Bundesnetzagentur Bundeskartellamt

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Report

Monitoring Report 2021

Monitoring Report 2021

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)Stand: 1.
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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 2021 more than 7,000 undertakings 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

In 2020, the effects of the coronavirus pandemic were also felt on the energy markets where a temporary decline in demand made it possible to achieve the energy transition target figures for 2020. Unfortunately, current trends have shown that this has not been a lasting effect. At present, economic activity is picking up again worldwide and with it the demand for energy. Consequently, energy prices are rising not only in Europe but throughout the world. These current trends can only be lightly touched upon in the present monitoring report as it is the very nature of the report that the figures can only be reliably determined at the end of 2021.

The 2021 Monitoring Report accompanies, documents and analyses the trends of 2020. The monitoring carried out jointly by the Bundesnetzagentur and the Bundeskartellamt aims to inform consumers, create transparency in the market and provide an analysis of developments in competition. This close collaboration has continued with 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 network expansion, evaluating security of supply, and delivery to household customers.

Progress made in the energy transition is not only evident from the figures for electricity generation and from the renewable capacity connected to the grid, but also from the reality of the planned phase-out of coal by 2038 at the latest and from the nuclear phase-out. The ban on coal-fired electricity generation already affected the first hard coal-fired power plants in July 2021, while the last nuclear power plants will be shut down in 2022. All electricity generation declined by around 5.5% in 2020, mainly as a result of the coronavirus pandemic. Non-renewable energy sources once again recorded a clear minus of 11.6% in 2020. This was particularly noticeable in coal-fired power plant generation, which fell significantly in 2020 for the second year in a row and even before the legal decision to phase it out caused the first power stations to be shut down. The decline in electricity generation from hard coal was around 25% and from lignite around 20%, whereas electricity generation from renewable energy sources managed a slight increase of around 3.4% in 2020. Electricity generation from renewable energy sources achieved another record high, accounting for 45% of gross electricity consumption.

The decline in coal-fired electricity generation in 2020 is also reflected in the market conditions for conventional electricity generation, which does not receive support under the EEG, and where the cumulative market share of the five largest electricity producers in the first-time sale of electricity and in generating capacity has continued to decline. Nevertheless, the upcoming closures of power plants as a result of the nuclear and coal phase-out will lead to a reduction in domestic generating capacity and thereby strengthen the competitive significance of the remaining major power plant operators to cover German demand. This development will continue to be monitored intensively, primarily as part of the regular market power reports produced by the Bundeskartellamt.

Electricity network charges remained steady for the most part in 2021. However, a growth trend can be expected in subsequent years due to the investment needed in the network expansion. The rise in energy prices will also be noticeable in the network charges to a certain extent as a result of higher costs for loss and balancing energy, as well as higher costs for grid reserve and a rise in costs for redispatching measures. Congestion management measures have been carried out in a new and more transparent and effective manner in the form of Redispatch 2.0 since 1 October 2021. Only one aspect of what is referred to as balancing has had to be postponed to March 2022 as the data transfer process could not be set up in time. The provisional total costs of feed-in management, redispatching including countertrading, and grid reserve provision and use amounted to around €1.4bn in 2020.

The continuing high level of trading volume or liquidity on the power exchanges and power wholesale markets in 2020 should continue to have a positive effect both on market access and on the options for providers and users, and thus also on competition. The trend in electricity and gas wholesale prices in 2020 was somewhat ambivalent. The marked decline in prices during the early stages of the pandemic had been corrected by the end of 2020. This was then followed from about June 2021 by a considerable and unbroken rise in wholesale prices.

The combined market shares of the four largest electricity and gas suppliers for standard load profile and interval-metered customers in the respective retail markets were, again, clearly below the statutory thresholds for presuming market dominance, irrespective of the changes in market share in the electricity sector brought about by the takeover of innogy by E.ON. As in previous years, it may continue to be assumed that there is currently no single dominant undertaking in these markets.

In light of the energy transition, electromobility plays an ever-increasing role and thus also its associated charging infrastructure. Energy monitoring accounts for this by collecting data on publicly accessible recharging points and their respective charging prices. In addition, the Bundeskartellamt is currently conducting a sector survey on the provision and marketing of publicly accessible charging points for electric vehicles to identify structural competition problems at an early market stage of charging infrastructure rollout. An assessment report with the interim results of the survey was published on 12 October 2021.

The positive developments on the retail electricity and gas markets documented in the 2021 Monitoring Report become especially clear when looking at the number of household customers who switched supplier. This number reached a new record high of around 5.4m in 2020. Even in the gas sector around 1.6m gas customers changed supplier, which was also a new high. This shows that consumers are more actively making use of opportunities to save. However, this trend did not extend to non-household customers in the gas sector, where the supplier switching rate fell for the first time in three years.

As at 1 April 2021, electricity prices for household customers were once again up by around 2% compared with the previous year. An increase in prices could also be noted for non-household electricity customers. For the first time in ten years, default supplier electricity prices for non-default supply household customers were below the average prices of suppliers that were not the local default supplier. This, too, is a sign of a functioning energy market.

Energy procurement costs, which make up around one quarter of the electricity price, added considerably to the rise in prices. In April 2021, the electricity volumes procured at short notice already reflected the price changes on the wholesale markets, which were marked by a renewed rise in demand despite the pandemic occurring at the same time as a fall in renewable generation and thus automatically a rise in conventional generation. The higher prices for carbon emission allowances also affected wholesale prices. This trend became much more apparent in summer and autumn 2021.

With the adoption of the Act on National Allowance Trading for Fuel Emissions (BEHG), which complements the European emissions trading system, the first step was taken for a national CO_2 emission trading system for transport and heating, which are not subject to the European trading system. In the process the price of gas rose by around 6% and it is expected to continue rising over the next few years, not only because the law provides for a gradual annual increase in carbon pricing until 2026 but also due to developments on the wholesale markets in the second half of 2021.

Gas imports decreased compared to the previous year but it is difficult to say to what extent this effect was due to weather conditions or to the coronavirus pandemic. Germany remains dependent on natural gas imports owing to the continued decline in domestic production. The main sources of gas imports to Germany were Russia and Norway.

The gas storage levels were filled as to 71.3% as at 31 October 2021 and were thus clearly below the average storage levels of past years at the same point in time. This is due almost entirely to the extremely low storage levels of the storage tanks belonging to the Gazprom operator. Other market players have stored large amounts of gas even though the gas price trend in 2021 did not provide any major incentives to store gas.

Prices have risen sharply, not just in Europe but worldwide. Hence the current prices are not a sign of a lack of security of supply but rather reflect primarily the increasing interplay between the European gas market and gas markets worldwide.

To alleviate the consequences of the pandemic for final customers, the right to withhold payment was extended in the first half of 2020. This was one of the measure that led to a decrease of around 20% in the number of electricity supply disconnections in 2020. The number of gas disconnections fell even more sharply at around 22%. Energy suppliers were also very accommodating and around three quarters of them waived the disconnection of electricity and gas services, at least temporarily, for customers who were behind with their payments.

