In its decision-making practice the Bundeskartellamt defines a relevant product market for the operation of underground gas storage facilities that includes both porous rock and cavern storage facilities. In geographical terms the Bundeskartellamt has defined this market as a national market and in the process also considered including the "Haidach" and "7Fields" storage facilities in Austria.[123] These two storage facilities are located near the German border in Austria and are connected directly or indirectly to the German gas networks. The European Commission also recently considered this alternative market definition, – and a number of other

[122] Cf. Bundeskartellamt, Guidance on substantive merger control, para. 25.

[123] Cf. Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, para. 215 ff., Bundeskartellamt, decision of 31 January 2012, B8-116/11 - Gazprom/VNG para. 208 ff.

alternatives – and ultimately left open the exact market definition.[124] The Haidach and 7Fields storage facilities in Austria will be fully included in the following assessment to illustrate the concentration in the market for the operation of underground natural gas storage facilities. The Bundeskartellamt calculates the market shares in this market on the basis of storage capacities (maximum usable working gas volume).[125]

This year's survey, which is based on a questionnaire sent out to underground natural gas storage facility operators, again focused on all storage facilities and requested, among other data, information on working gas volumes at the reference date 31 December 2017. The storage facility operators comprise a total of 24 legal entities. Companies were attributed to a group according to the dominance method (cf. the methodological notes in section I.A.3 "Market concentration", p. 36).

The market for the operation of underground natural gas storage facilities is characterised by a high level of concentration. Concentration has remained constant compared to the previous year. The maximum usable working gas volume of the underground natural gas storage facilities connected to the German gas network and analysed in the course of monitoring was around 299 TWh on 31 December 2017 (in 2016: 300.4 TWh).

On 31 December 2017, the cumulative market share of the three largest storage facility operators amounted to approx. 204.7 TWh (2016: 226 TWh). The CR3 value was around 68.2% and remained constant compared with the previous year.

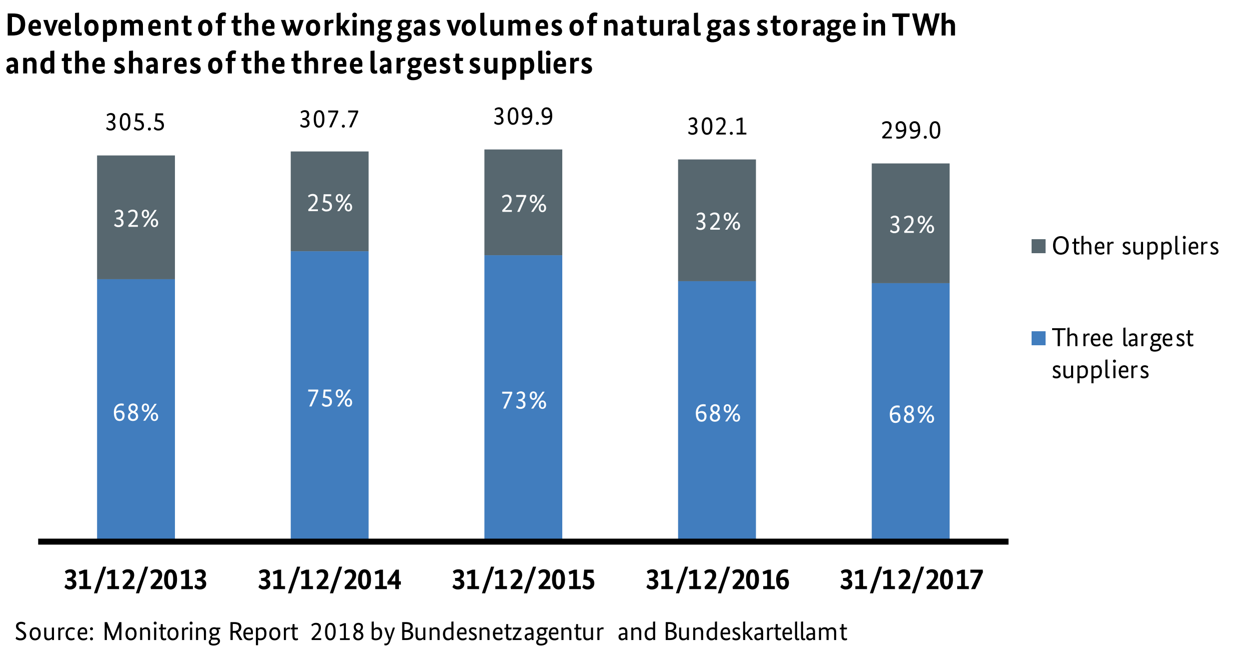

Figure 145: Development of the working gas volumes of natural gas storage facilities in TWh and the shares of the three largest suppliers

[124] Cf. COMP/M.6910 – Gazprom/Wintershall of 3.12.2013. para. 30 ff.

[125] Cf. Bundeskartellamt, decision of 23.10.2014, B8-69/14 – EWE/VNG, para. 236 ff.

3.2 Gas retail markets

On the gas retail markets the Bundeskartellamt differentiates between customers with metered load profiles and those with standard load profiles. Metered load profile customers are customers whose gas consumption is determined on the basis of a recording load profile measurement. They are generally industrial or large-scale commercial customers and gas-fired power plants. Standard load profile customers are those with relatively low levels of gas consumption and usually include household customers and smaller commercial customers. The distribution of their gas consumption over specific time intervals is based on a standard load profile. The Bundeskartellamt currently defines the market for the supply of gas to customers with metered load profiles and the market for the supply of gas to customers with standard load profiles under special contracts as national markets (cf. see the comments in "Market concentration" chapter, Electricity retail markets, p.43). The supply of gas to standard load profile customers under a default supply contract is a separate product market which continues to be defined according to the relevant network area.[126]

In energy monitoring the sales volumes of the individual suppliers (legal entities) are collected as national total values. In the case of sales to standard load profile customers, a differentiation is made between default supply and supply under special contracts. The following analysis is based on the data provided by around 966 gas suppliers (legal entities) (995 in the previous year). In 2017, these companies sold a total of approx. 378 TWh of gas to standard load profile customers in Germany (371 TWh in the previous year) and approx. 454 TWh of gas to customers with metered load profiles (453 TWh in the previous year). In accordance with the Bundeskartellamt's approach to market definition, sales to customers with metered load profiles also include sales to gas-fired power plants. Of the total volume of sales to standard load profile customers, special contracts accounted for 321 TWh (309 TWh in the previous year) and default supply contracts for 58 TWh. (62 TWh in the previous year).

Sales volumes were attributed to company groups on the basis of the dominance method which provides sufficiently accurate results for the purposes of this report (cf. methodological notes in section I Electricity market, A 3. Market concentration, p. 38).

The Monitoring Report analyses the market concentration (CR) of the four strongest companies on the gas retail market. The total cumulative sales of the four strongest companies to customers with standard load profiles amounted to around 87 TWh in 2017, of which some 74 TWh consisted of special contracts. Cumulative sales to customers with metered load profiles were around 138 TWh. In 2017 the aggregated market share of the now four strongest companies therefore amounted to about 23% for customers with a standard load profile contract (25% for the previous year's figure CR3) and about 30% for customers with metered load profiles (28% for the previous year's CR3). Both market shares continue to be significantly below the statutory thresholds for the presumption of market dominance (Section 18(6) GWB). The market concentration of the four strongest companies for customers with a standard load profile contract was found to decline slightly whereas for customers with metered load profiles it increased by two per cent. With regard to the data on percentages, it should be noted that the monitoring survey among gas suppliers improved again because of the higher number of suppliers taking part, but does not cover the whole market. The percentages consequently merely approximate the actual values.

[126] Cf. Bundeskartellamt, decision of 23 December 2014, B8-69/14 – EWE/VNG, para. 129-214.

Share of the four strongest suppliers in the sale of gas to metered load profile (RLM) and standard load profile (SLP) customers in 2017

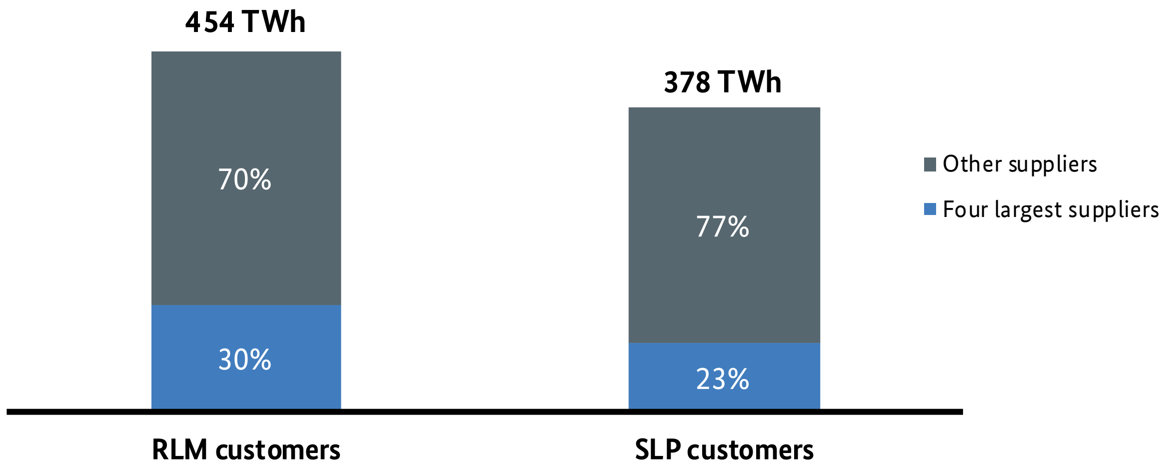

Figure 146: Share of the four strongest suppliers in the sale of gas to metered load profile (RLM) and standard load profile (SLP) customers in 2017

B Gas supplies

1. Production of natural gas in Germany

In 2017, natural gas production in Germany fell by 0.6bn m³ to 7.2bn m³ of gas (with calorific adjustment)[127]. This corresponds to a decline of 8.1% compared to the previous year. The decline in natural gas production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output.[128] Another factor is the lack of major new gas finds. Consequently, Germany was able to cover only some 7% of its own consumption through domestic gas production in 2017 (Working Group on Energy Balances (AGEB) 2017).

The reserves-to-production ratio of proven and probable natural gas reserves, calculated on the basis of the previous year's production and reserves, was 8.0 years as at 1 January 2018, compared to 8.1 years as at 1 January 2017. The reserves-to-production ratio does not take the natural decline in output from the deposits into account and therefore should not be seen as a forecast, but rather as a snapshot and guideline figure.[129]

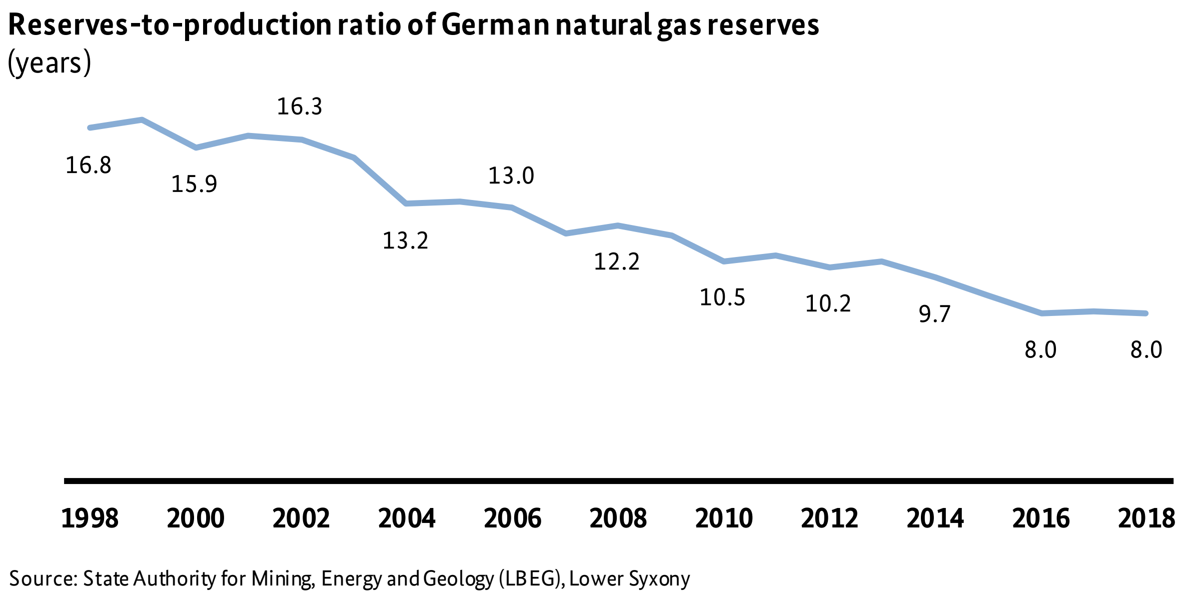

Figure 147: Reserves-to-production ratio of German natural gas reserves since 1998

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127 Gas volumes with calorific adjustment are amounts measured in a manner that is commercially relevant. Calorific adjustment is used because natural gas is not sold according to its volume but according to its energy content (9.7692 kWh/m³). In contrast, gas without calorific adjustment has a natural calorific value that may vary depending on the location of the deposit (in Germany this figure varies between 2 and 12 kWh/m³).

128 Source: Annual report "Erdöl- und Erdgasreserven in der Bundesrepublik Deutschland am 1. Januar 2017" [Crude Oil and Natural Gas Reserves in the Federal Republic of Germany as at 1 January 2018]; State Authority for Mining, Energy and Geology (LBEG), Lower Saxony.

129 Ibid.

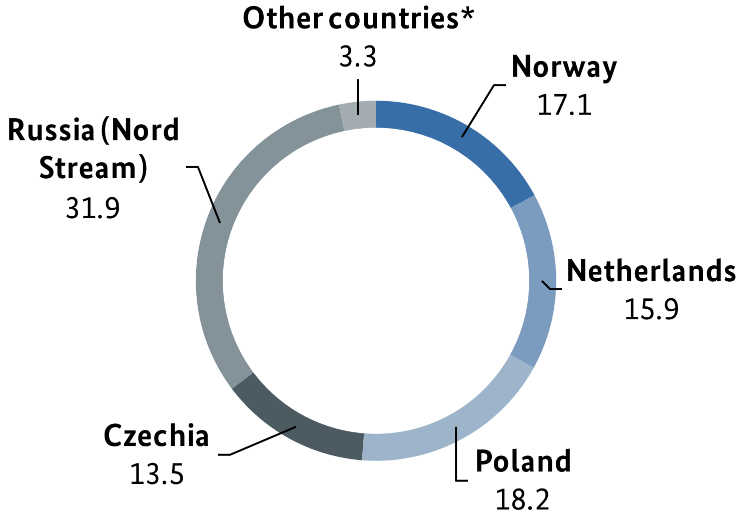
2. Natural gas imports and exports

The monitoring report bases its assessment of imports and exports on the physical gas flows that enter and exit Germany at cross-border transfer points, reported daily by the TSOs to the Bundesnetzagentur. Because of the infrastructure in place, recorded import and export volumes may also include transit flows or loop flows (eg volumes of gas that leave Germany at the Olbernhau cross-border transfer point using the GAZELLE gas pipeline and then re-enter the German network at the Waidhaus cross-border transfer point).

In 2017, the total volume of natural gas imported into Germany was 1,676 TWh. Based on the previous year's figure of 1,641 TWh[130], imports to Germany increased by 35 TWh, a rise of slightly more than 2%. When looking at the countries of origin, the focus here is on the countries that Germany imports from at their given cross-border transfer point. Imports from Norway decreased by just over 9%, while imports from Russia through the Nord Stream pipeline rose by 16.6%.

The main sources of gas imports to Germany remain Russia and Norway. However, the Netherlands, as an established and liquid European producer, trading hub and point of arrival for LNG shipments with connections to natural gas fields in Norway and the United Kingdom, is also a significant source of imports for Germany. Improved integration of national markets and more efficient management of cross-border capacities has eased trading and provided further alternatives for gas traders.

Gas volumes imported to Germany (physical load flows) in 2017, according to transfer country
(%)

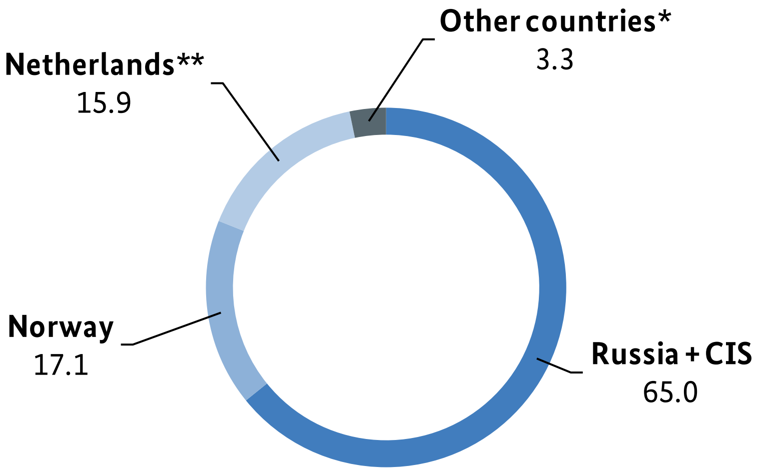


* Other countries: Belgium, Denmark, Austria

Figure 148: Gas volumes imported to Germany in 2017, according to transfer country

[130] The figure shown in the 2017 monitoring report (1,626 TWh) had to be corrected retrospectively to 1,641 TWh because of a late addition to the data.

Gas volumes imported to Germany (physical load flows) in 2017, according to source country
(%)

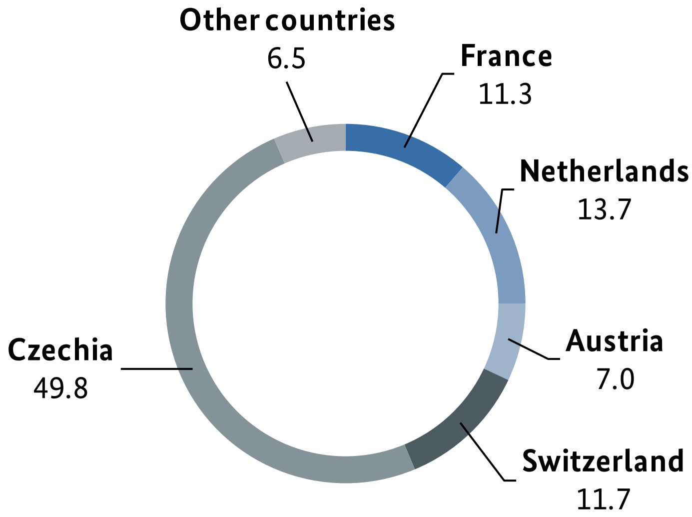


* Other countries: Belgium, Denmark
** Includes gas from UK

Figure 149: Gas volumes imported to Germany in 2017, according to source country

In 2017, the total volume of natural gas exported by Germany was 743.5 TWh. Compared with the previous year's figure of 770.4 TWh, exports from Germany decreased by 27 TWh (3.5%). When looking at the destination countries, the focus here is on the countries that Germany exports to at their given cross-border transfer point. Around 50% (previous year: 46%) of German natural gas exports went to Czechia, an increase of 5.4% compared to the previous year's figures. Exports to Belgium and Poland rose sharply (+93.1% and +23.1% respectively), while there was a large decrease in exports to Luxembourg (-36.2%), the Netherlands (-27.5%) and Austria (-20.5%).

Gas volumes exported by Germany (physical load flows) in 2017, according to importing country
(%)



* Other countries: Belgium, Denmark, Luxembourg, Poland

Figure 150: Gas volumes exported by Germany in 2017, according to importing country

The tables below are a consolidated look at the volumes of gas that were imported and exported, divided into countries exporting from and importing to Germany, giving a picture of the changes that took place between 2017 and 2016.

Change in gas imports (physical load flows)

Transfer country	Imports 2017 (TWh)	Imports 2016 (TWh)	Year on year change (TWh)	Year on year change (%)
Russia (Nord Stream)	535.0	458.9	76.0	16.6
Poland	305.8	312.7	-6.9	-2.2
Norway	286.1	314.3	-28.2	-9.0
Netherlands	266.7	281.6	-14.9	-5.3
Czechia	226.9	245.3	-18.4	-7.5
Belgium	29.6	10.1	19.5	193.5
Austria	22.3	11.9	10.4	87.8
Denmark	4.1	6.7	-2.6	-38.8
Total	1,676.5	1,641.6	35.0	2.1

Table 107: Change in gas imports between 2017 and 2016[131]

Change in gas exports (physical load flows)

Importing country	Exports in 2017 (TWh)	Exports in 2016 (TWh)	Year on year change (TWh)	Year on year change (%)
Czechia	370.6	351.5	19.0	5.4
Netherlands	101.6	140.2	-38.5	-27.5
Switzerland	86.7	95.3	-8.5	-8.9
France	83.9	87.6	-3.7	-4.2
Austria	52.1	65.6	-13.5	-20.5
Belgium	39.4	20.4	19.0	93.1
Poland	6.3	5.1	1.2	23.1
Luxembourg	1.7	2.7	-1.0	-36.2
Denmark	1.1	2.1	-1.0	-48.4
Total	743.5	770.4	-27.0	-3.5

Table 108: Change in gas exports between 2017 and 2016

[131] The figure shown in the 2017 monitoring report (1,626 TWh) had to be corrected retrospectively to 1,641 TWh because of a late addition to the data.

According to the survey of gas suppliers and wholesalers there are 25 companies importing gas into Germany.

3. Market area conversion

Over the next few years, gas supplies in north-western Germany will be converted from L-gas to H-gas. Almost 5m appliances hitherto burning L-gas, such as gas cookers, gas-fired boilers and heating systems, have to be converted.

The conversion costs are shared evenly across all gas customers in Germany in the form of a balancing charge. In 2017 the charge amounted to €0.1339 kWh/h/a. As a result of the increasing numbers of areas being converted, the charge for 2018 rose to €0.2587 kWh/h/a, and in 2019 it will increase to €0.3181 kWh/h/a. Apart from this, there is no impact on the gas bills of individual customers. Crucially, customers must not be charged for hours worked or for materials needed for the technical adjustment of appliances.

The procedure for conversion is as follows: before the conversion itself is carried out, employees of the network operator visit the customers and register all gas appliances. On the date set for the conversion (about a year after the appliances are registered), skilled technicians carry out any necessary modifications of the appliances, such as replacing burner nozzles or adjusting the settings. In a small number of cases technical adjustment of the appliance is not possible, for instance because the manufacturer has gone out of business. In such cases customers have to replace the appliance at their own expense. Information on any subsidies that may be available is provided on the Bundesnetzagentur website or by the network operator. At a later date, network operator personnel carry out random inspections to monitor the converted appliances.

These employees always call ahead suggesting a date for an appointment, never visit without prior arrangement and always carry the relevant identification.

Market area conversion, ie the conversion from low-calorific L-gas to high-calorific H-gas coordinated by the TSOs, is a central issue for gas supply. H-gas is mainly produced in Russia and Norway and has a higher calorific value than L-gas. Since the two types of gas have very different calorific values, they must be transported via separate transmission systems so that each heating appliance can be supplied with the appropriate gas. Technical adjustment of heating appliances during the market area conversion is therefore essential to guarantee safe operation in future.

L-gas regions in the northern and western parts of Germany are having to be converted because of continually falling domestic production and declining volumes of L-gas imported from the Netherlands. According to current estimates, no more Dutch gas will be exported to Germany as of 1 October 2029. The resulting scarcity of L-gas resources means that L-gas will largely disappear from the German gas market by 2030. This is why the companies responsible, namely the TSOs and affected DSOs, are taking the necessary steps to prevent the declining availability of L-gas from adversely affecting the security of supply. The new natural gas supply structure will affect more than four million household, commercial and industrial customers with an estimated 4.9m appliances burning gaseous fuels. All of these appliances must gradually be converted from L-gas to H-gas.

The conversion of German L-gas networks to supply H-gas started well in 2015 with the conversion of smaller network areas. Some larger network operators such as Westnetz, Avacon and wesernetz Bremen are now also in the process of converting their networks.

Gastransport Nord, Gasunie Deutschland Transport Services, Nowega, Open Grid Europe and Thyssengas are TSOs directly affected by the market area conversion. In 2015, these five TSOs covered a total of 969 L-gas interconnection points that had to be converted. Some 950 were left in 2016 and 922 one year later.

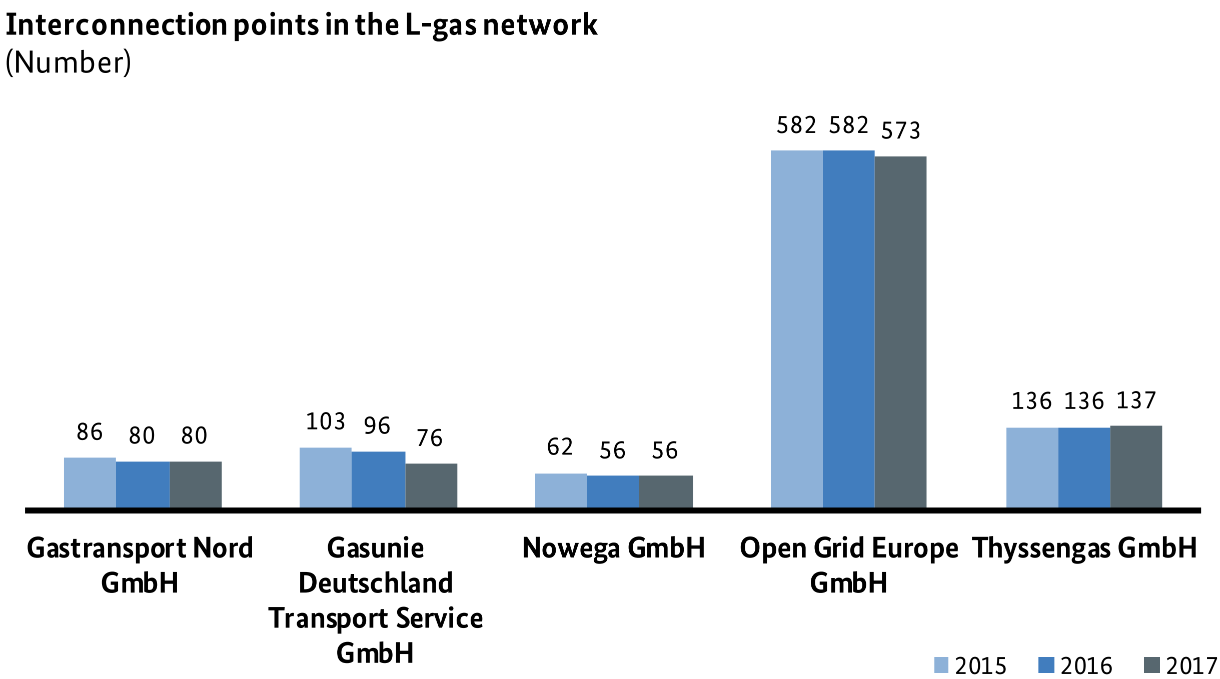


Figure 151: Interconnection points in the L-gas network, 2015 to 2017

The planned conversions by individual network operators tend to take place in months when less gas is consumed, from April to October. By 2023, some 2,982 conversions will be carried out for interval-metered customers and 1,695,250 for SLP customers.

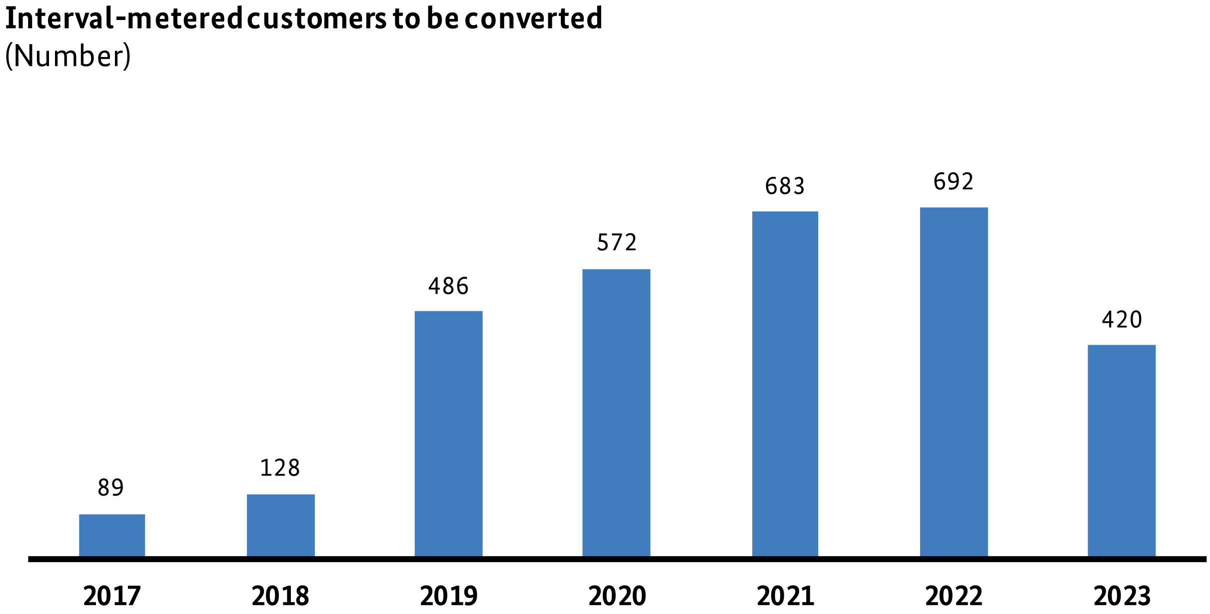


Figure 152: Interval-metered customers to be converted by 2023

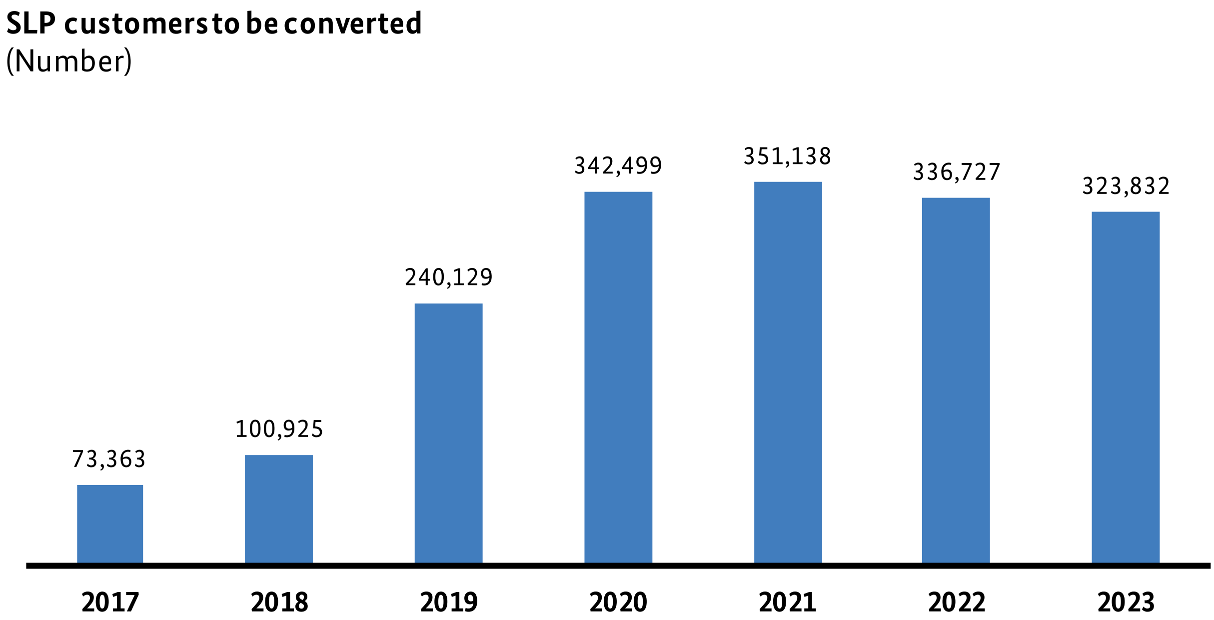


Figure 153: SLP customers to be converted by 2023

To cope with such a large number of adjustments to appliances, network operators are utilising technical skills provided by external specialist companies (with DVGW G676-B1 certification). The adjustments are carried out in three steps. First of all, a list is compiled of all appliances burning gaseous fuels that are connected to the network. On the basis of data from this list, the project management team plans the adjustments to gas appliances. In the next step, all appliances are adapted to match the new gas quality. In most cases, this requires the appliance's nozzles to be replaced. In the final step of the conversion process, 10% of the appliances are inspected one more time to monitor quality. Just a few years ago, only one or two companies provided such services. After the market area conversion became official, an increasingly competitive market began developing that currently counts 31 active companies, up from 28 a year ago. There continued to be a high response rate to the calls for bids from the network operators to carry out this work. Compared with the previous year's survey, significantly more companies are now sharing one package, especially for the services relating to registration and to conversion and adjustment. This is partly due to the fact that some companies are still too small to carry out the work in one package on their own, and also that sharing gives larger companies greater flexibility to use their workforce efficiently. As a result of the rapidly growing number of appliances that require adjustment, companies sometimes have to carry out several assignments in parallel. So far, in almost all cases, they have been able to do so without fail, but in the years ahead they will need significantly more personnel.

On average, 7.1 service providers bid for the "registration of appliances" package, of which, on average, 3.8 bids were successful. On average, 5.2 companies submitted bids for the "monitoring registration" package, of which, on average, 1.2 companies were successful. On average, 7 bidders bid for the "conversions and appliance adjustments" package, which was assigned to, on average, 3.7 companies. On average, 5.2 bids were submitted for the "inspection of conversions and appliance adjustments" package, of which, on average, 1.5 companies were successful. On average, 4.2 companies were interested in taking on the important tasks of the project management team. In this case, on average, 1.1 companies were successful in their bids.

Bids and awards for individual task packages for the market area conversion

Task package	Bids			Awards		
	2015	2016	2017	2015	2016	2017
Appliance registration	5.7	5.8	7.1	2.5	2.1	3.8
Monitoring the registration process	3.7	4.7	5.2	1.3	1.2	1.2
Conversions and appliance adjustments	5.4	5.7	7.0	2.4	2.2	3.7
Inspection of conversions and appliance adjustments	3.8	4.5	5.2	1.3	1.1	1.5
Project management	4.4	4.0	4.2	1.3	1.1	1.1

Table 109: Comparison of bids and awards for individual task packages for the market area conversion, 2015 to 2017

Some 250,110 appliances were registered last year, of which 82,338 were condensing boilers (32.9%) and 19,593 self-adaptive appliances (7.8%). During the reporting period, 91,160 appliances were adapted for SLP customers and 89 for interval-metered customers. In addition, one power station and one biogas input facility were adapted. A total of 2,723 appliances (3%) could not be converted for technical reasons. A total of 457 customers made use of the entitlement for a €100 rebate granted under section 19a(3) of the Energy Industry Act (EnWG) for the purchase of a new appliance that does not require adaptation in the course of market area conversion. Only two customers made use of the reimbursement granted under the Gas Appliance Reimbursement Ordinance (GasGKErstV).

The market area conversion poses a variety of challenges to the various groups involved, including network operators, traders, storage facility operators and heating, plumbing and installation companies, as well as those affected such as household or small business final customers and industrial gas users. It is evident that there is a significant need for information on this issue. The Bundesnetzagentur therefore held a market area conversion forum, the third of its kind, in 2018 to allow affected parties the opportunity to obtain information and participate in discussion. The main topics of this forum were the earthquake in Groningen and consumer protection. A BMWi report described the conclusions and measures set out by the Dutch government in the wake of the earthquake of 8 January 2018, which had led to disquiet among gas industry actors. However, there will be no direct impact on gas supplies in Germany, so the TSOs did not deem it necessary to make significant changes to the market area conversion plans. The Verbraucherzentrale Niedersachsen (Lower Saxony Consumer Advice Centre) reported on the most common reasons for complaints and emphasised that it was difficult to explain to customers why certain appliances cannot be converted. Other topics raised during a round table discussion were the shortage of staff among service providers and the availability of conversion kits to adjust the appliances. Information about these events can be found on the Bundesnetzagentur website.[132]

According to data submitted by the two market area managers, NetConnect Germany GmbH & Co. KG and GASPOOL Balancing Services GmbH, a total of €327,057,765.06 was spent on the market area conversion charge referred to in section 19a EnWG between 2015, when the charge was first levied, and 2019 (planning costs for 2019 are included). In 2017 the Germany-wide charge was €0.1339 kWh/h/a, increasing to €0.2587 kWh/h/a for 2018 as a result of the rising numbers of areas being converted. In 2019 the charge will increase to €0.3181 kWh/h/a. Over the course of the next few years in particular, the market area conversion charge is expected to rise further as a result of the growing number of adjustments to appliances being carried out.

[132] Forums on 27 April 2016, 26 April 2017 and 18 April 2018

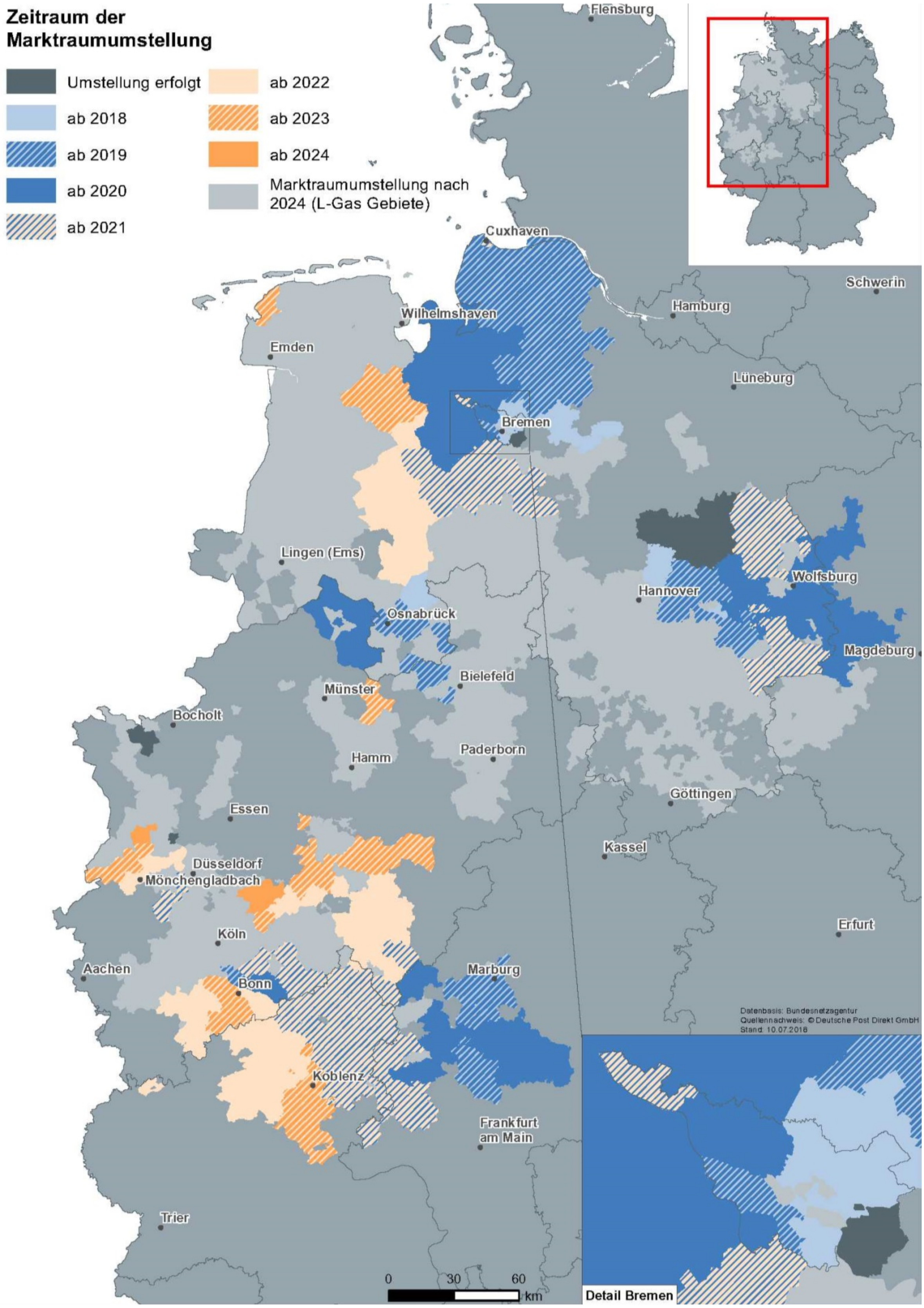


Figure 154: Market area conversion in individual network areas over the coming years

4. Biogas (including synthesis gas)

As at 31 December 2017, key biogas injection figures within the meaning of section 3 para 10c EnWG[133] were as follows:

Biogas injection key figures

	Unit	2013	2014	2015	2016	2017
Number of facilities injecting biogas		144	185	190	198	190
of which facilities injecting hydrogen						5
of which facilities injecting synthesis gas						6
Volume of biogas injected		520	688	774	856	853
of which hydrogen injected	m Ncm					<1
of which synthesis gas injected						22
Volume of biogas injected		5,471	7,489	8,364	9,222	9,220
of which hydrogen injected	m kWh					2
of which synthesis gas injected						257
Ancillary costs of the gas network operators passed down to all network users	€m	131	154	178	172	184
Ancillary costs per kWh biogas injected	ct/kWh	2.394	2.056	2.124	1.865	1.865

Table 110: Biogas injection, key figures for 2013-2017

[133] According to section 3 para 10c EnWG the term biogas applies to biomethane, gas from biomass, landfill gas, sewage treatment plant gas and mine gas as well as hydrogen produced by water electrolysis and synthetically produced methane if the electricity used to perform electrolysis and the carbon dioxide or carbon monoxide used for methanation are mainly and verifiably derived from renewable energy sources within the meaning of Directive 2009/28/EC (OJ L 140, 5 June 2009, p. 16).

5. Gas storage facilities

5.1 Access to underground storage facilities

Some 23 companies operating and marketing a total of 34 underground natural gas storage facilities took part in the 2018 monitoring survey. On 31 December 2017 the maximum usable working gas volume in these storage facilities was 280.10 TWh[134]. Of this, 132.22 TWh was accounted for by cavern storage, 125.86 TWh by pore storage facilities and 22.01 TWh by other storage facilities. Reflecting the structure of the German natural gas market, the largest part of the storage facilities, by far, is designed for the storage of H-gas (259.86 TWh, compared to 20.24 TWh for L-gas).

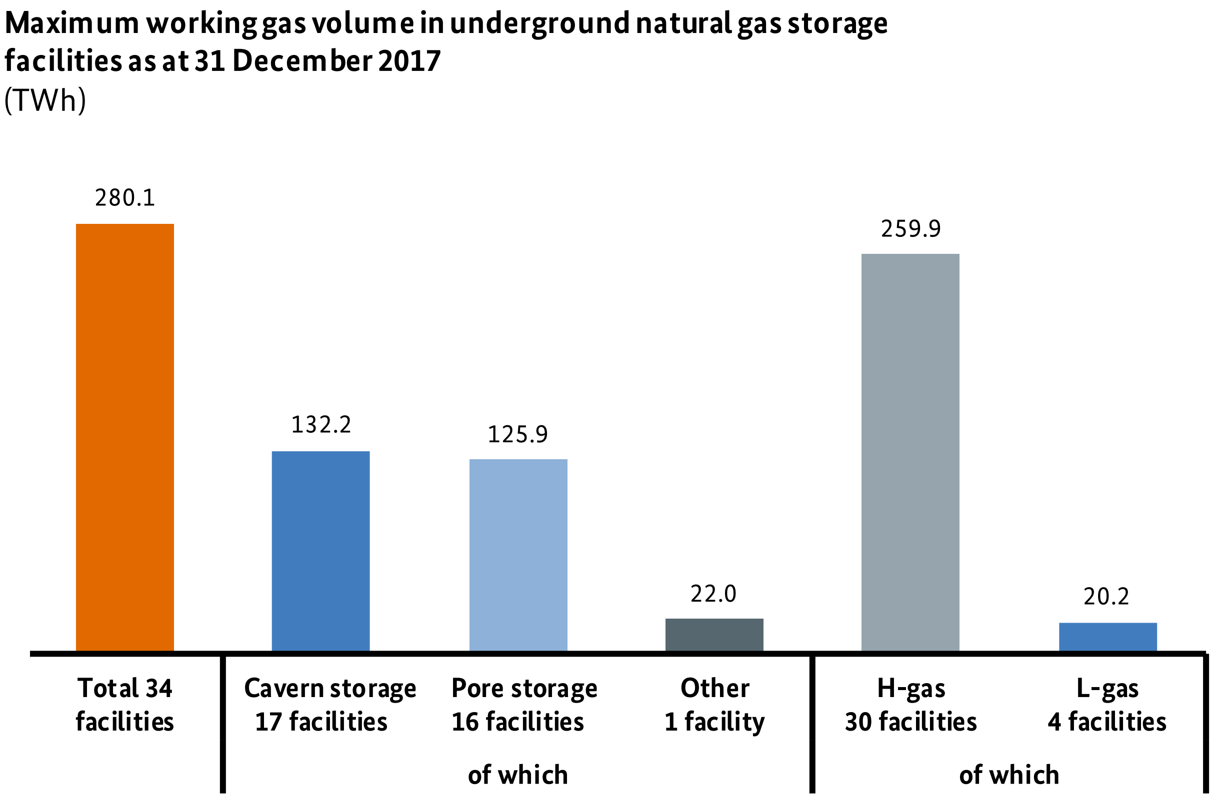


Figure 155: Maximum usable volume of working gas in underground natural gas storage facilities as at 31 December 2017

[134] This figure includes the 7 Fields storage facility and a portion of the Haidach storage facility, both of which are located in Austria. They are included because they are directly connected to the German gas network and thus have an impact on it. Equally, storage facilities that are located in Germany, but only connected to the Dutch network, are not taken into account since they have no direct impact on the German gas network.

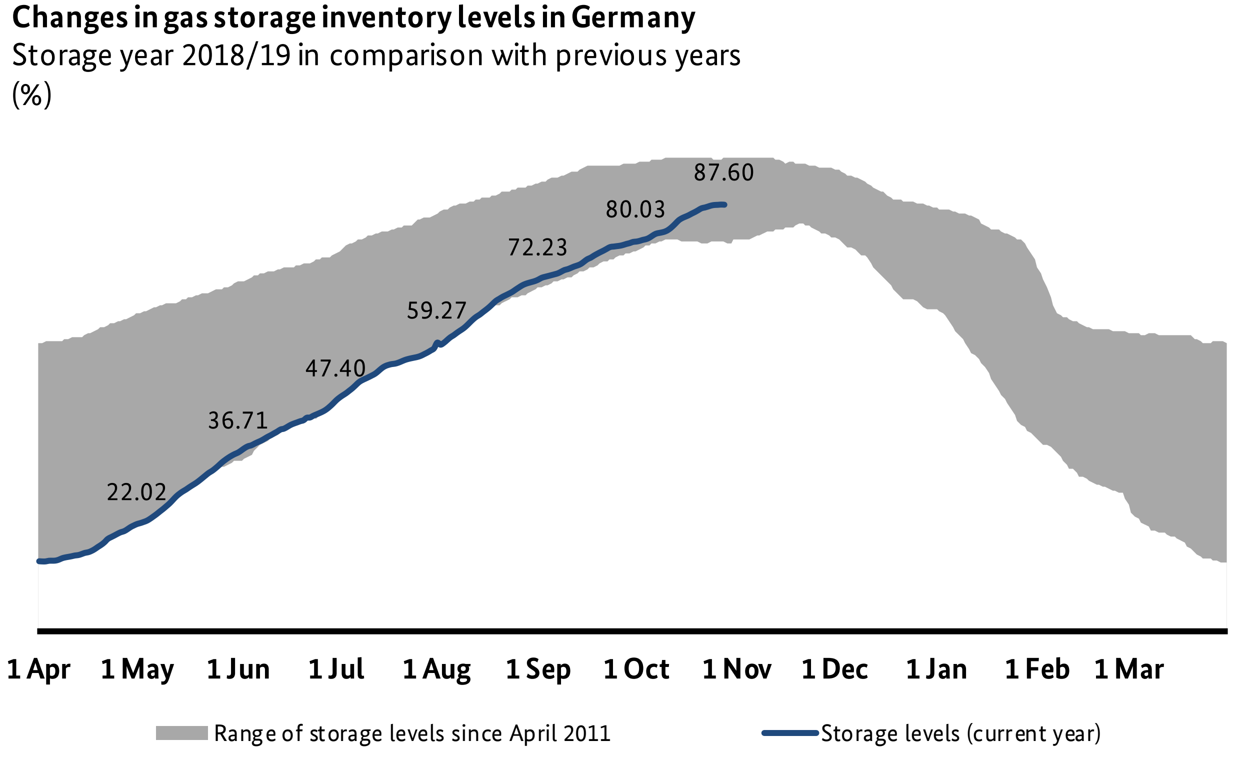


Figure 156: Changes in gas storage inventory levels in Germany – as at 1 November 2018

At the beginning of the 2018/19 storage year, an even larger volume of gas had been withdrawn from German storage facilities than in the previous years. In late February/early March, European gas markets saw high demand for gas due to low temperatures and from power stations due to slightly restricted gas supply for a variety of reasons. This resulted in short-term price spikes on the gas markets (in Germany the market price on one specific day rose to almost €70/MWh) and storage levels in gas storage facilities fell to an overall level of just over 14%. At the time of the current report (1 November 2018) the storage facilities had been refilled to an overall level of more than 87%.