The Bundesnetzagentur and the Bundeskartellamt will continue to follow the dynamic development of the electricity and gas markets in Germany and will play a role in shaping this process within their areas of activity.

Jochen Homann
Präsident of the
Bundesnetzagentur für Elektrizität, Gas,
Telekommunikation, Post und Eisenbahnen

Andreas Mundt
Präsident of the Bundeskartellamt

Key findings

Generation

Market concentration in electricity generation and in the first-time sale of electricity (not entitled to payment under the Renewable Energy Sources Act (EEG)) saw another decline in 2020 as far as the market shares of producers was concerned. The aggregate market share of the five largest undertakings in the market for the first-time sale of electricity based on the German market area, including Luxembourg, was 65.3%, compared to 70.1% in 2019.

With respect to the German conventional generating capacity generally available for use in the market for the first-time sale of electricity, the share of the five largest suppliers was 56.7% and thus also below the previous year's level of 57.5%.

However, despite the falling level of concentration, the upcoming closures of power plants in the course of the nuclear and coal phase-out will lead to a reduction of domestic generating capacity and thereby strengthen the competitive significance of the remaining major power plant operators to cover German demand.

Since the legal decision to phase out coal-fired electricity generation came into effect on 14 August 2020, the results of the first three tendering processes to reduce the production of electricity from coal have so far been published. The tenders attracted a strong level of participation, with a total capacity of 8,434 megawatts (MW) from hard coal-fired power plants and smaller lignite plants (of up to 150 MW net rated capacity) being awarded. For the plants awarded in the first round of tendering (4,788 MW), the ban on producing electricity from coal entered into force on 8 July 2021.

At 530.7 terawatt hours (TWh), Germany's net electricity generation in 2020 was 5.5% lower than the 2019 level, primarily due to the coronavirus pandemic. There was a steep drop in generation from conventional power stations. Electricity generated by coal-fired plants, in particular, saw a large decrease for the second year in a row. There was a 7.7 TWh year-on-year increase in generation from renewable energy sources, which reached a 45% share of gross electricity consumption.

The total installed generating capacity stood at 233.8 gigawatts (GW) at the end of 2020 (2019: 226.4 GW), with 103.3 GW of non-renewable and 130.6 GW of renewable capacity. In the renewable energy sector, there was an increase in capacity of 6.1 GW from the level of 2019. A clear increase of withdrawals from the conventional energy market could be observed as a result of the phase-out of nuclear and coal.

The growth in renewable energy capacity of 6.5 GW (sum of renewable energy installations with and without payments under the EEG) is due in particular to the larger increase in solar capacity (+4.6 GW). The net growth in onshore wind was 1.2 GW, the same as the previous year.

The development of generation volumes and the energy mix in 2021 are not covered by this report

Redispatching and feed-in management

Overall, the volume of network congestion management measures was greater in 2020 than in the previous year. The costs for congestion management measures (feed-in management, redispatching including countertrading, and grid reserve provision and use) are provisionally put at around €1.4bn and are thus also higher (2019: €1.3bn).

Electricity network charges

Average network charges for household customers remained largely stable in 2021 at 7.52 cents per kilowatt hour (ct/kWh). With respect to non-household customers, the arithmetic mean charges for commercial customers increased by around 3% to 6.64 ct/kWh and decreased for industrial customers by around 1% to 2.67 ct/kWh.

Wholesale electricity markets

The trading volume and liquidity of the wholesale electricity markets remained at a high level in 2020. In particular, there was another increase in trading volume on the EPEX SPOT and Nord Pool intraday markets. Volumes of on-exchange futures trading also increased, with the Phelix-DE futures volume standing at 1,416 TWh in 2020, an increase of around 5%. Volumes traded off-exchange via broker platforms also recorded significant growth.

Average electricity wholesale prices were lower in 2020 than in 2019. The spot market Phelix Day Base average for 2020 was about €30.46 per megawatt hour (MWh) and the Phelix Base Year Future average was about 40.20 ct/kWh, although future prices were about 9% higher at the end of 2020 than they had been at the beginning of the year. On the futures market, the Phelix-DE Peak Year-Ahead Future stood at €53.02/MWh at the start of the year and €57.54/MWh at the end of December 2020. It thus saw considerable growth across the year, although there was a noticeable dip in prices in the middle of the period.

It should be noted that this report covers developments in prices and volumes in 2020 and not those in 2021.

Retail electricity markets

As in previous years, the Bundeskartellamt assumes that there is currently no single dominant undertaking in either of the two largest electricity retail markets. The combined market share of the four largest undertakings was around 28.5% (2019: 24.5%) in the national market for supplying interval-metered customers and 42.8% (2019: 34.1%) in the national market for non-interval-metered (standard load profile, SLP) customers on special contracts. The rise in combined market share is largely due to the fact that the four largest providers were joined by another undertaking following the takeover of innogy by E.ON. The figures are therefore not easily comparable with those from the previous year. Nevertheless, the joint market share of the four biggest providers in 2020 is still well below the threshold for presuming market dominance.

The supplier switching rate for non-household customers has been fairly constant since 2009. The volume-based switching rate for customers with an annual consumption of more than 10 MWh stood at 11.6% in 2020, compared to 11.7% in 2019. The percentage of household customers' consumption provided by a supplier other than the local default supplier was around 38% (2019: 34%). The number of household customers switching electricity supplier rose to nearly 5.4m (2019: 4.5m). There was another slight increase in the number of undertakings operating in the market for household customers, who had a choice between an average of 142 different suppliers (2019: 138). The most recent developments in 2021 are not included in this report.

At the same time, there was a further decrease in the number of customers whose electricity supply was disconnected. In 2020, a total of 230,015 customers were disconnected, representing a year-on-year decrease of around 20% (2019: 289,012). It may be assumed that this drop was partly due to the right to withhold performance set out in Article 240 section 1 of the Introductory Act to the Civil Code (EGBGB), which was put in place in the first half of the year because of the Covid-19 pandemic to provide temporary relief for consumers. Around 72% of the electricity suppliers surveyed also stated they had voluntarily decided not to disconnect their customers. The German Bundesrat consented to amendments to the Electricity Default Supply Ordinance (StromGVV) on 5 November 2021. These included changes to the rules on interrupting supply, naming explicit reasons that would make a disconnection disproportionate (a specific risk to life and limb). Under the new rules, it is only possible to disconnect a customer who is at least twice the monthly instalment/one sixth of the annual amount in arrears and the sum owed is more than €100. Energy suppliers are also required to offer final customers who owe money arrangements to prevent disconnection, such as interest-free repayments by instalment or a continued supply on a prepayment basis.

The average total price (excluding value added tax (VAT) and possible reductions) for industrial customers with an annual consumption of 24 gigawatt hours (GWh) as at 1 April 2021 was about 16.94 ct/kWh, up 0.40 ct/kWh on the average for 2020. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh in April 2021 was 23.23 ct/kWh, up 0.20 ct/kWh on the previous year. The increase in prices for industrial and commercial customers this year is mainly accounted for by the price components controlled by the supplier. Because the monitoring is based on a specific date, 1 April 2021, developments that occurred after this time are not included.