5.2 Use of underground storage facilities for production operations

Production operations involve the use of storage facilities by companies that produce gas in Germany. In 2017, around 0.5% of the maximum usable volume of working gas in underground storage facilities was used for production operations. After deducting the working gas used for production operations, the total working gas volume available to the market in all underground storage facilities was 278.68 TWh in 2017 (compared to 279.88 TWh in 2016). The total injection capacity was 149.40 GWh/h and the withdrawal capacity was 285.19 GWh/h.

5.3 Use of underground storage facilities – customer trends

According to the data provided by 23 companies, the average number of storage customers in 2017 was 5.9, compared to 5.3 in 2013, 6.1 in 2014, 6.1 in 2015 and 5.8 in 2016. The table below shows the trend in the number of customers per storage facility operator.

Changes in the number of customers per storage facility operator
(Number of storage companies)

No. of customers	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1	10	12	7	8	8	7	9	8	10	11	9
2	3	3	3	2	2	3	3	4	2	2	2
3 - 9	6	6	6	7	6	7	7	5	4	6	6
10 - 15	1	2	2	2	1	2	2	3	3	1	3
16 - 20	0	0	1	1	1	1	2	1	1	2	3
> 20	0	0	0	0	1	1	1	2	2	2	0

Table 111: Changes in the number of customers per storage facility operator over the years

There was another slight year-on-year decrease in the number of storage customers. However, the number of storage operators with only one customer has slightly decreased as well.

5.4 Capacity trends

The following chart shows the working gas capacity still bookable on 31 December 2017 in underground natural gas storage facilities compared to the previous years.

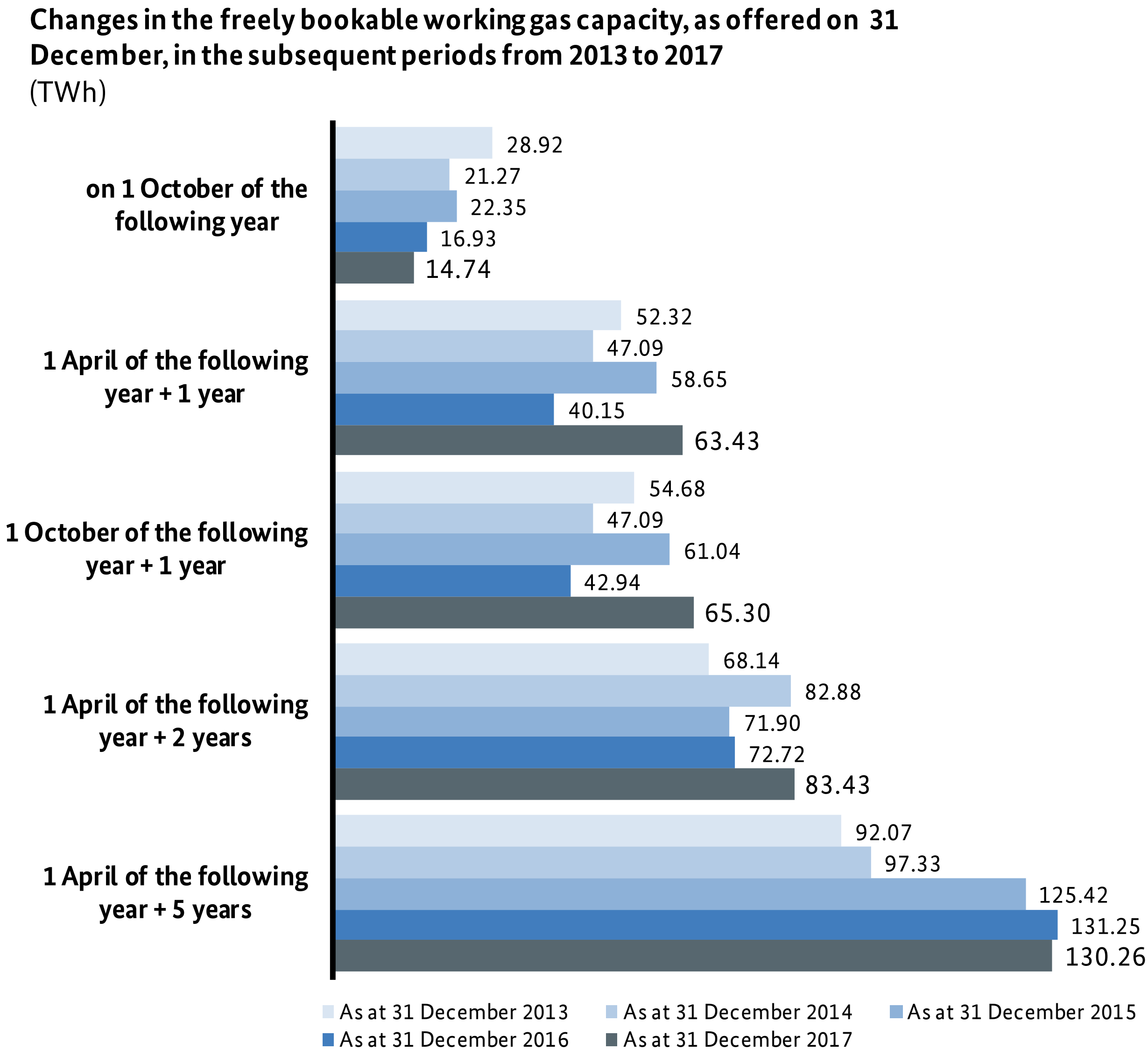


Figure 157: Changes in the freely bookable working gas capacity, as offered on 31 December, in the subsequent periods from 2013 to 2017

Short-term (up to 1 October 2017) freely bookable working gas capacity declined slightly again, whereas there was an increase in the capacity still bookable for 2019. Long-term working gas capacity bookable from 2020 likewise rose. Compared to the previous year, the volume of working gas that can be booked five years in advance decreased slightly. The overall trend shows a further move towards shorter-term booking in the storage market.

C Networks

1. Network expansion

1.1 Gas Network Development Plan

The gas network development plan (Gas NDP) includes measures for needs-oriented optimisation, reinforcement and expansion of the network, as well as for maintaining security of supply; these will be necessary in the next decade to ensure secure and reliable network operations. As required by law, the Gas NDP was published annually until 2016 and from then on it will be published every two years. The content of the Gas NDP focuses firstly on expansion issues arising due to the connection of new gas power plants – there is an interconnection here with the electricity market – and of gas storage facilities and industrial customers. Secondly it looks at connections between the German gas transmission network and those in neighbouring European countries and at capacity needs in the downstream networks. Finally, the conversion of numerous network areas from low-calorific gas (L-gas) to high-calorific gas (H-gas) is an important element of the Gas NDP.

On 1 April 2018, the TSOs submitted their draft Gas NDP 2018-2028 to the Bundesnetzagentur.[135] Essentially, the measures in the Gas NDP 2016-2026 are confirmed by the results of the Gas NDP 2018-2028. Moreover, the TSOs are proposing a further 41 expansion measures in the period until 2028. The TSOs' proposal includes the expansion of transmission pipelines (approximate length 1,390 km) and the expansion of compressor stations (approximate power 499 MW). Compared to the previous expansion proposal in the Gas NDP 2016-2026, investment costs have risen significantly from €4.5bn to €7.0bn.

The planned European Gas Pipeline Link (EUGAL) is a significant driver of this cost increase. EUGAL is due to receive gas from the planned Nord Stream 2 import pipeline and transport it within Germany and on into the Czech Republic. The planned route stretches 480 km from Lubmin on the Baltic coast to Deutschneudorf on the German-Czech border. The investment volume for the EUGAL pipeline itself is about €2.3bn. Including all further expansion measures directly associated with the pipeline, such as establishing connections to the existing network, the total investment volume reaches approximately €2.7bn. The resulting annual capital costs for the participating TSOs Gascade, Fluxys D, Gasunie Deutschland and Ontras are expected to amount to about €175m over the coming years. There are already long-term bookings by transport customers for the additional capacity to be created by EUGAL and by other network expansion measures delivering gas from the Nord Stream 2 pipeline. According to the TSOs, these bookings will contribute significantly to the refinancing of the investment costs. The total volume of bookings already in place for additional capacity associated with Nord Stream 2 over the next few years thus amounts to roughly €200m per year. This does not yet include any potential changes to network charges or bookings of any further capacities that may be available.

In addition, a number of new network expansion measures will become necessary to connect two planned power plants in Wolfsburg and Griesheim. For the first time, the Gas NDP also includes a terminal for

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[135] The draft gas network development plan 2018-2028 is available on the internet at: https://www.fnb-gas.de/de/netzentwicklungsplan/nep-2018/nep-2018.html

liquefied natural gas (LNG) at the Brunsbüttel site on the German coast which, according to the TSOs, likewise triggers a need for network expansion.

Furthermore, several measures are intended for the conversion of network areas from low-calorific gas (L-gas) to high-calorific gas (H-gas). In the wake of the powerful earthquake in the Groningen area on 8 January 2018, the TSOs are currently examining what network expansion measures could be implemented in response to a potential reduction of gas production at the Groningen gas field. In the draft NDP, for example, the TSOs propose constructing an H/L-gas mixing plant in which H-gas will be added to the L-gas delivered from the Netherlands – which has a relatively low calorific value even compared to other L-gas. The resulting mixture – still L-gas but with a higher calorific value – can then be fed into the German L-gas networks. According to the NDP this will allow the substitution of up to 8 TWh of gas from the Groningen field annually. The TSOs also indicate that if necessary they would incorporate further expansion measures in the NDP 2018-2028 in the further course of the procedure with a view to compensating for potentially lower imports from the Groningen field.

Against the background of protracted investigations and maintenance work on one section of the TENP pipeline (Trans Europa Naturgas Pipeline), the TSOs introduced an additional modelling variant in the Gas NDP 2018-2028 in which they examined the theoretical possibility that the present transport situation along TENP I will persist beyond 30 September 2020. The main concern here is the supply for Baden-Württemberg and the transit to Switzerland and Italy required to ensure security of supply for these neighbouring countries.

The TENP runs from Bocholtz on the German/Dutch border to Wallbach on the German/Swiss border and was put into operation in the 1970s. Investigations in 2017 revealed corrosion damage in one of the two lines, which led to the affected sections of the pipeline being temporarily shut down. The transport capacity of the TENP transmission system is therefore currently limited, with capacity at the Wallbach cross-border interconnection point reduced by about half. As things stand, the investigations and maintenance work on the TENP I pipeline section will continue until 30 September 2020.

On 1 August 2018 the TSOs submitted the results of their calculations to the Bundesnetzagentur for examination, as part of the draft TENP security of supply variant. The TSOs propose to build two new pipeline sections with a total length of 54 km running parallel to the existing TENP pipeline route. The proposal also includes cross-connections between the TENP I and TENP II lines, which would make it possible to continue to use the undamaged sections of the TENP I pipeline. The costs of this expansion proposal amount to €171m.

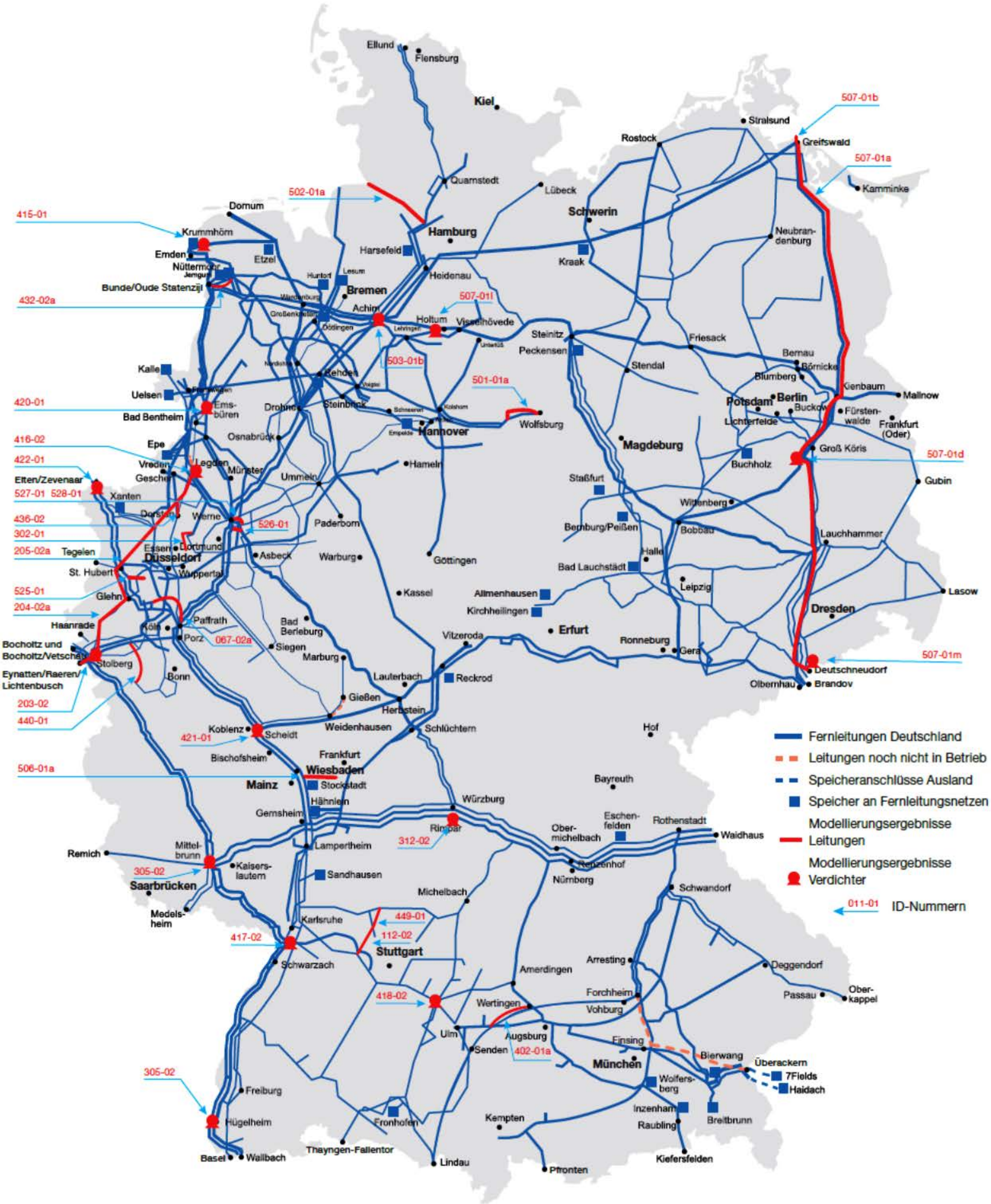


Figure 158: Expansion measures in the draft Gas NDP 2018-2028 in the period until 2028
(source: transmission system operators)

1.2 Incremental capacity – market-based process for creating additional gas transport capacity

Commission Regulation (EU) 2017/459 establishing a network code on capacity allocation mechanisms in gas transmission systems (NC CAM) entered into force on 16 March 2017.

The Regulation includes provisions for a new process to assess the market demand for additional gas transport capacity at cross-border interconnection points (so-called incremental capacity process). The TSOs use the results of the process as a sound basis for determining the demand for network expansion.

The incremental capacity process, which all TSOs within the EU must carry out every two years beginning in April 2017, can be subdivided into three phases: a demand assessment, followed by – if it is found that there is demand for additional capacity at cross-border interconnection points – a structured design phase and finally a booking and realisation phase.

a) Demand assessment

The market demand assessment process was completed by the TSOs on 27 July 2017. In the course of this process the TSOs evaluated the demand indications for all entry and exit points into and out of Germany and within Germany that had been submitted by 1 June 2017. Demand indications for incremental gas capacity were registered at four cross-border points into/out of Germany (Russia, Poland, Austria and the Netherlands) and one demand indication at the market area border within Germany, Gaspool to NCG.

b) Design phase and economic test

Immediately after the market demand assessment reports were published, the TSOs launched the respective design phases for these demand indications. During this period, until October 2017, the TSOs carried out technical studies on projects for additional capacity at cross-border interconnection points. This entailed investigating what expansion measures were needed for pipelines and compressors in order to meet the demand for additional capacity. The incremental capacity process also provides that every investment decision taken following the assessment of market demand for capacity must be subject to an economic test carried out by the TSOs and the regulatory authority. This is intended to ensure that an appropriate share of the costs associated with making incremental capacity available (in particular costs of network expansion measures) is borne by those network users who triggered the investment decision by expressing their demand.

This second phase of the process concludes with the drafting of project proposals and determination of the parameters for the economic test for the referenced projects providing incremental capacity; the TSOs concerned then submit the proposals and parameters to the responsible national regulatory authorities for coordinated approval. The project proposals are expected to be submitted by autumn 2018 at the latest, depending on the individual project. The subsequent approval process, coordinated between the neighbouring regulatory authorities, should be concluded no later than April 2019, according to the schedule.

The first such notice of approval for the creation of gas transport capacity was issued as early as 25 April 2018 with respect to the German-Austrian cross-border interconnection point Überackern/Überackern SUDAL. At the request of the Austrian regulatory authority E-Control, the approval process – which normally takes two years – was completed within one year.

c) Booking phase and market testing

Once approval has been granted, the new gas transport capacity is offered to the market participants for binding booking together with any existing capacity.

As a rule, auctions are used to allocate incremental capacity at cross-border interconnection points. If the outcome of the economic test is positive – in other words sufficient binding capacity is booked to cover the specified proportion of investment costs – the gas transport capacity must be created by the TSOs concerned. The project will then be included in the network development plan, at the size confirmed by the market.

The incremental capacity at the German-Austrian border was offered to market participants on the PRISMA booking platform on 2 July 2018. However, the market participants did not make sufficient use of the opportunity to book this capacity in order for the project to be realised. That said, the additional demand probably still exists, so the TSOs concerned will examine how certain features of the project can be improved in order to be able to offer an optimised version of the capacity at the next annual auction.

The Bundesnetzagentur has actively accompanied this process since early 2017. In order to increase transparency, the Bundesnetzagentur has developed a calculation tool to be used for the economic test pursuant to Article 22 NC CAM. Network users and TSOs can download the tool (in German and English) from the Bundesnetzagentur website.

The Bundesnetzagentur website also contains further information and links to ongoing and completed incremental capacity processes.[136]

2. Investments

Investments as defined in the monitoring survey are considered to be gross additions to fixed assets capitalised in 2017 and the value of new fixed assets newly rented in 2017. Expenditures consist of the combination of any technical, administrative or management measures taken to maintain or restore working order to an asset during its life cycle so that it can perform the function required. The results shown below are the figures supplied by the TSOs and DSOs under commercial law as listed in the respective company balance sheets. The figures supplied under commercial law do not correspond to the imputed values included in the calculation of the TSOs' revenue caps using the system prescribed in the Incentive Regulation Ordinance (ARegV). Introducing indicator-based investment monitoring according to section 33(5) ARegV will make it possible to carry out comparative calculations using the figures supplied under commercial law and those derived from the incentive-based regulation. The figures supplied under commercial law can also be used to extrapolate medium- to long-term trends. The Bundesnetzagentur is currently making preparations to introduce indicator-based investment monitoring according to section 33(5) ARegV while considering, among other issues, the cost of data transmission for companies.

2.1 Investments and expenditure by TSOs

In 2017 the 16 German TSOs invested a total of €970m (2016: €469.9m) in network infrastructure. Of this total, €847.9m (2016: €422.4M) was investment in new installations/expansion/extension and €122.1m (2015: €47.5) investment in maintenance/renewal of network infrastructure. Of the total investments in 2017, 31% could be attributed to the transmission systems in the GASPOOL market area and 69% to the NCG market area (2016: 22% GASPOOL, 78% NCG). The investments planned for 2018 amount to a total of €1.49bn, which would

[136] https://www.bundesnetzagentur.de/EN/Areas/Energy/Companies/GridDevelopment/Gas/IncrementalCapacities/IncrementalCap_node.html

equate to an increase of 53% compared to 2017. This relatively large fluctuation is a result of investments in a few individual large-scale projects.

Across all TSOs, expenditure on maintenance and repair of network infrastructure amounted to €306.4m in 2017 (2015: €283.3m), of which 55% was applicable to the NCG market area and 45% to the GASPOOL market area (2016: 52% NCG, 48% GASPOOL). The overall total for investments and expenditure across all TSOs is thus approximately €1.276bn. The chart below shows investments and expenditure both separately and as a sum total since 2013, as well as the planned figures for 2018.

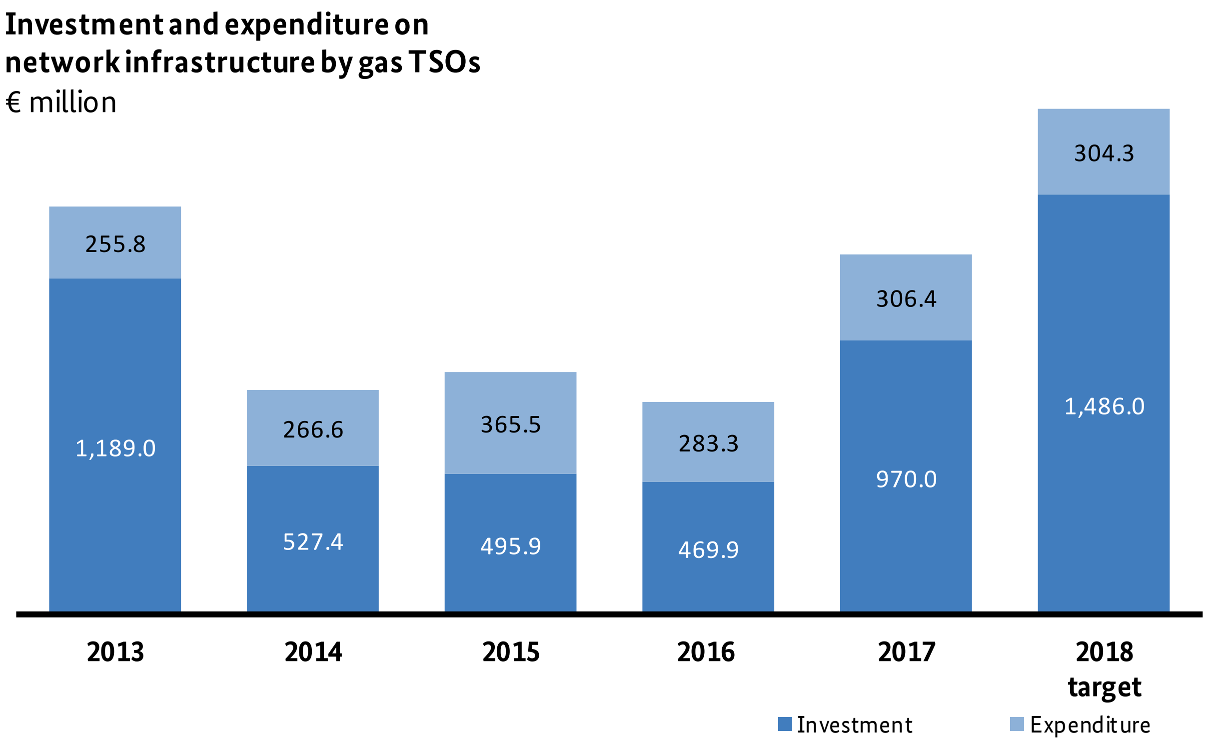


Figure 159: Investments in and expenditure on network infrastructure by TSOs

2.2 Investments in and expenditure on network infrastructure by gas DSOs

In the course of data collection for the 2018 Monitoring Report, 633 gas DSOs declared investment in new installations, expansions and extensions (€623m) and maintenance and repair (€408m) of network infrastructure totalling €1,020m for 2017. The projected total investment for 2018 is €1,244m.

According to the gas DSOs' reports, expenditure on maintenance and repair in 2017 was €1,084m. The projected expenditure on maintenance and repair for 2018 is €1,074m.

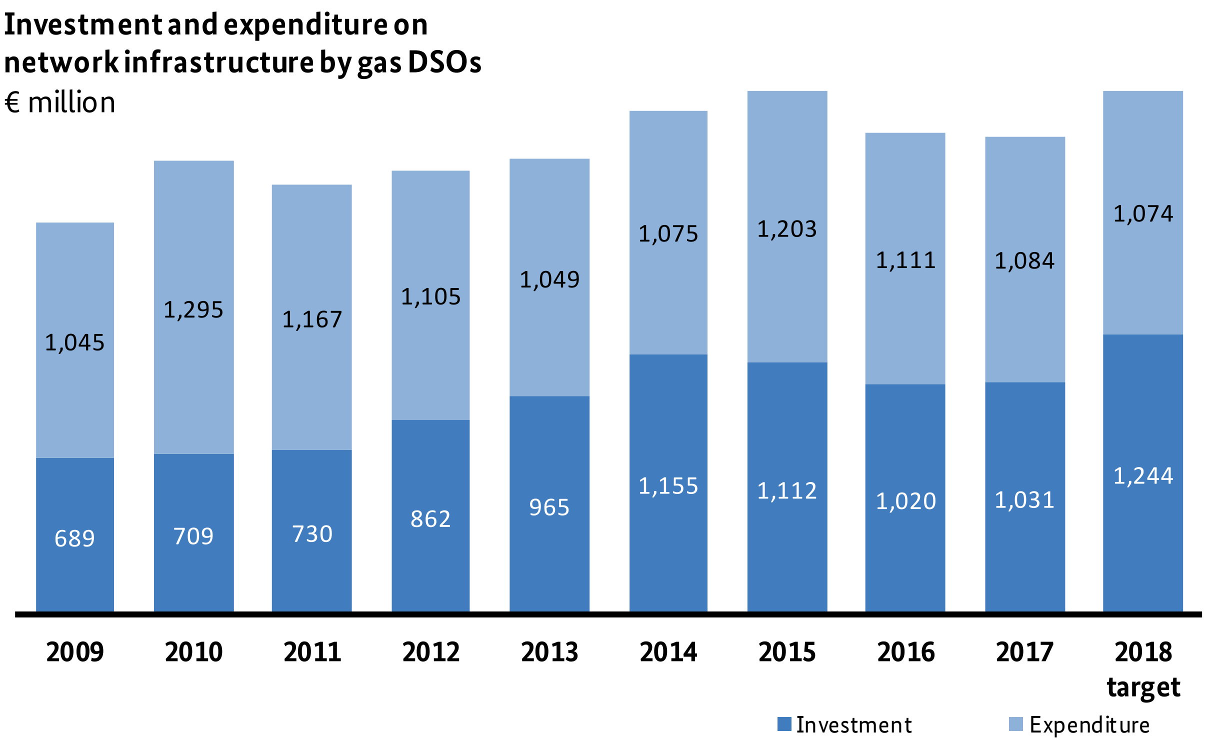


Figure 160: Investments in and expenditure on network infrastructure by gas DSOs

The level of DSO investment depends on the length of their gas pipeline network and the number of meter points served as well as other individual structure parameters, including, in particular, geographical circumstances. While 148 of the surveyed gas DSOs reported investments of between €100,001 and €250,000, only 43 gas DSOs made investments totalling more than €5m.[137]

[137] These figures are based on data submitted by 633 DSOs.

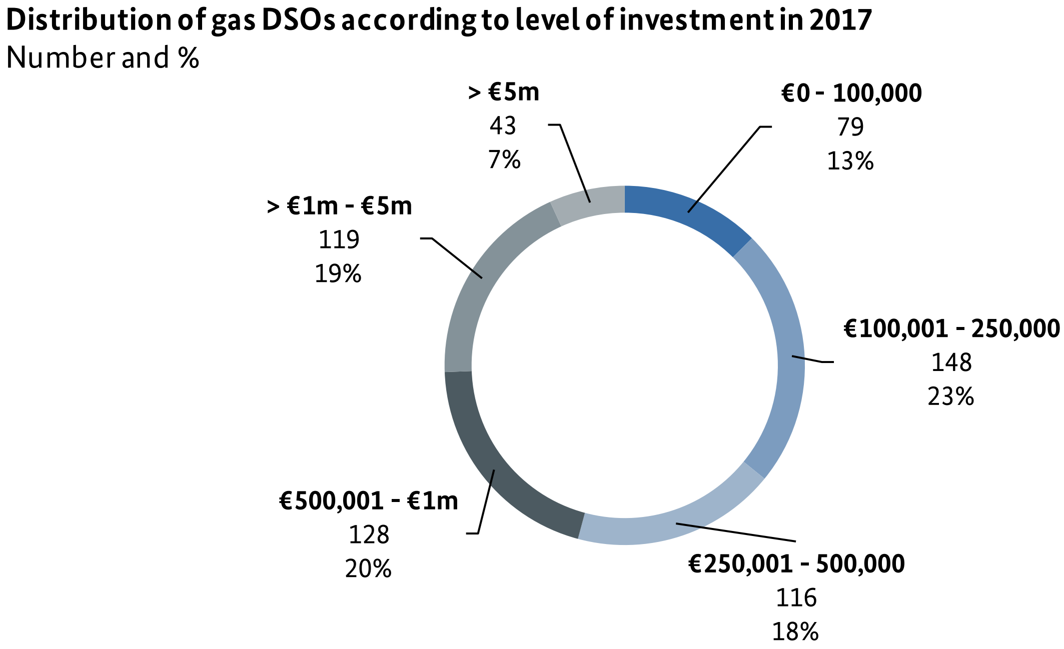


Figure 161: Distribution of gas DSOs according to level of investment in 2017

Of the surveyed gas DSOs, 157 reported total expenditures in the bracket between €100,001 and €250,000, while only 52 gas DSOs reported expenditures totalling more than €5m.[138]

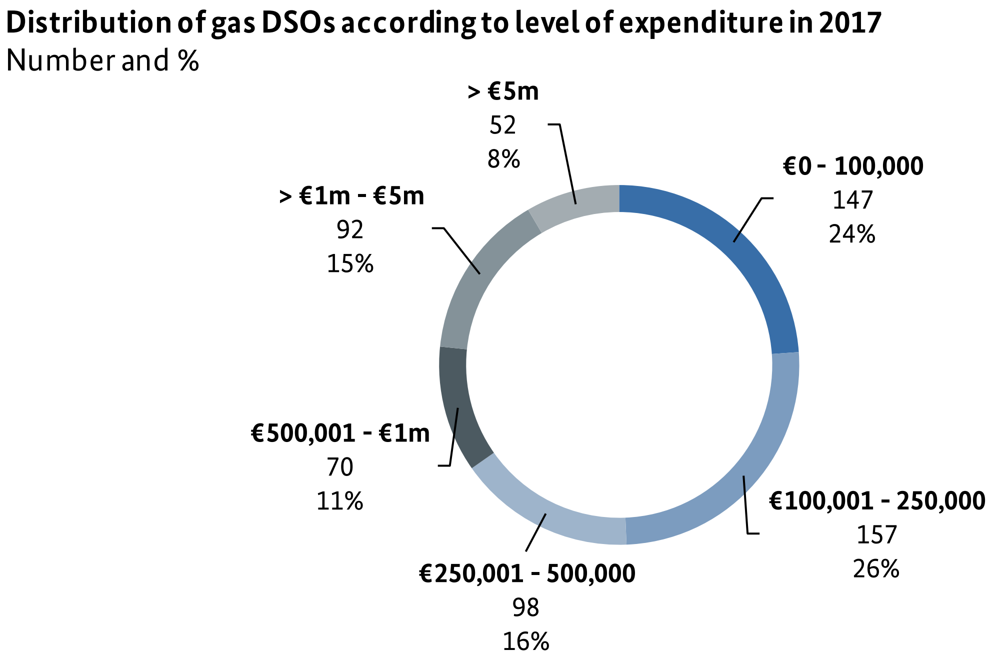


Figure 162: Distribution of gas DSOs according to level of expenditure in 2017

[138] These figures are based on data submitted by 616 DSOs.

2.3 Investments and incentive-based regulation

The Ordinance concerning Incentive Regulation for the Energy Supply Networks (ARegV) offers network operators an opportunity to budget for costs for expansion and restructuring investment beyond the authorised revenue cap of network charges. Based on section 23 ARegV, upon application the Bundesnetzagentur grants approval for individual projects if the prerequisites stated in the Ordinance have been met.

Since the amendment to section 23 ARegV in spring 2012, approval of a project is granted on the merits of the investment. Once the approval has been given, the network operator may adjust his revenue cap by the costs of capital and of operation connected to the project immediately in the year the costs are incurred. The costs budgeted are checked by the Bundesnetzagentur in an ex-post control.

As of 31 March 2018, gas TSOs had submitted 17 new applications for investment projects totalling about €180m to the competent Ruling Chamber. While the number of applications compared to 2017 remained the same, the investment volume covered by the applications fell by roughly half.

2.4 Capex mark-up pursuant to section 10a Incentive Regulation Ordinance

As a result of the amendment to the Incentive Regulation Ordinance (ARegV 2016), the expansion factor was no longer used as of the third regulatory period. It was replaced by the capital expenditure (capex) true-up, which the gas network operators were able to apply for on 30 June 2017 for the first time. It grants the network operators a mark-up on the revenue cap for capital costs. Capital costs arise as a result of investments made after the base year. These investments must already have been undertaken or must be expected in the year in which approval is granted. In 2017, 153 applications were made for a capex mark-up. Of these, 60 applications were submitted by network operators under the responsibility of the Bundesnetzagentur and 93 by network operators under delegated responsibility. Decisions have already been taken on all applications, with a total of just under €172m being approved on the basis of the projected costs. The number of applications for the capex mark-up in 2018 remained the same, at 153.

3. Capacity offer and marketing

3.1 Available entry and exit capacities

As in previous years, for 2017, too, questions were asked concerning the marketing of transport capacity and were answered by the TSOs. The offered transport capacities relate to the right to inject or withdraw gas into/from the network. The volume of gas that shippers actually inject into or withdraw from the transmission network when making use of this right may differ from the volume offered. This section distinguishes between the various capacity products offered on the market, whereas the next section differentiates according to the duration of the corresponding entry and exit capacity products. The questions principally concerned the median offer of firm capacity at cross-border and market area interconnection points and also at points of interconnection with storage facilities, power stations and final consumers.

This survey does not include the reserve capacity agreed with the downstream network operators within the internal booking process since the network interconnection points with distribution networks are not marketed directly to shippers (see section II.C.3.5 for more information on internal booking).

The total entry capacity offered across both market areas was 486 GWh/h, a slight increase of 6 GWh/h compared to the previous year. The offer of firm and freely allocable capacity (FZK) amounted to 147.8 GWh/h, corresponding to about 56.6% of the total entry capacity offered in the GASPOOL market area. In contrast, the volume of FZK products offered in the NetConnect Germany market area amounted to 93.3 GWh/h, meaning that the entry offer for this product fell by slightly more than 4% compared to 2016. The total volume of capacity products offered in the NetConnect Germany market area equates to around 46.3% of the total entry capacity offered across the whole of Germany. The remaining and larger share of 53.7% is attributed to the GASPOOL market area.

Entry capacity offered in the 2016/2017 gas year
GWh/h

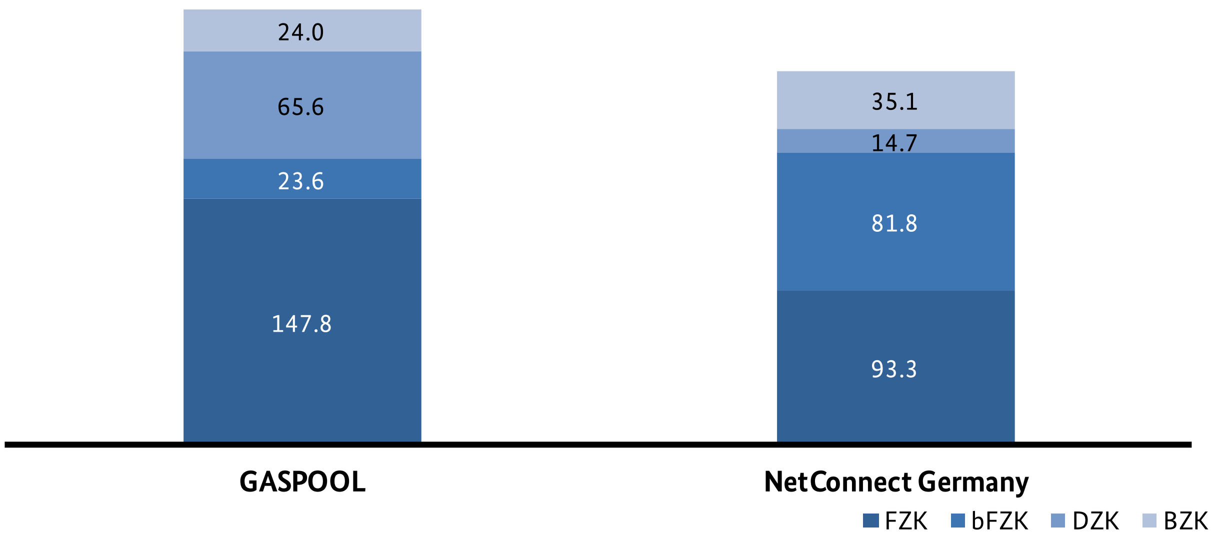


Figure 163: Entry capacity offered

With regard to exit capacity, the total volume of capacity products offered increased by 23.3 GWh/h compared to the previous year to 354 GWh/h. It should be noted that not every TSO offers all capacity products. The aggregated developments therefore cannot be projected onto each individual TSO.

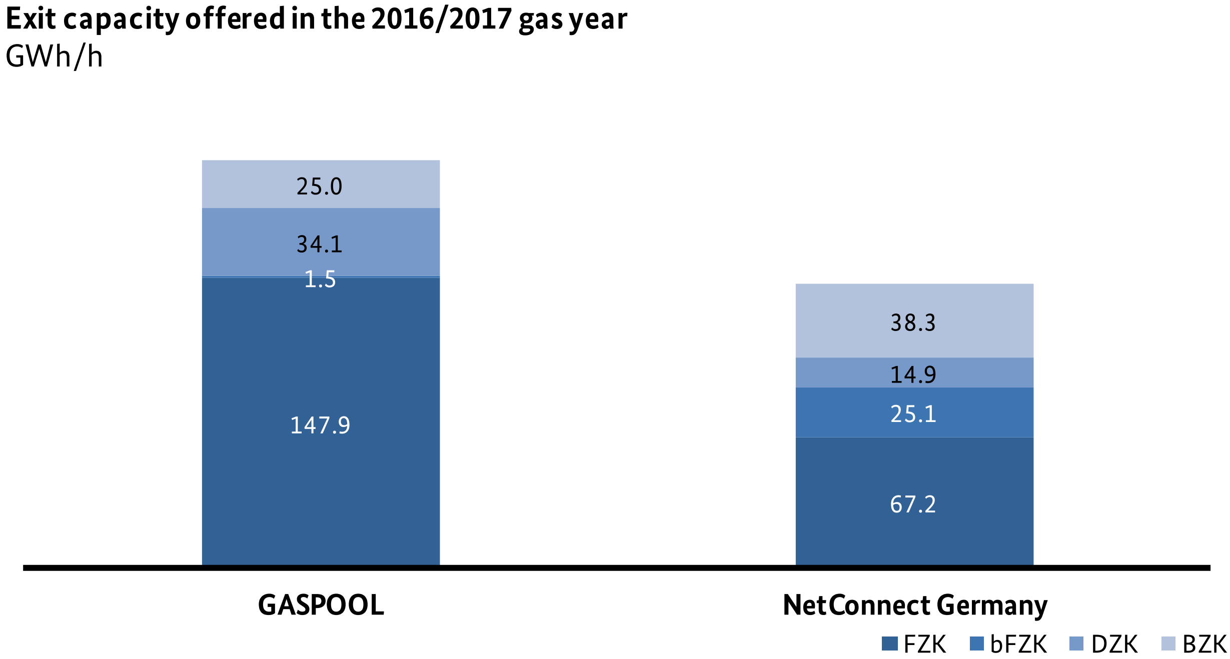


Figure 164: Exit capacity offered

As described above, the capacities for distribution networks and therefore the majority of final consumers are not included in this list because they are not marketed directly to the shippers by the transmission system operators. These marketing levels should therefore not lead to the drawing of incorrect conclusions. Overall, the German gas networks have more exit capacity than entry capacity across all network levels. This is apparent from the scale of internal bookings by the DSOs (see section II.C.3.5). In 2017, the total capacity booked with TSOs by downstream DSOs was 260.7 GWh/h. This is roughly 74% of the bookable capacity offered in the 2016/17 gas year considered in this report. As the periods under review are different, however, it is not appropriate to simply add the two figures together.

According to section 12 para 3 of the cooperation agreement (KoV) X annex 1, renominations carried out by the balancing group manager are subject to a restriction. The renomination is permitted if it does not exceed 90% of the total (firm) capacity booked by shippers at the booking point and does not fall below 10% of the booked (firm) capacity. In the case of initial nominations of a maximum of 20% of booked (firm) capacity, half of the nominated capacity is allowed for downward renomination. Renomination beyond these restrictions remains possible but is equated to the nomination of interruptible capacities. The restrictions allow TSOs to offer more capacity than is the case in a base case without a renomination restriction. Once again, this instrument made it possible to offer additional capacity. In the year 2017, the offer of entry capacity through TSOs' renomination restrictions amounted to 1.8m kWh/h in the NCG market area, which corresponds to a decrease of 25% compared with the year 2016. The offer of corresponding exit capacity also decreased, by 21.2% to 2.6m kWh/h. Compared with the previous year, the change in the offer of entry and exit capacity in the GASPOOL market area resulting from the renomination restriction is especially notable. The entry and exit capacity offered rose by more than 300% to 8.9m kWh/h and 11.1m kWh/h respectively compared to the 2016 calendar year.

3.2 Product durations

The time period for which a capacity is assured depends on how the corresponding capacity product is marketed. As a general principle the entire capacity offer is initially made for a whole gas year. If there is no demand or insufficient demand, the TSOs market the relevant capacity on a quarterly basis within a gas year. If the capacity still cannot be marketed for this time frame, whether in full or in part, owing to a lack of demand, the TSOs auction the remaining capacity on a monthly basis, then on a daily basis and finally on a within-day basis.

Booking of entry capacity according to product duration and market area in the 2016/2017 gas year GWh/h

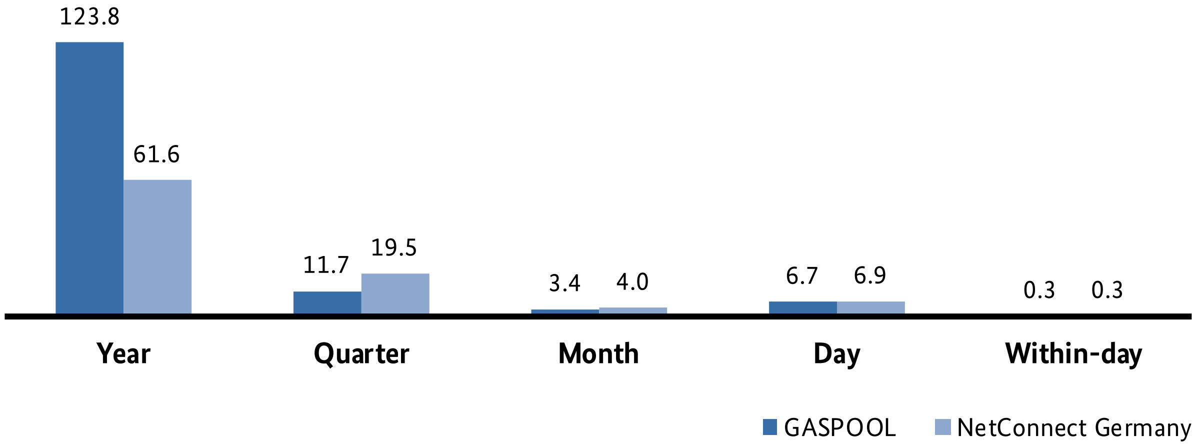


Figure 165: Booking of entry capacity by capacity product

The chart showing the entry and exit capacity bookings clearly illustrates that, during the period under review, most bookings were for longer-term capacity products. The capacity volume booked on a long-term basis in the GASPOOL market area, with a total of 205.5 GWh/h of yearly capacity marketed and 21.4 GWh/h of quarterly capacity marketed, was significantly larger than the long-term capacity booked in the NetConnect Germany market area, where the corresponding volumes were 109.4 GWh/h and 38.5 GWh/h respectively. Despite the increasingly short-term nature of capacity booking, monthly, daily or within-day capacity products account for only small proportions of the total capacity booked in both these market areas to date.

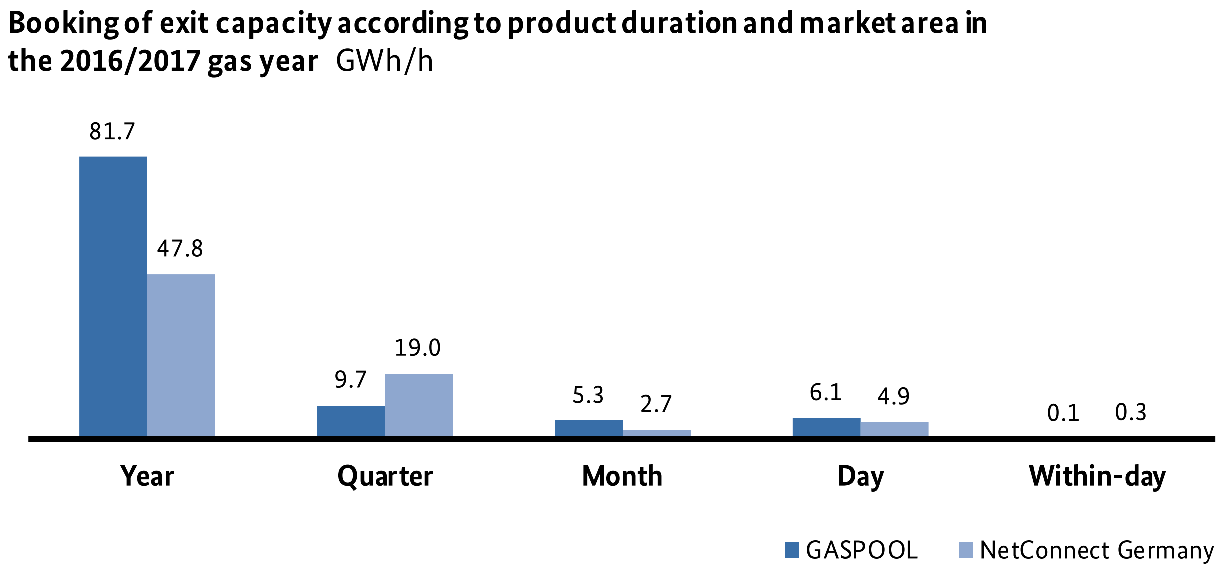


Figure 166: Booking of exit capacity by capacity product

A comparison of the two charts on entry and exit capacity reveals a number of differences. For instance, it is apparent that, overall, in the 2017 gas year considerably more entry capacity was booked than exit capacity: the total volume of entry capacity booked was 238.2 GWh/h, significantly exceeding exit capacity, which amounted to a total of 177.6 GWh/h. There is a difference between the total capacity booked in the GASPOOL market area and the booking volume in the NetConnect Germany market area in terms of the booking of both entry capacity and exit capacity. The TSOs in the GASPOOL market area mainly marketed entry capacity in the form of yearly products (123.8 GWh/h) and quarterly products (11.7 GWh/h). Likewise, entry capacity in the NetConnect Germany market area was mainly booked in the form of yearly and quarterly products (61.6 GWh/h and 19.5 GWh/h respectively). The marketing of capacity with monthly, daily or within-day durations is less significant in both market areas, as is the case with exit capacities.

3.3 Termination of capacity contracts

The termination of capacity contracts is regulated by the rules and conditions governing TSOs' entry and exit contracts. The TSOs may terminate a contract without notice if the shipper repeatedly and severely breaches important contractual provisions in spite of written warnings. Likewise, shippers have the right to terminate contracts under various preconditions. In such cases the shippers must comply with the notice periods and terms of termination laid down in the contract, which vary according to the grounds for termination.

In 2017, a total of 126 long-term capacity contracts were terminated. In absolute terms the number of contract terminations thus fell by 51 compared to the previous year. The reasons for the termination of capacity contracts are varied and may include the dissipation of further contractual congestion situations as well as the secured procurement of short-term capacity. As a general rule, in this context it is possible to differentiate between the termination of capacity contracts according to types of product and according to network interconnection points.

Termination of capacity contracts by type of network interconnection point in the 2016/2017 gas year
Number

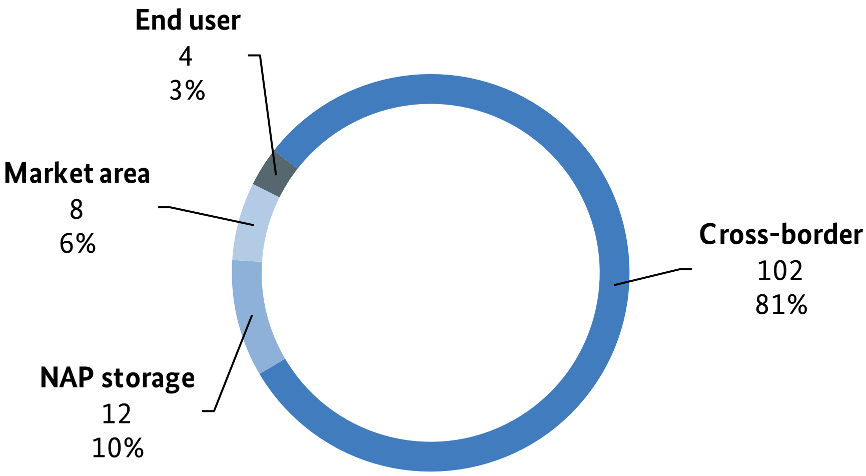


Figure 167: Termination of capacity contracts according to network interconnection points

Of the total of 126 terminated capacity contracts, the majority (102) were contracts terminated at cross-border interconnection points. A further 12 capacity contracts were terminated at storage facility connection points. The remaining 12 cases of contract termination were recorded at market area interconnection points (8) and at connection points to end users (4). In general terms, a considerable change in the distribution of contract terminations is observable compared to the previous year, with terminations of capacity contracts at cross-border interconnection points in particular rising by 240%. Furthermore, while in 2016 terminations of capacity contracts at storage facility connection points amounted to 77% of the total number of cases, the same category accounted for only 10% of the total reported during the period covered by this survey. The termination of capacity contracts at market area interconnection points and at connection points to end users accounts for a comparatively small proportion of the total, at 6% and 3% respectively.

Termination of capacity contracts by product type in the 2016/2017 gas year
Number

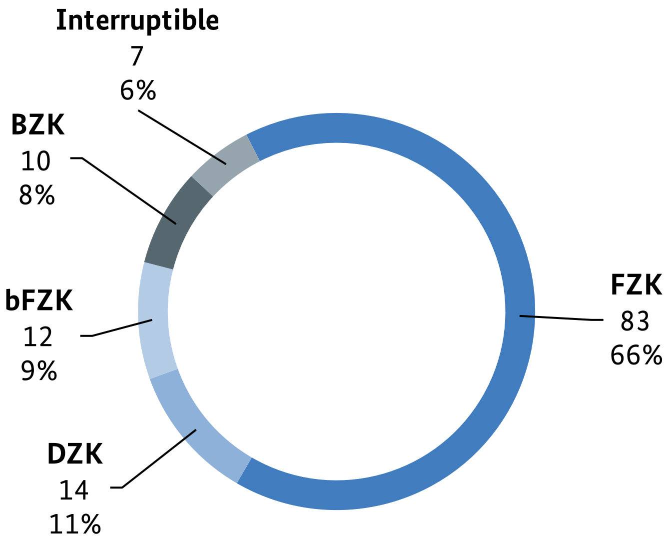


Figure 168: Termination of capacity contracts according to product type

If terminated capacity contracts are differentiated according to product type, it is noticeable that in 2017 FZK products accounted for the majority (83). A further 14 contracts were terminated for firm, dynamically allocable capacity (DZK) and 12 for capacity with conditional firmness and allocability (bFZK). Firm capacity with limited allocability (BZK) (10) and interruptible products (7) accounted for the smallest proportion of the overall number of terminations of capacity contracts. Comparison with the previous year shows that in 2017 contracts for bFZK and BZK products were also terminated in addition to FZK, DZK and interruptible products.

3.4 Interruptible capacity

Interruptible gas capacity tends to be less expensive than firm capacity. The lower price brings with it the risk that the gas may not be transported at all or only in part. Key elements for calculating the tariffs for interruptible capacity are defined in the Determination for Pricing Entry and Exit Capacity ("BEATE").

Eleven suppliers and/or wholesalers, two fewer than in the 2015/2016 gas year, reported that the interruptible capacity that they had booked was in fact interrupted during the 2016/2017 gas year. As in the previous year, there was a very uneven distribution of both the duration and the number of interruptions among the traders. In the 2016/2017 gas year the maximum duration of interruption was 2,571 hours and the maximum number of interruptions 124, while the minimum duration was one hour and the minimum number just one. The data submitted by the traders were anonymised in order to protect confidential business information.

In the 2016/2017 gas year the aggregated total duration of interruption was 5,440 hours and the aggregated number of interruptions was 327. This corresponds to an increase in the overall duration of interruption by more than 17% compared to the previous year. The number of interruptions also rose, by more than 33% compared to the 2015/2016 gas year. The total duration of interruption in the 2016/2017 gas year is the second highest within the past six gas years (2015/2016 gas year: 4,625 h; 2014/2015 gas year: 1,515 h; 2013/2014 gas year: 946 h; 2012/2013 gas year: 1,975 h; 2011/2012 gas year: 6,753 h).

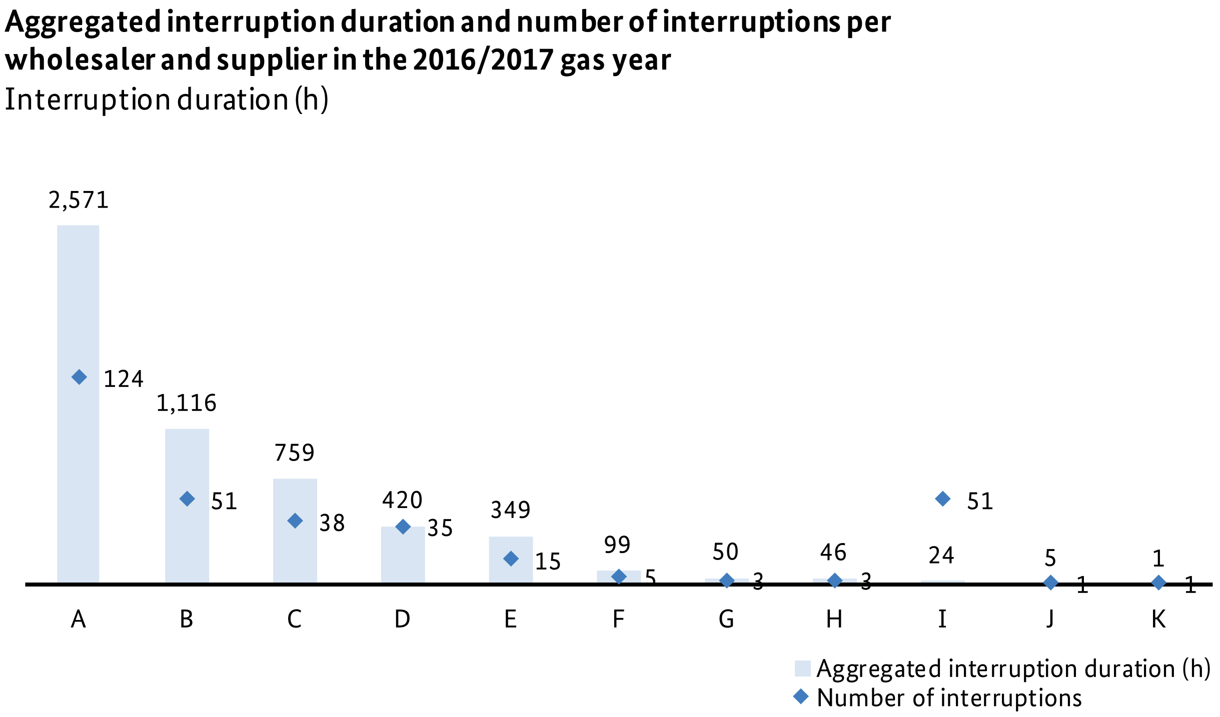


Figure 169: Aggregated interruption duration in hours and number of interruptions in transmission systems per wholesaler and supplier

Both shippers and transmission system operators were surveyed on the duration of interruption and interrupted volume of both interruptible and firm capacity products in relation to the initial nomination or alternatively the last figure renominated by the shipper before the interruption was made known.

In 2017, the volume of initially (re-)nominated gas that was not transported through all entry and exit points into or out of the market area was 3.95bn kWh (2016: 2.8bn kWh). Of this, interruptible capacity made up the largest proportion at 99.99% whereas firm capacity that was interrupted accounted for only a negligible amount of the total. There was no significant change to the distribution of interruptions across the various network interconnection points compared to the previous year. The majority of interrupted volume (55.2% compared to 54.3% in 2016) was attributed to interruptions at storage facility connection points. Interruptions at cross-border interconnection points accounted for 44.6% (2016: 44.2%) of the total interrupted volume. As in the previous years, the smallest share of the interruptions (0.2%) was attributed to inter-market-area transports.

With regard to firm capacity contracts (which include FZK, bFZK, DZK and BZK), the interrupted volume was made up entirely of interruptions at cross-border interconnection points.

Interruptions in 2017 calendar year
Interruption volume (GWh)

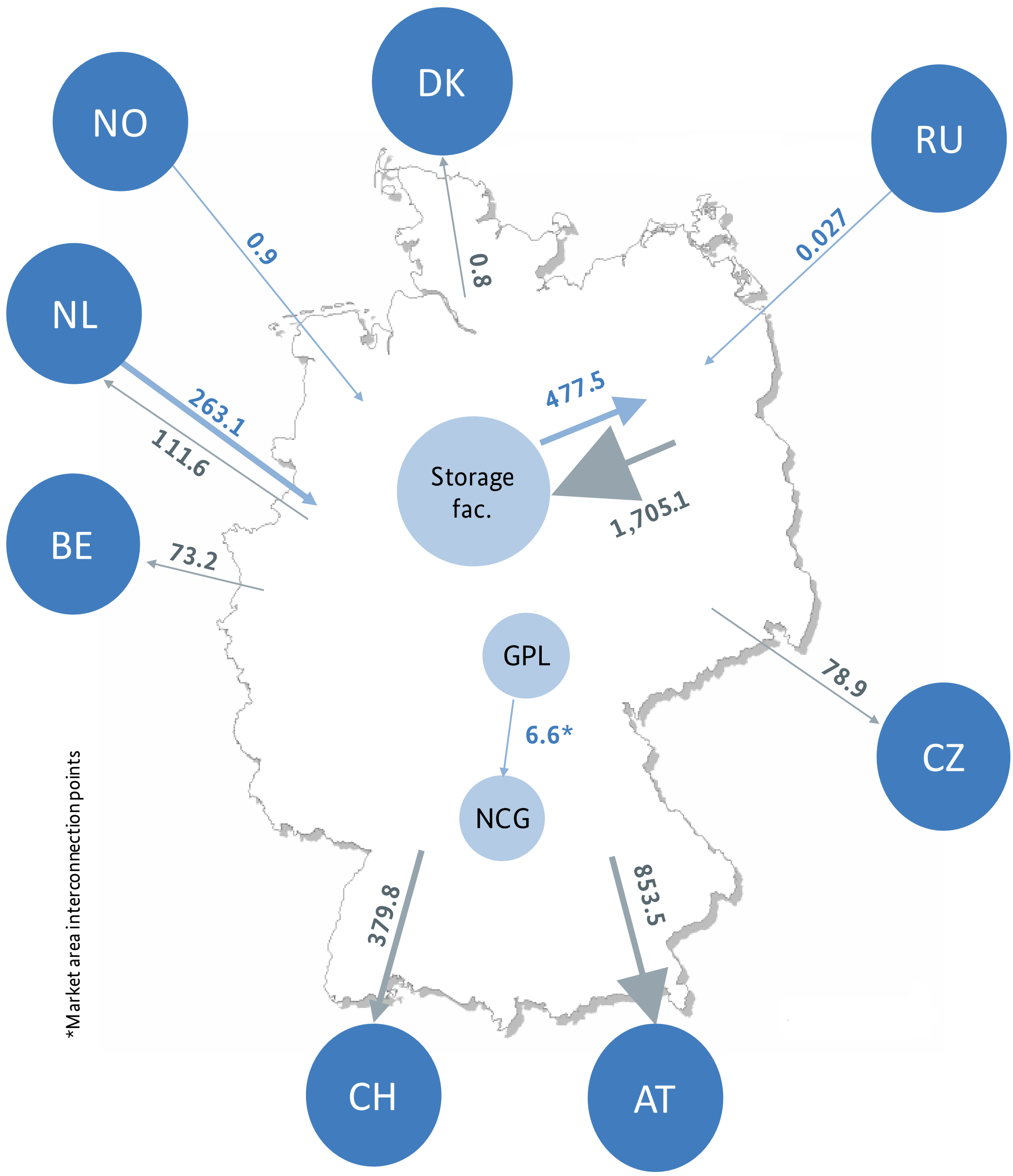


Figure 170: Interruption volumes according to region

The above diagram depicts the geographical distribution of interrupted volumes at entry and exit points where there is a nomination obligation. It shows, for instance, that during the 2017 calendar year the volume of gas exported from Germany to the Netherlands that was subject to interruptions was 111.6 GWh and the volume of gas imported from the Netherlands into Germany that was subject to interruptions was 263.1 GWh.

3.5 Internal booking

A fundamental element of the TSOs' capacity model is the firm exit capacity (internal booking) agreed with the downstream network operators. Internal booking is a reserve capacity provided by the TSOs to the DSOs. It guarantees supply to customers in distribution networks without a shipper having to book capacity in those networks. Instead the shipper enters into a supplier framework contract with the relevant DSO, which enables the shipper to use the network to transport gas to exit points. The TSOs and DSOs within a market area cooperate in order to ensure the provision of capacity and thus access to the distribution networks.

The figure below shows internal bookings for the calendar year 2017 for the two market areas NetConnect Germany and GASPOOL respectively.

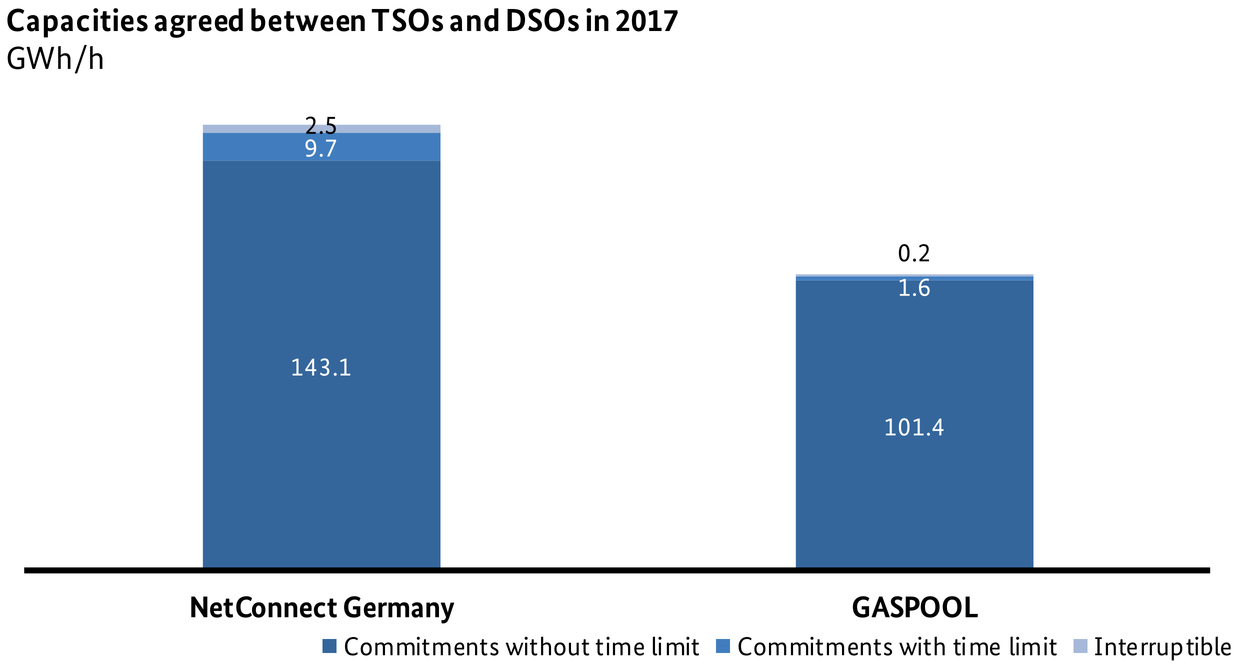


Figure 171: Capacities agreed between TSOs and DSOs

Compared to the previous year, the volume of internal bookings in the two market areas rose from a total of 255.2 GWh/h to 260.7 GWh/h in the 2017 calendar year. Of this total, internal bookings with a volume of 258.4 GWh/h were agreed between the TSOs and the downstream network operators. The majority of these internal bookings (155.3 GWh/h) agreed between the operators were agreed in the NetConnect Germany market area, and the remainder (103.1 GWh/h) in the GASPOOL market area. The GASPOOL market area accounts for roughly 40% of all internal bookings agreed in the two market areas, with the remaining 60% shared accordingly among the TSOs in the NetConnect Germany market area. There was thus no significant change in distribution compared to 2016.

4. Gas supply disruptions

As in the previous years, the Bundesnetzagentur again conducted a comprehensive survey of all gas supply interruptions throughout the Federal Republic of Germany. Section 52 of the Energy Industry Act (EnWG) requires gas network operators to report all interruptions in supply during the previous year to the Bundesnetzagentur by 30 April of each year. The Bundesnetzagentur uses the information to calculate the system average interruption duration index (SAIDI). This indicates the average interruption duration per final customer over the course of one year. The SAIDI does not take into account scheduled interruptions, nor those caused by force majeure, for example by natural disasters. Only unplanned interruptions caused by third-party intervention, ripple effects from other networks or other disturbances in the network operator's area are included in the calculations.

The 2017 results of the comprehensive survey of supply disruptions in all existing gas networks in the Federal Republic of Germany that are registered in the Bundesnetzagentur's energy database (724) were as follows:

SAIDI results for 2017

Pressure range	Specific SAIDI	Comments
≤ 100mbar	0.97 min/Jahr	Household and small-volume consumers
> 100mbar	0.02 min/Jahr	High-volume consumers, gas-fired power plants
> 100mbar	0.60 min/Jahr	Downstream network operators
All pressure ranges	0.99 min/Jahr	SAIDI figure for all final customers

Table 112: SAIDI results for 2017

The Bundesnetzagentur has calculated the SAIDI figures for gas network operators in Germany since 2006. The figures have been as follows over the years:

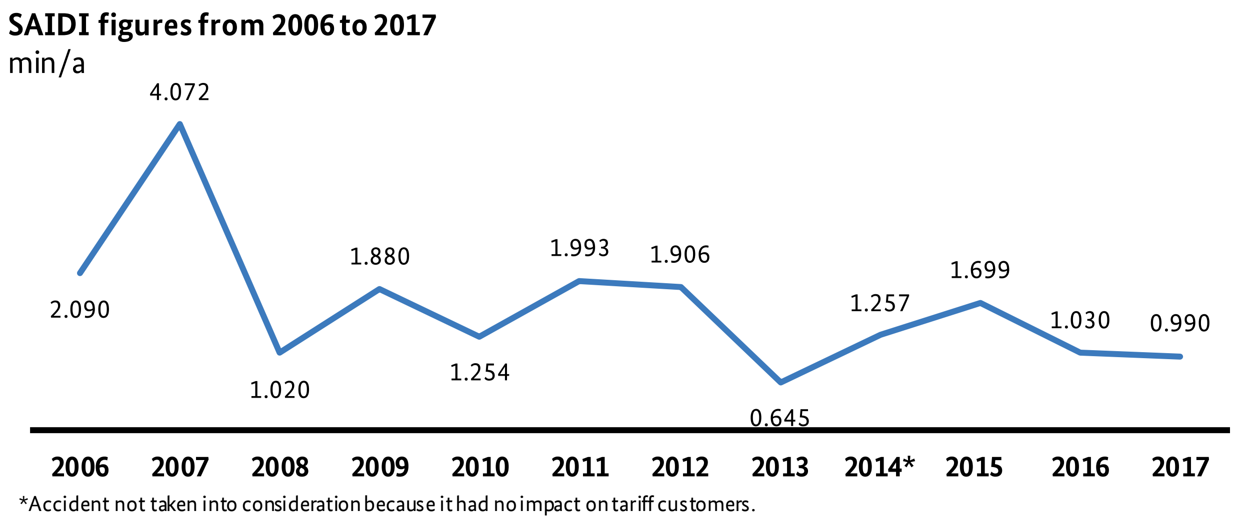


Figure 172: SAIDI figures from 2006 to 2017

Every year, the Bundesnetzagentur assesses the duration and the extent of interruptions to gas supply in Germany. The average value, referred to by the abbreviation SAIDI, indicates the number of minutes for which gas supplies to end users were interrupted on average over the course of one year.

The fact that this value has remained in the low single-digit range since 2006 is a clear indication of the high reliability of German gas networks.

5. Network charges

The network charge is a **fee** that **every network user** transporting gas through the network must pay **to the network operator**. In the case of household customers, the **network user** is the individual gas supplier who collects the network charges from consumers and passes them on to the network operator.

In recent years the gas network charges have seen only minor fluctuations, with household customers currently paying on average approximately 1.49 ct/kWh (around 22% of the overall gas price).

5.1 Calculation of network charges for gas

Network charges are fees charged by the TSOs and DSOs and form part of the retail price (see also "Price level" in Chapter II.F Retail (Gas)). The network charges are the means of spreading the costs of operation, maintenance and expansion of networks among all network users. The calculation of the network charges is based on a system prescribed by the Gas Network Charges Ordinance (GasNEV), which is binding for all network operators. The network operator's charges must be non-discriminatory and as cost-reflective as possible, taking due account of a revenue cap. The revenue cap for each network operator is calculated for each year of a regulatory period using the rules laid down in the Incentive Regulation Ordinance (ARegV). The network charges are therefore a regulated part of the final price.

The revenue cap is calculated using the instruments of the incentive regulation on the basis of a previously conducted cost examination, during which the responsible regulatory authority ascertains and examines the costs of network operation. The cost examination is carried out before the start of a regulatory period, ie every five years, on the basis of the audited annual accounts for the financial year completed two years previously. The network costs are obtained from this as the total of current outlay costs, imputed depreciation allowances, expected return on equity and imputed taxes less cost-reducing revenues and income.

The values calculated for the base year are used to determine the revenue caps with the application of various adjustment factors (eg sectoral productivity development, efficiency requirements, capital cost deduction because of assets written down in the meantime and capex mark-up for new investments etc).

To this end, the network costs are divided into different cost components. Particular mention should be made of the permanently non-controllable costs, which are not subject to the instruments of the incentive regulation. Significant cost components in this regard include, at the transmission network level, costs for investment measures in accordance with section 23 ARegV. Key permanently non-controllable costs for the DSOs include upstream network costs. The revenue cap is adjusted annually with respect to certain cost components. The forecast and actual figures are compared using the network operator's incentive regulation account. The network charge system is used to share the revenues allowed for the respective network operators among the network users.

In principle, section 3 GasNEV allows for two different tariff systems to be used for cost unit accounting. Of those two systems, entry and exit capacity charges prescribed by section 13 GasNEV are the norm, and are calculated using the entry-exit access model. By contrast, section 18 GasNEV stipulates that commodity and capacity prices or commodity and base prices are set on the exit side for local distribution networks. No entry tariffs are charged in this case. A few regional distribution networks use the entry-exit tariff system. The network charge system for gas networks thus differs significantly from the system for electricity networks, which currently has neither entry tariffs nor capacity charges.

The exit tariffs charged by all other DSOs comprise two components, a capacity price and a commodity price. The so-called network participation model is used very often to form these prices. This entails dividing the distribution network and its associated costs into two parts, a local transport network and a local distribution network. A mathematical function is used to determine the share of the local distribution network apportionable to a customer with given consumption. Customers with lower consumption require a larger share of the local distribution network, while it is more probable that customers with higher consumption are connected to local transport capacity. This results in a degression of the specific network charge at higher levels of consumption. The procedure is carried out separately for the capacity price and the commodity price. For non-interval-metered customers (all household customers and many small commercial customers) an average reserve capacity is used, so the capacity component is represented by a base price.

Other systems apart from the network participation model are also used to calculate tariffs. In the main, these systems yield comparable results with respect to tariff degression and likewise do not depend on an individual customer's specific connection situation.

On 1 January each year the network operators must demonstrate to the regulatory authority that the established tariff system does not exceed the revenue cap. In the event of a downward adjustment of the revenue cap according to the rules of the Incentive Regulation Ordinance, the network operators are obliged to adjust their tariffs, whereas in the event of an upward adjustment they have the right to do so but it is not mandatory.

5.2 Development of average network charges in Germany

The figure below shows the development of the average volume-weighted net gas network charges for three consumption categories in ct/kWh from 1 April 2007 to 1 April 2018. The charges for metering and meter operation have been added to the network charges shown in the figure below. Since 1 January 2017 the charge for accounting forms part of the network charges and is no longer shown separately. The values shown are based on data provided by gas suppliers, which shows considerable spread. The data collection systems used have also been adjusted on numerous occasions over the course of time. The network charges shown are based on the following three consumption categories:

- Household customers (volume-weighted across all contract categories): As of the reporting date 1 April 2016, differentiation according to consumption band II is at an annual consumption of between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh). Before this date – as in previous years – the network charges were determined with respect to the average consumption of 23,269 kWh.

- Business customers: Consumers with an annual consumption of 116 MWh and without a fixed annual usage time.

- Industrial customers: Consumers with an annual consumption of 116 GWh and an annual usage time of 250 days (4,000 hours).

The data submitted by the suppliers is then used to calculate an average network charge for each consumption group for the whole territory of the Federal Republic of Germany. The network charge for household customers is calculated on a volume-weighted basis while that for business and industrial customers is calculated arithmetically. It should be noted that in these consumption categories the arithmetic mean does not reflect the considerable spread of the network charges and the heterogeneity of the network operators.

As of 1 April 2018, the average volume-weighted network charge including the charges for metering and meter operation (volume-weighted across all contract categories) for household customers in consumption band II was 1.51 ct/kWh (2017: 1.50 ct/kWh), a slight increase compared to the previous year. For business customers, as of 1 April 2018 the arithmetic mean of the network charge including the charges for metering and meter operation was 1.25 ct/kWh (2017: 1.25 ct/kWh), therefore unchanged from the previous year. For industrial customers, as of 1 April 2018 the arithmetic mean of the network charge including the charges for metering and meter operation increased to 0.33 ct/kWh (2017: 0.28 ct/kWh), amounting to a rise of around 18% compared to the previous year, although as before this figure is still at a low level.

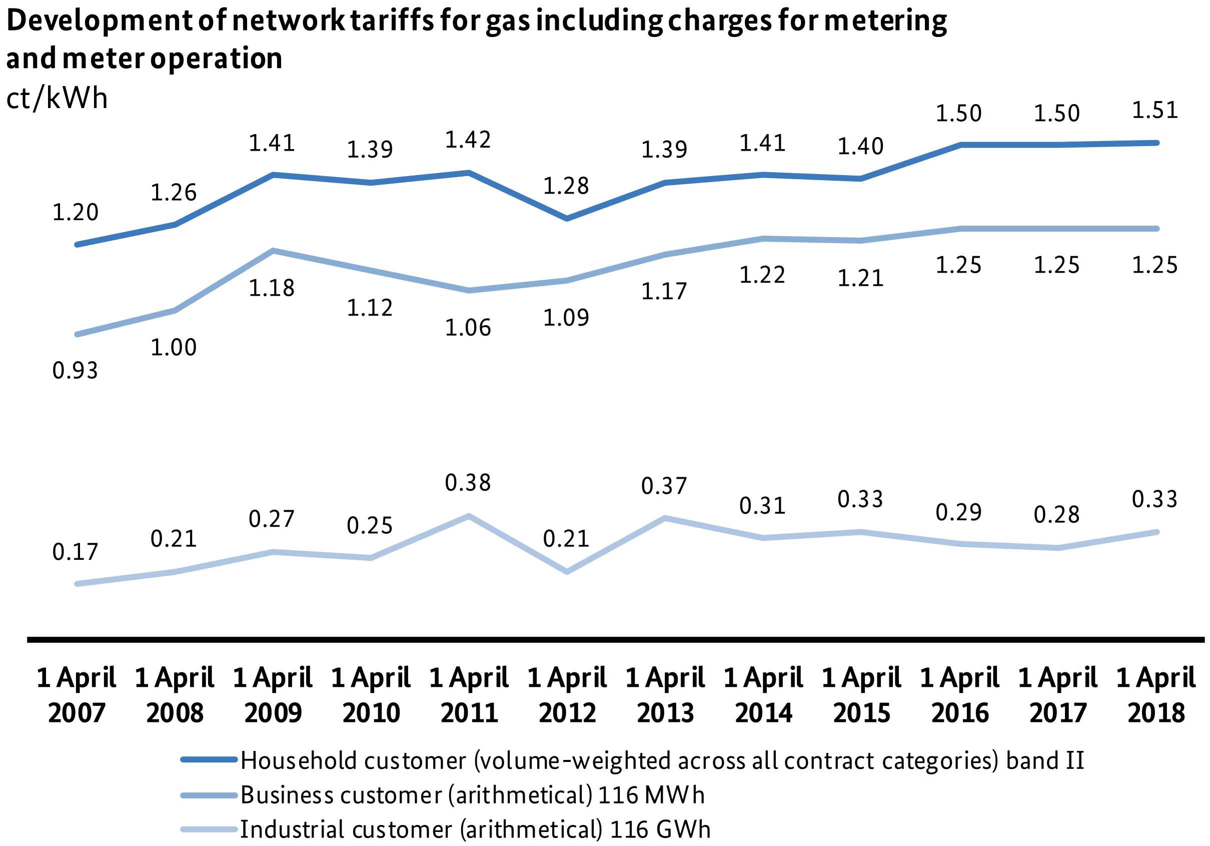


Figure 173: Development of network charges for gas (including charges for metering and meter operation) according to the survey of gas suppliers

Compared to 2018, on average a rise in the low single-digit percentage range is anticipated in 2019 for the underlying consumption categories concerning DSOs. The definitive charges for the DSOs will not be published until 1 January 2019. The definitive charges at the level of the TSOs were already published on 30 June 2018. Between 2018 and 2019 the changes in the network charges for the majority of TSOs were below ±10%.

5.3 Regional distribution of network charges

There is wide regional variation in the level of network charges. The price sheets published by all DSOs are used as the basis for compiling the relevant information on the three consumption categories (household, business and industrial customers) in order to compare network charges in Germany. According to section 27(1) GasNEV all network operators are obliged to publish the network charges applicable in their networks on their website. The information on the respective base, capacity and commodity prices provided by each DSO is then used to determine the 2018 network charges in ct/kWh. The figures do not include the metering and meter operation charges or value added tax; from 1 January 2017 charges for accounting are included in the network charges. For the sake of clarity, network charges are divided into six (household and business customers) or five (industrial customers) categories.[139] Just over 700 gas networks were analysed to

[139] Only regions with an existing gas distribution network are shown in colour on the maps. Accordingly, regions without an existing gas distribution network are shown in white.

determine the level of network charges for household and business customers. This corresponds to market coverage of 98% in both areas. The network charges were also entered in a chart broken down by federal state, in which the individual network charges are weighted by the number of meter points in each case, to obtain information on the average network charge level in each state.

The lowest network charges for household customers across Germany are set at 0.64 ct/kWh, and the highest 3.62 ct/kWh. With the exception of Saarland, there is an East to West gradient with regard to the distribution of network charges. The average network charge for household customers in the new federal states (not including Berlin) is 1.58 ct/kWh, while the average in the old states (including Berlin) is 1.36 ct/kWh. Looking at the averages by federal state, the highest network charges for household customers are found in Saarland and Saxony-Anhalt, and the lowest in Berlin and Hamburg.

Net network charges for household customers in Germany for 2018
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Saarland	1.82	1.28	2.31	19
Saxony-Anhalt	1.70	1.02	2.99	27
Baden-Württemberg	1.59	0.93	2.89	100
Mecklenburg-Western P.	1.58	0.97	2.55	18
Saxony	1.57	0.93	2.39	37
Thuringia	1.56	1.05	2.21	29
Brandenburg	1.47	0.95	3.62	28
North Rhine-Westphalia	1.46	0.67	3.09	122
Rhineland-Palatinate	1.41	0.84	2.28	35
Hesse	1.37	1.00	1.74	44
Schleswig-Holstein	1.30	0.93	2.45	40
Lower Saxony	1.29	0.64	3.52	61
Bremen	1.21	1.17	1.45	2
Bavaria	1.21	0.84	3.11	105
Berlin	1.15	1.15	1.15	1
Hamburg	1.13	1.13	1.13	1

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Table 113: Distribution of network charges for household customers in Germany, as at 1 January 2018

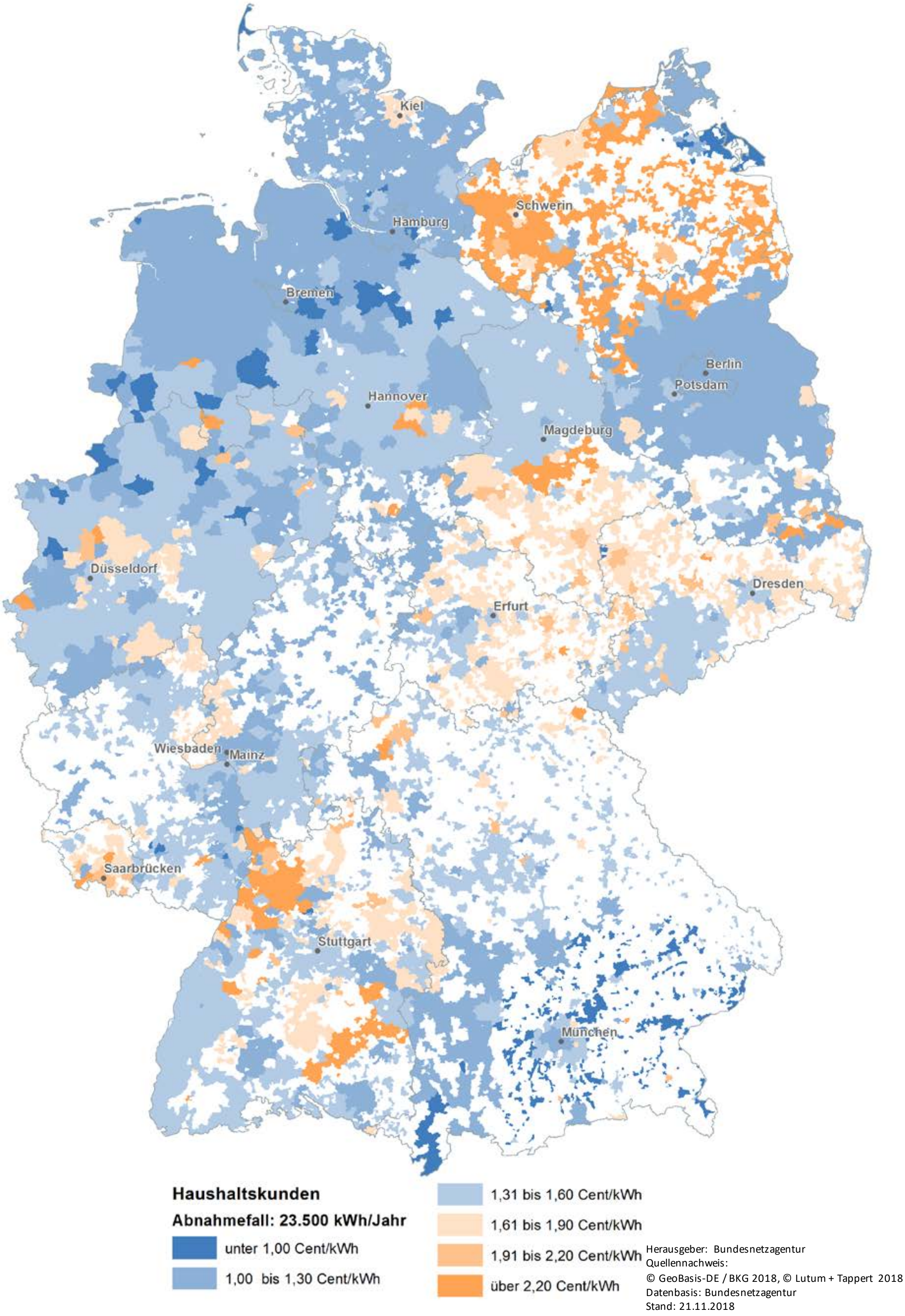


Figure 174: Distribution of network charges for household customers, as at 1 January 2018

The distribution of network charges for business customers is similar to that for household customers. Across Germany, the spread between the lowest and highest network charges extends from 0.37 ct/kWh to 3.51 ct/kWh. As for household customers, there is an East to West gradient in the distribution of network charges for business customers. The average network charge for business customers in the new federal states (not including Berlin) is 1.34 ct/kWh, while the average in the old states (including Berlin) is 1.11 ct/kWh. Looking at the averages by federal state, the highest network charges for business customers are found in Saxony-Anhalt and Saarland, and the lowest in Bremen and Hamburg.

Net network charges for business customers in Germany for 2018
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Saxony-Anhalt	1.52	0.96	2.40	27
Saarland	1.42	0.95	2.09	19
Mecklenburg-Western P.	1.39	0.83	2.10	18
Saxony	1.34	0.55	1.98	37
Baden-Württemberg	1.30	0.80	2.60	100
Brandenburg	1.25	0.79	3.51	28
North Rhine-Westphalia	1.21	0.37	2.82	122
Thuringia	1.19	0.68	1.84	29
Bavaria	1.16	0.68	2.62	105
Hesse	1.13	0.81	1.59	44
Rhineland-Palatinate	1.10	0.62	2.01	35
Schleswig-Holstein	1.07	0.75	2.03	40
Berlin	0.98	0.98	0.98	1
Lower Saxony	0.98	0.48	1.67	61
Hamburg	0.95	0.95	0.95	1
Bremen	0.92	0.87	1.04	2

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Table 114: Distribution of network charges for business customers in Germany, as at 1 January 2018

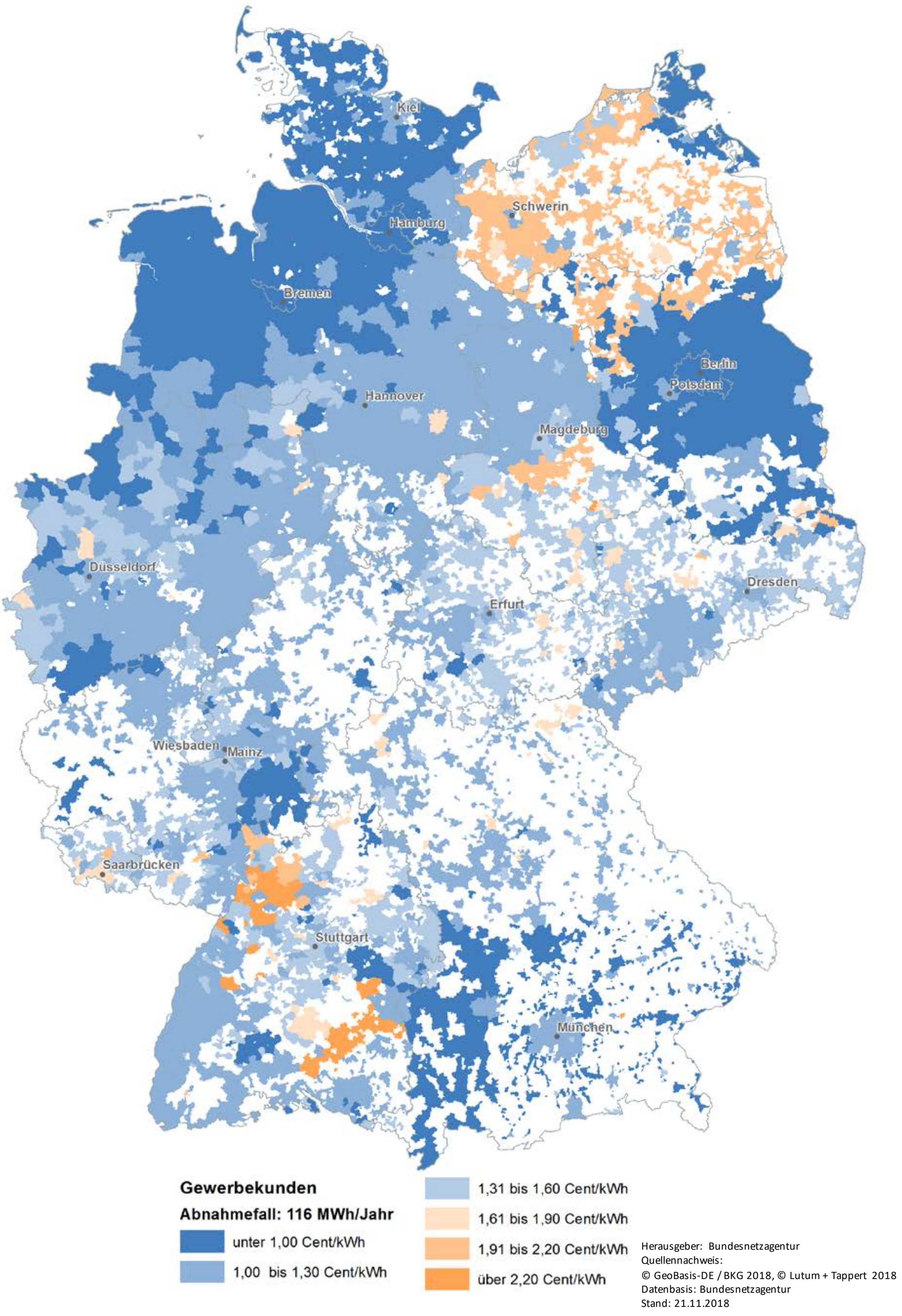


Figure 175: Distribution of network charges for business customers in Germany, as at 1 January 2018

Only those gas networks that have at least one customer withdrawing 116 GWh were taken into account when determining the average network charges for industrial customers. Figures from 132 network operators were thus included in the analysis of network charges for industrial customers. Across Germany, the spread between the lowest and highest network charges extends from 0.11 ct/kWh to 0.99 ct/kWh. The average network charge for industrial customers in the new federal states (not including Berlin) is 0.35 ct/kWh, while the average in the old states (including Berlin) is 0.30 ct/kWh. Looking at the averages by federal state, the highest network charges for industrial customers are found in Saarland and Saxony-Anhalt, and the lowest in Hamburg and Bremen.

Net network charges for industrial customers in Germany for 2018
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Saarland	0.50	0.40	0.87	4
Saxony-Anhalt	0.39	0.21	0.99	9
Thuringia	0.39	0.19	0.54	7
Lower Saxony	0.38	0.23	0.48	8
Saxony	0.34	0.11	0.41	7
Mecklenburg-Western P.	0.32	0.31	0.33	2
Rhineland-Palatinate	0.31	0.24	0.73	7
Brandenburg	0.31	0.28	0.47	3
Baden-Württemberg	0.30	0.19	0.46	20
North Rhine-Westphalia	0.30	0.17	0.54	22
Berlin	0.30	0.30	0.30	1
Hesse	0.29	0.16	0.37	14
Bavaria	0.28	0.12	0.53	20
Schleswig-Holstein	0.28	0.24	0.36	5
Hamburg	0.21	0.21	0.21	1
Bremen	0.18	0.16	0.24	2

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Table 115: Distribution of network charges for industrial customers in Germany, as at 1 January 2018

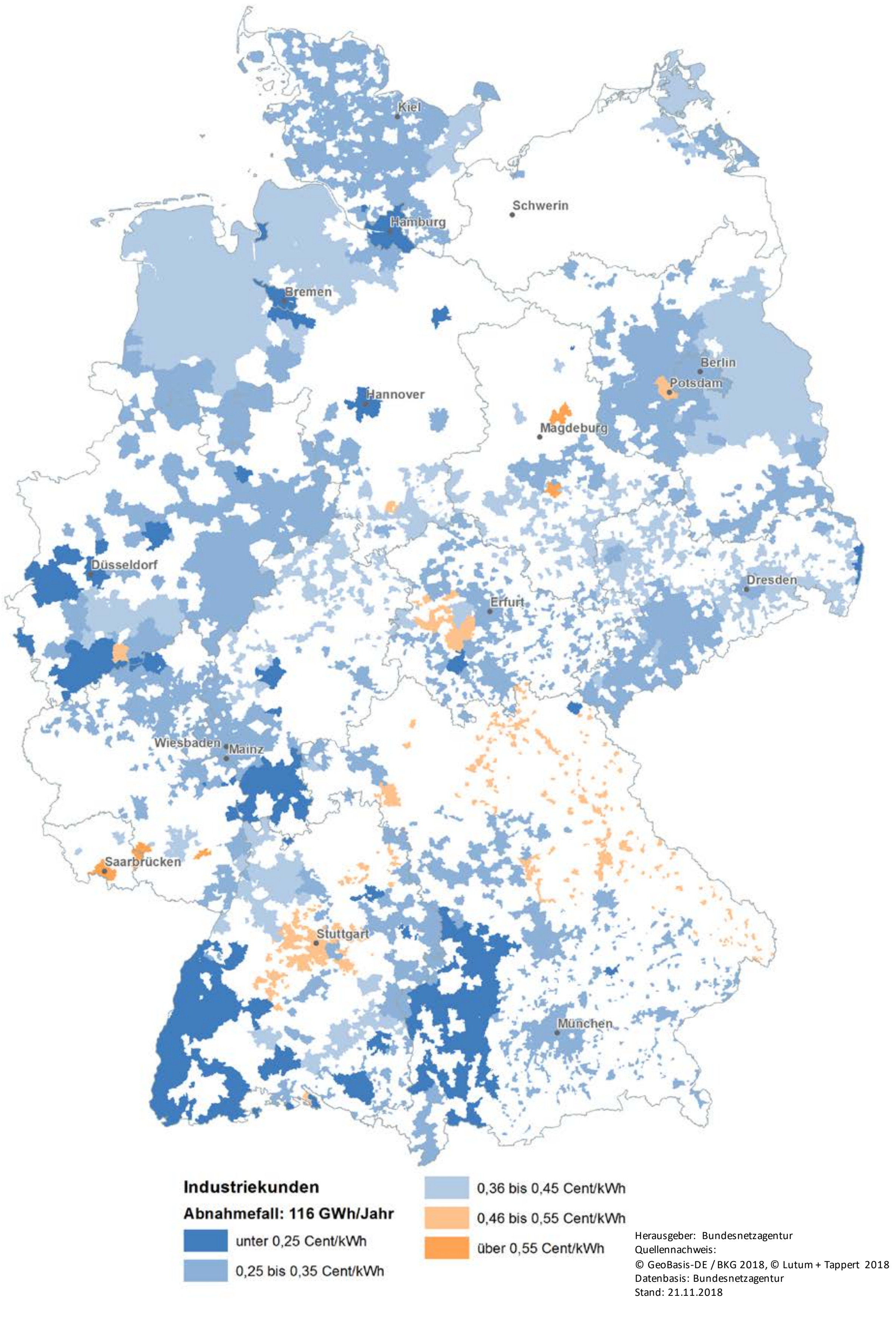


Figure 176: Distribution of network charges for industrial customers in Germany, as at 1 January 2018

The reasons for the regional differences in network charges are manifold. Key factors are lower levels of utilisation of the networks and the average age of the networks in the respective regions. The modernisation of networks in the new federal states following German reunification often resulted in networks which, from today's perspective, are oversized. In some cases these networks are now insufficiently utilised, while still incurring costs in line with their size. Another cost driver is population density: in sparsely populated regions the network costs have to be spread over a small number of network users, whereas the opposite is the case in densely populated regions. The age structure of individual networks also has an impact on tariffs. More recently built networks have higher residual values, which increases specific capital costs and in turn leads to higher tariffs. As a result of their greater depreciation, older networks have lower residual values and therefore lower capital costs, thus in turn leading to lower tariffs. However, with advancing age, networks incur higher costs for maintenance and repair, which have a corrective effect that tends to equalise the tariffs.

5.4 Incentive regulation account as per section 5 ARegV

Following the amendment of the Incentive Regulation Ordinance (ARegV), the network operators submit applications to adjust their revenue caps for the third regulatory period in accordance with section 4(4) first sentence para 1(a) in conjunction with section 5(3) and (4) ARegV. This process involves the network operators applying for an incentive regulation account balance, which is derived from the higher or lower revenues, together with interest earned, in the relevant calendar years. The application from the network operators further provides that this balance including interest be allocated to the revenue cap on an annuity basis, by additions and deductions, over the three calendar years following the year in which the balance was determined The Ruling Chamber reviews the incentive regulation account balances applied for by the network operator and the resulting adjustment amounts for the revenue caps before deciding on them.

The transitional arrangement in section 34(4) ARegV enabled the network operators to submit applications to adjust their revenue caps for the first time on 30 June 2017. These applications relate to the differences determined for the outstanding calendar years (2012 to 2016) and the resulting regulatory account balance as at 31 December 2016. In derogation of section 5(3) first sentence ARegV, the calculated balance is allocated on an annuity basis until the end of the third regulatory period, therefore over a period of five years.

The draft decisions are currently being consulted upon, with the aim of a timely decision being reached.

5.5 Network transfers under section 26(2) to (5) ARegV

In the event of a partial transfer of an energy supply network to a different network operator, in accordance with section 26 ARegV the regulatory authority specifies the share of the revenue cap to be transferred between the affected network operators concerned. This requires the two network operators to submit a joint agreed application.

If no corresponding application from the two network operators is received within six months of the commencement of network operation, the regulatory authority shall determine the share of the revenue cap ex officio (section 26(3) to(5) ARegV). The share of the revenue cap is calculated on the basis of the capital costs of the part of the network to be transferred in accordance with section 26(4) plus a fixed amount to cover the remaining costs of the network to be transferred. If the affected network operators submit a corresponding application, the share of the revenue cap to be transferred is determined again in accordance with section 26(6) ARegV. There are currently several "disputed" network transfers going through the consultation process on which decisions are expected shortly.

Last year 16 applications for network transfers were submitted, and decisions have already been taken on most of them. Together with applications from previous years, decisions were taken on a total of 30 applications for network transfers last year.

5.6 Cost examination according to section 6 and efficiency comparisons for DSOs and TSOs according to sections 12 et seq, section 22 ARegV

The third regulatory period for the DSOs and TSOs began on 1 January 2018; it will last until 2022. In preparation, in 2017 the Bundesnetzagentur first conducted a cost examination according to the rules laid down in GasNEV to determine the base level for calculating the revenue caps for gas for the third regulatory period.