The average price for household customers rose from 32.05 ct/kWh on 1 April 2020 to 32.63 ct/kWh on 1 April 2021, corresponding to an increase of around 2%. This average is calculated by weighting the individual prices across all contract models for an annual consumption of 2,500 kWh to 5,000 kWh according to consumption volumes to obtain a reliable average price for household customers. For the first time in ten years, the various contracts reveal a non-default price from the default supplier that is lower than the price of a supplier that is not the local default supplier.

The price component controlled by the supplier (energy procurement, supply and margin) accounted for about 8.59 ct/kWh (26% of the total electricity price) as at 1 April 2021 and had thus increased, as in the previous year. The average network charge and the meter operation charge added up to 7.52 ct/kWh in 2021, around 23% of the total price. The EEG surcharge (6.50 ct/kWh) accounted for around 20% of the total price.

The rise in retail prices as at 1 April 2021 is largely due to the increase in the price component controlled by the supplier (energy procurement, supply and margin). Procurement costs are significantly influenced by wholesale prices. In April 2021, there was higher demand for electricity, despite the pandemic, while at the same time there was a rise in conventional generation and a fall in renewable generation. For the electricity volumes procured at short notice, both of these factors contributed to the rise in wholesale prices. The higher prices for carbon emission allowances also affected wholesale prices.

Electric heating

Developments in the electric heating sector need to be viewed against the backdrop of the transfer of market locations and volumes from E.ON Heizstrom to Lichtblick GmbH. There were major changes in 2020: for example, the amount of electricity supplied for night storage heating and heat pumps by a legal entity other than the local default supplier rose to 4.29 TWh from 2.15 TWh in the previous year. Around 37.3% of the total volume of electricity for heating in 2020 was made up by non-default suppliers (2019: 16%).

The supplier switching rate in the electric heating segment based on the number of market locations was higher than in the previous year. The supplier switching rate for 2020 was around 12% by volume and around 14.8% by market location. However, the transfer of market locations and volumes from E.ON Heizstrom to Lichtblick GmbH is likely to have played an important role in the higher level of supplier switching, because it basically meant an automatic change of supplier for affected customers.

The total gross price for night storage heating was 23.93 ct/kWh as at 1 April 2021 and thus higher than the previous year's level of 23.14 ct/kWh. The average total gross price for heat pump electricity was 23.80 ct/kWh and thus also higher than the previous year's average of 23.58 ct/kWh. Here, too, developments that occurred after the monitoring date are not covered in this report.

Electricity imports and exports

Electricity exports again exceeded imports in 2020. Germany's electricity exports were down slightly in 2020 compared to a year earlier. Total cross-border trade volumes for electricity amounted to 83 TWh in 2020, up from 73 TWh in 2019. The 2020 export balance was 11 TWh, making the export surplus worth €48m.

Gas imports and exports

The total volume of natural gas imported into Germany in 2020 was 1,446 TWh. Imports to Germany were thus down by 257 TWh from the previous year's figure of 1,703 TWh. The main sources of gas imports to Germany remain Russia and CIS as well as Norway.

Gas supply disruptions

In 2020, the average interruption in supply per connected final customer was 1.09 minutes (2019: 0.98 minutes in the year). Despite the slight increase, this figure shows that the German gas network still has a high quality of supply.

Market area conversion

The market area conversion from low-calorific L-gas to high-calorific H-gas, which is coordinated by the TSOs, is proceeding according to plan. During the reporting period, 347,599 appliances were adapted for standard load profile (SLP) customers and 723 for interval-metered customers. A total of 9,066 appliances that were to be adapted could not be, a proportion of 2.6% (2019: 2.2%).

Gas storage facilities

The market for the operation of underground natural gas storage facilities is still highly concentrated. The cumulative market share of the three largest storage facility operators stood at around 67.2% at the end of 2020, representing a slight increase compared to the previous year (66.6%).

The total maximum usable volume of working gas in underground storage facilities as at 31 December 2020 was 274.72 TWh. Of this, 136.01 TWh was accounted for by cavern storage, 117.01 TWh by pore storage and 21.71 TWh by other storage facilities. Around 106 TWh of gas has been injected into German natural gas storage facilities since the beginning of the injection season at the end of March 2021, taking the overall level of storage in the country to about 164.2 TWh as at 31 October 2021. The storage level rose from just over 25% at the end of March to 71.3%, well below the average of previous years at the same time.

Gas network charges

The average network charge for household customers was 1.59 ct/kWh in 2021 and thus around 2% higher than in the previous year. For commercial customers, the average network charge was almost unchanged at 1.28 ct/kWh, while for industrial customers there was a significant drop of just over 13.5% to 0.32 ct/kWh.

Wholesale natural gas markets

The liquidity of the natural gas wholesale markets decreased again owing to lower energy demand as a result of the coronavirus pandemic. There was a year-on-year drop of around 11% in the total volume traded on the exchange (spot market: -9%; futures market: -23%), while for the volume of off-exchange wholesale trading via broker platforms, which accounts for a much larger share, a very small rise of 2% was recorded for 2020, but this was probably caused by an additional broker being included in the evaluation for the year.

It should be noted that this report covers developments in prices and volumes in 2020 and not those in 2021.

Retail gas markets

The levels of concentration in the two largest gas retail markets for SLP and interval-metered customers are still well below the statutory thresholds for presuming market dominance. In 2020, the cumulative sales of the four largest companies to SLP customers were about 92.9 TWh, while to interval-metered customers they were around 139.2 TWh. The aggregate market share of the four largest companies (CR4) in 2020 was thus 26% for SLP customers (2019: around 24%) and 28% for interval-metered customers (2019: 29%).

The total consumption amount of non-household customers affected by supplier switches in 2020 was 80.6 TWh, corresponding to a clear year-on-year decrease of 8.3 TWh from 2919 levels. The switching rate for non-household customers fell to 7.3% from 9% the year before. The total number of supplier switches by household customers hit a new high in 2020, passing the 1.6m mark. Around 1.3m of these household customers changed directly by cancelling their previous contract. The remaining around 0.3m chose an alternative supplier rather than the default one right away when moving home.

The number of customers changing contract, which usually means changing to a less expensive contract, remained stable at around 0.6m. The percentage of household customers who had a contract with a supplier other than the local default supplier increased further to 35%, while the percentage of customers with a default supply contract remained stable at 17%. The local default supplier supplied 48% of household customers under a non-default contract.

There was also another significant increase in the number of undertakings operating in the market. Household customers can choose on average from among 113 different suppliers. The most recent developments in 2021 are not included in this report.