Eighty-one network operators participated in the standard procedure and 90 network operators in the simplified procedure. The costs necessary for network operation incurred by the gas network operators were calculated as part of the cost examination. In the course of 2017, the Bundesnetzagentur determined the base level for the revenue caps of the gas network operators participating in the standard procedure and of those participating in the simplified procedure.

Efficiency comparisons were then conducted for the network operators participating in the standard procedure – both those under the responsibility of the Bundesnetzagentur and those under the responsibility of the regulatory authorities of the federal states. The efficiency comparisons were carried out separately for DSOs and TSOs and looked at the diverse and complex supply services provided by the network operators and the individual resources needed to provide them in each case. Various structural parameters were used to reflect the supply services provided by the network operators in order to find out which network operators provide equivalent supply services at the lowest cost.

For the network operators participating in the simplified procedure, a blanket efficiency figure of 93.46% was determined on the basis of the efficiency data from the second regulatory period.

The revenue caps for the DSOs participating in the standard procedure have not yet been set. In consequence of three decisions by the Federal Court of Justice (BGH) dated 12 June 2018 (EnVR 43/16, EnVR 53/16 and EnVR 54/17), the reasons for which have been available since 16 July 2018, it is necessary to reassess the procedure used for the efficiency comparison between the DSOs for the third regulatory period. The Bundesnetzagentur, supported by the consortium of efficiency comparison experts, is currently in the process of assessing the necessary adjustments. In addition, any data on structure parameters which the DSOs admit were submitted in error and any adjustments to input parameters resulting from decisions made by the Federal Court of Justice under EnVR 23/16 relating to non-wage labour costs are included in the reassessment process as permanently non-controllable costs. This can potentially result in changes to the cost driver analysis and the selection of parameters used for the efficiency comparison and ultimately also changes to the efficiency figures themselves.

The revenue caps for the TSOs and for the network operators participating in the simplified procedure have already been set in most cases.

5.7 Network code on harmonised transmission tariff structures (NC TAR)

The Bundesnetzagentur has begun implementing Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures, which entered into force on 6 April 2017.

In Germany the regulation is being implemented through a number of determinations (INKA, REGENT, MARGIT, BEATE 2.0 and AMELIE), thereby in large part replacing the previous national provisions on tariff setting. While INKA mainly delineates the allocation of responsibilities between the TSOs and the Bundesnetzagentur and serves the purpose of the collection of data, the other determinations govern various aspects of tariff setting across individual market areas, ranging from the basic principles of tariff setting (REGENT) to discounting and surcharge arrangements (MARGIT and BEATE 2.0) and, finally, the compensation payments between the TSOs resulting from these arrangements (AMELIE).

In order to be able to involve industry representatives and the affected TSOs early on in the process, the Ruling Chamber invited them to attend several implementation workshops and discussed initial drafts of the determinations with them in advance. In the further course of the proceedings the Ruling Chamber will evaluate and publish the comments it receives and initiate the final consultations, with the intention of concluding the proceedings in the first quarter of 2019.

D Balancing

1. Balancing gas and imbalance gas

1.1 Balancing gas

Balancing gas is used to ensure network stability and security of supply within the market areas and is procured by the market area managers. A distinction is to be made here between internal balancing gas that is free of charge (network buffer within the market area) and chargeable external balancing gas (procurement through exchanges and/or a balancing platform). External balancing gas is procured by the market area managers according to a merit order list (MOL), divided into ranks 1-4.

As a rule, the share of internal balancing gas is higher, as the market area managers are obligated to use this energy first. Because in winter months there are more frequent fluctuations regarding short and long portfolios, there is an increase in the share of external balancing gas during this period.

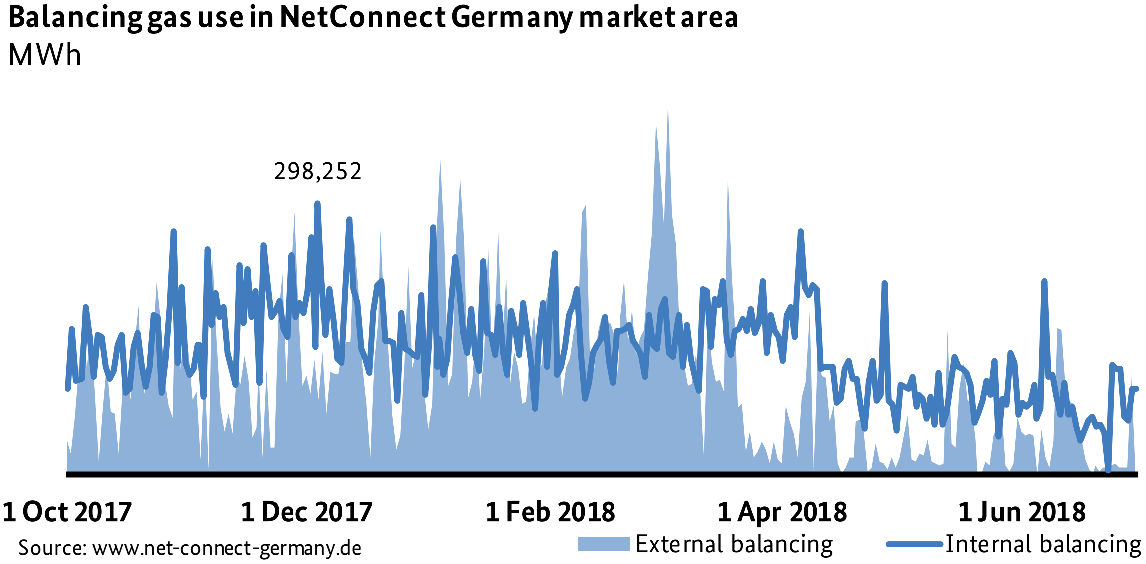


Figure 177: Balancing gas use from 1 October 2017 in the NetConnect Germany market area, as at July 2018

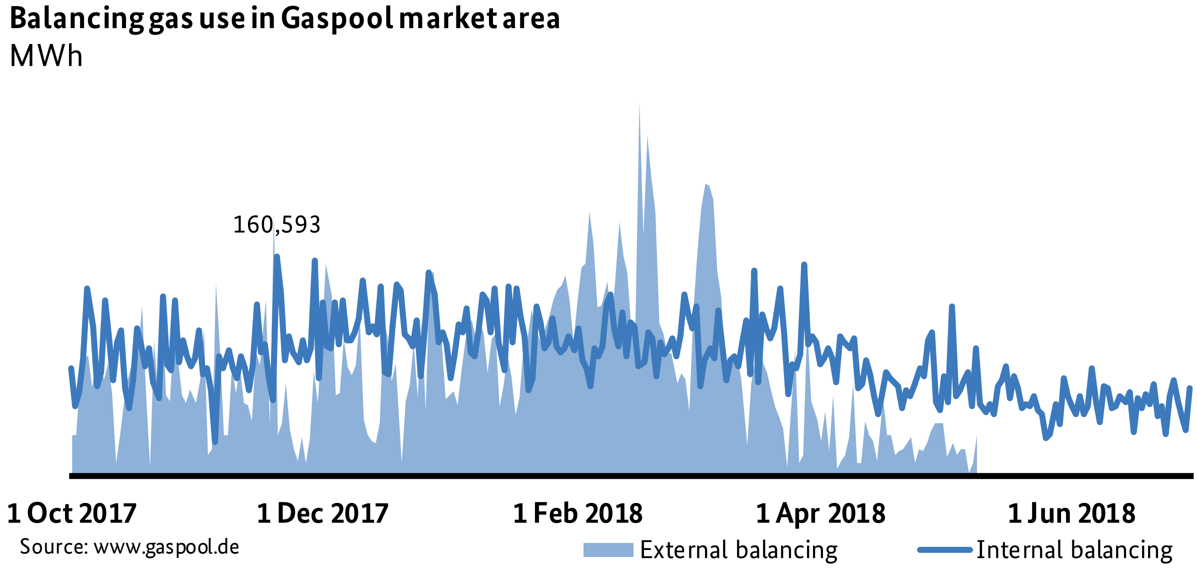


Figure 178: Balancing gas use from 1 October 2017 in the Gaspool market area, as at July 2018

The purchase prices for balancing gas depicted below are calculated as an average of the daily balancing gas prices.

The charts show that the demand for external balancing gas in both market areas is mainly covered by products from MOL ranks 1 and 2. Quality-specific products within MOL rank 2 account for the largest proportion of the procured volume. However, in the NetConnect Germany market area in particular the share of global non-quality-specific balancing gas (MOL1) also increased significantly compared to the previous year.

During the period under review, the balancing product MOL3 was not purchased in either the Gaspool or NetConnect Germany market area and procurement of this product was discontinued as of 1 January 2018. MOL4 products were purchased only between the start of the 2017/2018 gas year on 1 October and 3 October 2017.

As purchasing is mainly exchange-traded, the purchase prices are on the same level as general market prices. An unusual situation arose on the markets between 27 February and 2 March 2018: a Europe-wide cold spell combined with a number of infrastructure-related supply restrictions resulted in extreme price spikes, which were also reflected in the purchase prices for balancing gas in both market areas. In some call orders these prices reached levels of over €100/MWh, many times the price usually achieved on the markets.

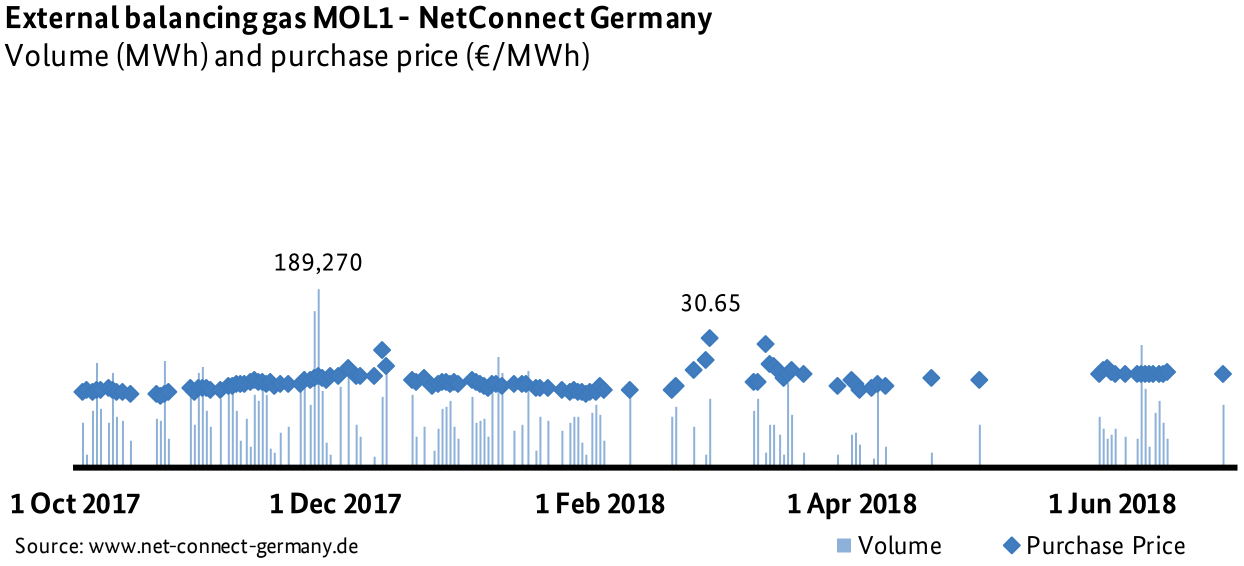


Figure 179: External balancing gas purchase prices and volumes from 1 October 2017 for MOL 1 in the NetConnect Germany market area, as at July 2018

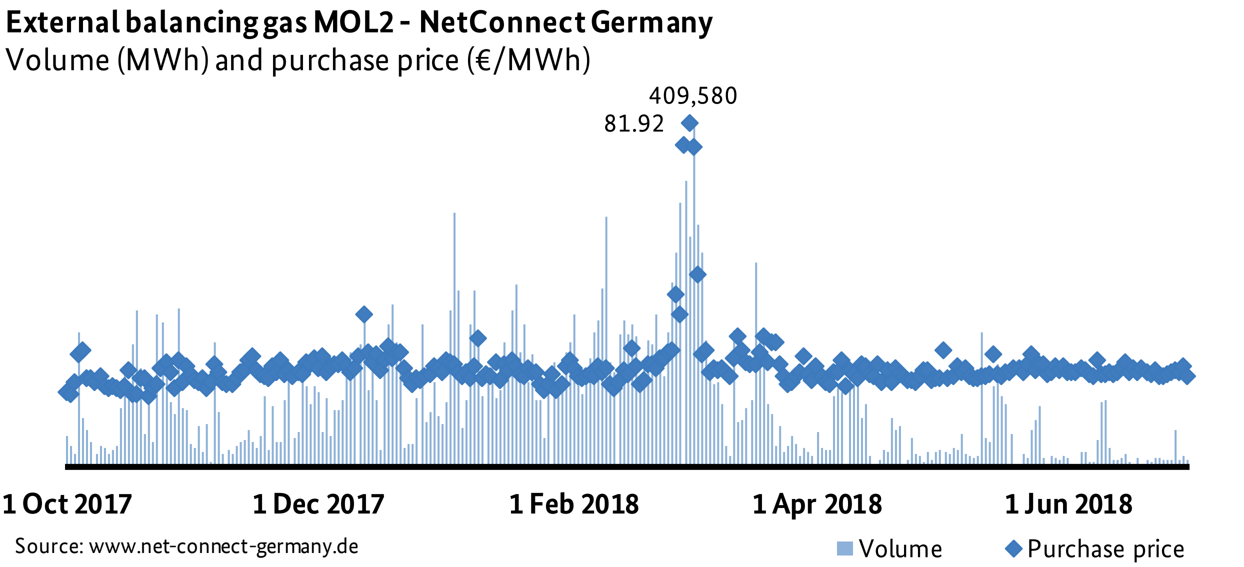


Figure 180: External balancing gas purchase prices and volumes from 1 October 2017 for MOL2 in the NetConnect Germany market area, as at July 2018

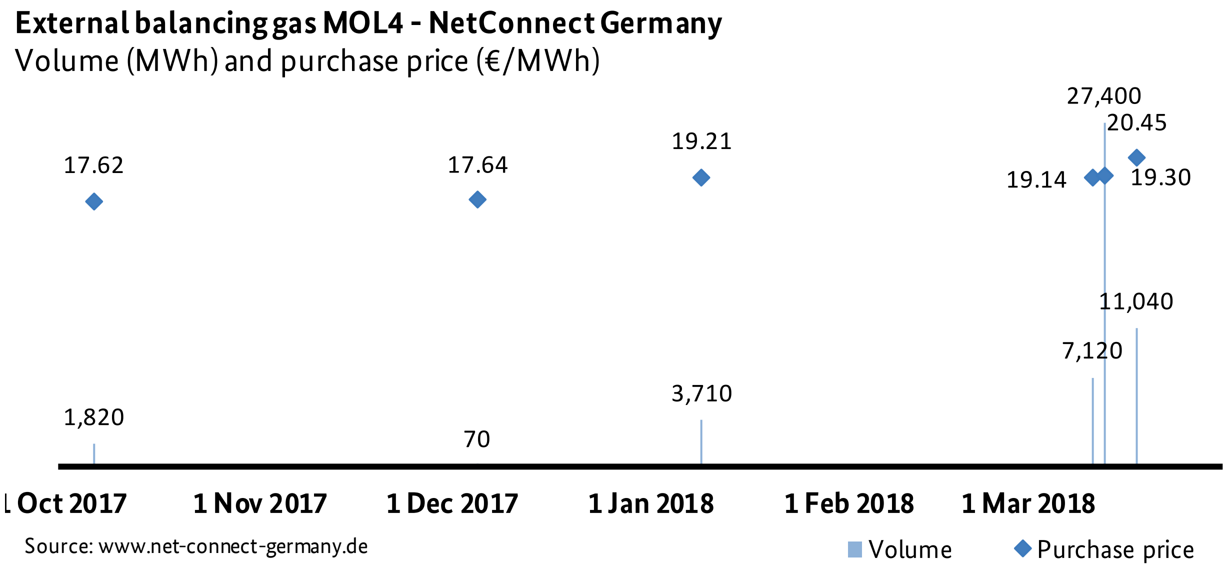


Figure 181: External balancing gas purchase prices and volumes from 1 October 2017 for MOL4 in the NetConnect Germany market area, as at July 2018

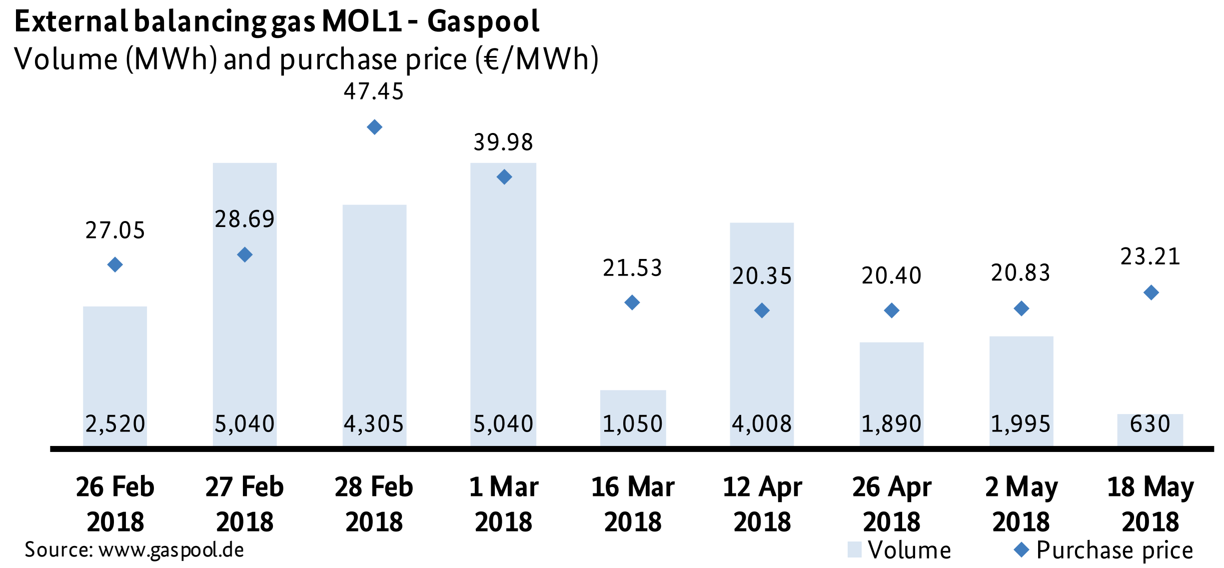


Figure 182: External balancing gas purchase prices and volumes from 1 October 2017 for MOL1 in the Gaspool market area, as at July 2018

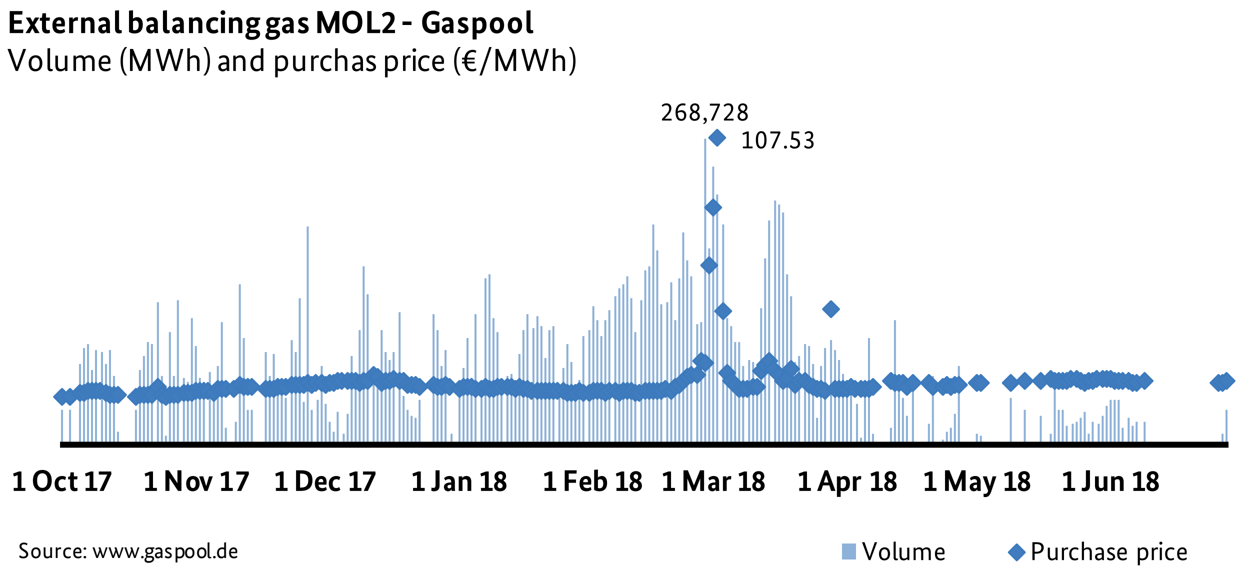


Figure 183: External balancing gas purchase prices and volumes from 1 October 2017 for MOL2 in the Gaspool market area, as at July 2018

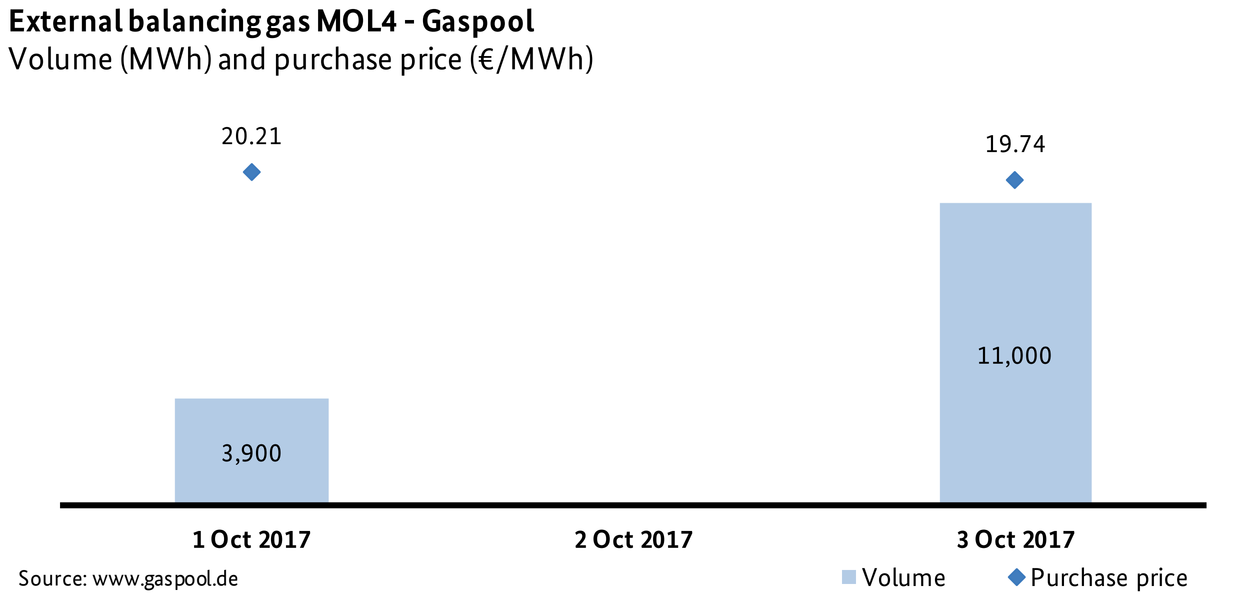


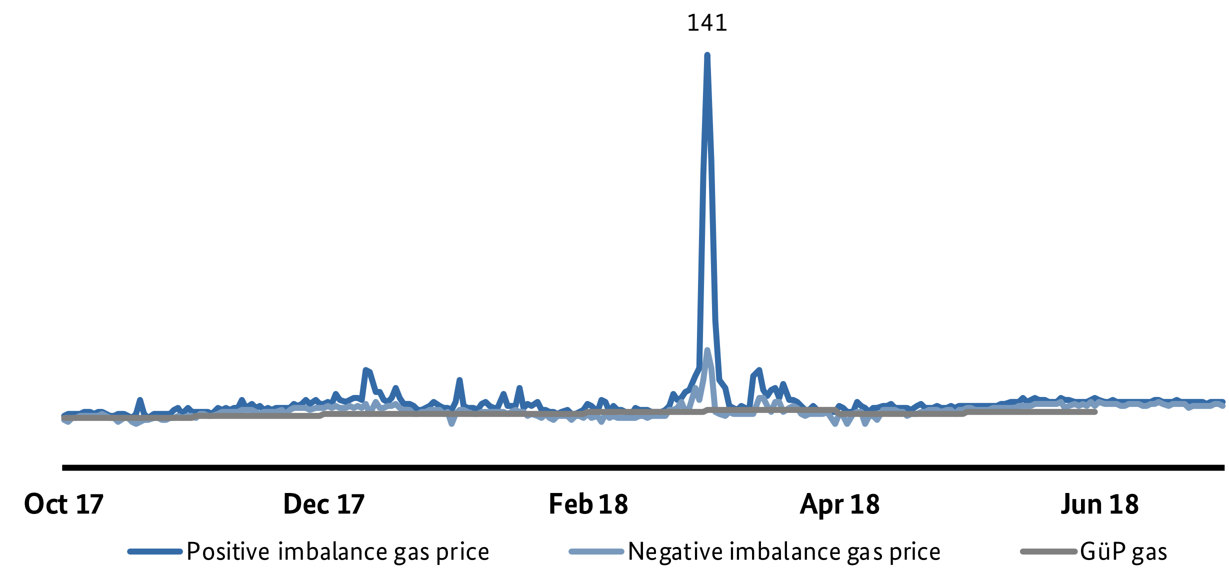
Figure 184: External balancing gas purchase prices and volumes from 1 October 2017 for MOL4 in the Gaspool market area, as at July 2018

1.2 Imbalance gas

The term imbalance gas refers to the difference between entry and exit quantities within a balancing group at the end of the balancing period. It comes about through deviations between the amount of gas actually consumed and the forecast consumption volume. For this quantity of gas the balancing group manager is charged a positive imbalance price in the case of short supply and a negative imbalance price in the case of surplus supply.

The introduction of GaBi Gas 2.0 as of 1 October 2015 led to fundamental changes in the way imbalance gas prices are calculated. The previous calculation system used a price pool involving various exchanges to calculate imbalance prices, whereas now the balancing gas prices (MOL1 and MOL2, excluding local and hourly products) and the volume-weighted average price of gas including a 2% addition/deduction are used to calculate the positive and negative imbalance price. As a result, the two market areas may have different imbalance prices. The figure below shows the development of the imbalance price according to the new calculation method since 1 October 2017.

Development of imbalance price - NetConnect Germany
€/MWh



Source: imbalance price MAM: www.net-connect-germany.de, cross-border point (GüP): www.bafa.de, as at July 2018

Figure 185: Development of NetConnect Germany imbalance prices since 1 October 2017, as at July 2018

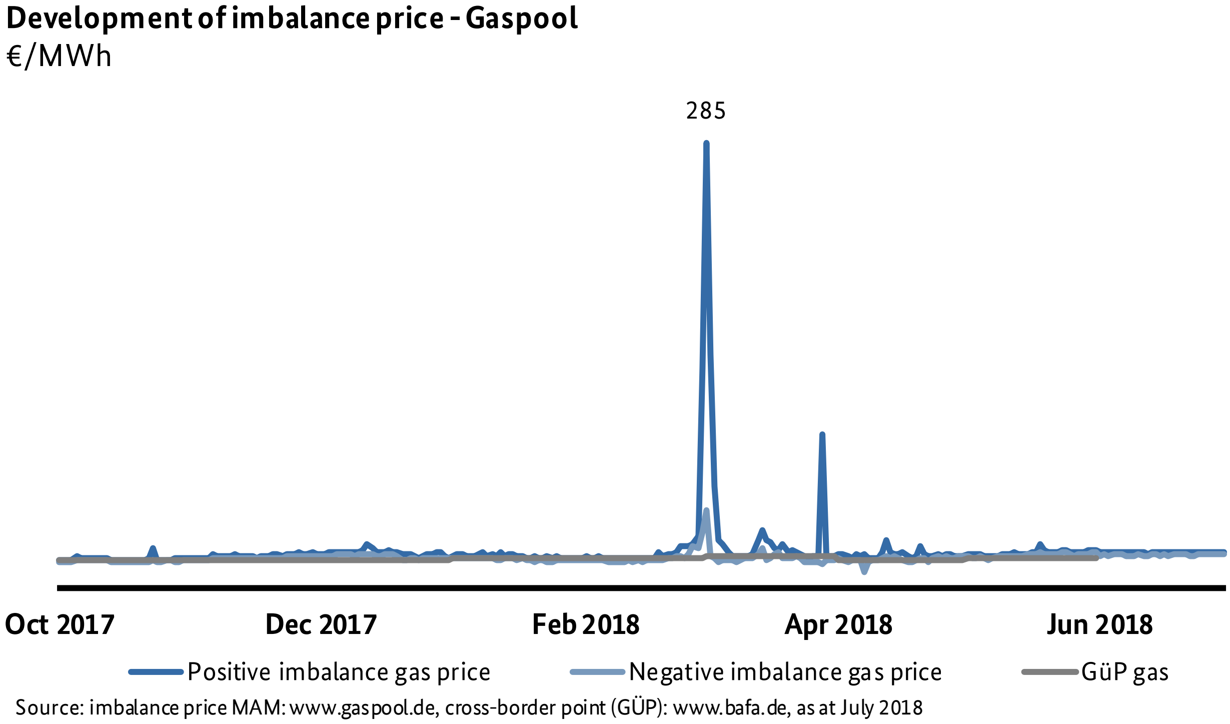


Figure 186: Development of Gaspool imbalance prices since 1 October 2017, as at July 2018

2. Development of the balancing neutrality charge

The costs and revenues incurred by the market area manager from the gas balancing regime must be allocated to the balancing group managers. In the process, the market area manager forecasts the future costs and revenues for his neutrality charge account. If the forecasted costs exceed forecasted revenues, the market area manager levies a balancing neutrality charge from the respective balancing group managers.

The increasing procurement of balancing gas at the exchanges and a well-functioning balancing system, among other factors, have allowed both of the market area managers to temporarily lower the balancing neutrality charges to €0/MWh for several periods.

The introduction of GaBi Gas 2.0 on 1 October 2015 made it mandatory for the market area managers to set up two separate neutrality charge accounts, one for SLP exit points and another for RLM exit points. If the costs are forecast to exceed revenues, the market area manager levies a neutrality charge from the respective balancing group managers. As of 1 October 2016, the neutrality charges (SLP and RLM) each apply for one year.

For the period from 1 October 2017, no neutrality charge for SLP and RLM will be levied in the NCG market area. For the same period, a neutrality charge of €0.20/MWh will be levied for SLP and €0.08/MWh for RLM in the Gaspool market area.

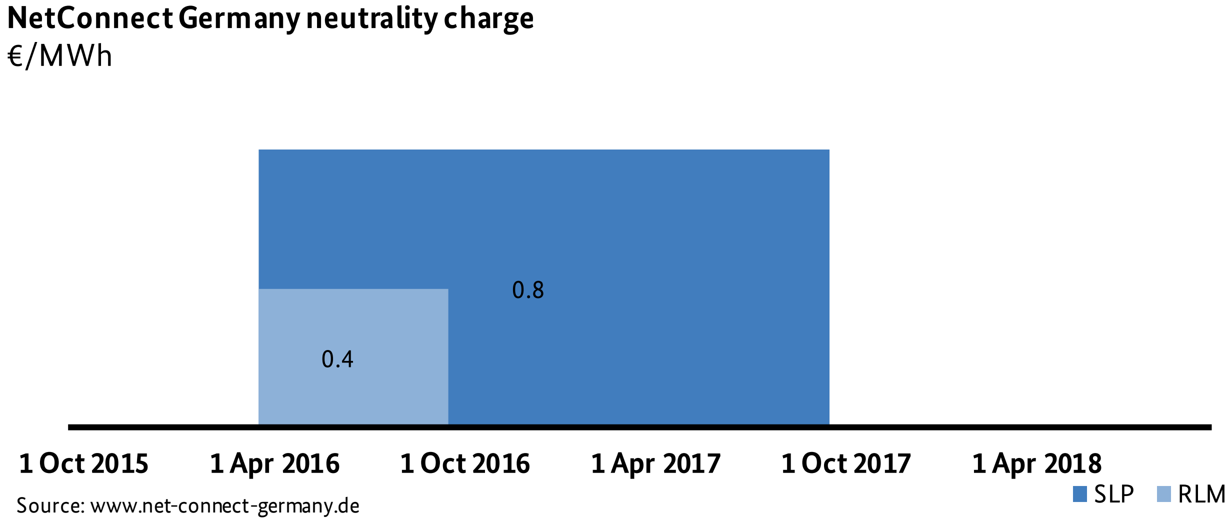


Figure 187: Neutrality charge in the NetConnect Germany market area, as at July 2018 (source: www.net-connect-germany.de)

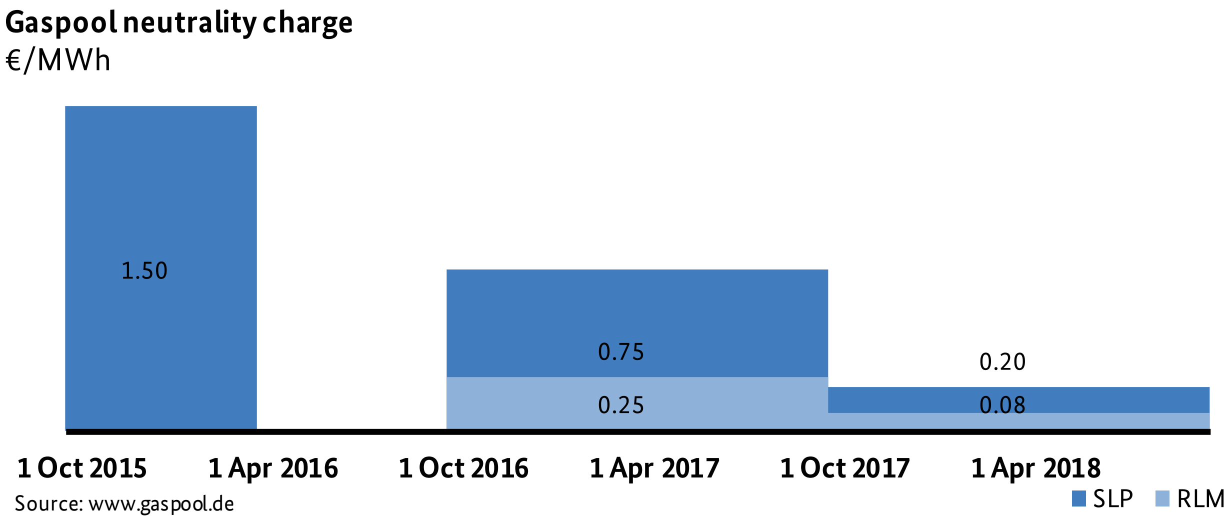


Figure 188: Neutrality charge in the Gaspool market area, as at July 2018 (source: www.gaspool.de)

3. Standard load profiles

Network operators can use two types of standard load profile (SLP): analytical profiles, which, in general terms, are based on the previous day's consumption at the time of estimation, and synthetic profiles, which rely on values derived from statistics. In 2017, the synthetic SLP profiles were used by 81.2% of operators; analytical profiles were used by 14.1% of operators, compared with 14.5% in 2016.

The significance of SLP profiles is evident in the fact that nearly all exit network operators (98.3%) used them when delivering to household or small business customers. The synthetic profiles of the Technical University of Munich (TU München), used in the 2002 and 2005 versions, dominate with a market coverage of 94.5% This figure also remains high and unchanged compared with the previous year (likewise 94.5%).

The TU München offers a range of different profiles which reflect the offtake behaviour of various customer groups. 46.5% of network operators stated that all available profiles were applied, compared with 45.3% in 2016. As in the previous year, two to three profiles were generally used for household customers, whereas eight profiles were used on average for business customers.

As forecasts, SLP profiles by their very nature contain inaccuracies. The average deviation between allocation and the actual offtake on a daily basis was 5.4%. The average maximum deviation on any one day was 54%. However, the extent to which these fluctuations result in the use of external balancing gas can only be assessed by looking at the combined effects of all deviations from standard load profile offtakes within a market area. It must also be borne in mind that these figures may not be representative as only 62% of the network operators provided relevant data on deviations at all, and it might be assumed that the operators who responded tended to be those with a comparatively high forecast quality. In the previous year, too, only 64.2% of network operators provided relevant data.

7.6% of operators made adjustments to the load profiles owing to the deviations, compared to 9.2% in 2016.

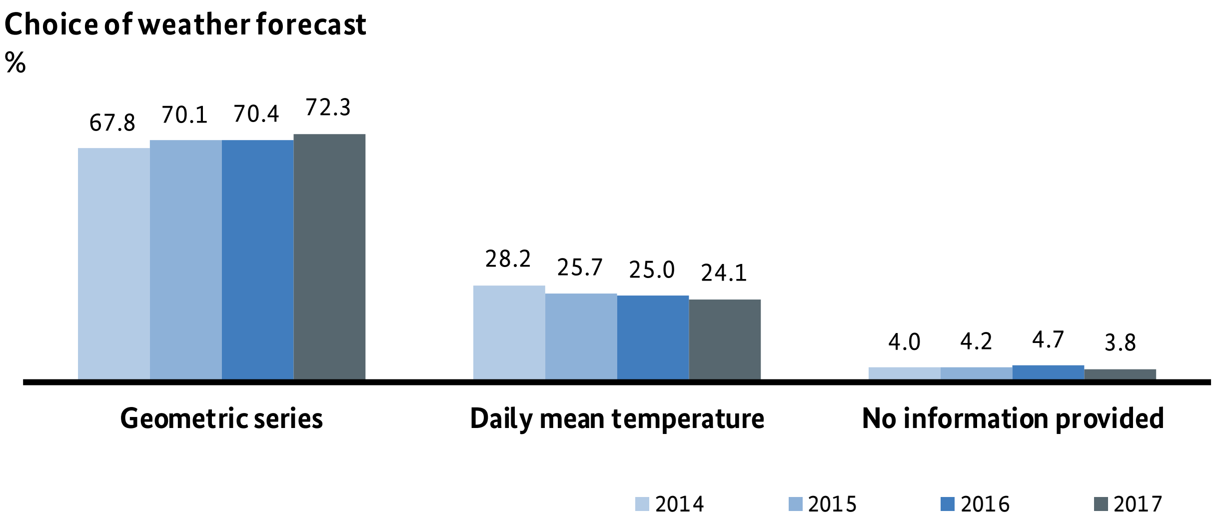


Figure 189: Choice of weather forecast

Due to the strong temperature dependence of SLP profiles, there is a continuing strong trend toward using a differentiated forecast temperature ("geometric series"). In this procedure, the actual temperatures of the days before the day of delivery are taken into account to decrease the deviation risk.

E Wholesale market

Liquid wholesale markets are vital to market development along the entire value chain in the natural gas sector, from the procurement of natural gas to the supply to end customers. More scope for short-term and long-term natural gas procurement at wholesale level makes companies less dependent on a single supplier in the long term. This increases the opportunities for market players to choose from a variety of trading partners and hold a diversified portfolio of short-term and long-term trading contracts. Liquid wholesale markets make it easier to enter the market and ultimately also promote competition for end customers.

The Bundeskartellamt assumes that the natural gas wholesale market operates at national level and therefore no longer defines it within the limits of networks or market areas. Overall liquidity in the natural gas wholesale market decreased in 2017. The volume of brokered bilateral wholesale trading fell by around 14% in 2017. The volume of on-exchange gas trading fell by around 7%.

2017 was characterised by significantly higher gas wholesale prices. The various price indices rose by around 12% (BAFA cross-border prices) to 24% (EEX daily reference price) year-on-year.[140]

1. On-exchange wholesale trading

The exchange relevant to natural gas trading in Germany is operated by the European Energy Exchange AG and its subsidiaries (referred to collectively as EEX below). As in previous years, EEX took part in this year's data collection in the course of monitoring. EEX carries out short-term and long-term trading transactions (spot market and futures market) and spread product trading. All types of contracts are equally tradable for the two German market areas NetConnect Germany (NCG) and GASPOOL.

On the spot market, natural gas can be traded for the current gas supply day with a lead time of three hours (within-day contract/intraday product), for one or two days in advance (day contract) and for the following weekend (weekend contract) on a continuous basis (24/7 trading). The minimum trading unit is 1 MW so that even small volumes of natural gas can be procured or sold at short notice. Quality-specific contracts (for high calorific gas or low calorific gas) are also tradable. The main purpose of the futures market is to hedge against price risks, optimise portfolios and, to a much lesser degree, ensure long-term gas procurement.

Launched as a partnership between EEX and the French Powernext SA in 2013, PEGAS has consolidated gas trading activities on a joint platform, which makes cross-border trading easier. Following merger control clearance by the authorities, including the Bundeskartellamt, EEX acquired the majority of shares in Powernext SA on 1 January 2015 and incorporated it into the EEX Group. Since November 2017 it has been the sole shareholder of Powernext SA.[141]

[140] The daily reference prices for the NCG market area increased by around 25% and for GASPOOL increased by around 22% year on year. The arithmetic mean of the European Gas Index Germany (EGIX) rose by around 21%.

[141] See https://www.eex.com/de/about/newsroom/news-detail/eex-wird-100--iger-anteilseigner-von-powernext/75780, retrieved on 13 September 2018

EEX and Powernext trade on the European gas market on the joint platform PEGAS. PEGAS allows its members to trade spot and futures market products for the German, French, Dutch, Belgian, British and Italian gas market areas. Futures can be traded for specific months, quarters, seasons (summer/winter) or years (so-called calendars).

After products from the Austrian Central European Gas Hub (CEGH) and Danish Gaspoint Nordic were added to the PEGAS portfolio in 2016, its geographical radius was extended further in 2017. The spot and futures market products of the Czech energy exchange (PXE (Power Exchange Central Europe) were transferred to Powernext. In addition, in the second half of 2017 a new European spot market index "European Gas Spot Index" (EGSI) was introduced to allow market participants to better mirror short-term price developments in their contracts The price index covers the gas markets of Germany (Gaspool and NCG), the Netherlands (TTF), France (PEG Nord and TRS), Austria (CEGH VTP), Denmark (ETF) and Belgium (ZTP). From January 2018 the EGSI will completely replace the daily reference price.

A total volume of 1,982 TWh was traded on the EEX Group's gas markets in 2017. This corresponds to a year-on-year increase of around 14% (1,744 TWh in 2016[142]). The spot market accounted for 828 TWh (653 TWh in 2016[143]) and a total volume of 1,154 TWh was traded on the futures market (1,091 TWh in 2016 TWh).[144]

The entire trading volume on PEGAS relating to the German market areas GASPOOL and NCG, including "cleared volume" was around 396 TWh in 2017, a decline of around 29 TWh, or 7%, on the previous year's figure of 425 TWh. While the trading volume for the GASPOOL market area increased by approximately 19 TWh or around 16%, the volume for the NCG market area declined by 48 TWh or around 16%. The on-exchange volume traded on the spot market increased again in 2017 and was around 309 TWh (around 295 TWh in the previous year). In 2017, as in previous years, the focus of spot trading for both market areas was on day-ahead contracts (NCG: 115.8 TWh, 128.5 TWh in the previous year); GASPOOL: 69.3 TWh, (51.1 TWh in the previous year). The trading volume of futures contracts decreased from about 130 TWh in 2016 to about 86 TWh in 2017, corresponding to a decline of 34%.

[142] The corresponding value in the Monitoring Report 2017 (1756.2 TWh) was amended.

[143] The corresponding value in the Monitoring Report 2017 (665.5 TWh) was amended.

[144] EEX Group Annual Report 2017, p. 54

Development of natural gas trading volumes on EEX for the German market areas (TWh)

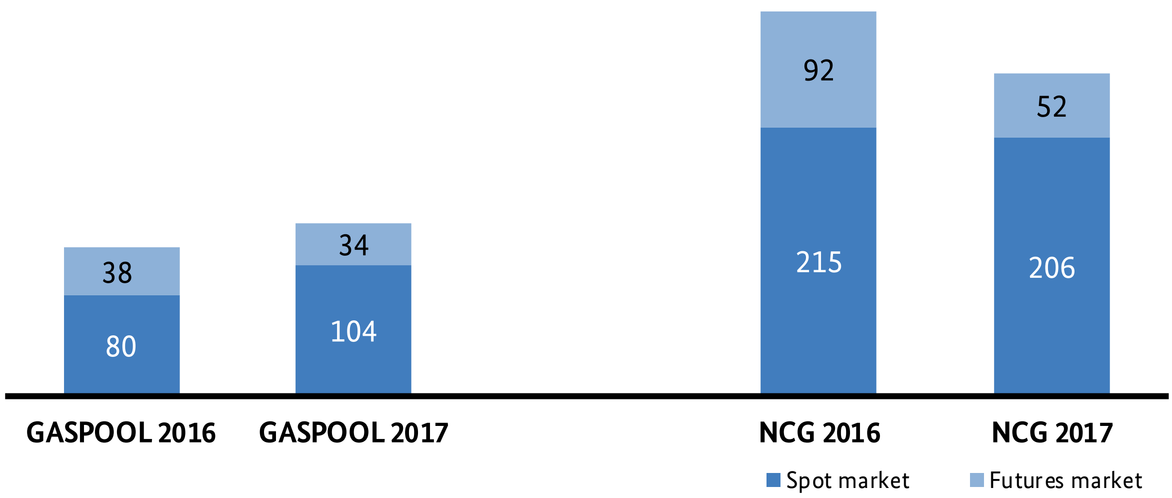


Figure 190: Development of natural gas trading volumes on EEX for the German market areas

The annual average number of active[145] participants on the spot market per trading day was 84 for NCG contracts (79 in the previous year) and around 71 for GASPOOL contracts (around 68 in the previous year). By contrast, the average number of active participants on the futures market per trading day was around 8.9 (NCG; 11.2 in the previous year) and around 6.4 (GASPOOL: 7.1 in the previous year). This corresponds to the number of participants from the previous year. The comparison of these figures has to take account of the fact that, owing to their term, futures contracts are geared towards higher volumes than spot contracts. In light of the lower growth rates on the futures market, an important role is played by the fact that due to daily margining (the daily adjustment of the pledged collateral) exchange-traded and thus cleared contracts represent a liquidity risk to the market player for the entire long period until maturity and can also entail a considerable amount of effort.

Market makers[146] operate on the PEGAS gas futures market to ensure liquidity and continuous trade. As market makers, the companies' share of turnover in all gas futures contracts concluded via PEGAS in 2017 was about 21% on the sales side and about 31% on the purchase side. Besides agreements with market makers, PEGAS also maintains contracts with trading participants who are committed to strengthening liquidity to an individually agreed extent (Liquidity Provider). In terms of trading volume, these companies accounted for 35% of sales and around 23% of purchases in 2017.[147]

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[145] Participants are considered to be active on a trading day if at least one of their bids has been submitted.

[146] An exchange participant who has undertaken to publish binding purchase and sales prices (quotations) at the same time is referred to as a market maker. Market makers are meant to increase the liquidity of the market place.

[147] The figures quoted in this section represent the respective shares of market makers and liquidity providers of the trading volume. However, not every megawatt hour supplied by these companies is traded by the companies in their capacity of market maker / liquidity provider. These companies also trade on the exchange independently of their contracts as market makers / liquidity providers.

2. Bilateral wholesale trading

By far the largest share of wholesale trading in natural gas is carried out on a bilateral basis, ie off the exchange ("over the counter" – OTC). Bilateral trading offers the advantage of flexible transactions, which, in particular, do not rely on a limited set of contracts. Brokerage via broker platforms is an important part of OTC trading.

2.1 Broker platforms

Brokers act as intermediaries between buyers and sellers and pool information on the demand and supply of short-term and long-term natural gas trading products. The services of a broker can reduce research costs and make it easier to effect large transactions while at the same time allowing greater risk diversification. Brokers also offer services to register trading transactions brokered by them for clearing on the exchange to hedge the counterparty default risk of the parties. Electronic broker platforms are used to formalise the bringing together of interested parties on the supply and demand sides and so increase the chances of the two parties reaching an agreement.

Nine broker platforms (ten in the previous year[148]) took part in this year's collection of wholesale trading data.

The natural gas trading transactions brokered by these broker platforms in 2017 with Germany as the supply area comprised a total volume of 2,672 TWh (3,120 TWh in the previous year), of which 1,120 TWh were contracts to be fulfilled in 2017 (fulfilment period of one week or more).

The decrease in volume is confirmed by the figures relating to brokered natural gas trading for the NCG and GASPOOL market areas published by the London Energy Brokers Association (LEBA).[149] Seven of the nine broker platforms that provided data on which the above evaluation was based are members of LEBA. These broker platforms accounted for a total of 2,483 TWh for the two German market areas in 2017. This represents a decrease of 11% on the previous year's volume of 2,775 TWh.

[148] In the 2017 Monitoring Report the data of eleven broker platforms was collected for the gas sector, one of these platforms was actually only active in the electricity sector.