There was a sharp drop in the number of gas disconnections. In 2020, about 24,000 customers were disconnected in total, representing a year-on-year decrease of around 22% (2019: 31,000). It may be assumed that this drop was partly due to the right to withhold performance set out in Article 240 section 1 EGBGB, which was put in place in the first half of the year because of the Covid-19 pandemic to provide temporary relief for consumers. Around 75% of the gas suppliers surveyed also said they had voluntarily decided not to disconnect their customers in 2020. Gas suppliers also accommodated customers by offering them special or individual payment arrangements. Some suppliers extended their criteria for disconnections to make them more customer-friendly. The German Bundesrat consented to amendments to the Gas Default Supply Ordinance (GasGVV) on 5 November 2021. The GasGVV now specifies how high the amount owed must be for gas to be disconnected. Under the new rules, it is only possible to disconnect a final customer who is at least twice the usual instalment in arrears and the sum owed is more than €100, or if the amount owed is at least one sixth of the annual amount.

The volume-weighted gas price for household customers across all contract categories rose to 6.68 ct/kWh in 2021. The new carbon levy amounting to 0.4551 ct/kWh, which was introduced on 1 January 2021, was partly responsible for the rise as it was passed on to final customers almost completely and paid by them as part of the gas price. The carbon levy expanded the existing emissions trading system to the transport and heating sectors. Gas prices may be expected to continue rising in the next few years as the law provides for annual increases in carbon pricing until 2026. In the average price across all contract categories, the largest price component "energy procurement, supply and margin",[1] which makes up around 45%, fell by over 5% from 3.12 ct/kWh to 2.95 ct/kWh.

The volume-weighted gas price for customers on a default contract[2] as at 1 April 2021 was 7.45 ct/kWh (2020: 6.99 ct/kWh), corresponding to an increase of around 6.5% compared to the previous year.
On 1 April 2021, the volume-weighted price for customers under a non-default contract with the default supplier was 6.58 ct/kWh, an increase of about 4.6% compared to 2020 (6.29 ct/kWh). On 1 April 2021, the volume-weighted price for a contract with a supplier other than the local default supplier was 6.41 ct/kWh, an increase of just over 7.6% compared to the previous year (2020: 5.96 ct/kWh).

The gas prices for non-household (industrial and commercial) customers as at 1 April 2021 showed substantial year-on-year increases caused by the introduction of the carbon levy. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 GWh ("industrial customer") was 2.95 ct/kWh, 0.42 ct/kWh or around 16.6% higher than the previous year's figure. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") was 4.74 ct/kWh on the reporting date, an increase of 0.22 ct/kWh or around 4.8% year-on-year. Because the monitoring is based on a specific date, 1 April 2021, developments that occurred after this time are not included.

Effects of the Covid-19 pandemic

The Covid-19 pandemic started to have noticeable effects in March 2020. The effects on the energy market that are summarised here are also dealt with in detail in the relevant sections of the main report.

At 530.7 TWh, Germany's net electricity generation in 2020 was 5.5% lower than the 2019 level, primarily due to the pandemic. The electricity consumption of industrial, commercial and other non-household customers fell 24.7 TWh, or 7%, year-on-year. One reason for this development is the reduction in industrial production

[1] It is not possible to break down the individual elements of this price component owing to the survey method used.

[2] Customer category according to Eurostat: band II (D2): annual consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh).

caused by the pandemic. Covid, with an increase in working from home, led to slightly higher electricity consumption among household customers than in 2019.

In 2020, a right to withhold performance (Article 240(1) EGBGB) was introduced for the period between 1 April and 30 June, which also applied to energy supply contracts. Some suppliers also chose not to disconnect their electricity or gas customers. There was, therefore, a significantly lower number of disconnections in 2020, but due to the exceptional circumstances no conclusions can be drawn from this about future developments.

People working from home and travelling less actually facilitated the gas market area conversion, with almost all network operators and companies carrying out adjustments reporting that it was easier to make contact with customers for the conversions.

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I Electricity market

A Developments in the electricity markets

1. Summary

1.1 Generation and security of supply

The Act to Reduce and End Coal-Fired Power Generation (KVBG) came into force on 14 August 2020. This is the legal basis upon which tendering processes are carried out for hard coal-fired power plants and smaller lignite plants (of up to 150 megawatts (MW) net rated capacity) to meet phase-out targets. Bids totalling 4,788 MW were awarded in the first tendering round. Following a six-month phase of operational readiness, the ban on producing electricity from coal for these plants entered into force on 8 July 2021. The award volume for the second tender process was 1,514 MW and for the third it was 2,133 MW.

At 530.7 terawatt hours (TWh), Germany's net electricity generation in 2020 was lower than the 2019 level (561.3 TWh). The main reason for the lower total electricity generation in 2020 was the fact that consumption was lower than in 2019 due to the Covid-19 pandemic. The decline in the overall level of net electricity generation was accompanied by a decrease in generation from non-renewable energy sources of 38.4 TWh or 11.6%. For the second year in a row, there was a particularly large drop in net electricity generation from coal-fired power plants: 13.5 TWh less was generated in hard coal-fired power plants (-25.2%) and 20.6 TWh in lignite-fired power plants (-19.7%). Continuing the trend that began in 2015 (with the exception of 2018), natural gas power stations produced more electricity (5.5 TWh/7.3%).

As in 2019, there was only a slight increase in generation from renewable energy sources of 3.4% to 236.6 TWh. The share of renewable electricity as a proportion of gross electricity consumption in 2020 was 45%.[3]

Installed generating capacity was characterised by a further increase in renewable capacity in 2020. Overall, renewable capacity growth amounted to 6.1 gigawatts (GW). The year-on-year increase in 2019 was 6.2 GW.[4] The largest increases in 2020 were in solar photovoltaic (+4.6 GW) and onshore wind (+1.2 GW). Non-renewable generating capacity (nuclear, lignite, hard coal, natural gas, mineral oil products, pumped storage and other sources) also registered growth of 1.3 GW.[5] Total (net) installed generating capacity thus increased to 233.8 GW at the end of 2020, with 103.3 GW of non-renewable and 130.6 GW of renewable capacity. The non-renewable generating capacity includes power stations operational in the market and those outside the market (for example standby lignite and grid reserve power plants).

The installed capacity of installations eligible for payments under the Renewable Energy Sources Act (EEG) in Germany stood at 126.7 GW at the end of 2020 (2019: 114.0 GW). This represents an increase of 6.5 GW (+5.4%). A total of 222.0 TWh of electricity from renewable energy installations received payments under the EEG

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[3] If the share of renewables generation is taken to be about 50% or more, it usually relates to the definition of consumption as the "grid load" (for example on the SMARD website).

[4] The 2019 figure from the 2020 monitoring has been updated.

[5] Part of this growth is due to a change in the database. For the first time, the 2020 evaluations are based on the electricity generating units registered in the core energy market data register (MaStR).

in 2020. Electricity generation from installations eligible for EEG payments thus increased by 4.8%. EEG payments were up 8% to €29.8bn. In 2020, renewable installation operators thus received an average of 13.4 cents per kilowatt hour (ct/kWh) under the EEG.[6] The expansion targets set out in the EEG 2021 for solar photovoltaic, onshore wind and offshore wind were met in 2020. Indications from the first half of 2021 are that this will also be the case for the full year.