[149] See London Energy Brokers' Association, OTC Energy Volume Report, https://cdn.evia.org.uk/content/monthly_vol_reports/LEBA%20Energy%20Volume%20Report%20December%202017.pdf (retrieved on 13 April 2018)

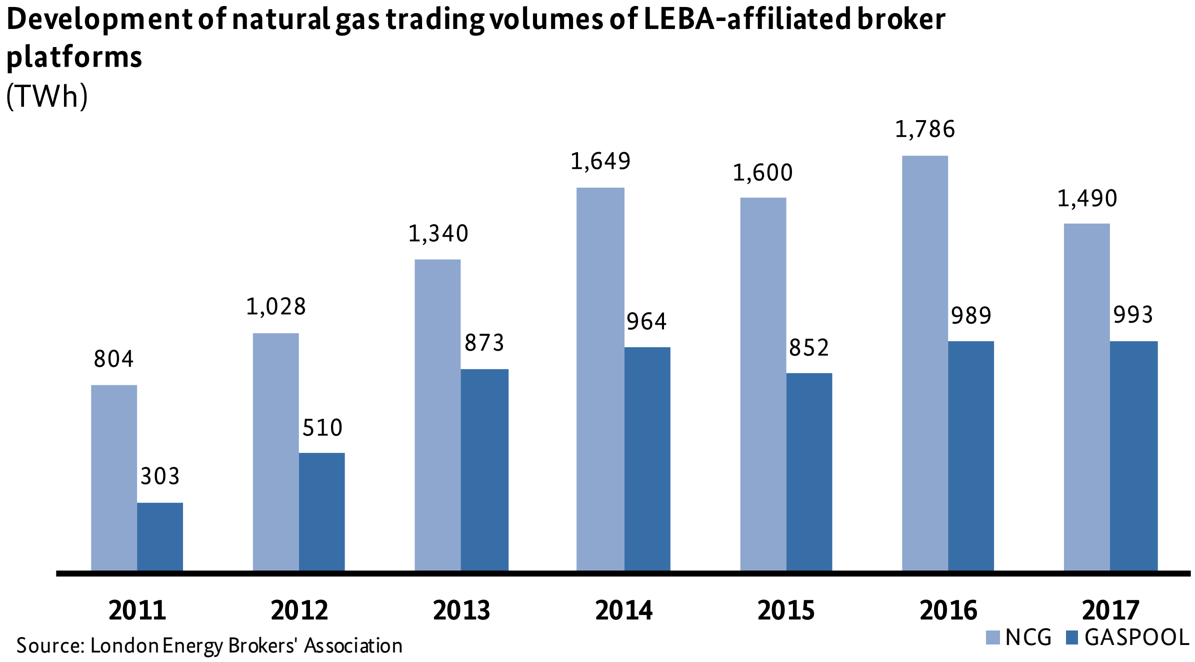

Figure 191: Development of natural gas trading volumes of LEBA-affiliated broker platforms for German market areas

On the spot market short-term transactions with a fulfilment period of less than one week account for about 18% of the trade brokered by the nine broker platforms whereas 82% are futures contracts.

Transactions in the current year make up the majority of brokered natural gas trading followed by the activities for the subsequent year. While natural gas traded during and for 2017 (including spot trading) constitutes as much as 60% of the total volume and still as much as 30% for the subsequent year 2018, the share of transactions with supply dates in 2019 and later is ten per cent. This structure largely corresponds to the previous year’s result with a slight reduction in the quota for transactions with supply dates in 2019 and later (minus three per cent).

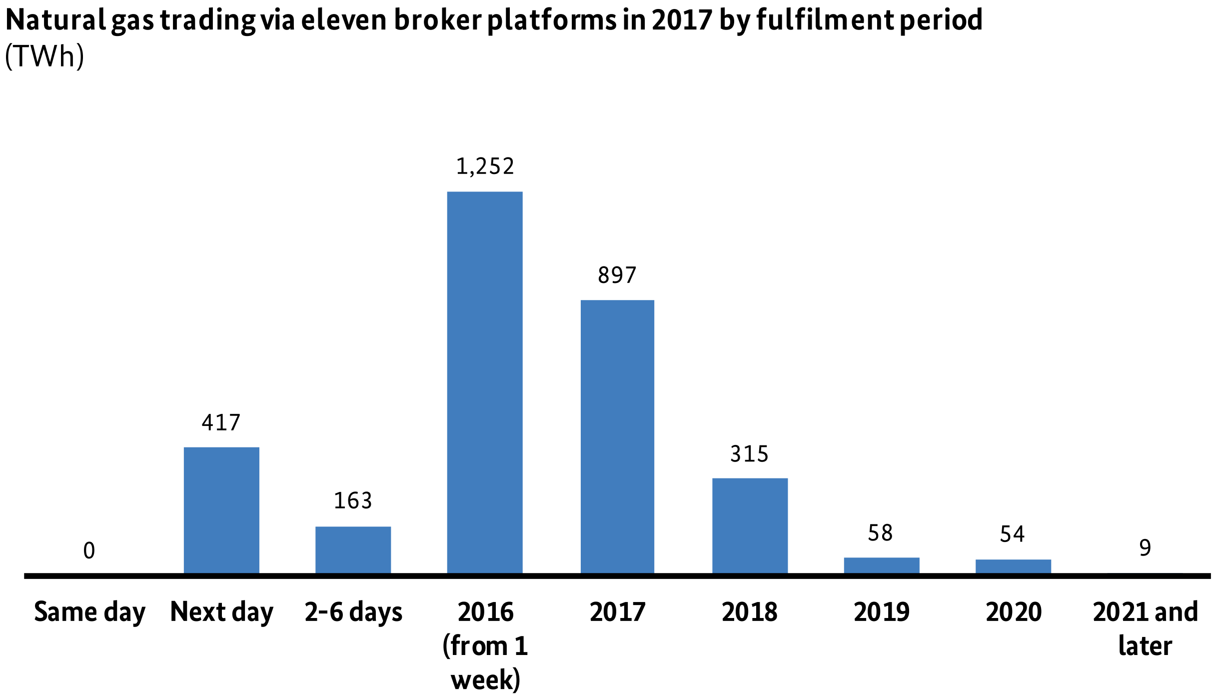

Figure 192: Natural gas trading for the German market areas via nine broker platforms in 2017 by fulfilment period

2.2 Nomination volumes at virtual trading points

The nomination volumes at the two German virtual trading points (VTPs) of NCG and GASPOOL are key indicators of the liquidity on the wholesale natural gas markets. Balancing group managers can transfer gas volumes between balancing groups via the VTPs through nominations.

Wholesale transactions with physical fulfilment are generally reflected in increasing nomination volumes. However, the nomination volume increases more slowly than the trading volume since only the trade balance between parties is nominated, i.e. between market players and the exchange in the course of the exchange transaction. Besides, not all nomination volumes are linked to transactions on the wholesale markets, one example being transfers between balance groups of the same company.

There has been an increase in nomination volumes at virtual trading points since the consolidation of the German market areas in October 2011. This trend did not continue in the reporting year.

The two parties responsible for the market area, NCG and GASPOOL, once again took part in this year's collection of gas wholesale trading data. The gas volumes nominated at the two VTPs decreased slightly from a total of 3,650 TWh in the previous year to 3,620 TWh, a decrease of about one per cent. The GASPOOL VTP accounted for about 43% of the nomination volume, and the NCG VTP for 57%. Almost 89% of the nomination volume consisted of high calorific gas, the remaining 11% of low calorific gas.

The nominated volumes of high calorific gas at GASPOOL VTP increased only marginally (about 5%) year-on-year. The nominated volume of high calorific gas at NCG VTP decreased by minus 3.5%. The nominated volume of low calorific gas at GASPOOL VTP decreased about four per cent and around nine per cent at NCG VTP. This was based on substantially lower trading volumes.

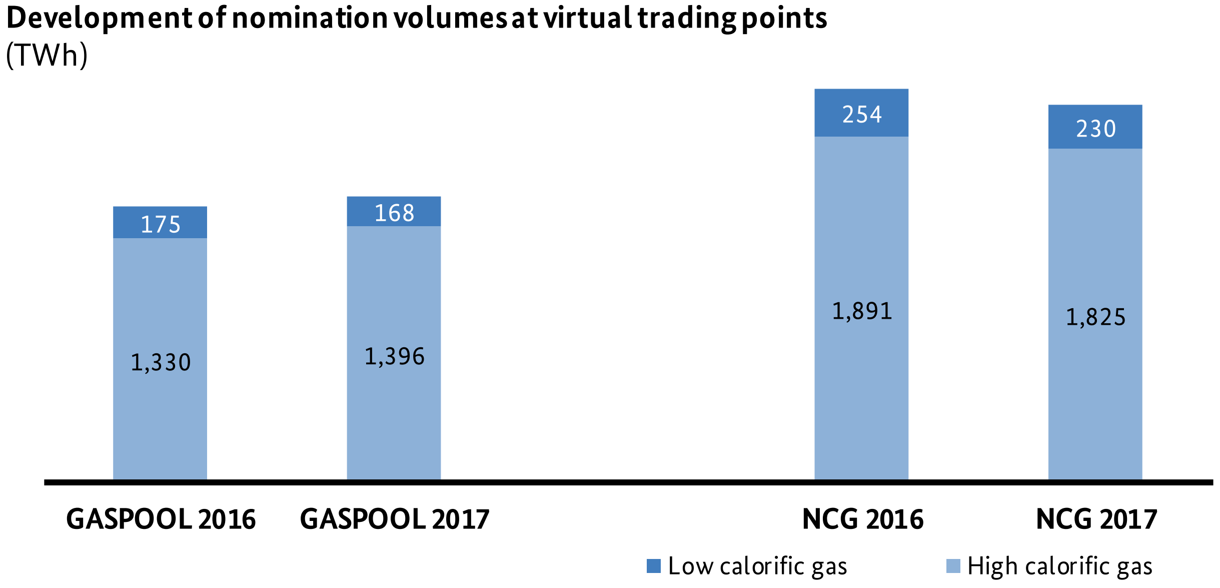

Figure 193: Development of nomination volumes at the German virtual trading points

As in previous years, the monthly nomination volumes reflect seasonal differences. The (aggregated) monthly nomination volumes of both VTPs peaked at 251 TWh between May and August 2017. The lowest nomination volume was 226 TWh in June 2017; the annual peak of around 439 TWh was reached in January 2017.

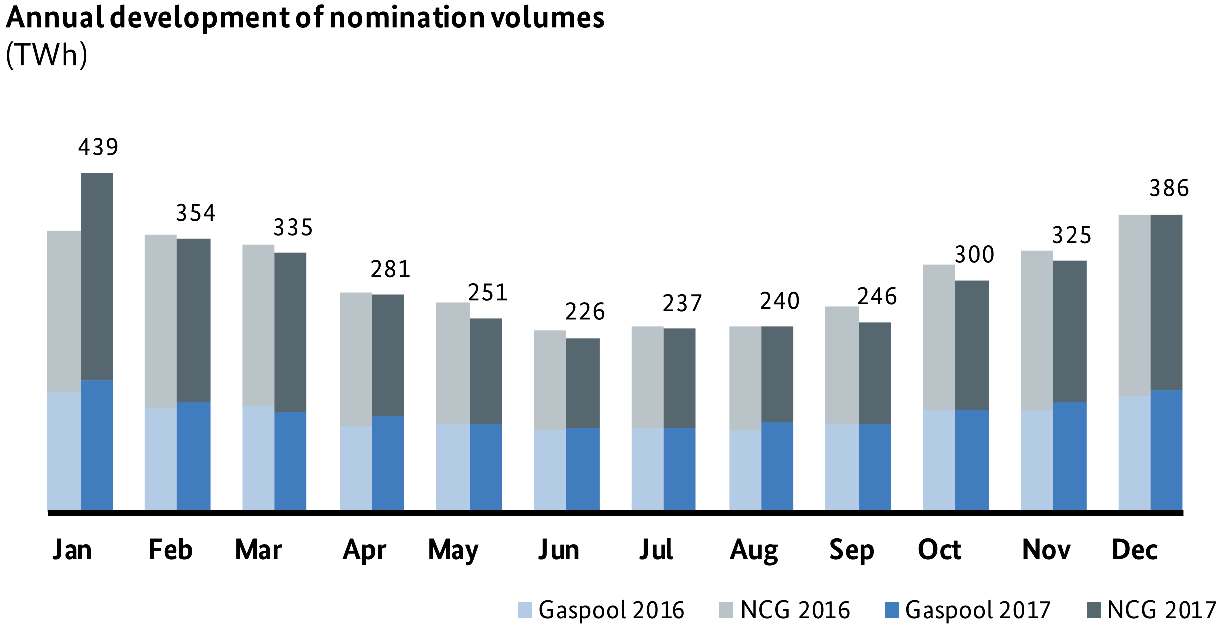

Figure 194: Annual development of nomination volumes at virtual trading points in 2016 and 2017

The number of active trading participants, i.e. companies that carried out at least one nomination in the relevant month, changed again in 2017. The number of active trading participants in the NCG market areas increased from 319 to 328 for high calorific gas and from 167 to 175 for low calorific gas (in both cases by about 3%). The annual average number of active participants in the GASPOOL market area increased year-on-year from 288 to 298 (by about 3%) for high calorific gas and the number of active participants in the GASPOOL market area decreased from 197 to 154 (by about 22%) for low calorific gas.

3. Wholesale prices

The daily reference price published by EEX shows the price level on the on-exchange spot market and therefore the average costs of short-term natural gas procurement. In addition, the European Gas Index Germany (EGIX) provides a reference price for procurement within a timeframe of approximately one month. The BAFA cross-border price for natural gas, which is described in greater detail on page 399 below, gives an approximate indication of the price of natural gas procurement on the basis of long-term supply contracts.

EEX determines daily reference prices on the on-exchange spot market for the GASPOOL and NCG market areas by calculating the volume-weighted average of the prices across all trading transactions for gas supply days on the last day before physical fulfilment.[150] The daily reference prices are published by EEX at 10:00 a.m. CET on the relevant supply day and are an indicator of the price level of spot market transactions.

The (unweighted) annual average of the daily reference price was €17.51/MWh for the NCG market area and €17.28 for GASPOOL in 2017. The previous year's figures were €14.12/MWh for NCG and €14.12/MWh for GASPOOL, which means that the annual average of the daily reference prices rose by about 24% (NCG) and 22% (GASPOOL). The daily reference prices fluctuated between €14.82/MWh on 25 June and €23.06/MWh on 6 February in the course of 2017.

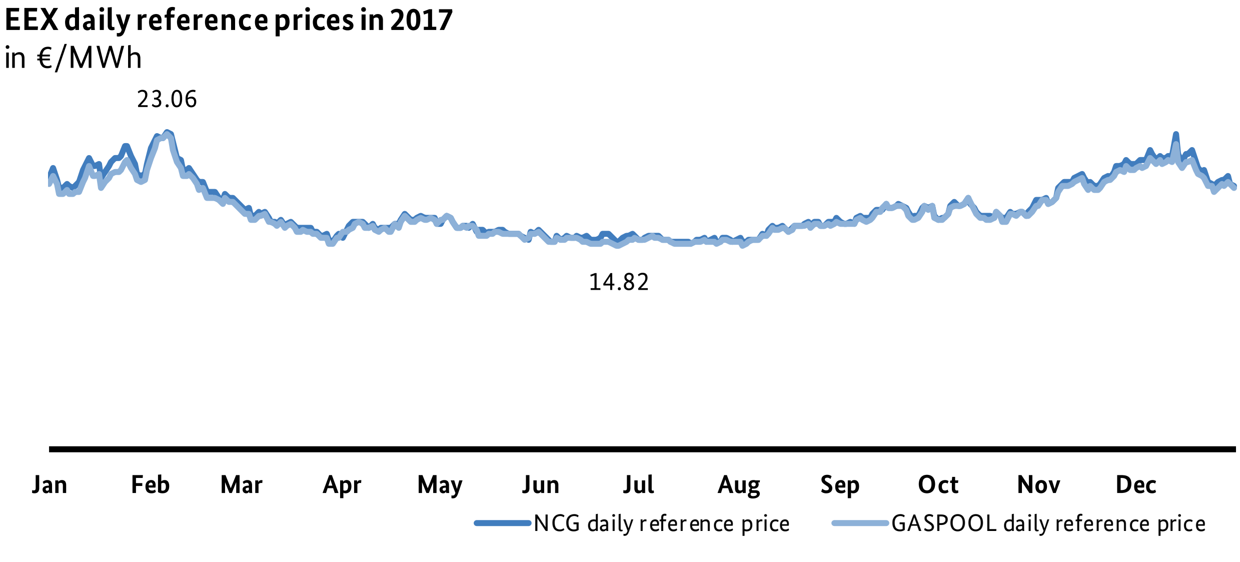

Figure 195: EEX daily reference prices in 2017

[150] For details of the calculation method see https://www.eex.com/blob/9276/b906c6cf0b59cd53d7bfe33d15080b75/2013-11-28-beschreibung-tagesreferenzpreis-pdf-data.pdf (retrieved on 13 April 2018).

The difference between the daily reference prices of NCG and GASPOOL was again quite small in 2017 with a maximum of 2% on 359 out of 365 days. The difference reached a higher level of more than 3% on six days only.

Distribution of the differences between the EEX daily reference price for GASPOOL and NCG in 2017
Number of days with a difference of

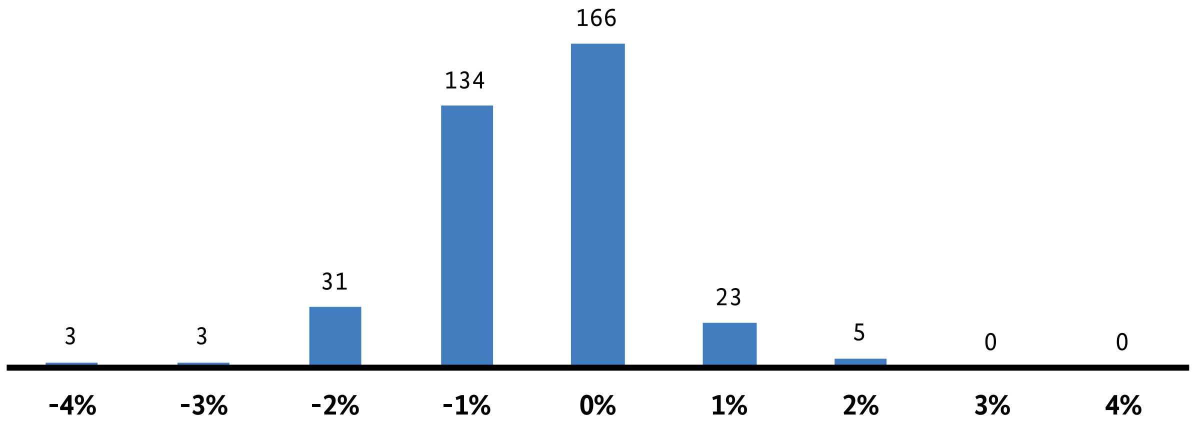

Figure 196: Distribution of the differences between the EEX daily reference price for GASPOOL and NCG in 2017

The EGIX Germany is a monthly reference price for the futures market. It is based on transactions on the on-exchange futures market that are concluded in the latest month-ahead contracts for the NCG and GASPOOL market areas[151]. In 2017, the EGIX Germany ranged from €15.12/MWh in August to €19.60MWh in March. The arithmetic mean of the twelve monthly figures was €17.11/MWh, an increase of approximately 21% compared to the previous year's figure of €14.15/MWh.

The cross-border price for each month is calculated by the Federal Office for Economic Affairs and Export Control (Bundesamt fu□r Wirtschaft und Ausfuhrkontrolle – BAFA) as a reference price for long-term natural gas procurement. To this end, BAFA evaluates documents relating to natural gas procured from Russian, Dutch, Norwegian, Danish and British gas extraction areas. The calculations are mainly based on import quantities and prices agreed in import contracts[152], spot volumes and prices are largely disregarded.

The monthly BAFA cross-border prices for natural gas ranged from €13.01 /MWh to €23.04/MWh between 2015 and 2017. The (unweighted) average of the monthly cross-border prices was €16.98 /MWh in 2017, up by 12% from the 2016 figure of €15.23 /MWh.

[151] For a detailed calculation of the values see https://www.powernext.com/sites/default/files/download_center_files/20180201_PEGAS_Reference_Price_EGIX.pdf (retrieved on 13 April 2018).

[152] See https://www.bafa.de/SharedDocs/Downloads/DE/Energie/egas_aufkommen_export_1991.html (retrieved on 13 April 2018).

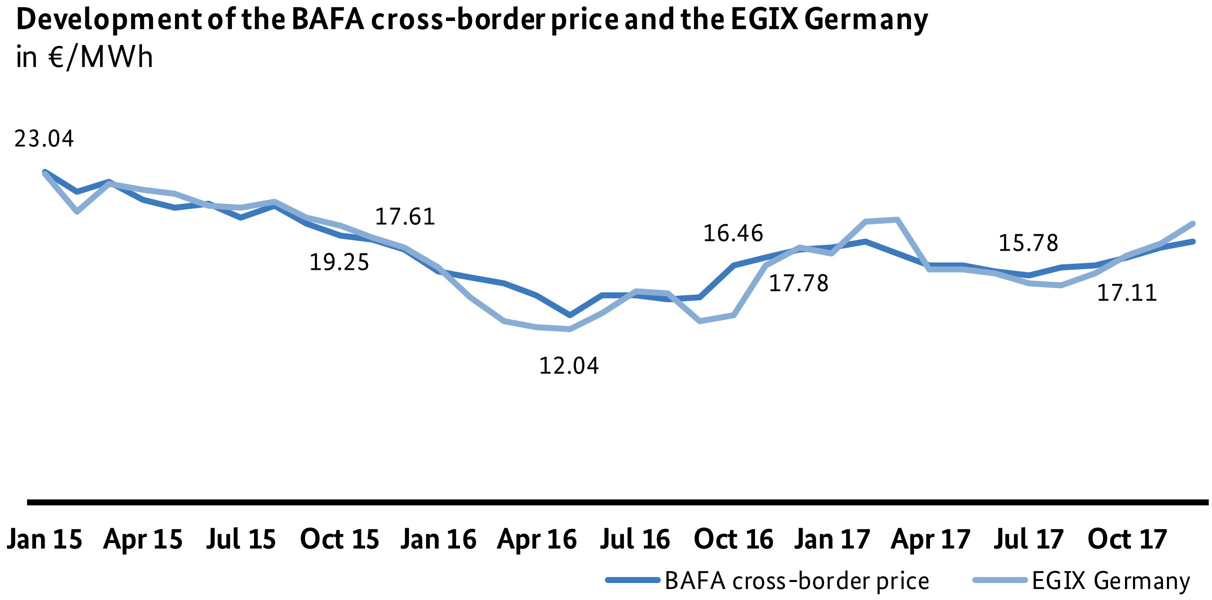

Figure 197: Development of the BAFA cross-border price and the EGIX Germany between 2015 and 2017

Older gas import contracts were usually based on price agreements linked to oil prices. In recent years, this link has been increasingly disregarded in new contracts and contract amendments. Price indices, such as the EEX daily reference price or the EGIX – allow long-term contracts to be indexed according to exchange prices. The development of the BAFA cross-border price in 2017 clearly shows that it is aligned with natural gas exchange prices.

F Retail

1. Supplier structure and number of providers

A total of 1,039 gas suppliers were surveyed for the 2018 Monitoring Report. In the evaluation of the data provided by gas suppliers, each supplier is considered as an individual legal entity without taking possible company affiliations or links into account. This evaluation came to the conclusion that the majority of gas suppliers (513 companies or 52%) supplied between 1,001 and 10,000 meter points each.[153] These 513 suppliers delivered gas to 2.2m or 15.9% of the total number of meter points.[154] The amount of gas that these suppliers delivered to final consumers was 140.4 TWh. Based on the total calculated volume of gas delivered of 830 TWh, this corresponds to a share of 17%.

The smallest group of gas suppliers (comprising 24 companies or just over 3%), in which each company supplies more than 100,000 meter points, supplies 5.6m or 41% of the consumer meter points. The amount of gas that these suppliers delivered to final consumers was 200 TWh. Based on the total reported volume of gas delivered of 830 TWh, this corresponds to a share of 24%. Most gas suppliers in Germany therefore have a relatively small number of customers, whereas in absolute terms the few large gas suppliers serve the majority of meter points.

Gas suppliers by meter points supplied (number and percentage)
These figures do not take account of company affiliations

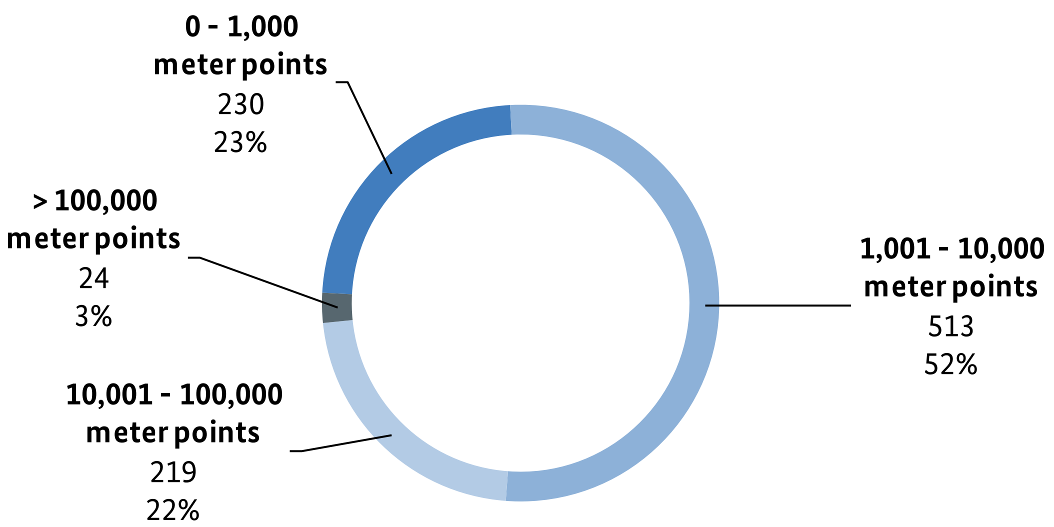

Figure 198: Gas suppliers by number of meter points supplied (number and percentage) – as at 31 December 2017

[153] The analysis is based on the data provided by 986 gas suppliers.

[154] The number of final consumer meter points reported by the gas suppliers, standing at 14.0m, deviates slightly from the figure reported by the network operators, which stands at 14.1m. This difference is due to the greater market coverage of gas TSOs and DSOs.

One indicator of the degree of choice for gas customers is the number of suppliers in each network area. In the 2018 survey, the gas network operators were asked to report on the number of suppliers serving at least one final consumer in their networks. This refers to the number of supplying legal entities, meaning that any company affiliations or links among the suppliers are not taken account of. Given that many suppliers are offering rates in many networks in which they do not have a considerable customer base, the reported high number of suppliers does not automatically mean a high level of competition, but does give an indication of potential competition.

Since market liberalisation and the creation of a legal basis for a well-functioning supplier switch, there has been a steady rise in the number of active gas suppliers for all final consumers in the different network areas. This positive trend continued in 2017 as well.

In 2017, more than 50 gas suppliers were operating in 93% of the network areas. Final consumers in over 56% of network areas had a choice of more than 100 gas suppliers. If viewed separately, the trend for household customers is similarly positive. In nearly 87% of network areas, household customers have a choice of 50 or more gas suppliers. More than 100 gas suppliers are operating in 40% of network areas.

On average, final consumers in Germany can choose between 116 suppliers in their network area; household customers can, on average, choose between 98 suppliers (these figures do not take account of corporate groups).

Breakdown of network areas by number of suppliers operating
(all final consumers (left graph) and household consumers (right graph) in %)

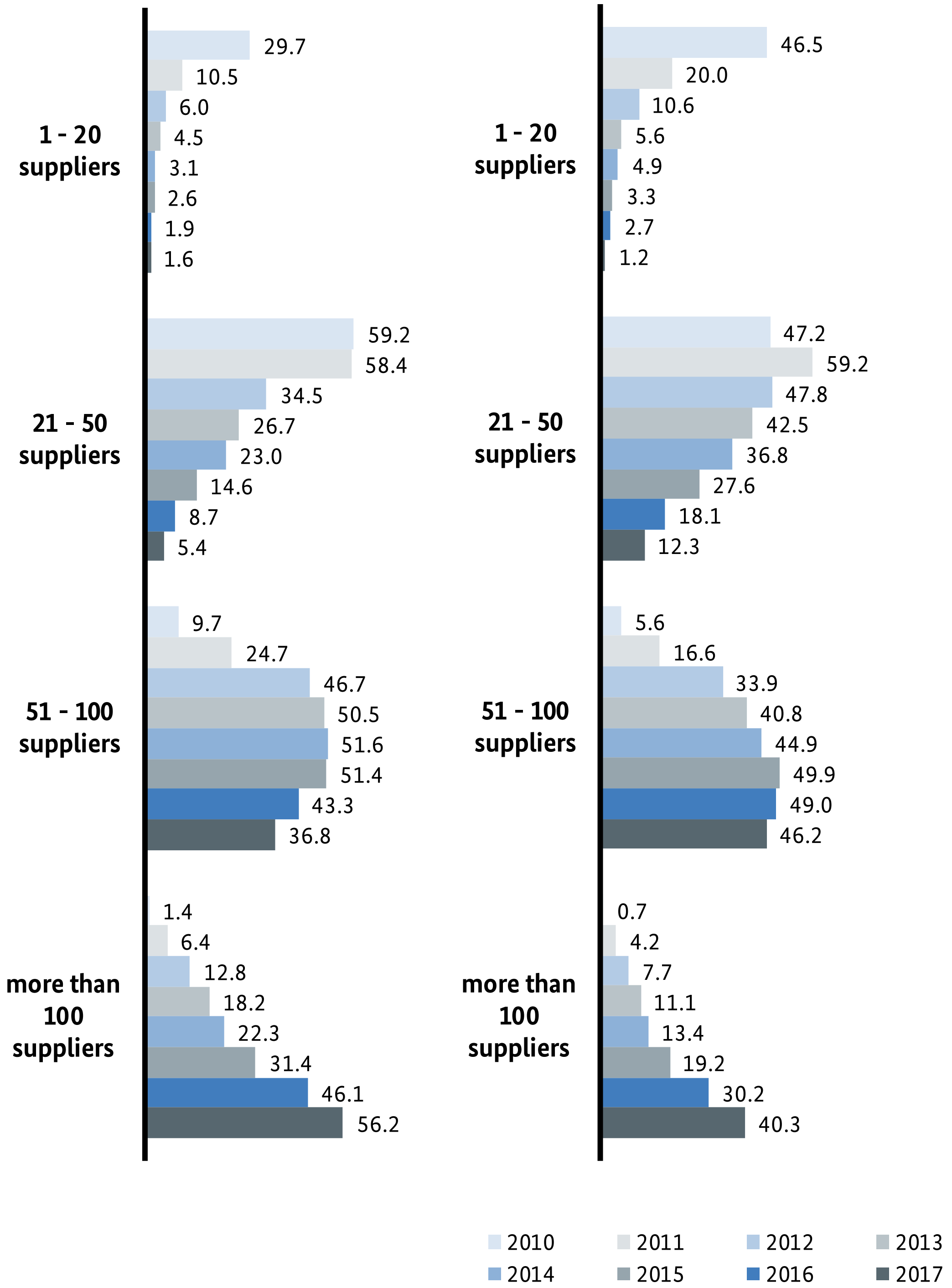

Figure 199: Breakdown of network areas by number of suppliers operating according to the survey of gas DSOs – as at 31 December 2017

Suppliers were also asked about the number of network areas in which they supply final consumers with gas. Only 13% of the gas suppliers operate in one established network area. Most of them (37%) supply final consumers in at most 10 network areas with gas and are therefore only active regionally. In order to determine the number of gas suppliers active nationwide, if a supplier is active in more than 500 network areas they are counted as active across all of Germany. A total of 46 gas suppliers (5%) fulfil this criterion and are regarded as suppliers that are active nationwide. On average, gas suppliers in Germany are active in around 75 network areas. A further criterion to measure nationwide activity of suppliers is the number of federal states in which they supply gas. Some 120 suppliers have contracts in all 16 federal states.

Gas suppliers by number of network areas supplied (number and percentage)
These figures do not take account of company affiliations

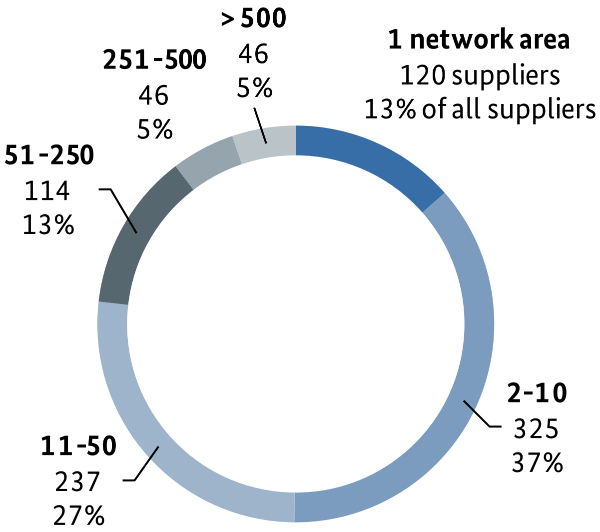

Figure 200: Gas suppliers by number of network areas supplied (number and percentage), according to the survey of gas suppliers – as at 31 December 2017

The German gas market is very heterogeneous, with many smaller gas suppliers and only about two dozen very large ones with large numbers of customers.

Nearly all household customers have at least 50 gas suppliers to choose from in their area. Almost half of them can actually select the best contract and rate for their needs from 100 suppliers.

The number of gas suppliers available to each household customer shows clear growth from year to year.

2. Contract structure and supplier switching

Changes in switching rates and processes are important indicators of the level of competition. There are challenges involved with the collection of such data, however, and the relevant data collection thus has to be limited to data that best reflects the actual switching behaviour.

In the monitoring survey, data on contract structures and supplier switching is collected through questions relating to each specific customer group to be completed by the TSOs, DSOs and suppliers.

Final consumers can be grouped according to their meter profile into customers with and without interval metering. For customers without interval metering, consumption over a set period of time is estimated using a standard load profile (SLP).

Final consumers can also be divided into household and non-household customers. Household customers are defined in the Energy Industry Act (EnWG) according to qualitative characteristics.[155] All other customers are non-household customers, which includes customers in the industrial, commercial, service and agricultural sectors as well as public administration.

According to gas retailers and suppliers, the total quantity of gas supplied by suppliers to all final consumers in 2017 reached 832 TWh (2016: 827.7 TWh). Based on the reported volumes of gas sold to SLP and interval-metered customers, about 454 TWh went to interval-metered customers and about 378 TWh to SLP customers, compared to 453 TWh and 371 TWh respectively in the previous year.[156] The majority of SLP customers are household customers. In 2017 the household customers alone were supplied with around 238.5 TWh (2016: 243.5 TWh).

In the monitoring survey, data is collected from the gas suppliers on the volumes of gas sold to various final consumer groups broken down into the following three contract categories:

- default contract,
- non-default contract with the default supplier, and
- contract with a supplier other than the local default supplier.

For the purposes of this analysis, the default contract category also includes fallback energy supply (section 38 EnWG) and doubtful cases.[157] Supply outside the framework of a default contract is either

[155] Section 3 para 22 EnWG defines household customers as final consumers who purchase energy primarily for their own household consumption or for their own consumption for professional, agricultural or commercial purposes not exceeding an annual consumption of 10,000 kilowatt hours.

[156] The difference between the amount of 825 TWh (total of interval-metered and SLP volumes) and the total volume of 830.1 TWh in Table 87 is due to incomplete data from the suppliers surveyed.

[157] In addition to household customers, final consumers served by fallback supply are usually included under the default supply tariff, section 38 EnWG. For monitoring purposes, suppliers were asked to allocate cases that could not be clearly categorised to "default supply".

designated as a non-default contract or is defined specifically ("non-default contract with the default supplier" or "contract with a supplier other than the local default supplier"). This is also known as a special contract sui generis between the supplier and the customer (cf section 1(4) KAV). An evaluation on the basis of these three categories makes it possible to draw conclusions as to the extent to which the importance of default supply and the default suppliers' competitive position have lessened since the liberalisation of the energy market.

The corresponding figures, however, should not be directly interpreted as "cumulative net switching figures since liberalisation". It must be noted that for monitoring purposes the legal entity is taken to be the contracting party, thus a contract with a company affiliated with the default supplier falls under the category "contract with a supplier other than the local default supplier".[158]

Once again, gas suppliers were asked how many household customers have switched or changed their energy supply contract in the 2017 calendar year (change of contract).

Data was also collected from the TSOs and DSOs on the number of customers in different groups switching supplier in 2017. A supplier switch, as defined in the monitoring survey, means the process by which a final consumer's meter point is assigned to a new supplier. In this analysis, too, it must be noted that the change of supplier question refers to a change in the supplying legal entity. A network operator cannot distinguish between an internal reallocation of supply contracts to another group company and a change of supplier initiated by a customer – or only at considerable time and expense – and therefore both fall under supplier switching. The same applies to any insolvency of the former supplier or in the event that the supplier terminates the contract ("involuntary supplier switch"). This is why the actual extent to which customers switched suppliers may deviate slightly from the figures established in the survey. In addition to supplier switches, the choice of supplier made by household customers upon moving home was also analysed.

Gas consumers are divided into household and non-household customers. Household customers are recorded using standard load profiles. A standard load profile is a consumption forecast for a typical household customer who uses gas to heat their home, for example.

The total gas consumption of household customers fell slightly in 2017, largely due to the warm weather.

Customers on default tariffs can make savings by switching tariff or supplier. The average household customer with gas consumption of 23,250 kWh a year could make an average annual saving of €135 as at 1 April 2018 by changing contract. The average potential saving for the year through changing supplier was €216.

[158] It is also possible that further ambiguities may arise, for example if the local default supplier changes.

2.1 Non-household consumers

2.1.1 Contract structure

Gas sold to non-household customers is mainly supplied to metered load profile customers where consumption is recorded at short intervals ("load profile"). Such customers are characterised by high consumption and/or high energy requirements.[159] All metered load profile customers are non-household customers with a high level of consumption, such as industrial customers or gas power plants.

In the reporting year 2017, around 804 gas suppliers (separate legal entities) provided information on metering points and on the volumes supplied to metered load profile customers (800 suppliers responded in the previous year). The 804 gas suppliers include a number of affiliated companies, so that the number of suppliers is not equal to the number of actual competitors.

Overall these suppliers sold over 454 TWH of gas to metered load profile customers via more than 39,115 metering points in 2017. Over 99% of this volume was supplied under contracts with the default supplier outside the default supply[160] (130 TWh) and under contracts with suppliers other than the local default supplier (323 TWh). It is unusual, but not impossible, for metered load profile customers to be supplied under a default or auxiliary supply contract. Around 0.32 TWh of gas was supplied to metered load profile customers with a default or auxiliary supply contract. This corresponds to about 0.07% of the total volume supplied to such customers.

About 29% of the total volume supplied to metered load profile customers was sold under contracts with the default supplier outside the default supply and about 71% under supply contracts with a legal entity other than the default supplier. This is the same distribution as in the previous year. The figures show that default supply status is of only minor importance for the acquisition of gas customers with a metered load profile.

[159] In accordance with section 24 of the Gas Network Access Ordinance (GasNZV), interval metering is generally required for customers with a maximum hourly consumption rate exceeding 500 KW or maximum annual consumption of 1.5 GWh.

[160] In accordance with Section 36 of the German Energy Act (EnWG), default supply relates only to household customers. In the following, the term default supply used in connection with non-household customers refers to an auxiliary supply.

Contract structure for metered load profile customers in 2017
Volume and distribution

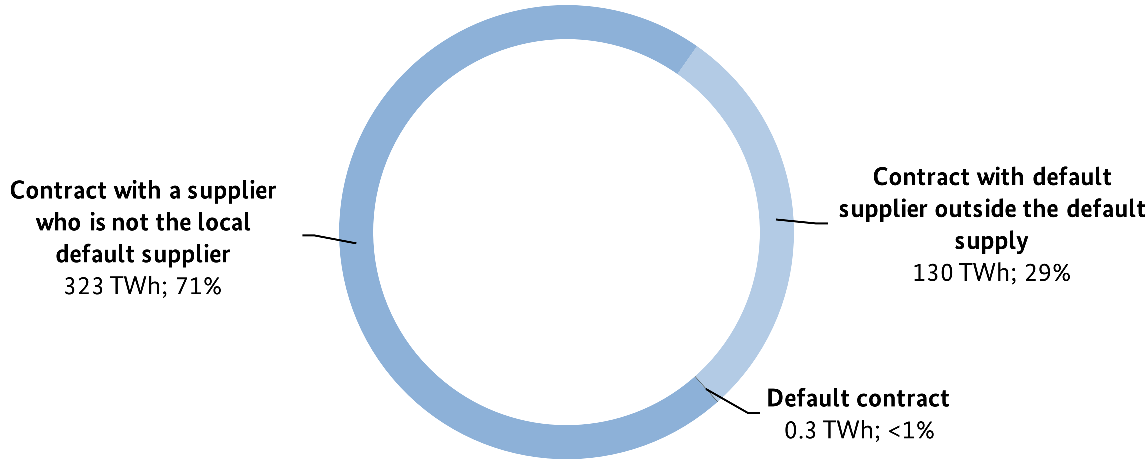

Figure 201: Contract structure for metered load profile customers in 2017

2.1.2 Supplier switching

Data on the supplier switching rates (as defined for monitoring, see above) of different customer groups in 2017 was collected in the TSO and DSO surveys. This did not include the percentage of industrial and commercial customers who have changed supplier once, more than once or not at all over a period of several years. The supplier switching figures were retrieved and differentiated by reference to five different consumption categories. The calculation of the switching rate for non-household customers included only four consumption categories with a final consumption exceeding 0.3 GWh/year, including gas-fired power plants. The survey produced the following results:

Supplier switching by consumption category in 2017

End consumer category	Number of metering points with change of supplier	Share of all metering points in the consumption category	Volume consumed at metering points with change of supplier	Share of total volume consumed in the consumption category
< 0.3 GWh/year	1,396,721	9.9%	35.1 TWh	10.4%
≥ 0.3 GWh/year < 10 GWh/year	15,541	11.2%	14.3 TWh	11.0%
≥ 10 GWh/year < 100 GWh/year	654	7.6%	11.2 TWh	10.1%
≥ 100 GWh/year	285	48.1%	24.8 TWh	9.7%
Gas power plants	2	0.9%	2.6 TWh	2.6%
Total	**1,413,203**		**88.0 TWh**	

Table 116: Supplier switching by consumption category in 2017

The total number of metering points with a change of supplier fell by 99,025 (-6.8%) compared to the previous year. This decrease is attributable in particular to customers with a consumption below 0.3 GWh/year, which also includes household customers. Here the number of metering points decreased by 97,108 (minus 6.5%) compared to the previous year. In 2017, the total gas volume affected by supplier switching was 88 TWh in all five categories. Compared to the previous year, it decreased by 15 TWh or 15%. The four categories with consumption exceeding 0.3 GWh/year (including gas-fired power plants) consist entirely of non-household customers. The volume-based switching rate across these four categories was 8.9% in 2017, significantly lower than around 11.1% in the previous year.[161]

[161] This significant decrease could be partially due to the fact that the return of reports on supplier switching was significantly lower than the level of the previous year. However, irrespective of this effect the volume-based switching rate declined in 2017 compared to 2016, if only to a lesser extent.

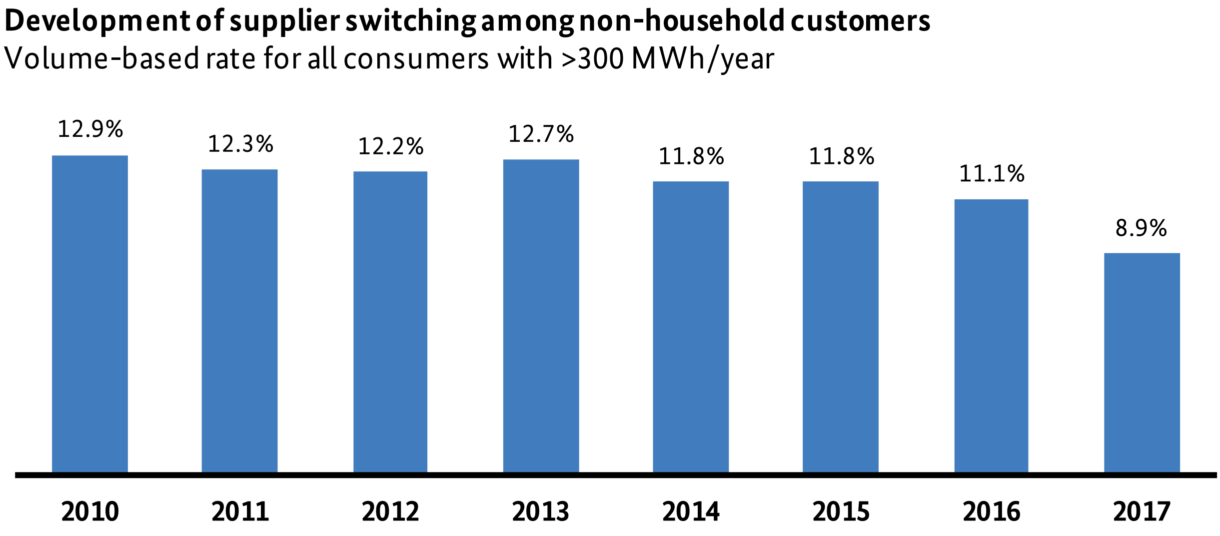

Figure 202: Development of supplier switching among non-household customers

2.2 Household customers

2.2.1 Contract structure

In the data survey for the 2018 Monitoring Report, the survey of quantities of gas supplied to household customers was broken down into three different consumption bands:

- Band I (D1): annual consumption below 20 GJ (5,556 kWh)

- Band II (D2): annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh)

- Band III (D3): annual consumption above 20 GJ (55,556 kWh).

An overall analysis of how household customers were supplied in 2017 in terms of volume shows that just over half of them, 51%, were supplied by the local default supplier under a non-default contract and were supplied with 126.4 TWh of gas (2016: 53% or 128.3 TWh).

Only 19% of household customers had a default supply contract in 2017 and were supplied with 47.3 TWh of gas, compared with 22% and 52.8 TWh, respectively, in 2016. The percentage of household customers who had a contract with a supplier other than the local default supplier increased again and was 30% (2016: 25.6%) for 75.5 TWh of gas (2016: 62.4 TWh).[162] Thus supply by the default supplier at a default tariff is the least popular form of supply.

[162] The total volume of gas supplied to household customers reported by gas suppliers of 249.2 TWh differs from the amount reported by gas DSOs (278.8 TWh) because the market coverage of the network operator survey is higher.