1.2 Cross-border trading

Electricity exports again exceeded imports in 2020. Germany's electricity exports were down slightly compared to a year earlier. Cross-border trade volumes for electricity amounted to 83 TWh in 2020 (2019: 73 TWh). With an export surplus of €48m, Germany is still one of Europe's biggest electricity exporters.

1.3 Networks

1.3.1 Network expansion

The projects currently listed in the Power Grid Expansion Act (EnLAG) (as at the second quarter of 2021) comprise lines with a total length of about 1,827 kilometres (km). Around 8 km are currently in the spatial planning procedure and around 266 km are in or about to start the planning approval procedure. A total of 466 km have been approved and are under or about to start construction, and 1,087 km have been completed.
The projects listed in the Federal Requirements Plan Act (BBPlG) comprise lines with a total length of about 10,412 km (as at the second quarter of 2021). The 29 projects designated as crossing federal state or national borders, which fall under the responsibility of the Bundesnetzagentur, account for around 6,397 km of this total. The total length of the lines in Germany will largely depend on the route of the north-south corridors and will become apparent in the course of the procedure. In the second quarter of 2021, some 2,901 km of the total were ready to start the planning approval procedure. Around 912 km are in the spatial planning or federal sectoral planning procedure, and 5,779 km are in or about to start the planning approval or notification procedure. A total of 136 km have been approved and are under or about to start construction, and 684 km have been completed. Additionally, approximately 218 km are being carried out in procedures by the Federal Maritime and Hydrographic Agency (BSH).

1.3.2 Investments

In 2020, investments in and expenditure on network infrastructure by the network operators amounted to around €12,332m (2019: €10,629m) (both figures under commercial law).[7] This comprised €8,088m of investments and expenditure by the distribution system operators (DSOs) and €4,244m by the four German

[6] The average EEG payment is calculated by dividing the total sum paid under the EEG in a year by the total amount of renewable electricity fed in during that year.

[7] 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). 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. 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.

transmission system operators (TSOs). Investments were up on the previous year, 42% for those by the TSOs (2019: €2,727 m, 2020: €3,862 m) and 12% for those by the DSOs (2019: €4,337 m, 2020: €4,838 m).

1.3.3 Congestion management

The total volume of network congestion management measures was higher in 2020 than the year before. The total costs for these measures (feed-in management, redispatching including countertrading, and grid reserve provision and use) are provisionally put at around €1.4bn and are thus also slightly higher (2019: €1.3bn).

Redispatching measures: the reductions and increases in feed-in from conventional operational and grid reserve power plants requested as part of the redispatching process amounted in 2020 to about 16,795 gigawatt hours (GWh) (8,522 GWh of feed-in reductions and 8,273 GWh of increases). The total volume of requested reductions and increases in feed-in from power plants in 2020 was therefore higher than in 2019 (13,521 GWh). In particular, the volume of voltage-related measures was higher in the second quarter than in the previous year due to the reduced load caused by the lower electricity consumption during the first pandemic-related lockdown. There was a further increase in the volume of countertrading, data on which is combined with redispatching. The increase is largely due to the bilateral agreement between Germany and Denmark. This agreement provides for minimum trading capacities across the border between western Denmark and Germany as well as for cooperation between the TSOs on countertrading measures. The latter incurred costs of €134.1m (2019: € 64.2m).

The costs for redispatching measures using operational and grid reserve power plants and for countertrading measures are provisionally put at around €443m in 2020 and are thus about 19% higher than the previous year's level (2019: €373m).

Grid reserve power plants: according to the Bundesnetzagentur's current information, the costs of reserving the grid reserve plant capacity plus costs not dependent on the use of the reserve are provisionally put at €194.8m in 2020 and are thus slightly lower than in the previous year (2019: €196.5m). The costs of using the grid reserve amounted to around €88m, which was slightly up on last year's €81.6m.

Feed-in management measures: in absolute terms, the volume of curtailments from electricity from renewable sources as part of feed-in management measures was 6,146 GWh in 2020, around 5% lower than in the same period of the preceding year (2019: 6,482 GWh). The decline was probably due to the network expansion projects in Schleswig-Holstein successively going into operation.

Onshore wind is the most-curtailed energy source, making up around 67% of energy curtailed, followed by offshore wind with nearly 29%. Installations in Schleswig-Holstein are curtailed the most (50%) followed by those in Lower Saxony (34%). Although 69% of curtailments were in the distribution system, around 79% of the network congestion that caused them was in the transmission system or in the network level between the transmission and distribution systems.

The estimated compensation claims of installation operators for these curtailments ran to about €761.2m in 2020 (2019: €709.5m). This rise, which amounts to about 7%, was caused by the greater curtailment of offshore wind turbines. Compensation payments are covered by final customers via the network charges although a share of these costs is offset by the reduction in the EEG surcharge, which network users also have to pay, since curtailed installations do not receive any remuneration or market premium under the EEG.

1.3.4 Network charges

The volume-weighted network charges (including meter operation charges) for household customers for 2020 were stable (+0.02 ct/kWh): for household customers with an annual consumption of 2,500 to 5,000 kWh, the weighted average was 7.52 ct/kWh. With respect to non-household customers, the arithmetic mean charges for commercial customers are slightly higher than the previous year's level.[8] The network charges (including meter operation charges) for commercial customers increased by 3% to about 6.64 ct/kWh (2020: 6.46 ct/kWh). The network charges (including meter operation charges) for industrial customers decreased by around 1% to 2.67 ct/kWh (2020: 2.70 ct/kWh).

1.4 Costs for system services

The net costs for system services, which are passed on to final customers, were higher in 2020 than in 2019 at around €2,018.3m (2019: €1,931m). Major costs were the costs of reserving and using grid reserve power plants at around €282.8m (2019: €278.1m), national and cross-border redispatching at €220.5m (2019: €227.2m), the estimated claims for compensation for feed-in management measures at €761.2m (2019: €709.5m) and loss energy at about €398.8m (2019: €321.2m). There was an increase in particular in the costs for countertrading, which totalled €134.1m (2019: €64.2m). The increase is largely due to the bilateral agreement between Germany and Denmark.

The structure of the costs for system services in 2020 was different to that in 2019 in that the costs for network congestion management measures and loss energy were higher while the costs for balancing capacity were lower.

1.5 Wholesale

The trading volume and liquidity of the wholesale electricity markets remained at a high level in 2020. In particular, there was another increase in trading volume on the EPEX SPOT and Nord Pool intraday markets. However, the volume of day-ahead trading is not fully comparable with the figure from the previous year since the presentation for 2020 was adjusted. Volumes of on-exchange futures trading also increased, with the Phelix-DE futures volume standing at 1,416 TWh in 2020, an increase of around 5%. Volumes traded off-exchange via broker platforms recorded significant growth as well. The volume of OTC clearing of Phelix-DE futures on EEX rose by about 28% to 1,668 TWh in 2020, well over the volume traded on the exchange.

Average wholesale electricity prices fell in 2020. The spot market Phelix Day Base average for 2020 was about €30.46 per megawatt hour (MWh) and the Phelix Base Year Future average was about 40.20 ct/kWh, although future prices were higher at the end of 2020 than they had been at the beginning of the year. On the futures market, the Phelix-DE Peak Year-Ahead stood at €53.02/MWh at the start of the year and €57.54/MWh at the end of December 2020. It thus saw growth of around 9% across the year, although there was a clear dip in prices in the middle of the period.

[8] 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.

1.6 Retail

1.6.1 Contract structure and competition

The number of electricity suppliers from which retail customers can choose increased slightly. In 2020, final customers could choose between an average of 162 suppliers in each network area (not taking account of corporate groups), compared to 156 suppliers in 2019. The average number of suppliers for household customers in Germany was 142 (2019: 138).

In 2020, a relative majority of 37% of household customers' consumption was supplied on non-default contracts with local default suppliers (2019: 40%). The volume-weighted percentage of household customers' consumption supplied under default contracts stood at 25% (2019: 26%). This represents only a very slight decrease in the percentage of consumption supplied under default contracts, as in the previous year. The percentage of household customers' consumption provided by a supplier other than the local default supplier is around 38% (2019: 34%). Overall, about 62% of all household customers' consumption is still provided by default suppliers (under either default or other contracts). Thus the strong position that default suppliers have in their respective service areas has declined by about 4% compared to the previous year.

There was a clear rise in the number of supplier switches in 2020 to almost 5.4m. The supplier switching rate based on the total number of household customers is 10.9% and thus one percentage point higher than in the previous year (2019: 9.9%). In addition, about 1.8m household customers changed energy supply contract with the same supplier. The switching rate for non-household customers – with an annual consumption of more than 10 MWh – based on consumption volumes was 11.6% (2019: 11.7%).

1.6.2 Disconnections

There was a clear decrease in 2020 in the number of electricity customers whose supply was disconnected. The number of disconnections actually carried out by the network operators was 230,015, representing a decrease of 20% compared to the previous year (2019: 289,012). The number of disconnection notices issued by suppliers to household customers was very much higher, although it was lower than the year before as well. The number of notices issued was approximately 4.2m, of which about 696,000 were passed on to the relevant network operator with a request for disconnection (2019: 4.8m notices and 911,000 requests). It may be assumed that this drop was partly due to the right to withhold performance set out in Article 240 section 1 of the Introductory Act to the Civil Code (EGBGB), which was put in place in the first half of the year because of the Covid-19 pandemic to provide temporary relief for consumers. Around 72% of the electricity suppliers surveyed also said they had voluntarily decided not to disconnect their customers.

1.6.3 Price level

The average total price (excluding value added tax (VAT) and possible reductions) for industrial customers with an annual consumption of 24 GWh as at 1 April 2021 was about 16.94 ct/kWh, up 0.40 ct/kWh on the average for 2020. The average total price (excluding VAT) for commercial customers with an annual consumption of 50 MWh in April 2021 was 23.23 ct/kWh, up 0.20 ct/kWh on the previous April. This increase in prices for industrial and commercial customers in 2020 is mainly accounted for by the price components controlled by the supplier.

Data was collected from the suppliers operating in Germany on the prices for household customers as at 1 April 2021. The average price (including VAT) increased slightly to 32.62 ct/kWh (2020: 32.05 ct/kWh). This average is calculated by weighting the individual prices across all contract models for an annual consumption of 2,500 kWh to 5,000 kWh according to consumption volumes to obtain a reliable average for the electricity price for household customers.

In 2021, the price component controlled by the supplier (energy procurement, supply and margin) accounts for around 26.3% of the total electricity price and has thus increased, as it did in the previous year. The network charge in 2021 is slightly higher than in the previous year and thus still at a high level. The EEG surcharge (6.50 ct/kWh) accounted for around 20% of the total price. Compared to 2020, the average price for household customers on default contracts with an annual consumption of 2,500 kWh to 5,000 kWh remained stable at 33.80 ct/kWh (2020: 33.80 ct/kWh). The average price for customers on a non-default contract with their default supplier is 31.89 ct/kWh (2020: 31.67 ct/kWh). In previous years there had been a convergence of prices of non-default contracts with the default supplier and non-default suppliers. This year's monitoring revealed that the price of non-default contracts with the local default supplier was lower than that of contracts with suppliers that were not the local default supplier for the first time in ten years. The price for customers on a contract with a supplier other than their local default supplier increased by around 5% to 32.70 ct/kWh (2020: 31.22 ct/kWh).

The rise in retail prices in 2021 is largely due to the increase in the price component controlled by the supplier (energy procurement, supply and margin). Procurement costs are significantly influenced by wholesale prices. In April 2021, there was higher demand for electricity, despite the pandemic, while at the same time there was a rise in conventional generation and a fall in renewable generation. For the electricity volumes procured at short notice, both of these factors contributed to the rise in wholesale prices. The higher prices for carbon emission allowances, which are included in the electricity price components that are not controlled by the supplier, also affected wholesale prices.[9]

As a rule, customers on default contracts can make savings by switching contract (-1.91 ct/kWh) and switching supplier (-1.10 ct/kWh).[10] Household customers with an annual consumption of 3,500 kWh could consequently cut their electricity costs by around €67 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 non-default contracts with their local default supplier average €56, and those for customers switching to a non-default supplier €70.

1.6.4 Surcharges

The network operators estimated that they would pass on around €25.85bn in surcharges to network users in 2021. In order of volume, this total comprises the EEG surcharge (€22.28bn), the offshore network surcharge (€1.41bn), the section 19 StromNEV surcharge (€1.21bn), the KWKG surcharge (€0.91bn) and the interruptible loads surcharge (€0.04bn).

The EEG surcharge continues to make up the largest share (over 86%) and would have been €10.8bn without the federal government assistance that was provided for the first time in 2021. This assistance is a means of

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[9] Carbon price: 2020 – €24.80/t; 2021 – €46 /t: source: Spectron
Grid load: April 2020 – 36.4 TWh; April 2021 – 41.4 TWh: source: **Fehler! Linkreferenz ungültig.**. smard.de

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

capping the EEG surcharge set out in budget legislation. In its Climate Action Programme 2030, the German government decided to introduce a national fuel emissions trading scheme and to use the proceeds from the pricing of carbon emissions from fossil fuels for the benefit of the public and the economy by reducing the burden of the EEG surcharge from 1 January 2021. Other budgetary funds from the stimulus package designed to mitigate the effects of the pandemic also helped to lower the EEG surcharge to 6.5 ct/kWh.

1.6.5 Electric heating

Developments in the electric heating sector need to be viewed against the backdrop of the transfer of market locations and volumes from E.ON Heizstrom to Lichtblick GmbH. There were major changes in 2020: for example, the percentage of electricity supplied for night storage heating and heat pumps by a legal entity other than the local default supplier rose to 4.29 TWh from 2.15 TWh in the previous year. Around 37.3% of the total volume of electricity for heating in 2020 was made up by non-default suppliers (2019: 16%).

The supplier switching rate in the electric heating segment based on the number of market locations was higher than in the previous year. The supplier switching rate for 2020 was around 12% by volume and around 14.8% by market location. However, the transfer of market locations and volumes from E.ON Heizstrom to Lichtblick GmbH is likely to have played a role in the higher level of supplier switching, because it basically meant an automatic change of supplier for affected customers.