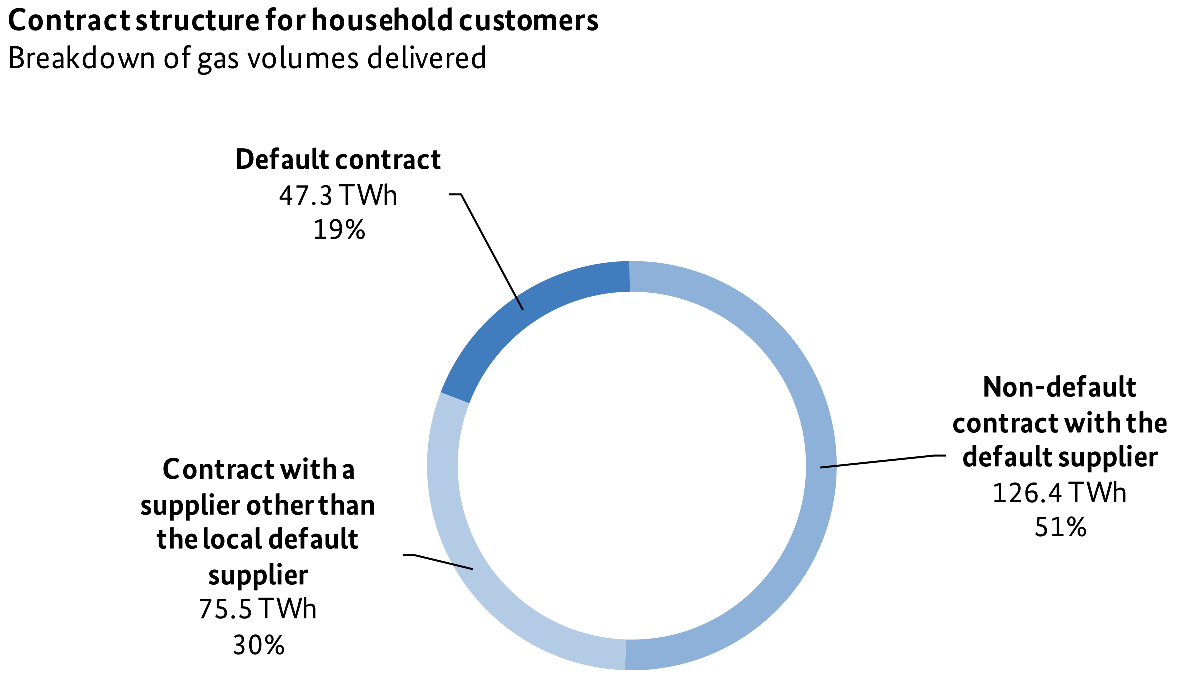

Figure 203: Contract structure for household customers (volume of gas delivered) according to survey of gas suppliers – as at 31 December 2017

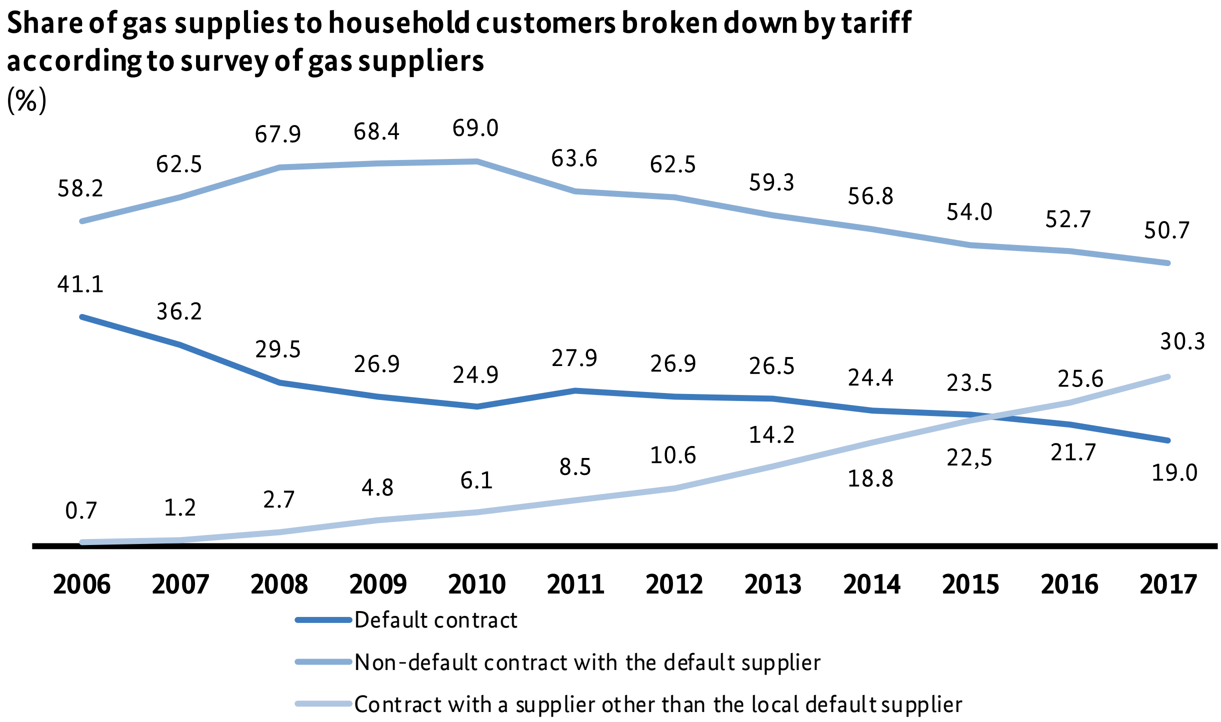

Figure 204: Share of gas supplies to household customers broken down by tariff according to survey of gas suppliers

The volumes of gas supplied to household customers were broken down into three consumption bands, D1, D2 and D3, to enable a more in-depth analysis of how household customers were supplied. This makes clear that the majority of low-consumption household customers (D1) were supplied under a default contract. Although disproportionately high at 43.9%, this figure was lower than the 47.8% from the previous year. By contrast, the majority of customers with average (D2) and high (D3) consumption were supplied under a non-default contract with the local default supplier.[163]

Contract structure for household customers (volume and distribution) broken down by consumption bands D1, D2 and D3

Contract type	Band I with a consumption of < 5,556 kWh (20 GJ)		Band II with a consumption of ≥ 5,556 kWh (20 GJ) < 55,556 kWh (200 GJ)		Band III with a consumption of ≥ 55,556 kWh (200 GJ)	
	Volume (TWh)	Distribution (%)	Volume (TWh)	Distribution (%)	Volume (TWh)	Distribution (%)
Default contract	2.4	44	32.7	20	6.5	12
Non-default contract with the default supplier	1.8	33	85.1	51	27.5	52
Contract with a supplier other than the local default supplier	1.3	23	48.8	29	18.8	36
Total	5.5	100	166.6	100	52.8	100

Table 117: Contract structure for household customers (volume) broken down into consumption bands – as at 31 December 2017

When focusing on the number of household customers supplied in 2017, it becomes clear that a relative majority of 43.7% of them signed a non-default contract with the local default supplier. In terms of both the volume of gas delivered and number of customers supplied, a total of about 71% of household customers are supplied by the default supplier under a default contract or a contract outside of default supply.[164] The differences between the share of customers supplied on default terms and those on non-default terms in a contract with the default supplier (19% compared with 27% and 51% compared with 44%) result from the fact that household customers with a higher consumption of gas tend to switch to a more affordable contract on non-default terms.

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[163] The analysis is based on a reported volume of gas supplied to household customers of 224.9 TWh. The difference from the total reported volume of gas supplied to household customers by all gas suppliers of 249.2 TWh is due to a lack of data from some suppliers.

[164] The total number of household customers reported by gas suppliers of 12.3m differs from the number of household customers reported by DSOs (12.5m) because the market coverage of the network operator survey is higher.

Contract structure for household customers
Number of customers supplied

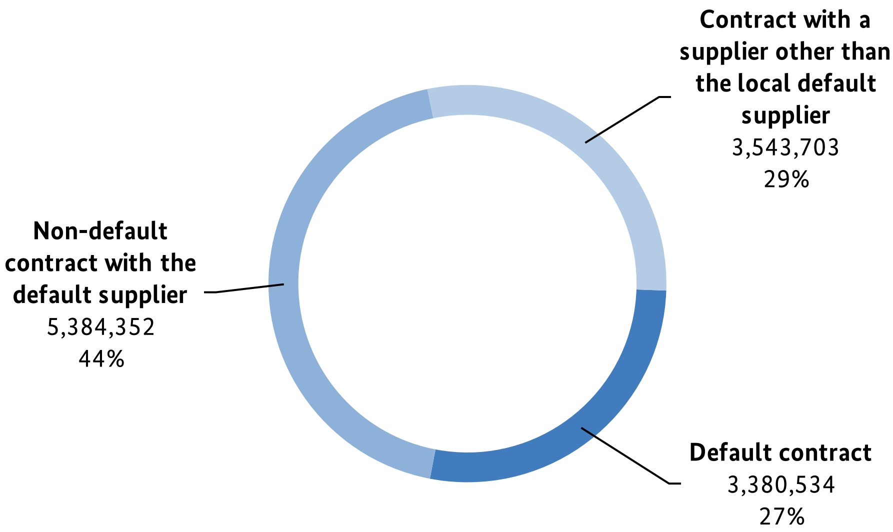


Figure 205: Contract structure for household customers (number of customers supplied) according to survey of gas suppliers – as at 31 December 2017

The number of households supplied was also broken down into three consumption bands (D1, D2 and D3) to enable a more in-depth analysis of how household customers were supplied. This makes clear that the majority of low-consumption household customers (D1) were supplied under a default contract (53.2%). The majority of customers with average (D2) and high (D3) consumption were supplied under a non-default contract with the default supplier.[165]

[165] The analysis is based on a reported total number of household customers of 11.4m. The difference from the total reported number of household customers of all gas suppliers of 12.3m is due to a lack of data from some suppliers.

Contract structure for household customers (number and distribution), broken down by consumption bands D1, D2 and D3

Contract type	Band I with a consumption of < 5,556 kWh (20 GJ)		Band II with a consumption of ≥ 5,556 kWh (20 GJ) < 55,556 kWh (200 GJ)		Band III with a consumption of ≥ 55,556 kWh (200 GJ)	
	Number (m)	Distribution (%)	Number (m)	Distribution (%)	Number (m)	Distribution (%)
Default contract	1.1	52	2.0	22	0.1	17
Non-default contract with the default supplier	0.6	29	4.3	49	0.3	50
Contract with a supplier other than the local default supplier	0.4	19	2.6	29	0.2	33
Total	2.1	100	8.8	100	0.6	100

Table 118: Contract structure for household customers (number of customers supplied), broken down by consumption bands – as at 31 December 2017

Just over half of household customers were supplied by the local default supplier under a non-default contract, ie they had already switched to a cheaper rate from their local gas supplier.

The number of household customers with the expensive default contracts has been falling for years and now makes up barely a fifth of the total.

A third of household customers are now under a contract with a supplier other than the default supplier, meaning they have actively chosen to go to another gas supplier.

Consumers are recommended to find out what type of contract they have (default or otherwise) and to compare the prices of their current supplier with those of competitors. It may be worthwhile to switch contracts or supplier.

2.2.2 Change of contract

Gas suppliers were asked about household customers that changed contract at their own request in 2017.[166] The total number of customers changing contract was 891,219, a significant rise on the year before. The volume of gas these customers were delivered was approx 9.5 TWh. The switching rate was 7.2%.

Household customers that changed their contracts

Categorie	Subsequent consumption in 2017 (TWh)	Share (%) of total consumption (249.2 TWh)	Number of contracts changed in 2017	Share (%) of all household customers (12.3m)
Household customers that had changed their contract with their existing supplier	9.5	3.8	891,219	7.2

Table 119: Household customers that changed their contracts in 2017 according to survey of gas suppliers

Changing contract enables final consumers to reduce their energy costs by entering into a more reasonably-priced contract. They can choose a contract that is cheaper for them without having to change supplier. Customers who are currently still under the default rate can make particular savings.

About 890,000 gas customers took this simple opportunity to save money in 2017.

2.2.3 Supplier switch

To determine the number of supplier switches by household customers, the DSOs were asked to provide information on the number of customers switching and volumes involved at meter points as well as information concerning customers choosing a supplier other than the default supplier within the meaning of section 36(2) EnWG immediately when moving home. The number of household customers who switched supplier fell by around 4% year-on-year (down 45,759 supplier switches) to 1,212,553 (2016: 1,258,312). The number of household customers who immediately chose an alternative supplier rather than the default supplier when moving home remained stable at 264,111 (2016: 264,954).

[166] Adjustments to the contract that result from changes to the general terms and conditions, expiring tariffs or customers moving to an affiliated company within the group do not apply here.

Household customer supplier switches

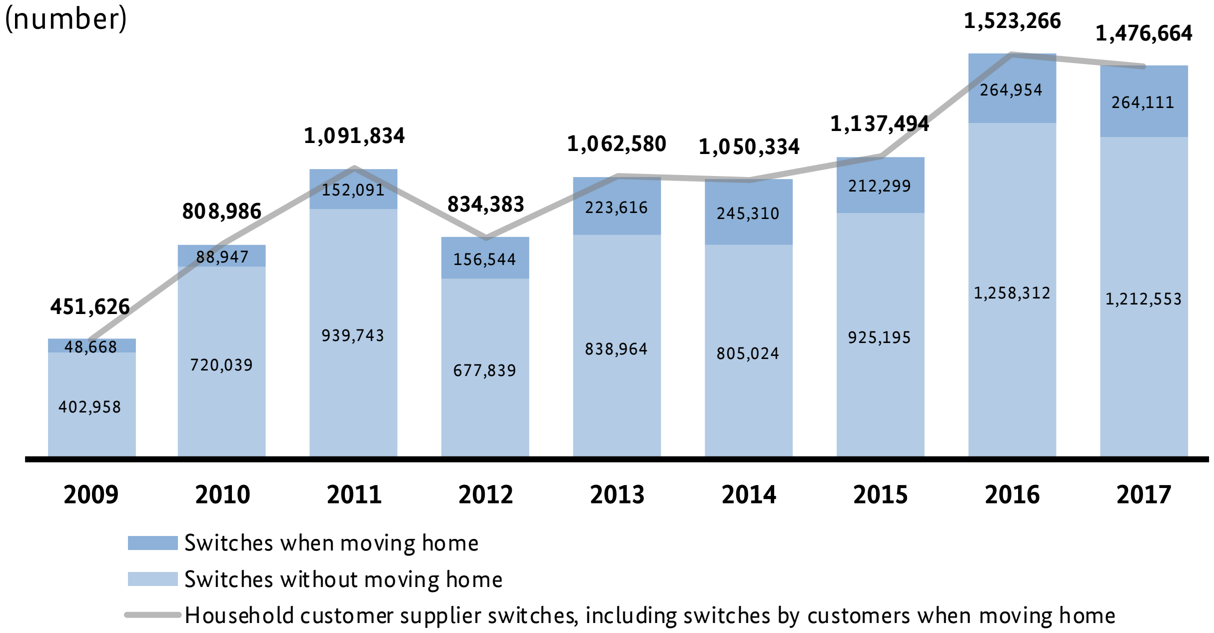


Figure 206: Household customer supplier switches according to the survey of gas DSOs

It can be seen that the number of household customers switching supplier in 2017 was down slightly. When looking at 12.5m household customers (according to DSO figures), the resulting overall numbers-based supplier switching rate for household customers is 11.8%, down from 12.3% in 2016.

Total household customer switching rate

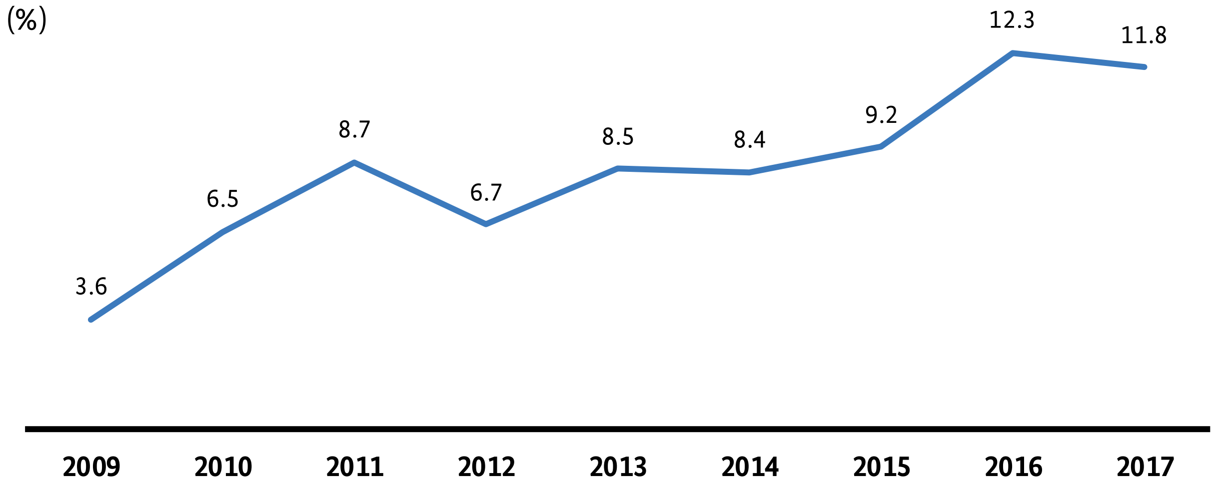


Figure 207: Total household customer switching rate based on DSO data survey

The gas DSOs were also asked to provide information on the volumes of gas recorded at the meter points of households that switched supplier or selected a new supplier in the process of moving home. The total volume of gas supplied to customers who switched supplier (including those who switched when moving) fell in 2017 by 3.1 TWh or just under 9% to 34 TWh (2016: 37.2 TWh).

Taking into account the slight rise in gas supplied to household customers by network operators in 2017, the volume-based switching rate fell to 12.2% from 13.5% in 2016. The volume-based supplier switching rate of 12.2% is still above the numbers-based rate of 11.8% because high-consumption household customers exhibit a greater willingness to switch. At around 24,000 kWh, the calculated annual consumption of an average gas customer that switched supplier is above the national average of 20,000 kWh.

Household customer supplier switches in 2017, including switches by customers when moving home

Category	Subsequent consumption in 2017 (TWh)	Share (%) of total consumption (278.8 TWh) (%)	Number of supplier switches in 2017	Share of all (12.5m) household customers
Household customer supplier switches without moving home	28.7	10.3	1,212,553	9.7
Household customers who immediately chose an alternative supplier rather than the default supplier when moving home	5.3	1.9	264,111	2.1
Total	34.0	12.2	1,476,664	11.8

Table 120: Household customer supplier switches in 2017, including switches by customers when moving home

Switching supplier is an easy way for household customers to save on energy costs. When they switch supplier, they take out a new gas supply contract with a supplier other than the local default supplier.

More than 1.2m household customers took advantage of this simple, risk-free opportunity to save money in 2017.

3. Gas supply disconnections and contract terminations, cash/smart card meters and non-annual billing

3.1 Disconnections and terminations

DSOs and gas suppliers were asked about disconnection notices, disconnection orders, disconnections that were actually carried out and the costs each action incurred.

Between 2011 and 2014, the survey on disconnections concerned only the notices and orders issued to disconnect a default supply customer and the disconnections carried out on behalf of the local default supplier.

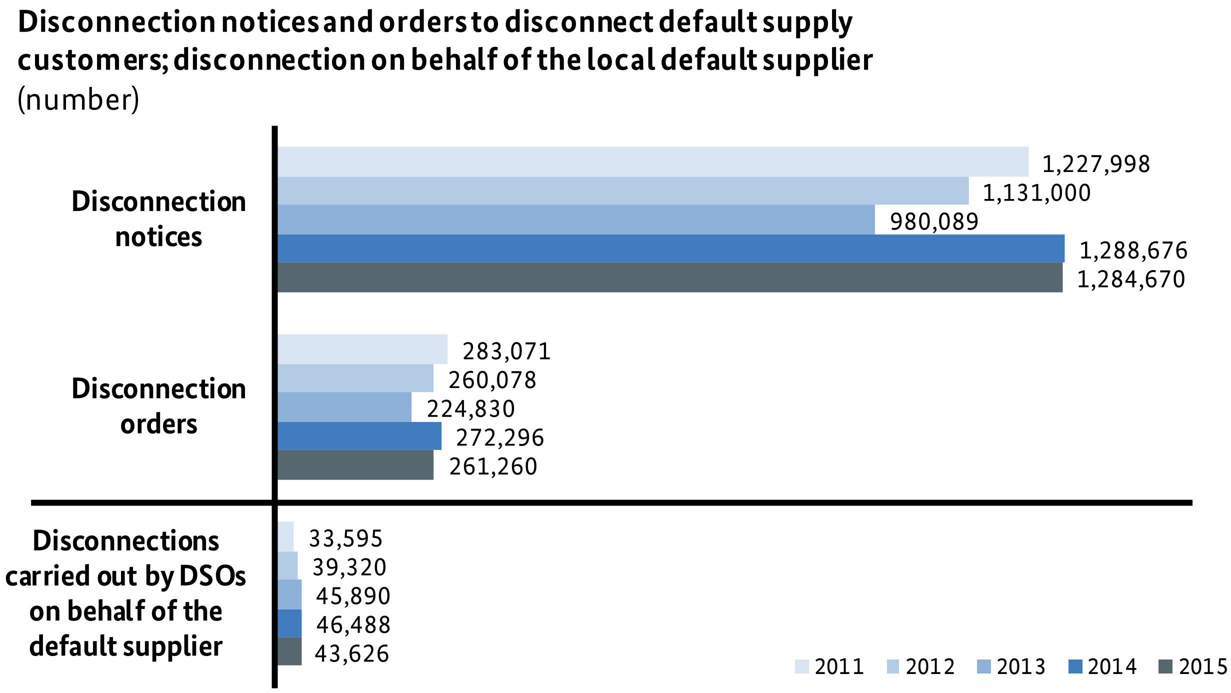


Figure 208: Disconnection notices and orders to disconnect default supply customers; disconnection on behalf of the local default supplier (gas) for the years 2011 to 2015

Since then, the survey of disconnection notices and orders has addressed all gas suppliers and not just default suppliers. Suppliers answered questions both about disconnections in default supply and disconnections for household customers with non-default contracts. Disconnections carried out by the DSOs on behalf of a supplier other than the local default supplier were also included.

The following analysis for 2017 is based on data provided by 464 DSOs and 445 gas suppliers. The figures provided by DSOs and gas suppliers show an overall decrease in gas disconnections in 2017.

The number of disconnections carried out by DSOs on behalf of the local default supplier fell to 37,992 (2016: 38,576), which represents a drop in disconnections of 584 or over 1.5% when compared with the previous year. Additionally, 2,056 (2016: 1,260) disconnections were carried out on behalf of suppliers other than the local default supplier. This figure is based on information from the DSOs that ultimately carry out the disconnections on behalf of the suppliers.

In 2017, gas DSOs restored supply to around 29,029 (2016: 30,633) customers whom they had previously disconnected on behalf of the default supplier. When compared with the previous year, this is about 1,600 meter points fewer. The decline in re-connected meter points is largely due to a general decrease in gas disconnections. In addition, supply was also restored to 1,946 meter points (2016: 1,486) on behalf of gas suppliers other than the local default supplier.

The average charge paid by suppliers to DSOs for disconnecting customers was around €56 (excluding VAT), with the actual costs charged ranging from €12 to €216 (excluding VAT). The average charge paid by suppliers to DSOs for restoring supply to customers was around €65 (excluding VAT), with the actual costs charged ranging from 14 to €263 (excluding VAT).

Disconnection notices and orders; disconnections carried out
2015 - 2017 (gas)

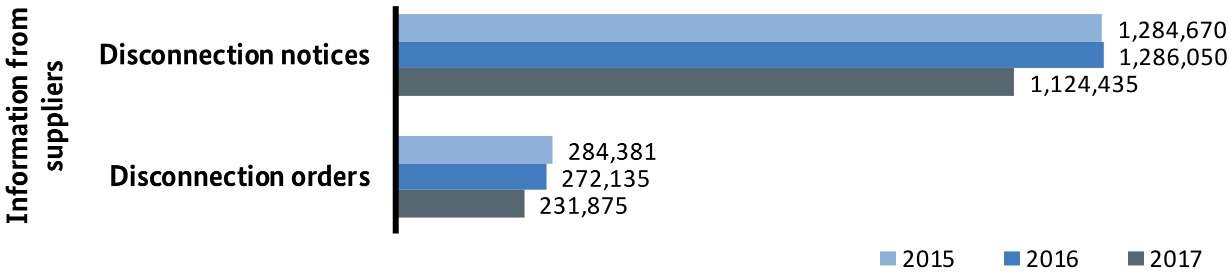
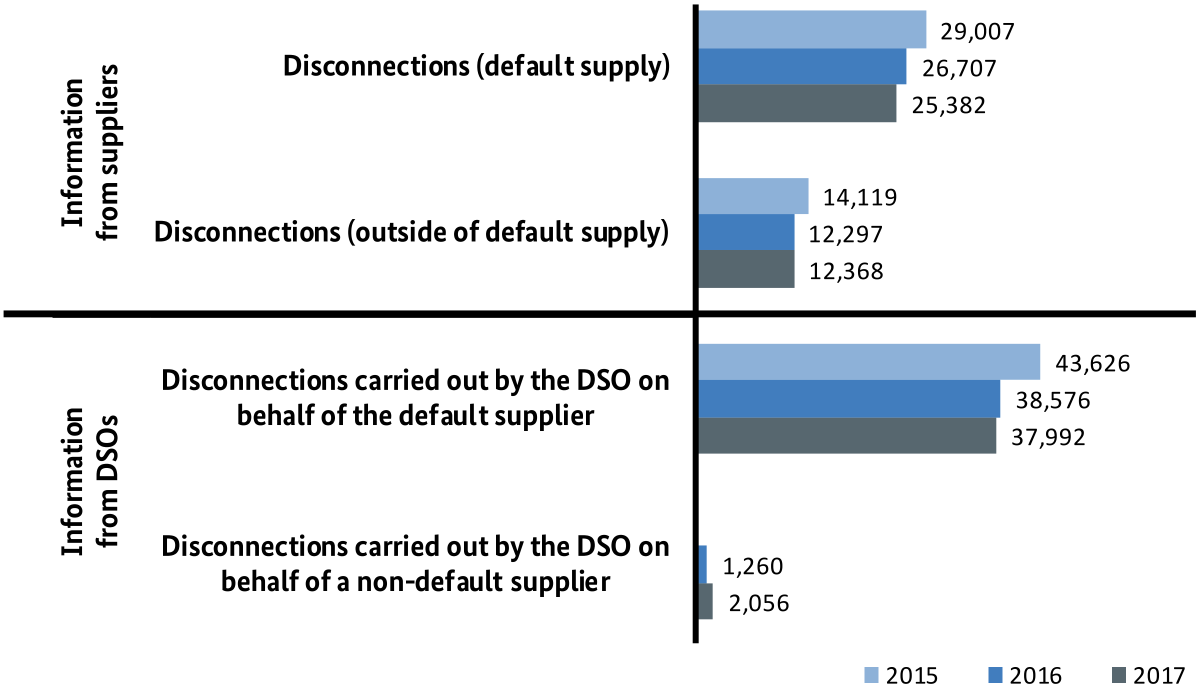


Figure 209: Disconnection notices and orders to disconnect according to the survey of gas suppliers

Disconnections carried out[1]
(number, 2015-2017, for gas)



[1] The number given in the figure below the dividing line is taken from the DSO survey. Only disconnections carried out by the DSOs on behalf of the local default supplier were recorded for 2015. Disconnections carried out on behalf of suppliers other than the default supplier were explicitly included in the survey from 2016 onwards. The DSOs do not have access to information about the contractual relationships of the disconnections. All of the data above the dividing line has been taken from the supplier survey. Here, the disconnections carried out are recorded according to contractual relationships (default contract and non-default contract). For this reason, the figures on disconnections shown here are only indirectly comparable.

Figure 210: Disconnections carried out according to the survey of gas suppliers and the survey of gas DSOs

The suppliers were asked how often in 2017 they had issued disconnection notices to customers that had failed to meet payment obligations and how often they had ordered the network operator responsible to disconnect supplies. Compared with the previous year, the number of disconnection notices – 1,124,435 – was a considerable fall from 1,286,050 in 2016, down some 12.5%. The number of disconnection orders also fell, by 14.8% to 231,875, down from 272,135 in 2016. The figures for disconnections notices and orders given in the 2016 and 2017 Monitoring Reports had to be adjusted following the receipt of revised data from companies.

According to the gas suppliers, 37,750 (2016: 39,004) disconnection notices (for customers on a default contract or a non-default contract with the default supplier) ended with an actual disconnection carried out by the network operator responsible. This signifies a decrease of 1,254 disconnections compared with the previous year. A comparison of the number of disconnection notices issued with the number of disconnections carried out clearly shows that over 3% of the notices issued actually resulted in a disconnection being carried out by the DSO. Furthermore, the gas suppliers stated that in 25,382 cases (2016: 26,707) they had disconnected customers with a default contract. The disconnection rate with respect to the total number of customers under a default contract was on average less than one percent (0.8%). Disconnection of non-default customers was carried out in 12,368 cases compared with 12,297 disconnections in 2016. The disconnection rate for non-default customers was 0.2%.

There are various reasons behind this low rate. It may be presumed that a disconnection notice often leads to a payment being made. Other customers refuse entry to the persons authorised to carry out the disconnection. A court order is then required to carry out the disconnection, which takes time and leads to a financial outlay.

According to the information provided by gas suppliers, 68% of the disconnections affected household customers supplied by a default supplier. 32% of all disconnected customers were supplied under a non-default contract. When considering the number of disconnections and the number of disconnected household customers, it becomes clear that approximately 5% of those household customers under a default contract who were disconnected, were disconnected multiple times. As many as 20% of household customers under a non-default contract were disconnected multiple times. The Gas Default Supply Ordinance (GasGVV) does not specify a minimum level of arrears for supply disconnection. The average level of arrears was about €120. Another common criterion for disconnection was the number of days a customer was behind in settling their accounts or making a partial payment.

Gas suppliers were asked for the first time in 2017 about reminder fees imposed when a customer is behind on their bill. Gas customers were charged an average of about €3.60 as a reminder fee, with the charge ranging from €0.50 to €30. While some suppliers only passed on the costs of the network operator which carried out the disconnection/reconnection, around 22% of suppliers additionally charged their customers an average of about €46 (including VAT) for carrying out a disconnection, with the actual fees charged ranging from €2 to €210 (including VAT). Customers were charged an average reconnection fee of about €56 (including VAT), with the actual fees charged again ranging from €2 to €210 (including VAT).

Despite issuing disconnection notices and orders, only a small number of gas suppliers actually terminate supply contracts with their customers. Moreover, the termination of a default supply contract is only permitted under stringent conditions. There must be no obligation to provide basic services or the requirements to disconnect gas supply must have been met repeatedly and the customer must have been warned of contract termination because of late payment. In 2017, gas suppliers had to terminate their contractual relationship with a total of 41,988 gas customers (2016: 47,957) due to their failure to fulfil a payment obligation. Reasons frequently cited for terminating contracts included reaching the final dunning level and missing two or three partial payments without any prospect of fulfilling the claim.

Around 38,000 gas customers were affected by disconnection in 2017, down about 3% year-on-year. The most common reason for a disconnection was that energy costs due had not been paid. Also, the number of disconnection notices declined sharply.

Around 30,000 customers had their gas reconnected. The average cost customers had to pay for the disconnection of their gas supply was about €56.

3.2 Cash meters and smart card meters

In the monitoring survey, gas metering operators and gas suppliers answered questions on prepayment systems, as per section 14 GasGVV, such as cash meters or smart card meters. Metering operators reported that in 2017, 1,125 cash/smart card meters or other comparable prepayment systems had been set up in the context of default supply by 41 metering operators (2016: 1,059). 285 prepayment systems were newly installed (2016: 229) and 188 existing prepayment systems (2016: 215) were removed during the year. Costs for meter operation and metering averaged €28 and €6.25 respectively per year and meter. The average annual base price charged to customers was €120 (2016: €129), with the costs charged ranging from €12 to €250. The average kilowatt-hour rate for gas billed using a prepayment meter was 6.4 ct/kWh and ranged from 3.6 ct/kWh to 10.1 ct/kWh.

Cash or smart card meters can be a solution for customers in financial difficulties and a way to avoid a potential disconnection. Customers can decide themselves how much gas they want to use. The costs they incur are limited to the amount of money they have already put on the meter. However, it must be noted that such meters often work out to be more expensive.

About 1,100 gas customers in Germany have a prepayment system.

3.3 Non-annual billing

Section 40(3) EnWG requires gas suppliers to offer final consumers monthly, quarterly or half yearly bills. The survey showed that demand for bills that are not the usual annual ones remains low.

Non-annual billing in 2017

	Requests	Non-annual bill issued	Average charge for each additional bill for customers reading their own meters (range)	Average charge for each additional bill for customers not reading their own meters (range)
Other forms of billing for household customers	5,057	6,136	€14.40 (€2 - €50)	€18 (€2 - €65)
Monthly	433	588		
Quarterly	83	116		
Semi-annual	1,244	1,305		
Period missing	3,297	4,127		

Table 121: Non-annual billing in 2017 according to gas supplier survey

Gas suppliers must offer final consumers monthly, quarterly or half yearly bills. However, only a fraction of gas customers take up this option to receive additional bills. Suppliers are allowed to pass on the costs of non-annual billing to customers.

The usual practice is for consumption to be billed annually and the monthly payments made during the year to be offset against the actual costs of gas used.

4. Price level

Suppliers of gas to final consumers in Germany were asked the retail prices their companies charged on 1 April 2018 for various consumption levels. Household customers' consumption levels were divided into three consumption bands. Prices for these bands were surveyed in various categories. The lowest category covers an annual gas consumption of less than 20 GJ (5,556 kWh), while the highest category is for annual consumption above 200 GJ (55,556 kWh). The typical household customer has consumption in the band between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh). Furthermore, as in previous years, the consumption levels of 116 MWh (= 417.6 GJ for "commercial customers") and 116 GWh (= 417,600 GJ for "industrial customers") were analysed.

Suppliers were asked to give the overall price in cents per kilowatt hour (ct/kWh) and to include the non-variable price components such as the service price, base price and transfer or internal price. Suppliers were also asked to provide a breakdown of the price components that they cannot control, including, in particular, network charges,[167] concession fees and charges for metering and meter operations. After deducting these components from the overall price, the amount remaining is the amount controlled by the supplier, which comprises above all gas procurement, supply and the supplier's margin.

The suppliers were asked to provide their "average" overall prices and price components for each of the consumption levels.

In respect of the consumption of household customers (bands I, II and III), suppliers were asked to provide data on the price components for three different contract types:

– default contract,

– non-default contract with the default supplier,

– contract with a supplier other than the local default supplier.

The findings are set out below, broken down by customer category and consumption level. The results have been compared to the previous year's figures to illustrate long-term trends. When comparing the figures as they stood as at 1 April 2018 and 1 April 2017, it should be noted that differences in the calculated averages are lower in some cases than the tolerance of error for the data collection method.

The survey was addressed to all suppliers operating in Germany. However, with regard to the prices for the 116 GWh/year and 116 MWh/year consumption levels, only those suppliers that served at least one customer whose gas demand fell within the range of the relevant level of consumption were asked to provide data (this applied to 99 and 775 suppliers respectively).

4.1 Non-household consumers

116 GWh/year consumption category ("industrial customers")

The customer group with an annual consumption in the 116 GWh range consists entirely of customers with metered load profiles, i.e. generally industrial customers. The wide range of options with regard to contractual arrangements is very important to this customer group. Suppliers generally do not use specific tariff groups for consumers who fall into the 116 GWh/year category but offer customer-specific deals. Their customers include those with a full supply and those whose negotiated consumption (in the amount relevant to this category) represents only part of their procurement portfolio. For high-consumption customers the distinction between retail and wholesale trading is inherently fluid. Supply prices are often indexed against wholesale prices. There are types of contracts where customers themselves are responsible for settling network tariffs with the network operator. In extreme cases, such a contract may even require a supplier to merely provide balancing group management services for its customers.

[167] Since 1 January 2017, the component "charge for billing" has been part of the network charges and is no longer reported separately.

The 116 GWh/year consumption category was defined as an annual usage period of 250 days (4,000 hours). Data was collected only from suppliers with at least one customer with an annual consumption between 50 GWh and 200 GWh. This customer profile applied to only a small group of suppliers. The following price analysis of the consumption category is based on data from 99 suppliers (99 in the previous year).

This data was used to calculate the (arithmetic mean) of the total price and the individual price components. The data spread for each price component was also analysed in terms of ranges. The 10th percentile represents the lower limit and the 90th percentile the upper limit of each reported range. This means that the middle 80% of the figures provided by the suppliers are within the stated range. The analysis produced the following results:

Price level for the 116 GWh/year consumption category on 1 April 2018

	Spread in the 10 to 90 percentile range of the supplier data sorted by size in ct/kWh	**Average** (arithmetic) in ct/kWh	**Percentage of total price**
Price components outside the supplier's control			
Net network charge	0.16 -0.45	0.33	12.0%
Metering, billing, meter operation	0.00 - 0.013	0.003	0%
Concession fee[1]	0.00	0.00	0%
Gas tax	0.55	0.55	20.0%
Price components controlled by the supplier (remaining balance)	1.60 - 2.26	1.93	0.68
Total price (excluding VAT)	2.37 - 3.20	2.82	

[1] Under Section 2, Paragraph 5, No. 1 of the Electricity and Gas Concession Fees Ordinance (KAV), concession fees for special contract customers apply only to the first 5 GWh (0.03 ct/kWh). Allocating this price component to the total consumption volume results in a very small average, i.e. an average of 0.00 ct/kWh (rounded) in the 116 GWh/year consumption category.

Table 122: Price level for the 116 GWh/year consumption category on 1 April 2018

Network tariffs, metering and concession fees account for an average of 12% of the overall price in the 116 GWh/year consumption category ("industrial customers"). This percentage is considerably lower than that applying to household customers or non-household customers with low consumption (see below).

The share of the components that can be controlled by the supplier (gas procurement costs, supply costs and the margin) is accordingly much larger at 68% than that applying to household customers.

The average overall price (excluding VAT) of 2.82 ct/kWH rose by 0.13 ct/kWh and is almost 5% higher than the previous year's figure of 2.69 ct/kWh. The components of the overall price outside the supplier's control (especially network tariffs and levies) were almost 1% lower than the previous year.

Development of average gas prices for the 116 GWh/year consumption category
in ct/kWh, excl. VAT

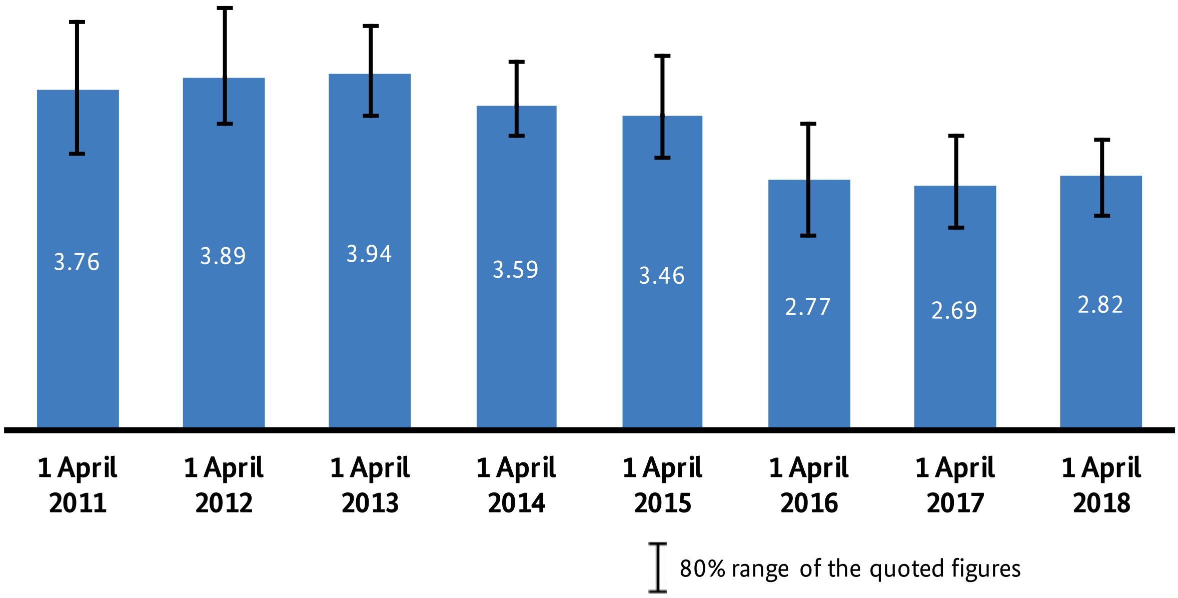


Figure 211: Development of average gas prices for the 116 GWh/year consumption category

116 MWh/year consumption category ("commercial customers")

The non-household customer category based on an annual consumption of 116 MWh includes commercial customers with a relatively low level of consumption. No annual usage period was defined for this customer category. It is one thousandth of the amount consumed by industrial customers (around 116 GWh) and five times higher than the average annual consumption of household customers (around 23 MWh). Given the moderate level of consumption, individual contractual arrangements play a significantly smaller role than in the 116 GWh/year consumption category. Since this consumption level is well below the 1.5 GWh above which network operators are required to use interval metering, it is safe to assume that consumption in this category is measured using a standard load profile. Suppliers were asked to make a plausible estimate of the charges for customers whose consumption profile is similar to that of the consumption category based on the terms and conditions that applied on 1 April 2018. Data was collected from suppliers that had customers with a consumption profile of roughly comparable magnitude, i.e. with an annual consumption between 50 MWh and 200 MWh.

The following price analysis of the consumption category was based on data from 786 suppliers (775 suppliers in the previous year). The data was used to calculate the averages of the overall price and of the individual price components. The data spread for each price component was also analysed in terms of ranges that included the 80% of the figures provided by the suppliers. The analysis produced the following results:

Price level for the 116 MWh/year consumption category on 1 April 2018

	Spread in the 10 to 90 percentile range of the supplier data sorted by size in ct/kWh	**Average** (arithmetic) in ct/kWh	**Percentage of total price**
Price components outside the supplier's control			
Net network charge	0.89 - 1.57	1.20	27%
Metering, billing, meter operation	0.01 - 0.06	0.05	1%
Concession fee[1]	0.03 - 0.03	0.04	1%
Gas tax	0.55	0.55	13%
Price component controlled by the supplier (remaining balance)	2.02 - 3.17	2.55	58%
Total price (excluding VAT)	3.77 - 5.09	4.40	

[1] 40 of the 702 suppliers quoted a figure above 0.03 ct/kWh for the concession fee. These suppliers sold only small volumes. A concession fee in excess of 0.03 ct/kWh could apply to non-household customers if the gas was supplied under a default supply contract (cf. Section 2, Paragraph 2, No. 2b of the Electricity and Gas Concession Fees Ordinance (KAV)).

Table 123: Price level for the 116 MWh/year consumption category on 1 April 2018

This year, an average 42% of the overall price in the commercial customer category (116 MWh) consists of cost items outside the supplier’s control (network tariffs, gas tax and concession fee). 58% relate to price elements that provide scope for commercial decisions.

The arithmetic mean of the overall price of 4.40 ct/kWh (excluding VAT) is 0.1 ct/kWh or around 2% lower than the previous year's figure. The absolute amount of the price components outside the supplier’s control was 1.84 ct/kWh, the same as in the previous year. The remaining balance that can be controlled by the supplier fell by 0.12 ct/kWh (from 2.67 ct/kWh on 1 April 2017 to 2.55 ct/kWh on 1 April 2018) or by about %.

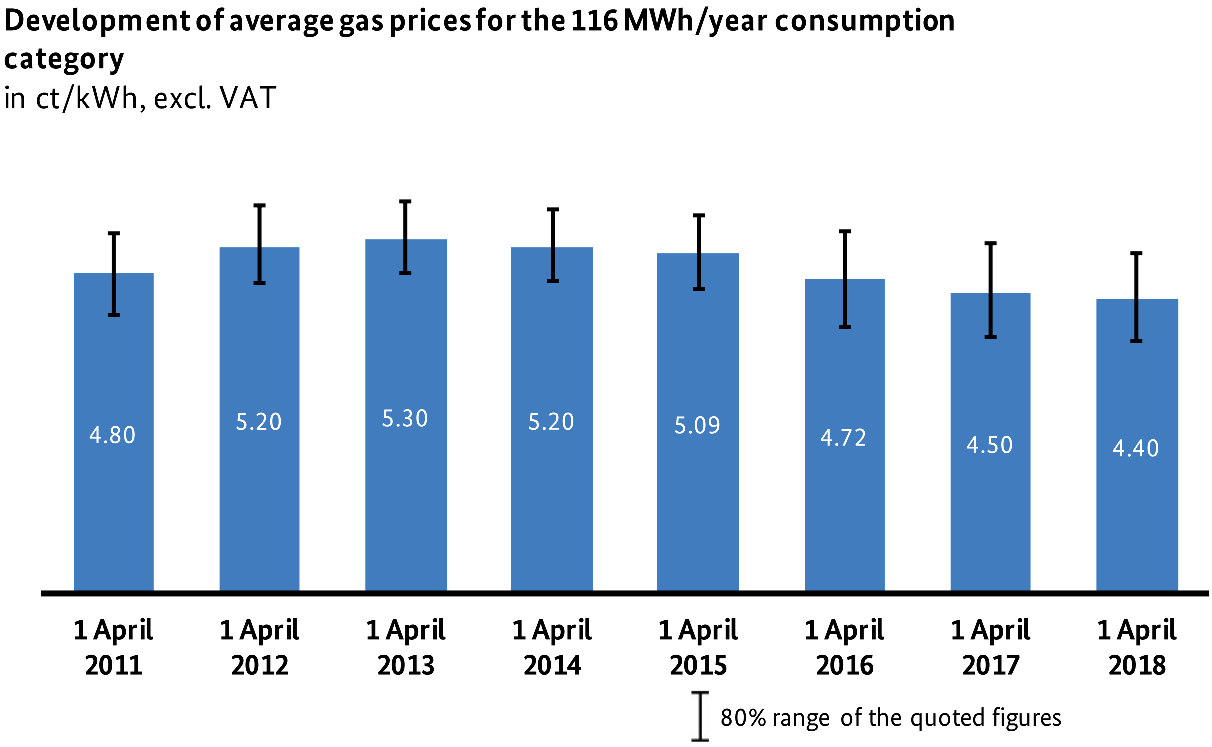


Figure 212: Development of average gas prices for the 116 MWh/year consumption category

4.2 Household customers

Household customer prices were divided into three bands for the survey:

- Band I (D1[168]): annual consumption below 20 GJ (5,556 kWh),
- Band II (D2): annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh),
- Band III (D3): annual consumption above 200 GJ (55,556 kWh).

The survey of gas prices in consumption bands took consideration of the European survey of prices carried out by Eurostat. The total quantities of gas that were delivered by each supplier in the previous year were used to weight the gas price. The prices of each consumption band were weighted with the volume of gas applicable to the band of the responding gas supplier. It is important to note that the average network charges listed for each type of contract category are calculated using figures provided by the suppliers, which in turn are the charges averaged over all the networks supplied. This results in a different network charge for each of the three types of supply contract. Since 1 January 2017, the charge for billing has been part of the network charges and is no longer reported separately.

[168] "D1", "D2" and "D3" refer to the consumption bands defined by Eurostat.

4.2.1 Volume-weighted price across all contract categories for household customers (Band II)

The great variety of the components that form the prices makes it difficult to compare the tariffs. Therefore, a separate synthetic average price is calculated as the key figure on the basis of the available data for the three types of supply contract – default contract, non-default contract with the default supplier (usually after change of contract), and contract with a supplier other than the local default supplier (usually after supplier switch) – taking into account all supply contracts with the correct proportions. For this purpose, the individual prices of the three types of supply contracts are weighted with the given volume of gas delivered. Band II, with an annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh), which best reflects the average consumption of household customers in Germany of 20,000 kWh, was selected for the diagram presenting the total synthetic price across all contract categories on 1 April 2018.

The average gas price calculated for all types of supply contracts was 6.07 ct/kWh as at 1 April 2018, about 1.3% lower than in the previous year. Gas prices have remained generally stable in recent years.

Average volume-weighted price across all contract categories for household customers for an annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh) per year (band II; Eurostat: D2) as of 1 April 2018 (ct/kWh)

Price component	Volume-weighted average across all tariffs (ct/kWh)	Share (%) of the total price
Price component for energy procurement, supply and margin	2.96	48.8%
Network charge including upstream network costs	1.42	23.4%
Charge for metering	0.02	0.3%
Charge for meter operations	0.07	1.2%
Concession fees	0.08	1.3%
Current gas tax	0.55	9.1%
VAT	0.97	16.0%
Total	6.07	100.0%

Table 124: Average volume-weighted price across all contract categories for household customers in consumption band II according to the gas supplier survey

Composition of the volume-weighted gas price across all contract categories for household customers - consumption band II
Prices as at 1 April 2018 (%)

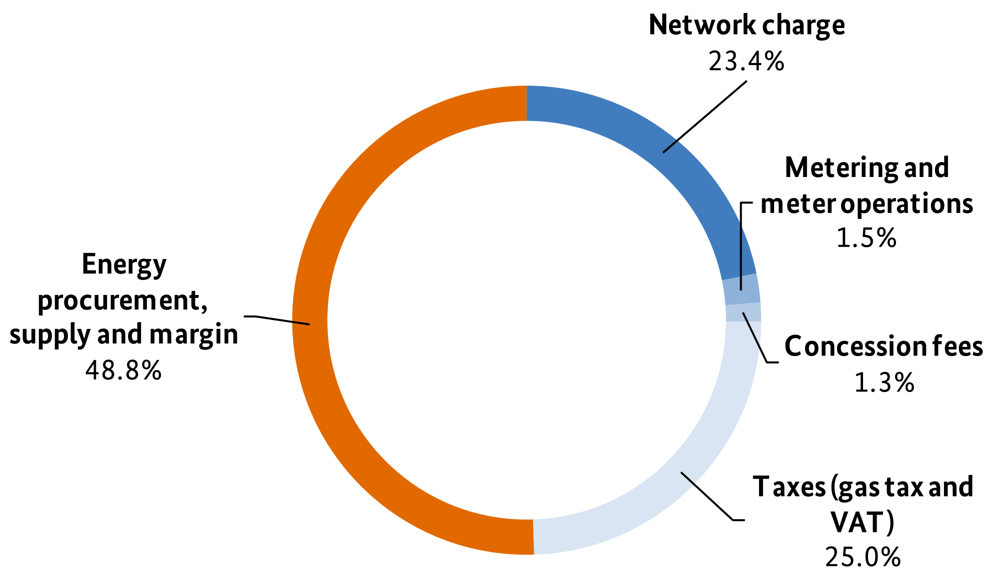


Figure 213: Composition of the volume-weighted gas price across all contract categories for household customers – consumption band II according to the gas supplier survey

Changes in the volume-weighted price across all contract categories for household customers. Consumption band between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh), (band II; Eurostat: D2)

Price component	Volume-weighted average across all tariffs on 1 April 2017 (ct/kWh)	Volume-weighted average across all tariffs on 1 April 2018 (ct/kWh)	Change in the price component	
			(ct/kWh)	(%)
Price component for energy procurement, supply and margin	3.02	2.96	-0.06	-2.0%
Network charge including upstream network costs	1.44	1.42	-0.02	-1.4%
Charge for metering	0.02	0.02	0.00	0.0%
Charge for meter operations	0.06	0.07	0.01	16.7%
Concession fees	0.08	0.08	0.00	0.0%
Current gas tax	0.55	0.55	0.00	0.0%
VAT	0.98	0.97	-0.01	-1.0%
Total	6.15	6.07	-0.08	-1.3%

Table 125: Changes in the volume-weighted price across all contract categories for household customers (for an annual consumption between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh) between 1 April 2017 and 1 April 2018 according to the gas supplier survey

Household customer prices by consumption band

The tables below provide detailed information on the composition of the gas price for household customers, broken down by individual bands I to III and contract category.