The total gross price for night storage heating was 23.93 ct/kWh as at 1 April 2021 and thus higher than the previous year's level of 23.14 ct/kWh. The average total gross price for heat pump electricity was 23.80 ct/kWh and thus also higher than the previous year's average of 23.58 ct/kWh.

1.7 Digitisation of metering

The Energy Transition Digitisation Act and the Metering Act (MsbG) contained therein made the rollout of modern metering equipment and smart metering systems legally mandatory in Germany. 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.

Default meter operators had until 30 June 2017 to notify the Bundesnetzagentur of their metering operations. These notifications also served to trigger a deadline set by the MsbG: three years after the notification of responsibility for default metering operations, ie by 30 June 2020, the default meter operators had to have installed modern metering equipment in at least 10% of the meter locations that have to be fitted with them by law. If they have not fulfilled this requirement, they are required to initiate a process to transfer their default responsibility.

The installation of smart metering systems was able to start when the first smart meter gateway was certified by the Federal Office for Information Security (BSI) on 12 December 2018. After the certification of a third gateway in December 2019 and the announcement of technical feasibility for certain applications, the BSI gave the go-ahead for the rollout of smart metering systems on 24 February 2020.

By February 2020, an Aachen-based company and some default meter operators, mainly municipal utilities, had started legal action against the BSI's general administrative order determining the technical feasibility of the installation of smart metering systems. At the time of writing, these legal disputes are still ongoing. However, in an application for an interim injunction, the Higher Administrative Court (OVG) in Münster ruled in favour of the complainant. Adjustments have been made to the MsbG to remove the resulting legal uncertainties. The law introducing these amendments (Act transposing provisions of Union law and regulating pure hydrogen networks in energy industry law) was promulgated in the Federal Law Gazette I No 47 on 26 July 2021 and entered into force on 27 July 2021. A central amendment to the MsbG was carried out in section 19(6) MsbG, creating a provision protecting vested rights for smart metering systems that have already been installed and those still to be installed.

A further important step towards creating greater legal certainty in the smart meter rollout was the setting up and consultation of the Gateway Standardisation committee, with the Federal Ministry for Economic Affairs and Energy (BMWi) subsequently agreeing to the expanded Technical Directive TR-03109-1 v1.1 of 23 September 2021. The Technical Directive focuses on the interoperability certification of smart meter gateways.

2. Network overview

All energy market players are required as from 1 February 2018 to introduce and exclusively use a new identification code to identify market locations and meter locations. Since the Monitoring Report 2019 the term "meter point" has therefore been replaced by the terms "market location" and "meter location", as applicable.

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.

A meter location is a location at which energy is measured and that has all the 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 MsbG.

2.1 Network balance

The network balance provides an overview of supply and demand in the German electricity grid in 2020. Total electricity supply was 578.3 TWh, comprising a net total of electricity generated of 530.7 TWh (including 10.3 TWh from pumped storage) and cross-border flows[11] from abroad amounting to 47.6 TWh. Total electricity consumption was 572.1 TWh, including 444.2 TWh for final consumers and 11.8 TWh for pumped storage stations from the general supply networks. The amount of energy consumed by pumped storage stations is 1.5 TWh higher than the amount generated because of the electricity needed for the pumping process (power station internal consumption). The net total of electricity generated but not fed into the general supply networks (industrial, commercial and domestic own use) was 33.8 TWh. It can be assumed that the actual value for self-generation is higher, because only data for plants generating 10 MW or more are reported to the Bundesnetzagentur. Distribution and transmission losses amounted to 27.2 TWh and physical flows to other countries 65.4 TWh. The sum of the individual entries for use minus pumping losses is around

[11] The physical flows, and not the trade flows, are decisive for the network balance. Trade flows (65.4 TWh of exports and 47.6 TWh of imports) are different from physical flows in the interconnected alternating current system.

572.1 TWh. The difference between this and the total supply of 578.3 TWh is 6.1 TWh or 1.1%. Supply and demand from the monitoring survey are therefore almost balanced. The difference of 6.1 TWh is due to the complex structure of the data survey involving a large number of different market players.