Average volume-weighted price per contract category for household customers with a consumption below 20 GJ (5,556 kWh) per year (band I; Eurostat: D1) as at 1 April 2018 (ct/kWh)

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the local default supplier
Price component for energy procurement, supply and margin	4.33	4.08	3.43
Network charge including upstream network costs	2.44	2.31	2.28
Charge for metering	0.23	0.12	0.13
Charge for meter operations	0.48	0.41	0.40
Concession fees	0.52	0.06	0.04
Current gas tax	0.55	0.55	0.55
VAT	1.62	1.43	1.30
Total	10.17	8.96	8.13

Table 126: Average volume-weighted price per contract category for household customers in consumption band I according to the gas supplier survey

Average volume-weighted price per contract category for household customers with a consumption between 20 GJ (5,556 kWh) und 200 GJ (55,556 kWh) per year (band II; Eurostat: D2) as of 1 April 2018 (ct/kWh)

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the local default supplier
Price component for energy procurement, supply and margin	3.29	3.01	2.66
Network charge including upstream network costs	1.41	1.42	1.43
Charge for metering	0.02	0.02	0.03
Charge for meter operations	0.06	0.06	0.09
Concession fees	0.25	0.03	0.04
Current gas tax	0.55	0.55	0.55
VAT	1.06	0.97	0.91
Total	6.64	6.06	5.71

Table 127: Average volume-weighted price per contract category for household customers in consumption band II according to the gas supplier survey

Average volume-weighted price per contract category for household customers with a consumption above 200 GJ (55,556 kWh) per year (band III; Eurostat: D3) as at 1 April 2018 (ct/kWh)

Price component	Default contract	Contract with the default supplier outside of default supply contracts	Contract with a supplier other than the local default supplier
Price component for energy procurement, supply and margin	3.05	2.66	2.28
Network charge including upstream network costs	1.20	1.25	1.20
Charge for metering	0.01	0.01	0.01
Charge for meter operations	0.02	0.02	0.03
Concession fees	0.25	0.04	0.03
Current gas tax	0.55	0.55	0.55
VAT	0.96	0.86	0.78
Total	6.04	5.39	4.88

Table 128: Average volume-weighted price per contract category for household customers in consumption band III according to the gas supplier survey

Data from 516 gas suppliers was taken into account for the evaluation of prices for customers supplied under a default contract. On 1 April 2018, the volume-weighted price for default supply in consumption band II was 6.64 ct/kWh (2017: 6.73 ct/kWh), a decrease of 1.3% compared to the previous year.

Gas prices for household customers under a default contract - consumption band II (volume-weighted averages)
(ct/kWh)

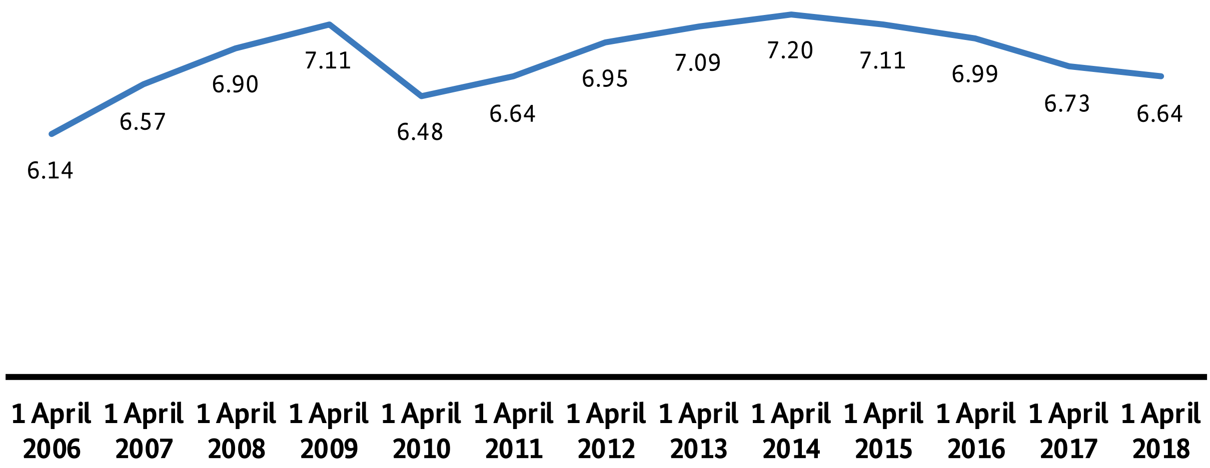


Figure 214: Gas prices for household customers under a default contract (volume-weighted averages) – consumption band II according to the gas supplier survey

Composition of the volume-weighted gas price for household customers under a default contract. Prices for consumption band II
Prices as at 1 April 2018 (%)

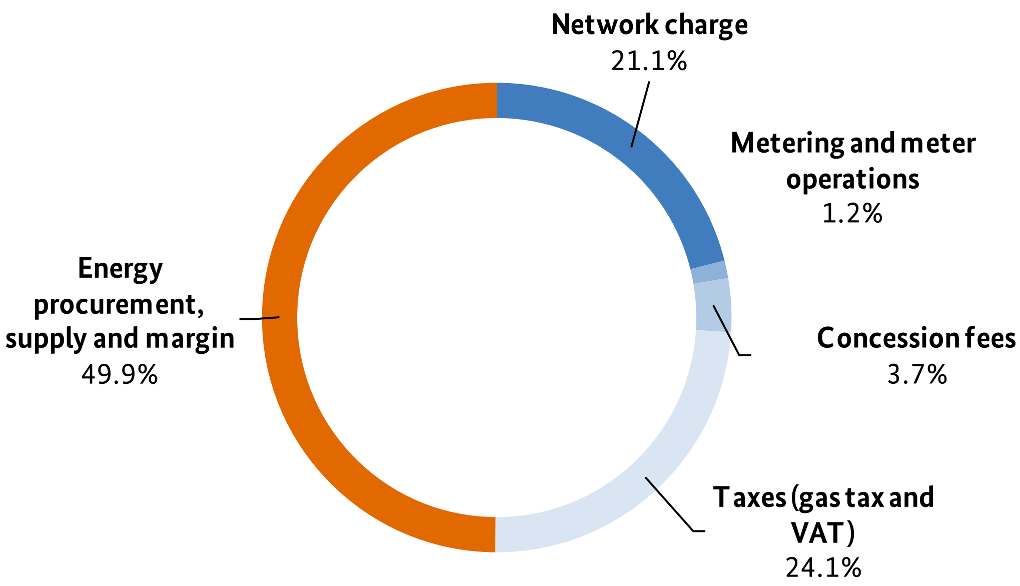


Figure 215: Composition of the volume-weighted gas price for household customers under a default contract. Prices for consumption band II, as at 1 April 2018 – according to the gas supplier survey

Data from 505 gas suppliers was taken into account for the evaluation of prices for customers supplied under a non-default contract with the default supplier. On 1 April 2018, the volume-weighted price for customers under a non-default contract with the default supplier in consumption band II was 6.06 ct/kWh, a decrease of 0.2% compared to 2017 (6.07 ct/kWh).

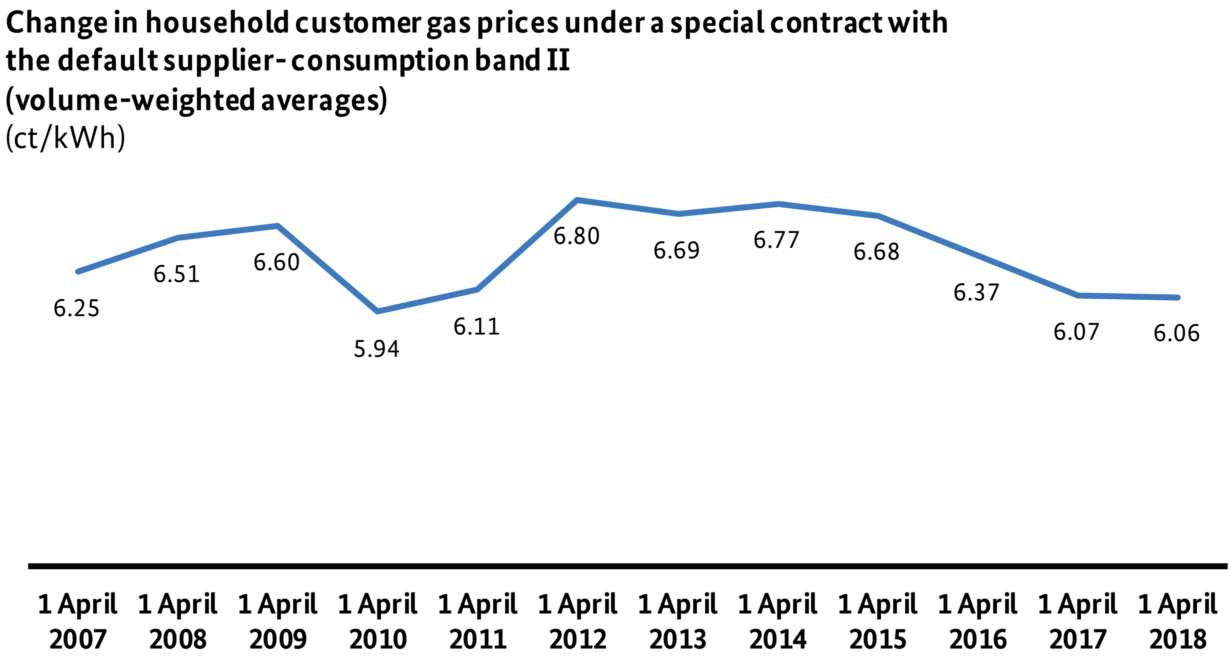


Figure 216: Change in household customer gas prices under a non-default contract with the default supplier (volume-weighted averages) – consumption band II according to the gas supplier survey

Composition of the volume-weighted gas price for household customers under a special contract with the default supplier - consumption band II
Prices as at 1 April 2018 (%)

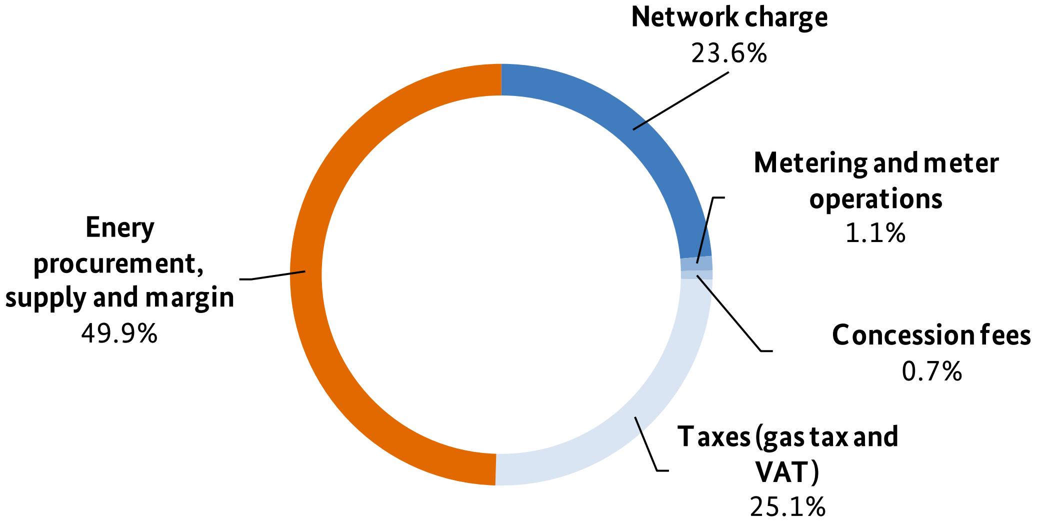


Figure 217: Composition of the volume-weighted gas price for household customers under a non-default contract with the default supplier. Prices for consumption band II, as at 1 April 2018 – according to the gas supplier survey

Data from 568 gas suppliers was taken into account for the evaluation of prices for a contract with a supplier other than the local default supplier. On 1 April 2018, the volume-weighted price for a contract with a supplier other than the local default supplier in consumption band II was 5.71 ct/kWh, a decrease of 1.2% compared to the previous year (2017: 5.78 ct/kWh). In 2018, gas prices for consumers under contract with a supplier other than the local default supplier thus reached the lowest level they have been since the first survey on 1 April 2008.

Gas prices for household customers under a contract with a supplier other than the local default supplier - consumption band II (volume-weighted averages)
(ct/kWh)

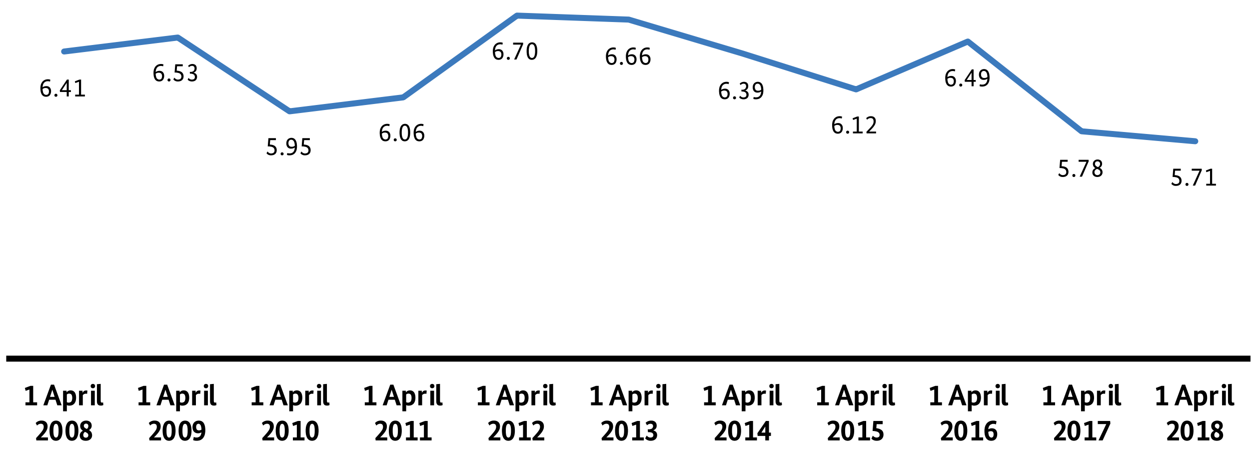


Figure 218: Gas prices for household customers under a contract with a supplier other than the local default supplier (volume-weighted averages) – consumption band II according to the gas supplier survey

Composition of the volume-weighted gas price for household customers under a contract with a supplier other than the local default supplier - consumption band II
Prices as at 1 April 2018 (%)

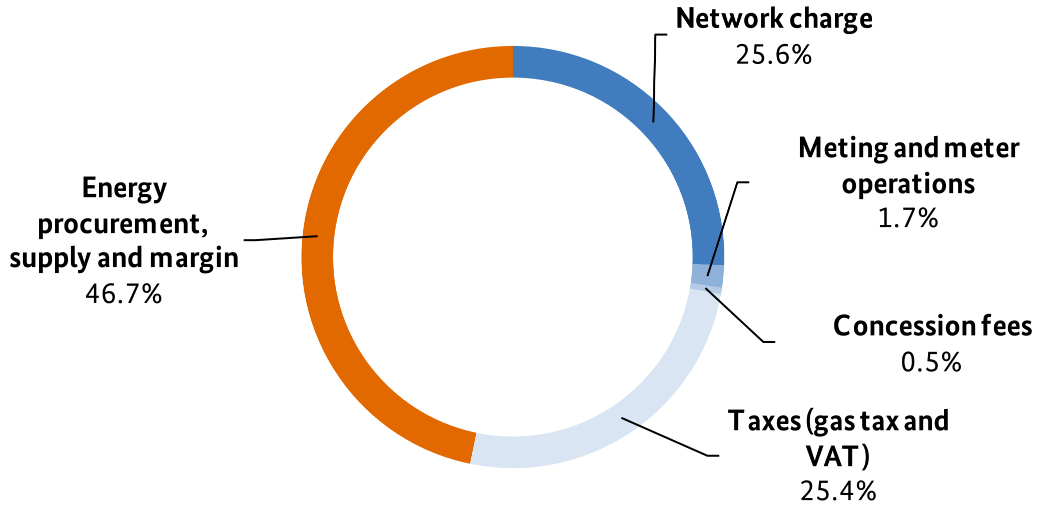


Figure 219: Composition of the volume-weighted gas price for household customers under a contract with a supplier other than the local default supplier, as at 1 April 2018 – consumption band II according to the gas supplier survey

Customers on default contracts can make savings by switching contract or supplier. The average household customer with gas consumption of 23,250 kWh could save an average of €135 a year as at 1 April 2018 by changing contract. The average potential saving for the year through changing supplier was €216.

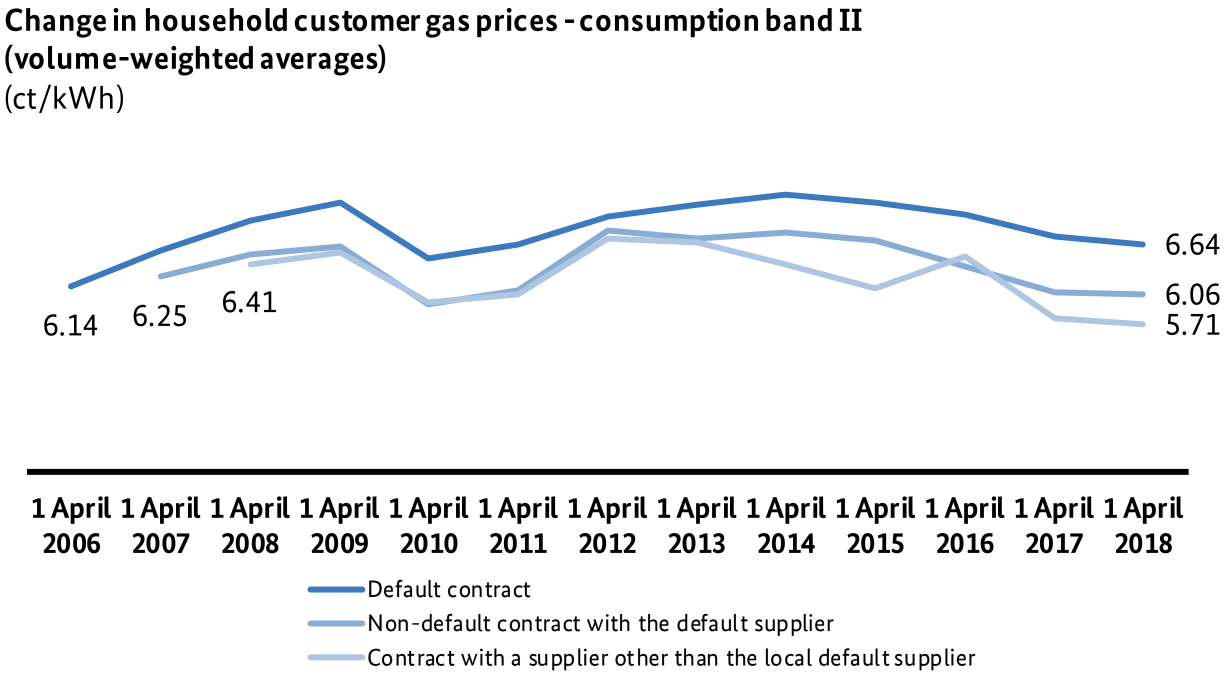


Figure 220: Household customer gas prices – consumption band II according to gas supplier survey

With regard to the main component of the gas price for household customers in band II, which is the price component that can be controlled by the supplier: "energy procurement, supply and margin", it is notable that in 2018 this price component for customers with a supplier other than the local default supplier hit the lowest level since the survey started, 2.66 ct/kWh (2017: 2.7 ct/kWh).

The price component "energy procurement, supply and margin" for default supply customers fell to 3.29 ct/kWh as at 1 April 2018 (2017: 3.35 ct/kWh). This price component was steady at 3.01 ct/kWh as at 1 April 2018 for customers with a non-default contract with their default supplier.

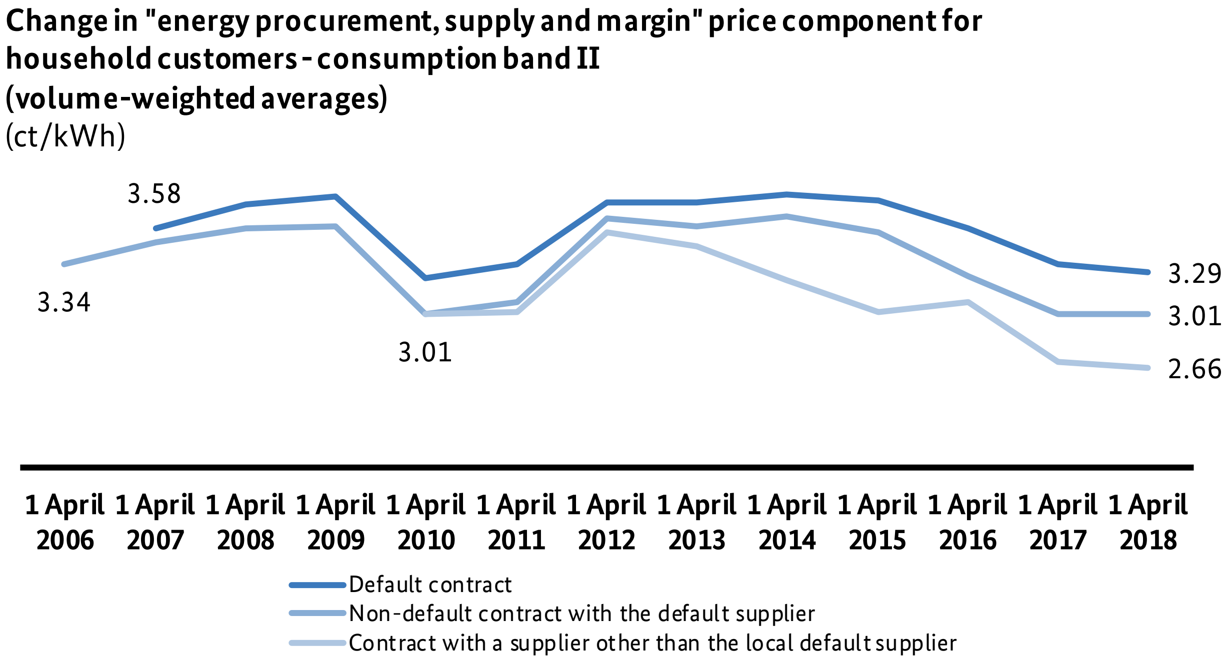


Figure 221: Change in “energy procurement, supply and margin” price component for household customers – consumption band II according to the gas supplier survey

Special bonuses and schemes

In addition to differences in the total price, non-default contracts with the default supplier and contracts with a supplier other than the local default supplier have other differences that gas suppliers use when competing for customers. These features may offer a certain level of security to the customer (eg price stability) or to the supplier (eg payment in advance, minimum contract period). In the data collection, gas suppliers were asked about their contracts and offers.

The following overview includes various special bonuses and schemes offered to household customers by gas suppliers. Among the most common features in the offers were minimum contract periods (on average for 12 months) and fixed prices (on average for 16 months). There is, of course, a very large spread among the values of the bonuses paid out. The bonuses awarded were between €5 and €310. These one-off payments amount to an average of €75 to €80.

Special bonuses and schemes for household gas customers

As at 1 April 2018	Household customers			
	Special contract with the default supplier		Contract with a supplier other than the local default supplier	
	Number of tariffs reported by surveyed companies	Scope of measure (on average)	Number of tariffs reported by surveyed companies	Scope of measure (on average)
Minimum contract period	339	12 months	392	12 months
Price stability	308	16 months	373	16 months
Advance payment	49	10 months	37	10 months
One-off bonus payment	124	€75	184	€80
Free kilowatt hours	12	1,400 kWh	8	550 kWh
Deposit	14	-	7	-
Other bonuses	72	-	61	-
Other special arrangements	35	-	33	-

Table 129: Special bonuses and schemes for household customers

The most expensive type of contract, default supply, has an average gas price of 6.64 ct/kWh. If a customer of the default supplier changes to a cheaper tariff, such as an online one, the average gas price is 6.06 ct/kWh. If a customer changes to a different supplier, which may be active nationwide, the average gas price is 5.71 ct/kWh. As at 1 April 2018, an average household customer with consumption of 23,250 kWh a year was able to save an average of €135 by changing contract and €216 by switching supplier.

5. Comparison of European gas prices

Eurostat, the statistical office of the European Union, publishes average end consumer gas prices for each six-month period paid by household customers and non-household customers in EU Member States. The figures published for each consumer group include (i) the price including all taxes and levies, (ii) the price excluding recoverable taxes and levies (particularly excluding VAT) and (iii) the price excluding taxes and levies. Eurostat does not collect the data itself but relies on data from national bodies or, until now, on data provided by the Federal Statistical Office on the basis of a report by the German Association of Energy and Water Industries.

Rules on the classification, analysis and presentation of the price data aim to ensure European-wide comparability. However, the survey method is set by the member state (cf. Directive 2008/92/EC, Annex I h), which leads to national differences.

5.1 Non-household consumers

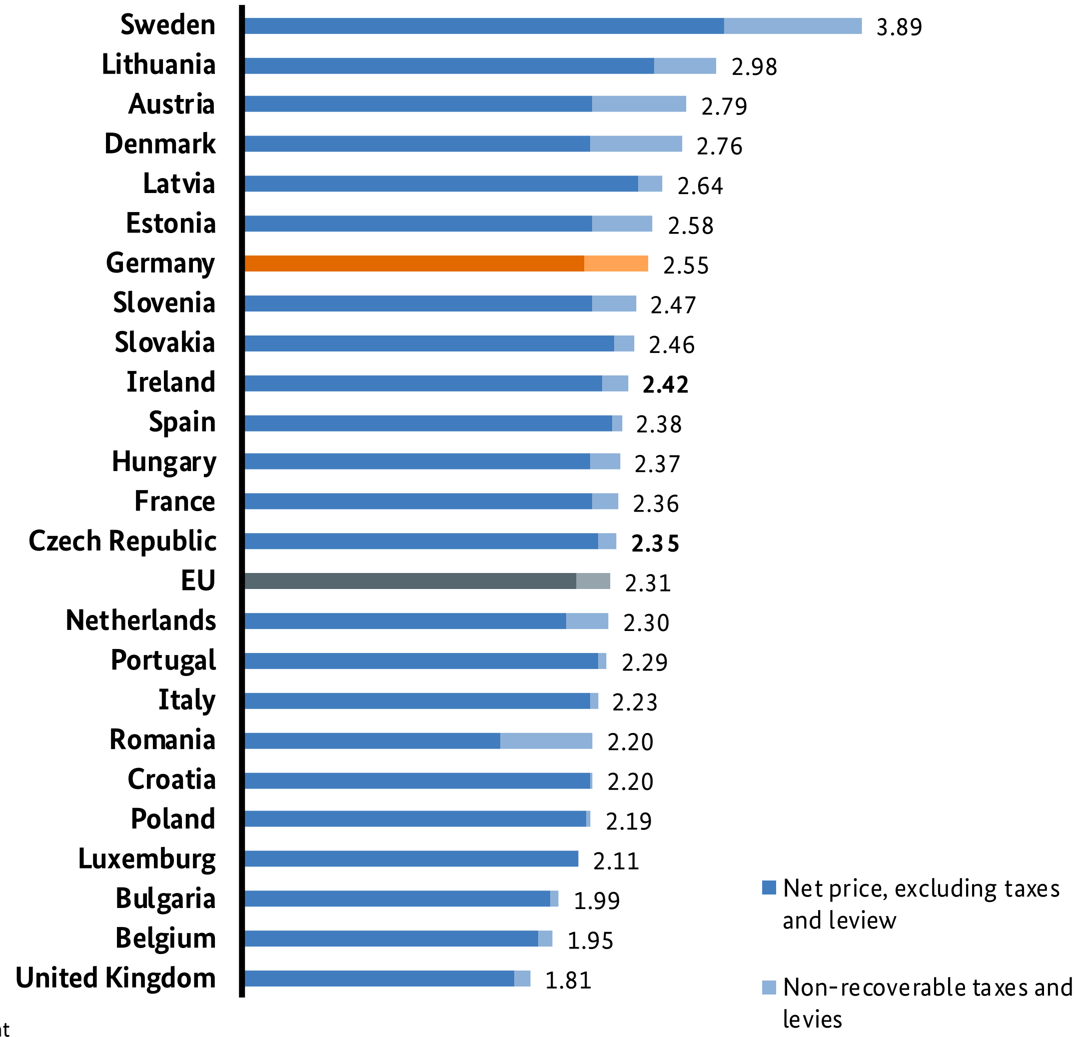
Eurostat publishes price statistics for six different consumer groups in the non-household sector that differ according to annual consumption ("consumption bands"). The following describes the 27.8 to 278 GWh/year consumption category (equivalent to 100,000 GJ to 1,000,000 GJ) as an example of one of these consumption bands. The 116 GWh/year category ("industrial customers"), for which specific price data is collected during monitoring, falls into this consumption range.

The customer group with this level of consumption consists mainly of industrial customers who can usually deduct national VAT. For this reason, the European-wide comparison is based on the price without VAT. Besides VAT there are various other taxes and levies resulting from specific national factors, which can typically be recovered by this customer group and which have also been deducted from the gross price in accordance with the Eurostat classification.[169] Most Member States impose additional taxes and levies that are not recoverable (eg gas tax and concession fee in Germany).

Across Europe, prices for industrial customers vary to a much lesser extent than those for household customers. The net gas price of 2.55 ct/kWH paid by German non-household customers with an annual consumption between 27.8 and 278 GWh in the second half of 2017 is in the upper range. The EU average is 2.31 ct/kWh. Non-recoverable taxes and levies amount to an average 10% (0.21 ct/kWh) of the net price in Europe. The figure of about 18% (0.40 ct/kWh) for Germany is above average in this respect.

[169] For more information on country-specific deductions see Eurostat, Gas Prices – Price Systems 2014, 2015 Edition: http://ec.europa.eu/eurostat/documents/38154/42201/Gas-prices-Price-systems-2014.pdf/30ac83ad-8daa-438c-b5cf-b52273794f78 (retrieved on 7 August 2018).

Comparison of European gas prices in the second half of 2017 for non-household customers with an annual consumption between 27.8 GWh and 278 GWh
in ct/kWh ; excl. recoverable taxes and levies



Source: Eurostat

Figure 222: Comparison of European gas prices in the second half of 2017 for non-household customers with an annual consumption between 27.8 GWh and 278 GWh[170]

5.2 Household consumers

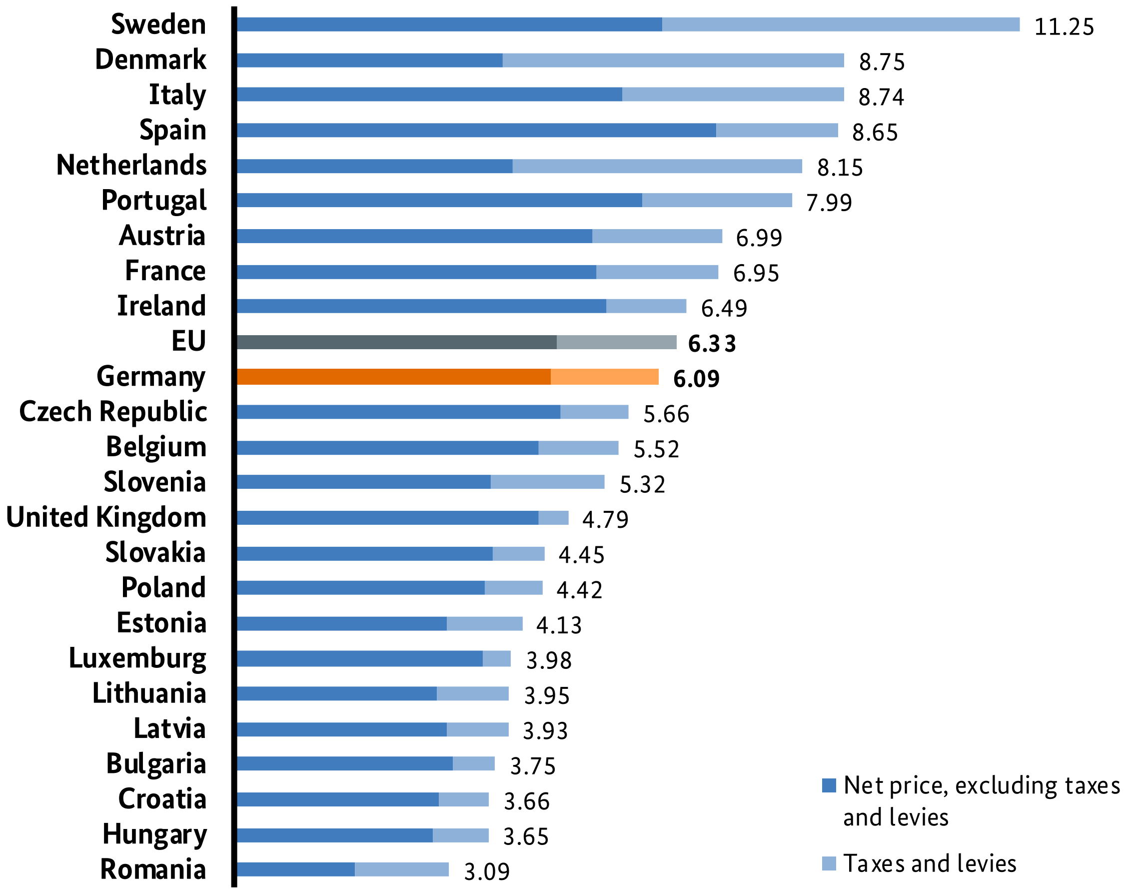
Eurostat takes three different consumption bands into consideration when comparing household customer prices: (i) annual consumption below 5,555 kWh, (ii) between 5,555 kWh and 55,555 kWh and (iii) above 55,555 kWh. The 23,269 kWh/year consumption level, for which specific price data is collected during monitoring, falls into the medium Eurostat consumption band. The following therefore shows a European comparison of the medium consumption band. Household customers generally cannot have taxes and levies refunded, which is why the total price including VAT is relevant to these customers.

[170] The Eurostat comparison does not include prices in Finland and Greece.

In contrast to prices in the industrial customer sector, gas prices for household customers vary greatly in Europe. Household customers in Sweden pay more than twice as much for natural gas as customers in Belgium and the United Kingdom and more than three times as much as customers in Bulgaria, Romania, Estonia, Hungary and Croatia. The gas price of 6.09 ct/kWh paid by household customers in Germany in the second half of 2017 was slightly less than the EU average price of 6.33 ct/kWh.

The percentage of the overall price made up by taxes and levies also varies widely across the EU. While taxes and levies account for only about 9% of the price in the United Kingdom, they make up about 56% of the price in Denmark. Germany's figure of about 26% again matches the European average in this respect. Around 1.56 ct/kWh of the overall price in Germany consists of taxes and levies; the EU average is 1,69ct/kWh (about 27%).

Comparison of European gas prices in the second half of 2017 for household customers with an annual consumption between 5,555 kWh and 55,555 kWh in ct/kWh ; incl. VAT



Source: Eurostat

Figure 223: Comparison of European gas prices in the second half of 2017 for household customers with an annual consumption between 5,555 kWh and 55,555 kWh[171]

[171] The Eurostat comparison does not include prices in Finland and Greece.

G Metering

1. The network operator as the default meter operator and independent meter operators

Metering was completely revamped in Germany with the adoption of the Metering Act (MsbG), which is an integral part of the Energy Transition Digitisation Act. This Act, which entered into force on 2 September 2016, replaced sections 21b et seq. of the Energy Industry Act (EnWG) and the Metering Framework Conditions Ordinance (MessZV).

The "basic responsibility for meter operations" is now legally defined for the first time and a distinction has been made between the basic responsibility for conventional metering systems and basic responsibility for modern metering devices and smart meters. The basic responsibility for both categories of equipment lies with network operators, but whereas the basic responsibility for conventional metering systems will remain permanently with the local network operator, since 1 October 2017 it has been possible to transfer the basic responsibility for modern metering devices and smart meters to a third party service provider.

Although metering activities have been fully liberalised, it is still predominantly the network operators that provide metering services under their "basic responsibility" (in their networks).

The results presented in this chapter take into account information collected from 685 companies. This paints the following picture for 2017 with regard to the distribution of market roles:

Meter operator roles

Function	2018
Network operator acting as default meter operator within the meaning of section 2(4) MsbG (until 2016: network operator acting as meter operator within the meaning of section 21b(1) EnWG)	671
Network operator acting as meter operator without basic responsibility and providing (metering) services in the market (until 2016: network operator acting as meter operator within the meaning of section 21b(2) of the EnWG, providing (metering) services in the market)	11
Supplier with meter operator activities	10
Independent third party that provides metering services	7

Table 130: Distribution of network operator roles according to data provided by gas meter operators as at 31 December 2017

2. Metering technology used for household customers

As at 31 December 2017, approximately 4.8 million meters for standard load profile (SLP) customers were able to be converted so that they could be connected to a smart meter gateway within the meaning of section 2(19) MsbG. About 155,000 meters have already been converted so that they can be connected to a smart meter gateway within the meaning of section 2(19) MsbG.

Metering equipment used by SLP customers in 2017

Types of metering equipment used by meter operators for SLP customers	No of meter points by meter size		
	G1.6 to G6	G10 to G25	G40 and higher
Diaphragm gas meters with mechanical counter	7,352,732	244,967	28,755
Diaphragm gas meters with mechanical counter and pulse output	6,003,394	194,153	21,359
Diaphragm gas meters with electronic counter and manufacturer-specific output (eg: Cyble, absolute encoder)	369,786	9,162	1,547
Diaphragm gas meters with electronic counter	9,475	332	1,105
Ultrasonic gas meters	5,622	0	214
Load/interval meters as for interval-metered customers	74	189	2,948
Other mechanical gas meters	9,724	3,335	23,912
Other electronic gas meters	4,012	186	790
Number of meters that can be converted so that they can be connected to a smart meter gateway within the meaning of section 2(19) MsbG	4,643,395	147,035	26,776
Number of meters that have actually been converted so that they can be connected to a smart meter gateway within the meaning of section 2(19) MsbG	147,902	4,833	1,717

Table 131: Breakdown of metering equipment used by SLP customers as at 31 December 2017

The overwhelming majority of meters use pulse generators as their communication technology (92%). The remaining 8% use Cyble sensors, absolute encoders, electronic meters or other means.

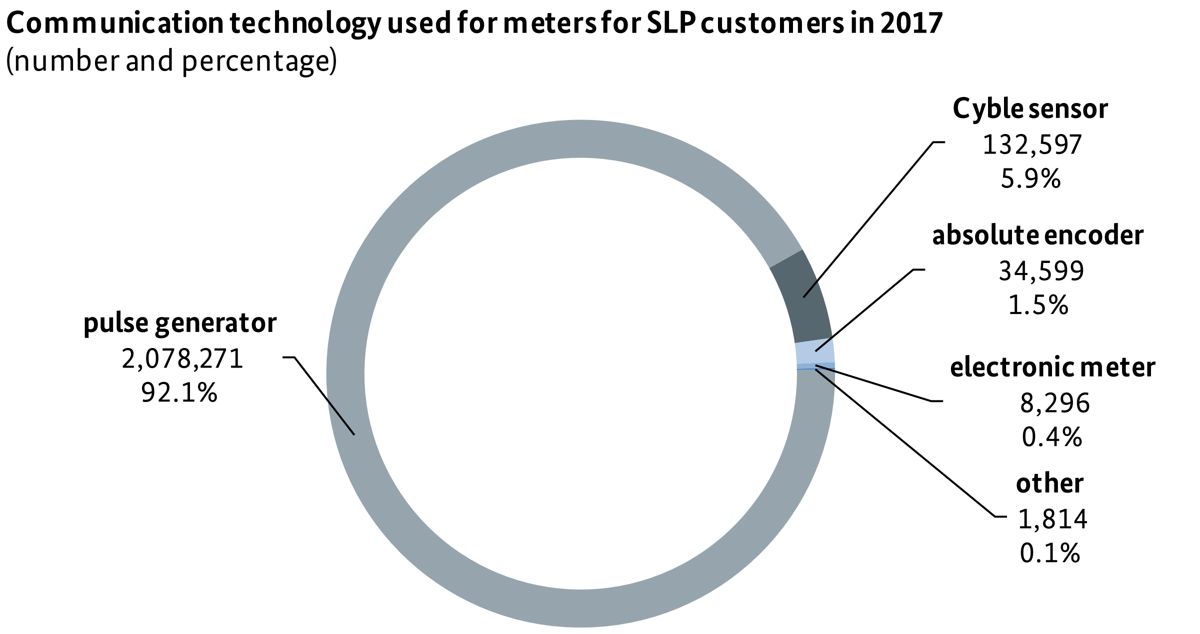


Figure 224: Communication technology used for meters for SLP customers – as at 31 December 2017

Most meters for SLP customers (about 63%) use telecommunication technology such as traditional telephone lines, DSL or mobile communications as their interface technology.

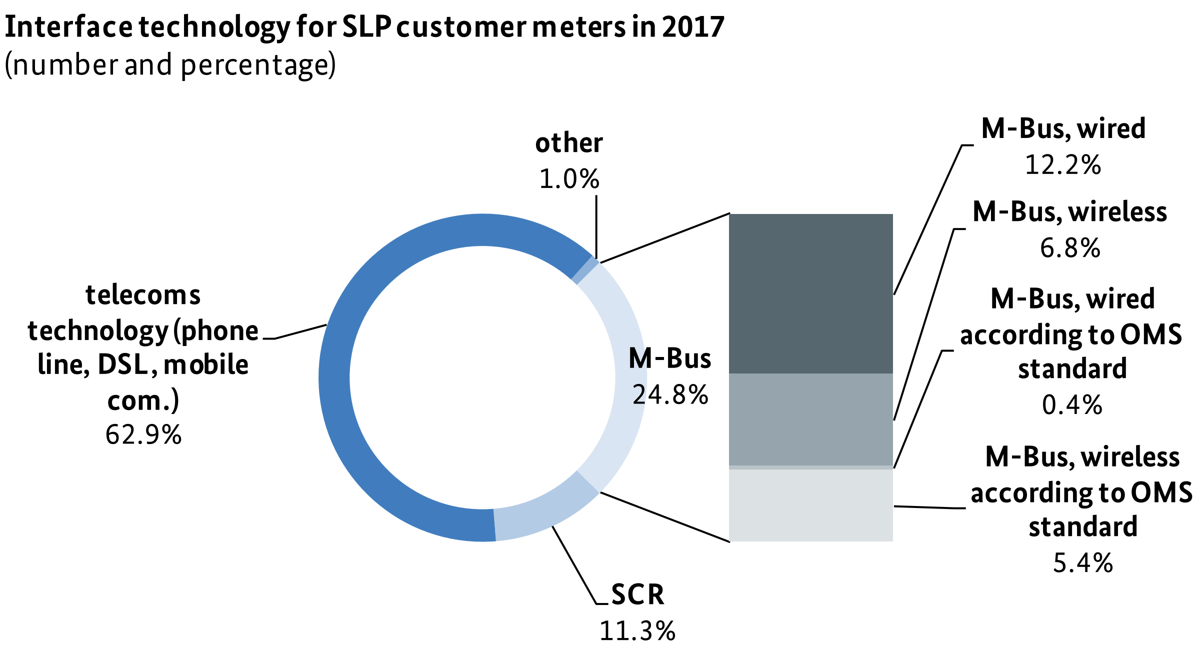


Figure 225: Interface technology for SLP customer meters – as at 31 December 2017

3. Metering technology used for interval-metered customers

The distribution of metering technology employed for interval-metered customers in 2017 is as follows:

Metering technologies used for interval-metered customers in 2017

Function	No of meter points
Transmitting meter with a pulse output/encoder meter + a recording device/data storage	15,886
Transmitting meter with a pulse output/encoder meter + volume converter	13,210
Transmitting meter with a pulse output/encoder meter + calorific value volume converter	303
Transmitting meter with a pulse output/encoder meter + volume converter + recording device/data storage	15,948
Transmitting meter with a pulse output/encoder meter + temperature volume converter + recording device/data storage	552
Transmitting meter with a pulse output/encoder meter + smart meter gateway	13
Other	87

Table 132: Breakdown of metering technologies used for interval-metered customers – as at 31 December 2017

The metering technology used by interval-metered customers transmits data almost exclusively via telecommunication systems (94.7%). Telecommunications include mobile communications up to 2.5G (GSM, GPRS, EDGE), mobile communications up to 3G (UMTS, HSDPA, LTE), telephone lines, DSL and broadband as well as power lines. The digital interface for gas meters is worth mentioning as an alternative technology used to transfer meter data. Approximately 4.3% of interval-metered customers use this interface.

Communication link-up systems used for interval-metered customers in 2017
(number and percentage)

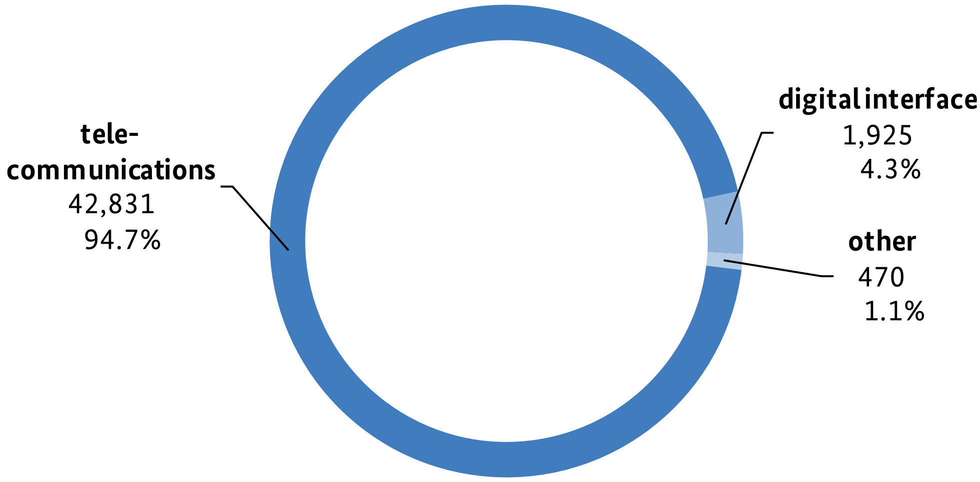


Figure 226: Number and percentage of communication link-up systems used for interval-metered customers – as at 31 December 2017

4. Ability of gas metering equipment to be connected to a smart meter gateway within the meaning of section 20(1) MsbG

Meter operators were asked about the number of meter points that they had fitted with metering equipment within the meaning of section 20(1) MsbG in 2017 and that could be connected to a smart meter gateway within the meaning of section 2 para 7 MbsG. 231 meter operators reported a total of 4,437,142 meter points for 2017 (as at 31 December 2017). By comparison, in 2016 the number of meter points fitted with metering equipment able to be connected to a smart meter gateway was 771,833, according to 189 meter operators.

The number of meter points that are fitted with metering equipment and already connected to a smart meter gateway was recorded for the first time. 16 meter operators stated that there were 660 such meter points. The number of meter points with smart metering equipment that is not connected to a smart metering system pursuant to section 2 para 7 MsbG was also recorded. A total of 112 meter operators reported 106,062 such meter points. Meter operators were further asked about the number of meter points they plan to fit with a smart meter but that will not be connected to a smart metering system pursuant to section 2 para 7 MsbG. A total of 15 meter operators reported 5,425 such meter points.

5. Metering investment and expenditure

Gas meter operators were asked about their investment behaviour in the monitoring survey. The evaluation is based on data from around 540 gas meter operators.

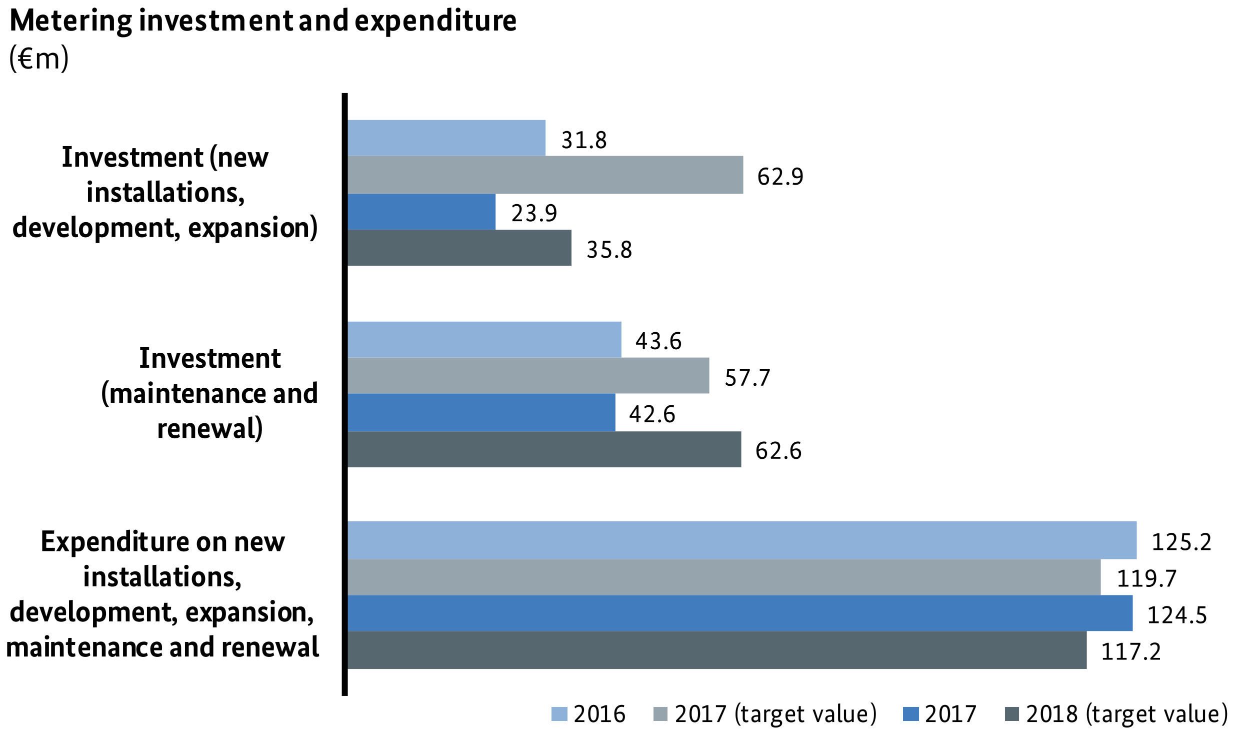


Figure 227: Metering investment and expenditure

III General topics

A Market Transparency Unit for Wholesale Electricity and Gas Markets

The tasks of the Market Transparency Unit for Wholesale Electricity and Gas Markets are carried out jointly by the Bundesnetzagentur and the Bundeskartellamt. To conduct market monitoring activities, the unit receives transaction and fundamental data transmitted to the Agency for the Cooperation of Energy Regulators (ACER) in accordance with Regulation (EU) No 1227/2011 (REMIT) in conjunction with Implementing Regulation (EU) No 1348/2014. These data are reported for about 4,300 registered market participants in Germany. Around 13,500 market participants are registered in the whole of Europe.[172]

The Market Transparency Unit received transaction data from ACER for the period 1 October 2017 to 31 August 2018. An average of 1.28m data records[173] for the category of standard contracts for the German energy market were transmitted each day in accordance with Article 6 of Implementing Regulation (EU) No 1348/2014. By comparison, ACER receives over 2 million transaction reports a day for the whole European energy market. Transaction reports comprise trades concluded and orders to trade. The following data was transmitted for the period given above:

Number of reports on transactions

Total number of reports on trades	**44,141,410**
reports on trades (buy side)	21,491,436
reports on trades (sell side)	22,649,962
Total number of reports on orders (bids)	**383,231,854**
reports on buy bids	192,904,126
reports on sell bids	185,769,857
reports on buy and sell bids[1]	4,557,871
Total transaction reports	**427,373,264**

[1]On some auction markets, an order can consist of a buy and a sell.

Table 133: Number of data reports

[172] As at 31 August 2018

[173] Data records/reports include updates of previously reported data and should not be interpreted as referring to individual trades or orders to trade.

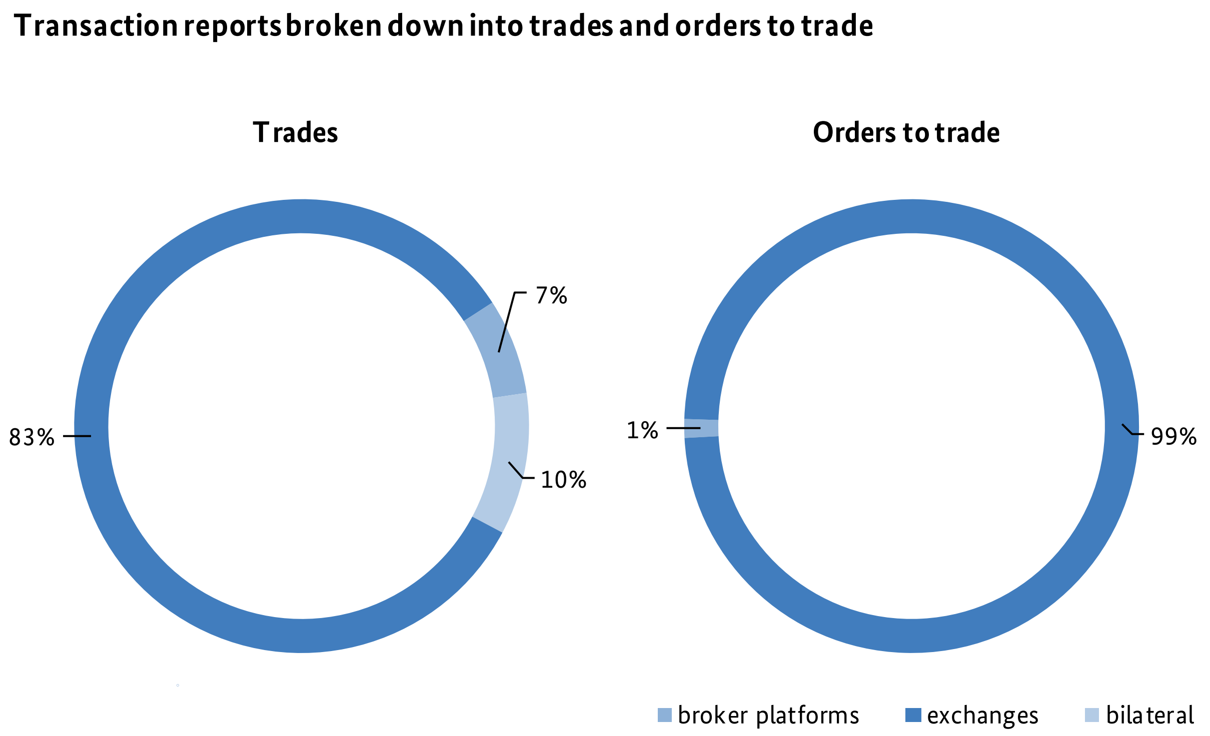


Figure 228: Transaction reports broken down into trades and orders to trade

The Market Transparency Unit also receives fundamental data, in particular those data published on the transparency platforms of ENTSO-E[174] and ENTSO-G[174].

[174] https://transparency.entsoe.eu/

B Selected activities of the Bundesnetzagentur

Tasks under REMIT

The Bundesnetzagentur monitors the wholesale energy market pursuant to Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT). It receives tips from sources including organised market places about suspicious behaviour by market participants that could breach the prohibitions on insider trading and market manipulation. Organised market places and other persons who arrange transactions in a professional capacity are required to inform the Bundesnetzagentur if they have reason to believe insider trading or market manipulation is taking place. They do so using ACER's European Notification Platform.[175] The Bundesnetzagentur carries out its own analysis of the data to investigate the reports of suspected breaches.

The numbers of reports received each year has been rising since the monitoring began.

A total of 51 reports have been received so far between 2012 and 2018. They first undergo preliminary investigation by the Bundesnetzagentur (assessing and clarifying the reported circumstances, etc). If the investigation shows that there may have been a breach of REMIT, the Bundesnetzagentur can start regulatory offence proceedings. It has so far only done so in one case, which is still ongoing. If there is insufficient evidence that a breach was committed, the case is closed. 24 of the 51 reports have so far been closed. Eleven cases affecting both Germany and other European Member States are being investigated in cooperation with the foreign regulatory authorities concerned. Examples of such cases are when the trading behaviour took place on the exchange of a different European Member State to the one in which the market participant has its registered headquarters.

From 2012 to 2015, only cases of market manipulation were reported, but since 2016 possible insider trading has also been reported. Some suspected cases of insider trading relate to transactions made before power plant outages were made known. Market manipulation includes such behaviour as placing orders with no intention of executing them or trading deliberately to exclude other participants from the market. The Bundesnetzagentur is also investigating the activities of market participants that led to peak prices for tertiary reserve on 17 October 2017 as possible breaches of the prohibitions on insider trading and market manipulation.

The graph below shows the number of suspected breaches reported between 2012 and 2018, broken down into market manipulation and insider trading:

[175] https://www.acer-remit.eu/portal/notification-platform

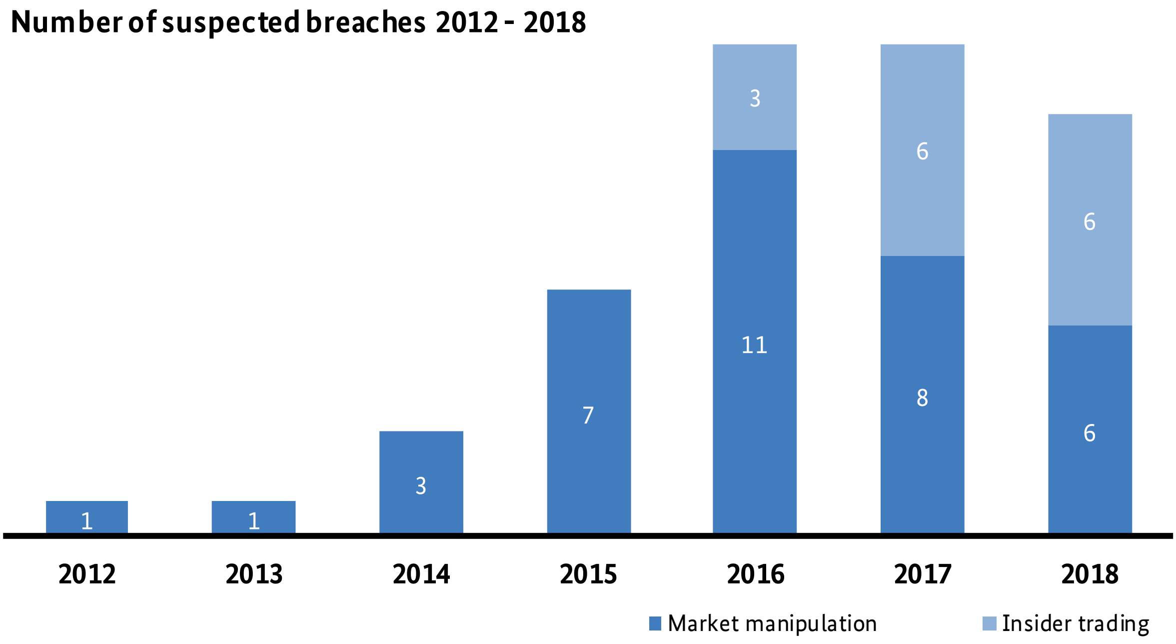


Figure 229: Reports of suspected breaches received by the Bundesnetzagentur 2012 – 2018[176]

[176] As at 24 July 2018

C Selected activities of the Bundeskartellamt

1. Guidelines on the control of the abuse of a dominant position in electricity generation

The Bundeskartellamt has drafted guidelines on the control of the abuse of a dominant position in electricity generation.

In the debate about the Electricity Market Act in 2015 and 2016 concerns were frequently expressed that the prohibition of abusive practices under competition law had the effect of an implicit price ceiling and prevented price peaks in situations of scarcity (see Monitoring Report 2016, page 375 f.). The Bundeskartellamt does not share these concerns. Contrary to what is sometimes claimed, the prohibition of the abuse of a dominant position does not generally prohibit companies from offering capacities with a surcharge on their marginal costs (mark-up). The prohibition of the abuse of a dominant position applies exclusively to dominant companies. These may not use their market power to, for example, drive up prices artificially and to a considerable extent. If, on the other hand, price peaks occur because of actual scarcities which are not market power-related, they are not objectionable under competition law.

In order to dispel these concerns, the Bundeskartellamt had proposed to publish guidelines on the control of the abuse of a dominant position in electricity generation. This proposal was adopted in the White Paper of the Federal Ministry for Economic Affairs and Energy published in 2015 as one of 20 measures to further develop the electricity market. The guidelines will define the objective, rules for the application and scope of the control of the abuse of a dominant position on the market for the first-time sale of electricity. In 2016 the Bundeskartellamt launched a consultation in preparation for the guidelines (the eight comments received are available on the Bundeskartellamt's website).

Addressing the issues in such a way that the guidelines remain viable in view of the current, foreseeable and possible changes in electricity generation and marketing posed a particular challenge in drafting the guidelines.

In addition to providing clarification on the control of the abuse of a dominant position on the market for the first sale of electricity, the joint guidelines of the Bundeskartellamt and Bundesnetzagentur will address questions on the interpretation of the REMIT regulation.

The guidelines are now in their final stage of coordination between the Bundeskartellamt and the Bundesnetzagentur and are then to be presented for public consultation.

2. Merger control proceedings in the energy sector: EnBW AG / MVV Energie AG

With its decision of 13 December 2017 the Bundeskartellamt cleared plans by EnBW AG (“EnBW”) to increase its share in MVV Energie AG (“MVV”) to 28.76% (ref. B8-73/17, B4-80/17). The investigations showed that although EnBW had for the first time acquired a blocking minority in MVV, the acquisition did not significantly impede effective competition in the waste management and energy supply markets concerned.

EnBW is one of Germany's five largest electricity producers and via its affiliated companies is active at several levels of the electricity and gas value added chain. MVV is also an energy supplier which is active throughout Germany in the supply of energy, district heating and water and energy trading. The key focus of the investigations in the energy supply area was the market for the first-time sale of electricity, the provision of balancing energy and, for the first time, the redispatch sector.

In its decision-making practice the Bundeskartellamt defines a market for the production and first-time sale of electricity which is not remunerated under the EEG and which in geographical terms covers the entire electricity bidding zone consisting of Germany, Austria and Luxembourg. The merger did not result in critical market shares. The splitting of the bidding zone at the border to Austria was not taken into consideration because this had not yet been formally decided. The prognosis which has to be made in a merger control proceeding fundamentally requires that the current legal situation forms the basis of the examination. The consideration of a possible bidding zone splitting would also not have altered the substantive assessment of the merger because based on an assessment of the German market alone, the merger did not significantly impede effective competition and, in particular, did not meet the thresholds for the creation or strengthening of a dominant position.

In the area of balancing energy, which is required to avoid unpredictable fluctuations in supply and demand in electricity transmission networks, the Bundeskartellamt has established that under the narrowest possible market definition, five balancing energy markets, at least at nationwide level, would have to be assessed: primary balancing capacity, positive and negative secondary balancing capacity as well as positive and negative minute reserve. The relevant market definition could be left open in this case because a significant impediment to effective competition could be ruled out in every possible scenario. In particular, the investigations showed that the provision of a core portion reserve within the control area is no longer required and no requirement for this is envisaged for the future.

The question whether redispatching constitutes a market under competition law and how this would be defined in product and geographic market terms could also be left open as the merger would not have fulfilled the prohibition requirements based on any possible market definition. The term redispatching refers to the management of capacity congestion in the transmission network by intervening in the operating schedules of power plants.

Power plant operators in Germany with a nominal capacity of 10 MW or more have to provide redispatch when requested by transmission system operators. The level of entitlement to adequate remuneration is regulated in 13a the Energy Industry Act. However, plant operators outside Germany are not subject to these regulations and can also negotiate the level of remuneration for the provision of dispatch. They therefore gain a scope of competitive action. With its electricity procurement rights to the Vorarlberger Illwerke power plants in Austria, EnBW has such plants outside Germany.

The investigations have shown that electricity generated in power plants outside Germany should be included in the redispatching assessment. In the period of reporting these volumes of electricity reached a substantial level. The assumption of a southern zone for redispatch consisting of the southern German Länder and the respective electricity generated in power plants outside Germany would also be feasible.

The decision is not yet final. An appeal against the clearance decision is pending at the Düsseldorf Higher Regional Court.

3. Sector inquiry: Comparison websites and consumer protection

In October 2017 the new Decision Division for Consumer Protection which was set up at the Bundeskartellamt in the same summer, launched a sector inquiry into "comparison websites". The sector inquiry focuses on a number of possible violations of consumer protection rules by comparison websites in different sectors. The sector inquiry also deals with comparison websites in the energy sector which offer household customers the possibility to compare electricity and gas tariffs and the website's services as an intermediary between the customer and the energy supplier. These websites are now a very important distribution channel in the energy sector. Nearly every fourth supply contract with a household customer is now concluded via a comparison website.

The topic areas investigated in the sector inquiry were cooperations and corporate links between websites, market coverage, pre-selection and ranking, how the offers are ranked in the comparison and how user rankings are set.

At the end of 2017 in a first step the Bundeskartellamt surveyed well over 100 websites, including around 30, which are (also) active in the energy sector. The aim of the inquiry was to identify the relevant market participants and to establish the relations between the websites, e.g. in the form of white label solutions or cooperations through affiliate networks.

Six of the websites were selected to examine comparison websites active in the energy sector, including Check24 and Verivox. In May 2018 these websites received a further, extensive questionnaire on various topic areas dealt with in the sector inquiry. The Bundeskartellamt also requested a number of documents such as e.g. contracts between the suppliers and comparison websites, which are currently being evaluated. A consultation paper, on which the companies concerned are invited to give their comments, is to be presented at the end of the year. A publication of the final report of the sector inquiry is envisaged for.

Lists

List of authorship

Joint texts

Key findings

Electricity markets summary (I.A.1)

Introduction to Retail: Contract structure and supplier switching (I.G.2)

Introduction to Retail: Price level (I.G.4)

Gas markets summary (II.A.1)

Introduction to Retail: Contract structure and supplier switching (II.F.2)

Introduction to Retail: Price level (II.F.4)

Market Transparency Unit for Wholesale Electricity and Gas Markets (III.A)

(Text passages in these four sections authored as listed below)

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Term	Definition
AbLaV	Interruptible Loads Ordinance
AC	Alternating current
ACER	Agency for the Cooperation of Energy Regulators
ARegV	Incentive Regulation Ordinance
AT	Austria
AusglMechV	Equalisation Scheme Ordinance
BAFA	Federal Office for Economic Affairs and Export Control
BBPlG	Federal Requirements Plan Act
bEXA	Block products traded on the Energy Exchange Austria (EXAA), eg bEXAbase and
bFZK	Capacity with conditional firmness and free allocability
BGH	Federal Court of Justice
BMWi	Federal Ministry for Economic Affairs and Energy
BSI	Federal Office for Information Security
BZK	Capacity with restricted allocability
CEE	Central East Europe
CEREMP	Centralised European Register of Energy Market Participants
CH	Switzerland
CHP	Combined heat and power
CR	Concentration Ratio
CSE	Central South Europe
ct/kWh	Cents per kilowatt hour
CWE	Central West Europe
CZ	Czechia
DC	Direct current
DIN	German Institute for Standardization
DSL	Digital Subscriber Line
DSO	Distribution system operator
DZK	Firm dynamically allocable capacity
EC	European Community
ECC	European Commodity Clearing AG
EEG	Renewable Energy Sources Act

EEX	European Energy Exchange AG
EHV	Extra-high voltage
EnLAG	Power Grid Expansion Act
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energy Industry Act
EPEX SPOT	European Power Exchange
Eurostat	Statistical Office of the European Communities
EXAA	Energy Exchange Austria Abwicklungsstelle für Energieprodukte AG
FBA	Flow Based Allocation
FZK	Freely allocable capacity
GABi Gas	Basic model of balancing services and balancing rules in the gas sector
GasGVV	Gas Default Supply Ordinance
GasNEV	Gas Network Charges Ordinance
GasNZV	Gas Network Access Ordinance
GeLi Gas	Business processes for change of gas supplier
GPKE	Business processes for supplying customers with electricity
GPRS	General Packet Radio Service
GSM	Global System for Mobile Communications
GW	Gigawatt
GWB	Restraints of Competition Act
GWh	Gigawatt hour
GWJ	Gas year
HVDC	High voltage direct current transmission
HV	High voltage
HVDC	High voltage direct current
IGCC	International Grid control Cooperation
ITC	Inter-TSO compensation
KAV	Electricity and Gas Concession Fees Ordinance
km	kilometre
KoV IV	Cooperation agreement pursuant to section 20(1b) EnWG between the operators of the
kV	kilovolt
kWh	kilowatt hour
KWKG	Combined Heat and Power Act
KraftNAV	Power Plant Grid Connection Ordinance
LNG	Liquefied natural gas

LSV	Charging Station Ordinance
LV	Low voltage
MessZV	Metering Framework Conditions Ordinance
MsbG	Metering Act
MV	Medium voltage
MW	Megawatt
MWh	Megawatt hour
NABEG	Grid Expansion Acceleration Act
NAV	Low Voltage Network Connection Ordinance
NCG	NetConnect Germany
Ncm	Normal cubic metre
Ncm/h	Normal cubic metre per hour
NDAV	Low Pressure Network Connection Ordinance
NDP	Network development plan
NEMOG	Network Charges Modernisation Act
NL	Netherlands
NTC	Net Transfer Capacity
OGE	Open Grid Europe
OMS standard	Open Metering System standard
OTC	Over-the-counter
PL	Poland
PLC	Powerline Carrier/Powerline Communication
PSTN	Public switched telephone network
REMIT	EU Regulation on wholesale energy market integrity and transparency
SAIDI	System Average Interruption Duration Index
SLP	Standard load profile
StromNEV	Electricity Network Charges Ordinance
StromNZV	Electricity Network Access Ordinance
TFEU	Treaty on the Functioning of the European Union
TSO	Transmission system operator
TWh	Terawatt hour
UMTS	Universal Mobile Telecommunications System
VAT	Value added tax
VNG	Verbundnetz Gas AG

Glossary

The definitions pursuant to section 3 of the Energy Industry Act (EnWG), section 2 of the Electricity Network Access Ordinance (StromNZV), section 2 of the Gas Network Access Ordinance (GasNZV), section 2 of the Electricity Network Charges Ordinance (StromNEV), section 2 of the Gas Network Charges Ordinance (GasNEV), section 3 of the Renewable Energy Sources Act (EEG) and section 2 of the Combined Heat and Power Act (KWKG) apply. In addition the following definitions apply:

Term	Definition
Adjustment measures	Section 13(2) EnWG entitles and obliges TSOs to adjust all electricity feed-in, transit and offtake or to demand such adjustment (adjustment measures) where a threat or disruption to the security or reliability of the electricity supply system cannot be removed or cannot be removed in a timely manner by network-related or market-related measures as referred to in section 13(1) EnWG. Where DSOs are responsible for the security and reliability of the electricity supply in their networks, they too are entitled and obliged under section 14(1) EnWG to take adjustment measures as referred to in section 13(2) EnWG. Furthermore, section 14(1c) EnWG requires DSOs to support the TSOs' measures as required by the TSOs with the DSOs' own measures (support measures). Curtailing feed-in from renewable energy installations under section 13(2) EnWG may also be necessary in situations other than those covered by the feed-in management provisions if the threat to the system is caused not by congestion but by another security problem. Adjustments pursuant to section 13(2) EnWG constitute emergency measures and as such are without compensation.
Affiliated undertakings within the meaning of section 15 Stock Corporation Act	As set out in the German Stock Corporation Act: legally independent companies that in relation to each other are subsidiary and parent company (section 16), controlled and controlling companies (section 17), members of a group (section 18), undertakings with cross-shareholdings (section 19) or parties to a company agreement (sections 291 and 292).
Annual peak load (final consumer)	Peak load, expressed in kilowatt (kW), as metered in 15 minute readings, in the course of a year.
Annual usage time (final consumer)	The annual usage time is the quotient of the energy drawn from the grid in an accounting year and the annual maximum capacity used in that year. It gives the number of days that would be required to withdraw the annual consumption volume by taking off the maximum daily amount (usage time in days = annual consumption divided by maximum daily amount). The usage time in hours indicates the number of hours required to withdraw the annual consumption volume by taking off the maximum hourly amount (usage time in hours = annual consumption divided by maximum hourly amount) (see annex 4 to section 16(2),(3) second sentence StromNEV).
Auxiliary capacity	Electrical power a generating unit requires to operate its auxiliary and ancillary facilities (eg for water treatment, water supply to steam generators, fresh air and fuel supply, flue gas cleaning), plus the power losses of step-up transformers (generator transformers). There are two types of internally used electrical power: the electrical power required to operate a generating unit's auxiliary and ancillary facilities during operating hours and the electrical power required to operate its auxiliary and ancillary facilities outside operating hours (see VGB, 2012).
Balancing capacity	Balancing capacity is maintained to ensure a constant balance between electricity generation and consumption.
Balancing group	As regarding electricity within a control area, the aggregation of feed-in and consumption points that serves the purpose of minimising deviations between feed-in

Term	Definition
	and output by its mix and enabling the conclusion of trading transactions (see section 3 para10a EnWG).
Balancing zone	Within a balancing zone all entry and exit points can be allocated to a specific balancing group. In the gas sector a balancing zone corresponds to the market area. This means that all entry and exit points in all networks or network segments that are part of the particular market area belong to a balancing group (see section 3 para 10b EnWG).
Baseload	Load profile for constant electricity supply or consumption from 00:00 to 24:00 every day.
Binding exchange schedules	Unlike physical load flows, which represent the actual cross-border flow of electricity, exchange schedules reflect the commercial cross-border exchange of electricity. Physical load flows and commercial exchange schedules do not necessarily have to match (eg due to loop flows).
Black start capability	Ability of a generating unit (power plant) to start up independently of power supplies from the electricity network. As a first step to restore supply, this is particularly important in the event of a disruption causing the network to break down. Additionally, a "stand-alone capability" is required with a steady supply voltage and capable of bearing loads without any significant voltage and frequency fluctuations.
Cavern storage facility	Artificial hollows in salt domes created by drilling and solution mining. In comparison to pore storage facilities, these often have higher injection and withdrawal capacities and a lower cushion gas requirement, but are also smaller in volume.
Change of contract	A customer's change to a new tariff with the same energy supplier at their own request.
Charge for billing	The charge for billing network use and forecasting annual consumption in accordance with section 13(1) StromNZV has been included in the net network charges since 1 January 2017 and is no longer shown separately (see section 7(2) of the Metering Act).
Charge for meter operations	Charge for meter installation, operation and maintenance. In accordance with section 17(7) first sentence StromNEV, in the electricity sector only a "charge for meter operations" may be shown from 1 January 2017. This includes the charge for metering.
Charge for metering	In the gas sector, the charge for reading the meter, reading out and passing on the meter data to the authorised party (section 15(7) first sentence GasNEV).
CHP electricity	CHP electricity is the mathematical product of useful heat and power-to-heat ratio of the CHP installation; for installations without equipment for the removal of waste heat, the entire net electricity generation is CHP electricity.
CHP net nominal capacity (electrical active power)	For rated thermal capacity, proportion of the net nominal capacity directly linked to heat extraction. The proportion of electrical capacity exclusively related to the generation of electricity is not included here.
Concentration ratio (CR)	Total market share of the three, four or five competitors with the biggest market shares (Concentration Ratio 3, CR4, CR5). The greater the market share covered by just a few competitors, the higher the degree of market concentration.
Consumption	Amounts of electricity delivered by electricity suppliers to final consumers.
Conventional generation base	Proportion of the price-inelastic conventional generation that is not part of the minimum generation.
Countertrading	Countertrading is a measure used by the TSOs to avoid overloading in the electricity grid. It is used when the agreed minimum trading capacity exceeds the capacity that can be transported in the networks. In this case, a countertrade is organised. This enables a minimum level of trading to be guaranteed at all times without the networks being overloaded.

Term	Definition
Day-ahead trade	Day-ahead trading on the EPEX Spot (the EEX spot market) is for energy supplied the next day.
Default supplier	The gas and electricity company providing default supply in a network area as provided for by section 36(1) EnWG.
Default supply	Energy supply by the default supplier to household customers on the basis of general terms and conditions and general prices (see section 36 EnWG).
Delivery volumes	Amount of electricity or gas delivered by electricity or gas suppliers to final consumers.
Dominance method	Simplified group accounting method for the purposes of evaluating market concentration. It focuses solely on whether one shareholder holds at least 50% of the shares in a company. If the shares in a company are held as to more than 50% by one shareholder, the company's volume of sales is attributed to the shareholder in full. If two shareholders have a shareholding of 50% each, then the sales are split in half and attributed to each of the shareholders. If there is no shareholding of 50% or more in a company, the volume of sales of this company is not attributed to any shareholder (the company is then itself a "controlling company").
Downstream distributor	Regional and local gas distribution network operator (not an exporter).
Dynamic prices	Prices of an electricity supply contract between a supplier and a final consumer that reflects the price on the spot market, including the day-ahead market, in intervals corresponding to at least the billing interval of the market in question.
Economic balancing energy	*Electricity* The activated energy that is settled with the balancing group managers causing the imbalances. Balancing energy is therefore the allocation of call-off costs for balancing capacity and represents the economic settlement of the activated energy. *Gas* Difference between entry and exit quantities established by the market area manager for the market area at the end of each balancing period and settled with the balancing group managers (see section 23(2) GasNZV).
EEX/EPEX Spot	European Energy Exchange/European Power Exchange. The EEX, which is indirectly part of the Deutsche Börse Group, operates marketplaces for trading electricity, natural gas, CO_2 emission rights and coal. EEX holds a 51% equity investment in the Paris-based EPEX Spot, which operates the power spot markets for Germany, France, Austria and Switzerland. The electricity futures market is operated by EEX Power Derivates GmbH (a 100% subsidiary of EEX). EEX also holds an around 88% stake in Powernext SA, also based in Paris, which operates short-term gas trading (see EEX).
Electric heating	Electricity for heating is the electricity supplied to operate interruptible (= controllable) consumer devices for the purposes of room heating. Interruptible (= controllable) consumer devices essentially comprises overnight storage heaters and electric heat pumps.
Energy price components	The price component that is controlled by the supplier, made up of energy procurement, supply and margin.
Energy to cover power losses	The energy required for the compensation of technical power losses.
Entry point	A point at which gas can be transferred to the network or subnetwork of a system operator, including transfers from storage, gas production facilities, hubs, or blending and conversion plants.
Entry-exit system	Gas booking system in which the shipper signs only one entry and exit contract, even if the transport is distributed among several TSOs.

Term	Definition
Exit point	The point at which gas can leave an operator's network for delivery to final customers, downstream networks (own and/or third party) or redistributors, plus the points at which gas can be taken off for delivery to storage facilities, hubs and conditioning or conversion plants.
Exit volume	The gas network operators' exit quantities.
Expenditure	Expenditure consists of the combination of all technical or administrative measures taken during the life cycle of an asset to maintain or restore working order so that the asset can perform the function required (expenditure on replacement and maintenance).
Fallback supplier	The default supplier is the fallback supplier (see section 38 EnWG).
Fallback supply	Energy received by final customers from the general supply system at low voltage or low pressure and not allocable to a particular delivery or a particular supply contract (see section 38 EnWG).
Feed-in management	This is a special measure regulated by law to increase network security relating to renewable energy, mine gas and combined heat and power (CHP) installations. Priority is to be given to feeding in and transporting the electricity generated by these installations (section 11(1) and (5) EEG and section 4(1) and (4) second sentence KWKG). Under specific conditions, however, the system operators responsible may also temporarily curtail priority feed-in from these installations if network capacities are not sufficient to transport the total amount of electricity generated (section 13(2) and (3) third sentence EnWG in conjunction with sections 14 and 15 EEG and, in the case of CHP installations, section 4(1) second sentence KWKG). Importantly, such feed-in management is only permitted once the priority measures for conventional installations have been exhausted. The expansion obligations of the operator answerable for the network restrictions remain in parallel to these measures. The operator of an installation with curtailed feed-in is entitled to compensation for the energy and heat not fed in as provided for in section 15(1) EEG The costs of compensation must be borne by the operator in whose network the cause for the feed-in management measure is located. The operator to whose network the installation with curtailed feed-in is connected is obliged to pay the compensation to the operator of the installation with curtailed feed-in. If the cause lay with another operator, that operator is held responsible and is required to reimburse the costs of compensation to the operator to whose network the installation is connected.
Flow Based Allocation (FBA)	Flow based allocation of capacity. Starting from the planned commercial flows (trades), the capacity available for cross-border electricity trading is determined and allocated on the basis of the actual flows in the network. FBA thus makes it possible to allocate transmission capacity in line with the actual market situation as reflected by the bids.
Futures	Contractual obligation to buy (futures buyer) or deliver (futures seller) a specified amount of, for example, electricity, gas or emission rights at a fixed price in a defined future period (period of delivery). Futures contracts are settled either physically or financially.
Futures market	Market for trading futures and derivatives. It differs from the spot market in that obligation and settlement do not take place at the same time.
Green electricity tariff	Tariff for electricity that, on account of green electricity labelling or other marking, is shown to have been produced with a high share/high promotion of efficient or regenerative production technologies and which is offered/traded at a separate tariff.
Grid connection	*Electricity* Pursuant to section 5 of the Low Voltage Network Connection Ordinance (NAV), the grid connection connects the general electricity network to the electrical installation of the customer. It begins at the branching-off point of the low voltage distribution network and ends with the service fuse, unless a different agreement has been made; in

Term	Definition
	any case, the provisions relating to grid connection are applicable to the service fuse. In the case of power plants, the grid connection is the provision of the line that connects the generating installation and the connection point, and its linkage with the connection point (section 2 para 2 of the Power Plant Grid Connection Ordinance (KraftNAV)). *Gas* Pursuant to section 5 of the Low Pressure Network Connection Ordinance (NDAV), the network connection joins the general supply network with the customer's gas facilities from the supply pipeline to the internal pipes on the premises. It comprises the connecting pipe, any shut-off device outside the building, insulator, main shut-off device and any in-house pressure regulator. The provisions on connection to the network are still applicable to the pressure regulator when it is installed after the end of the network connection within the customer's system.
Gross capacity	Delivered power to the terminals of the generator. In turbine operation for hydro power, gross capacity is measured at the generator's terminals. In a pumped storage station, net capacity is measured at the terminals of the generator if the facility is operated as a motor. Gross capacity is equal to net capacity plus the electrical power used by the plant, including power lost by the plant's transformers but not the power consumed in the process of generation and the power required for the phase shifter (VGB, 2012).
Gross electricity consumption	Gross electricity consumption is calculated from the gross electricity generation plus imports and minus exports (both physical flows).
Gross electricity generation	Electrical energy produced by a generating unit, measured at the generator's terminals (see VGB, 2012).
H-gas	A second-family gas with a higher amount of methane (87 to 99 volume percent) and thus a lower volume percentage of nitrogen and carbon dioxide than L-gas. It has a medium calorific value of 11.5 kWh/m^3 and a Wobbe index from 12.8 kWh/m^3 to 15.7 kWh/m^3.
Hub	An important physical node in the gas network where different pipelines, networks and other gas infrastructures come together and where gas is traded.
Interval-metered customer	Final customers with an annual electricity offtake exceeding 100,000 kWh, or with a gas offtake exceeding 1.5m kWh per year or more than 500 kWh per hour.
Intraday trading	Transactions involving gas and electricity contracts for supply on the same day are traded on the EPEX Spot (the spot market of the EEX), enabling the short-term optimisation of procurement and sale.
Investments	For the purposes of the energy monitoring survey, investments are defined as the gross additions to fixed assets capitalised in the reporting period and the total value of new fixed assets newly rented and hired in the reporting period. Gross additions also include leased goods capitalised by the lessee. The gross additions must be notified without deductible input value added tax. The value of internally generated assets as capitalised in the fixed asset account (production costs) is to be included. Notification is also required of assets under construction (work commenced for operational purposes, as far as capitalised). If a special "assets under construction" summary account is kept, notification should be made only of the gross additions without the holdings shown in the account at the beginning of the year under review. Payments on account should be included only if the parts of assets under construction for which they were made have been settled and if they have been capitalised. Not included are the acquisition of holdings, securities etc (financial assets), the acquisition of concessions, patents, licences etc and the acquisition of entire undertakings or businesses and the acquisition of rental equipment formerly used in the undertaking,

Term	Definition
	additions to fixed assets in branch offices or specialist units in other countries and financing charges for investments (Federal Statistical Office, 2007).
Length of circuit	System length (the three phases L1+L2+L3 together) of cables at the network levels LV, MV, HV and EHV (For example: If L1 = 1km, L2 = 1km and L3 = 1km, then the length of the circuit = 1km). In the case of different phase lengths, the average length in kilometres must be determined. The number of cables used per phase is irrelevant for the length of circuit. However, cables leased by, or otherwise made available to the network operator, should be included to the extent they are operated by the network operator. Planned cables, those under construction or leased out and decommissioned cables are not included. Lines in co-ownership should be included with their full number of kilometres to determine the network length. The circuit length at the low voltage network level should include service lines but not the lines of street lighting systems. Lines of more than 36 kV that have a transport function and are subject to a high voltage tariff may be considered at the high voltage level.
L-gas (low calorific gas)	A second-family gas with a lower amount of methane (80 to 87 volume percent) and higher volume percentages of nitrogen and carbon dioxide than h-gas. It has a medium calorific value of 9.77 kWh/m³ and a Wobbe index from 10.5 kWh/m³ to 13.0 kWh/m³.
Load control in the low voltage network (formerly load interruption)	Electricity distribution system operators are required to give a reduction in network charges to suppliers and final customers at the low voltage level with whom they have concluded network access agreements, in return for being able to control meter points with load control for the benefit of the network. Electric vehicles are counted as controllable loads within the meaning of sentence 1. The federal government is empowered, by ordinance having the force of law and requiring the consent of the German Bundesrat, to give concrete shape to the obligation pursuant to sentences 1 and 2, in particular by providing a framework for the reduction of network charges and the contractual arrangements, and by defining control actions that are reserved for network operators and control actions that are reserved for third parties, in particular suppliers. It must observe the further requirements of the Metering Act regarding the communicative integration of the controllable loads. (section 14a EnWG)
Load-metered final customers	Measurement of the power used by final consumers in a defined period. Load metering is used to establish a load profile showing a final customer's consumption over a defined period. A distinction is made between customers with and customers without load metering.
Market area	In the gas market, a market area means a grouping of networks at the same, or downstream, level, in which shippers can freely allocate booked capacity, take off gas for final consumers and transfer gas to other balancing groups.
Market coupling	A process for efficient congestion management between different market areas involving several power exchanges. Market coupling improves the use of scarce transmission capacities by taking into account the energy prices in the coupled markets. It involves day-ahead allocation of cross-border transmission capacities and energy auctions on the power exchanges being carried out at the same time based on the prices on the exchanges. For this reason, reference is also made here to implicit capacity auctions.
Market location	Energy is generated or consumed in a market location. The market location is connected to the network by means of at least one line. The market location is a connecting point for supply and balancing. In the data survey 2019, the relevant questionnaires use the terms "market location" (contracts) and "meter location" (meters) instead of "meter point".
Market maker	Trading participant who, for a minimum period of time during a trading day, has both a buy and a sell quote in his order book at the same time. Market makers ensure basic liquidity.

Term	Definition
Maximum usable volume of working gas	The total storage volume less the cushion gas required.
Meter location	A meter location is a location at which energy is measured and that includes all technical equipment required to collect and, if necessary, transmit the meter data. All relevant physical quantities at a point in time are collected no more than once at a meter location. The term "meter location" corresponds to the term "meter" within the meaning of section 2 para 11 of the Metering Act. In the data survey 2019, the relevant questionnaires use the terms "market location" (contracts) and "meter location" (meters) instead of "meter point".
Meter point	Point in the network at which the flow of energy, or the amount of gas transported, is recorded for billing purposes (see section2(28) of the Metering Act). In the data survey 2019, the relevant questionnaires use the terms "market location" (contracts) and "meter location" (meters) instead of "meter point".
Metering service	Metering the energy supplied in accordance with verification regulations and processing the metered data for billing purposes.
Minimum generation	The minimum generation is the feed-in capacity from conventional power plants required for the technical operation of the grid. Specifically, it is the feed-in capacity explicitly intended for the provision of non-transmission services. The non-transmission services must be provided for the purpose of stable network operation, which is why the technical necessity arises. The minimum generation must be fed in because only then can certain non-transmission services be provided (positive redispatching and balancing capacity, short circuit power and reactive power). It must even be fed in when the feed-in only provides the conditions necessary for non-transmission services to be provided, as in the case of negative balancing reserves. The capacity to safeguard the balancing reserves is included as part of the minimum generation because it directly contributes to its secure provision and works in the same way. However, this safeguard is not 1:1, but rather takes account of probabilities.
Natural gas reserves	Secure reserves: in known deposits based on reservoir engineering or geological findings that can be extracted with a high degree of certainty under current economic and technical conditions (90% probability). Probable reserves: a probability level of 50%.
Net capacity	The power a generating unit delivers to the supply system (transmission and distribution networks, consumers) at the high-voltage side of the transformer. It corresponds to the gross capacity less the power consumed by the unit in the process of generation, even if this is not supplied by the generating unit itself but by a different source (VGB, 2012).
Net electricity generation	A generating unit's gross electricity generation less the energy consumed in the process of generation. Unless otherwise indicated, the net electricity output relates to the reference period (VGB, 2012).
Net network charges	*Electricity* Electricity network charge, from 1 January 2017 including billing charge, not including charges for metering and meter operations, VAT, concession fees, renewable energy surcharge and surcharge payable under the KWKG. *Gas* Gas network charge, from 1 January 2017 including billing charge, not including charges for metering and meter operations, VAT and concession fees.
Net Transfer Capacity (NTC)	Net transfer capacity of two neighbouring countries (calculated as total transfer capacity minus transmission reliability margin).

Term	Definition
Network access	Pursuant to section 20(1) EnWG, operators of energy supply networks must grant non-discriminatory network access to everyone according to objectively justifiable criteria. The standard scenario is that the network is used by suppliers that then pay network charges to network operators. However, it is also permissible for final customers to use the network, in which case, the final customer pays the network charges to the network operator.
Network area	Entire area over which the network and substation levels of a network operator extend.
Network level	Areas of power supply networks in which electrical energy is transmitted or distributed at extra-high, high, medium or low voltage (section 2 para 6 StromNEV) low voltage ≤ 1 kV medium voltage > 1 kV and ≤ 72.5 kV high voltage > 72.5 kV and ≤ 125 kV extra-high voltage > 125 kV
Nominal capacity	Maximum capacity at which a plant can be operated for a sustained period under rated conditions at the time of handover. Capacity changes are only permitted in conjunction with major modifications of the nominal conditions and structural alterations at the plant. Until the exact nominal capacity has been determined, the value ordered in the supply contract should be indicated. If it is unclear whether the value ordered complies with the actual permit and operating conditions expected, a preliminary average nominal capacity is to be determined and applied until definitive measurement results are available. The average is to be fixed in such a way that higher or lower production levels, over a normal year, will be offset (eg on account of the cooling water temperature curve). The definitive nominal capacity of a power plant unit is determined when the plant has been handed over, usually when the acceptance measurement results are available. It should be noted that the nominal conditions apply to an annual average, ie that seasonal changes (for example in the cooling water and air inlet temperature) and internal electrical and steam-side requirements balance out, and that exemplary conditions used in the acceptance test, eg special closed circuit switching, must be converted to normal operating conditions. The nominal capacity, unlike the maximum capacity, may not be adjusted to a temporary change in capacity. The nominal capacity may not be changed in the case of a reduction in capacity as a result of, or to prevent, damage, nor may it be reduced on account of ageing, deterioration or pollution. Capacity changes require: • additional investment with a view to increasing the plant's capacity, eg retrofitting to enhance efficiency; • the decommissioning or removal of parts of the plant, accepting a loss of capacity; • operation of the plant outside the design range stipulated in the supply contracts on a permanent basis, ie for the rest of its life, for external reasons, or • a restriction of capacity, imposed by statutory regulations or orders of public authorities without there being a technical fault in the plant, until the end of its operating life (VGB, 2012).
Nominal pressure	The nominal pressure specifies a reference designation for pipeline systems. In accordance with DIN EN ISO, nominal pressure is given using the abbreviation PN (pressure nominal) followed by a dimensionless whole number representing the design pressure in bar at room temperature (20°C). EN 1333 specifies the following nominal pressure levels: PN 2.5 – PN 6 – PN 10 – PN 16 – PN 25 – PN 40 – PN 63 – PN 100 – PN 160 – PN 250 – PN 320 – PN 400.
Nomination	Shippers' duty to notify the network operator, by 2pm at the latest, of their intended use of the latter's entry and exit capacity for each hour of the following day.
Normal cubic metre (Ncm)	Section 2 subpara 11 GasNZV defines a normal cubic metre as the quantity of gas which, free of water vapour and at a temperature of 0°Celsius and an absolute pressure of 1.01325 bar, corresponds to the volume of one cubic metre.

Term	Definition
OMS standard	Selection of options chosen by the OMS Group from the European Standard 13757-x. This open metering system specification standardises communication in consumption metering.
OTC trading	OTC stands for "over the counter" and refers to financial transactions between market players that are not traded on an exchange. OTC trading is also known as off-exchange trading.
Peak load	Load profile for constant electricity supply or consumption over a period of 12 hours from 8am to 8pm every working day. Peak load electricity has a higher monetary value than baseload.
Phelix (Physical Electricity Index)	The Phelix Day Base is the calculated average of the hourly auction prices for a full day (baseload) for the market area of Germany/Austria. The Phelix Day Peak is the calculated average of the hourly prices from 8am to 8pm (peak load times) for the market area of Germany/Austria (see EEX).
Pore storage facility	Storage facilities where the natural gas is housed within the pores of suitable rock formations. These are often large in volume but, in comparison to cavern storage, have lower entry and exit capacity and greater cushion gas requirements.
Power plant status	Power plants whose closure has been prohibited by law: power plants whose closure has been prohibited by section 13a EnWG. Reserve capacity power plants: power plants that are operated only at the TSOs' request to ensure security of supply. Exceptional cases: plants temporarily not in operation (eg owing to repairs following damage) or with restricted operation. Seasonal mothballing: power plants that are closed during the summer season and fired up again afterwards.
Pulse output	Mechanical counter with a permanent magnet in the counter rotation. May be modified by a synchronising pulse generator (reed contact). Pulse output also includes what is known as a "Cyble meter".
Redispatching	Redispatching means measures to intervene in the market-based operating schedules of generating units to shift feed-in. In this context, power plants are instructed by TSOs, either under a contractual arrangement or a statutory obligation, to reduce/increase their feed-in while, at the same time, other power plants are instructed to increase/reduce their feed-in accordingly. These interventions have no impact on the overall balance between generation and load since action is taken to ensure that the reductions in feed-in are balanced physically and economically by increases elsewhere. Redispatching is undertaken by network operators to ensure the safe and reliable operation of the electricity supply networks. The aim is either to prevent overloading of power lines or to relieve overloading. Network operators reimburse the plant operators involved in the redispatching measures for the costs incurred. A distinction is made between electricity-related and voltage-related redispatching. Electricity-related redispatching is used to avoid or relieve sudden overloading affecting power lines and transformer stations. Voltage-related redispatching, by contrast, is used to maintain the voltage in the affected network area, for instance by adjusting reactive power. This involves adjusting the active power feed-in from power plants to enable them to provide the reactive power needed to maintain voltage stability. This can be done by firing idle power plants up to their minimum active power feed-in level or by reducing feed-in from power plants operating at full capacity down to their minimum level. As with electricity-related redispatching, this form of reactive power provision only involves conventional power plants on account of the priority dispatch rules. In the case of voltage-related redispatching, system balancing measures may take the form of market transactions. Redispatching can be an internal measure applicable to one control area only or a wider measure applicable to more than one control area.

Term	Definition
Renewable energy surcharge	The renewable energy surcharge is a provision of the EEG and laid down in greater detail in sections 60 et seq of the Act. The surcharge is used to finance the expansion of renewable energies. Renewable energy facility operators that feed electricity into the public grid receive a payment from network operators that has been set under the EEG or determined through auctions. The funds required are passed on to electricity consumers by the renewable energy surcharge. All non-privileged electricity consumers pay the renewable energy surcharge as part of the electricity price. The TSOs calculate the surcharge. They are required to determine and publish the surcharge for the following calendar year by 15 October each year. The network operators publish this online at www.netztransparenz.de. The Bundesnetzagentur ensures that the surcharge has been determined properly.
Self-supply (generating installations)	Self-supply is defined as an energy product that is used on the premises of a production site or a gas generation site to maintain operations eg electrical energy consumed in the auxiliary and ancillary facilities of a generating unit for water treatment, water supply to steam generators, fresh air and fuel supply and flue gas cleaning, but excluding the energy consumed in the process of generation. A power plant's self-supply includes step-up transformer losses, but not, however, the power consumed by auxiliary and ancillary facilities that are not electrically operated; this is covered by the power plant's total heat consumption. A power plant's self-supply during the reference period comprises two elements: self-supply for operations during operating hours and self-supply during idle hours. The latter is not taken into account in the net calculation (see VGB, 2012).
Spot market	Market where transactions are handled immediately. (Intraday and day-ahead auctions)
Standard load profile customer (SLP)	*Electricity* Section 12 StromNZV defines standard load profile customers as final customers with an annual offtake of up to 100,000 kWh for whom no load profile needs to be recorded by the DSO. (Any deviation to the specific offtake limit may be determined in exceptional cases by the DSOs.) *Gas* Section 24 GasNZV defines standard load profile customers as final customers with a maximum annual offtake of 1.5m kWh and a maximum hourly offtake of 500 kWh for whom no load profile needs to be recorded by the DSO. (Any variations above or below these specific withdrawal and offtake capacity limits may be determined by the DSOs.)
Storage facility operator	In this context the term refers to a storage facility operator in the commercial sense. It does not refer to the technical operator, but rather to the company which sells the storage capacities and appears as a market participant.
Supplier switch	This process describes the interaction between market partners when a final customer at a meter point wishes to change supplier from the current one to a different one. This does not include cases of final customers first moving into or moving premises.
Supplier switch when moving premises	If, when first moving into premises or moving premises, a final customer decides on a supplier other than the local default supplier within the meaning of section 36(2) EnWG, this is considered distinct from a supplier switch.
Transformation level	Areas in power supply networks in which electrical energy is transformed from extra high to high voltage, high to medium voltage and medium to low voltage (section 2 para 7 StromNEV). An additional transformation within one of the separate network levels (eg within the medium voltage level) is part of that network level.
Underground storage facilities	These are notably pore, cavern and aquifer storage facilities.
Working gas	Gas actually available for withdrawal from a gas storage facility. The formula is: storage volume − cushion gas (volume not available for use) = working gas.

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