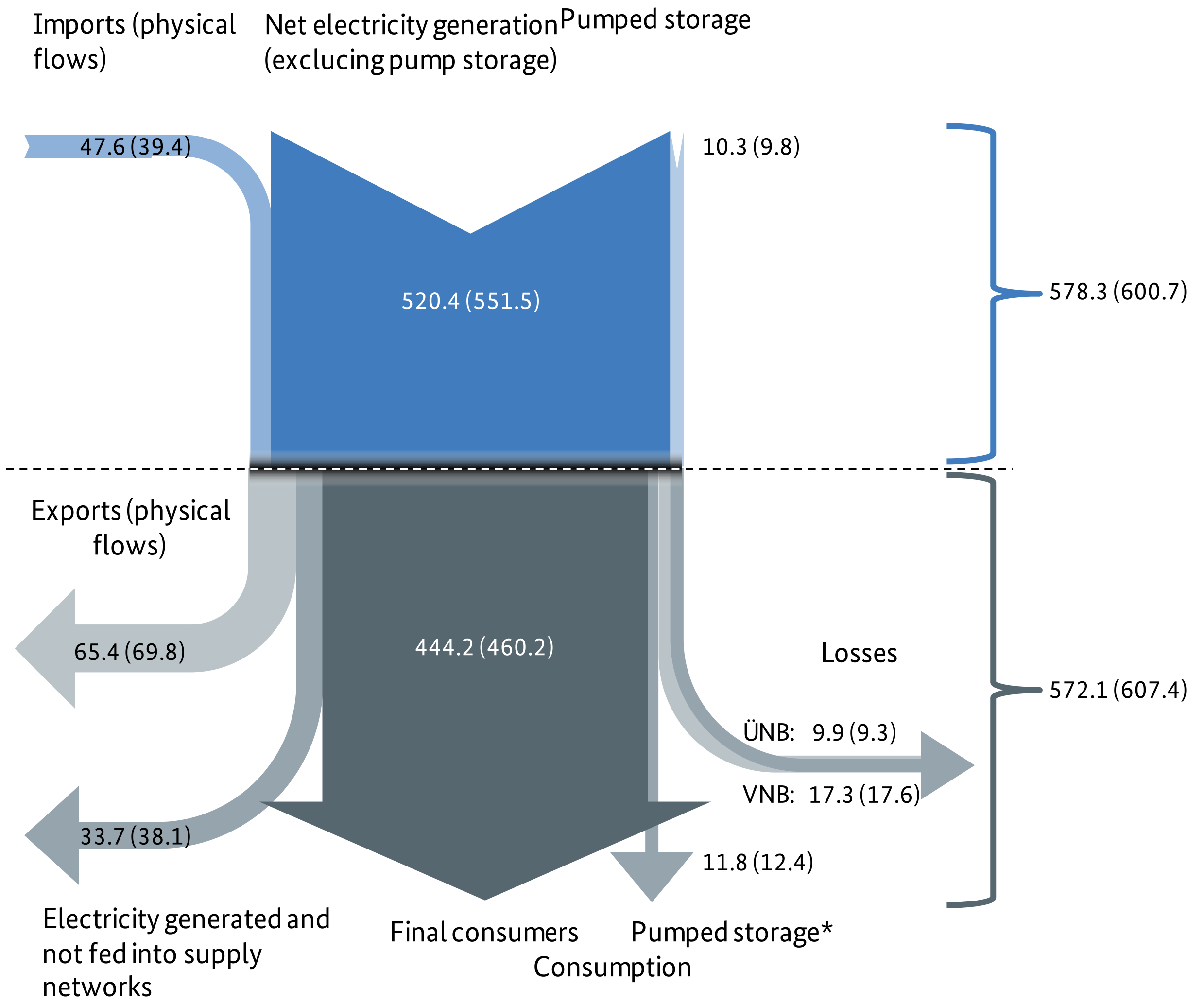
Electricity: network balance 2020

	TSOs	DSOs	Total 2020	Total 2019
Total net nominal generating capacity as at 31 December 2020 (GW)			**233.8**	**226.4**
Facilities using non-renewable energy sources			103.3	102.0
Facilities using renewable energy sources			130.6	124.4
Generation facilities eligible for payments under the Renewable Energy Sources Act			126.7	120.2
Total net generation (including electricity not fed into general supply networks) (TWh)			**530.7**	**561.3**
Facilities using non-renewable energy sources			294.1	332.5
Pumped storage			10.3	9.8
Facilities using renewable energy sources			236.6	228.9
Generation facilities eligible for payments under the Renewable Energy Sources Act			222.0	221.9
Net amount of electricity not fed into general supply networks (TWh)[1]			33.8	38.1
Losses (TWh)	**9.9**	**17.3**	**27.2**	**26.9**
Extra-high voltage	8.1	<0.1	8.1	7.7
High voltage (including EHV/HV)	1.8	3.1	4.9	4.8
Medium voltage (including HV/MV)		5.7	5.7	5.7
Low voltage (including MV/LV)		8.6	8.6	8.7
Cross-border flows (physical flows) (TWh)				
Imports			**65.4**	**69.8**
Exports			**47.6**	**39.4**
Consumption (TWh)[2]	**26.1**	**418.1**	**456.0**	**472.6**
Industrial, commercial and other non-household customers	26.1	292.4	318.5	336.5
Household customers		125.7	125.7	123.7
Pumped storage			11.8	12.4

[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: 2020 network balance based on data from TSOs, DSOs and power plant operators

Electricity: supply and demand in the electricity supply system in 2020
(TWh)



* This is the amount of electricity taken from the network by pumped storage stations, ie the amount required for the pumping p rocess.
The values in brackets are for 2019.

Figure 1: Supply and demand in the electricity supply system in 2020

2.2 Electricity consumption

For 2020 a gross electricity consumption reported for the monitoring survey of 532.8 TWh can be derived from the network balance presented in 2.1. This gross consumption comprises the sum of gross electricity generation from renewable (237.8 TWh) and non-renewable (312.8 TWh) energy sources and cross-border flows into Germany (47.6 TWh) less the cross-border flows out of Germany (65.4 TWh).[12] Gross generation is higher than net generation because it includes power station internal consumption. Generation from renewable energy sources thus accounted for 45% of gross electricity consumption in 2020.

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

Electricity: final consumption by customer category

Category	TSOs (TWh)	DSOs (TWh)	TSOs + DSOs (TWh)	Percentage of total (%)
≤ 10 MWh/year	< 0.1	119.1	119.1	27%
10 MWh/year - 2 GWh/year	0.1	115.4	115.5	26%
> 2 GWh/year	26.0	183.6	209.6	47%
Total 2020	**26.1**	**418.1**	**444.2**	**100%**
Total 2019	*26.8*	*433.4*	*460.2*	

Table 2: Final consumption (excluding pumped storage) by customer category based on data from TSOs and DSOs

Electricity: final consumption by load profile

Category	TSOs (TWh)	DSOs (TWh)	TSOs + DSOs (TWh)	Percentage of total (%)
Interval-metered customers	26.1	261.0	287.1	65%
Standard load profile customers		157.1	157.1	35%
Household customers within the meaning of section 3 para 22 EnWG		125.7	125.7	28%
Total 2020	**26.1**	**418.1**	**444.2**	
Total 2019	*26.8*	*433.4*	*460.2*	

Table 3: Final consumption (excluding pumped storage) by load profile based on data from TSOs and DSOs

The values in the table above show the consumption of electricity in 2020 by final consumers in the network areas of the transmission system operators (TSOs) and distribution system operators (DSOs) participating in the survey (consumption excluding pumped storage). Total consumption from the DSOs' networks was around 418.1 TWh and from the TSOs' networks 26.1 TWh. Table 2 shows that although the number of 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. Customers with an annual consumption between 10 MWh and 2 GWh accounted for 26% of the total consumption in 2020. The largest customer group in terms of numbers comprises final consumers with an annual consumption of up to 10 MWh. This group comprises almost exclusively household customers, but also smaller commercial customers. They represented 27% of the total volume in 2020.

A household customer consumed on average about 2,558 kWh in 2020, according to data from DSOs.[13] The highest household customer consumption was in the band between 2,500 kWh and 5,000 kWh and totalled about 43.1 TWh, according to data from electricity suppliers. The average consumption for this representative

[13] Household customers as defined in section 3 para 22 EnWG

case was about 3,383 kWh, and the total number of market locations around 12.7m. The largest number of household customers with around 16.7m market locations are in the band between 1,000 kWh and 2,500 kWh. The total amount of energy consumed by this group was around 29.0 TWh and the average 1,731 kWh.

2.3 Network structure data

The TSOs and 843 DSOs took part in the 2021 Monitoring Report data survey.[14] As at 2 November 2021, a total of 873 DSOs were registered with the Bundesnetzagentur.

Electricity: TSOs and DSOs in Germany

	2016	2017	2018	2019	2020	2021
TSOs with responsibility for control areas	4	4	4	4	4	4
Totals DSOs	875	878	890	883	879	873
DSOs with fewer than 100,000 connected customers	798	797	809	803	799	791
DSOs with fewer than 30,000 connected customers	607	625	614	645	678	674

Table 4: Number of TSOs and DSOs in Germany from 2016 to 2021

The following table shows the network structure figures "circuit length" and "market locations" for the TSOs and DSOs. Since 2018 the market location is the unit in the energy market in which connections are counted for delivering and balancing. It is always used when referring not to the technical connection but to the contractual relationships behind the technical connection. The number of customers, for example, is counted via the market locations, whereas the number of installed meters is counted via the meter location. The meter location thus forms the technical equivalent to the market location, though a one-to-one relationship does not exist. Multiple meter locations can be assigned to one market location, and in another possible scenario multiple market locations can be assigned to one meter location.

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

Electricity: network structure figures 2020

	TSOs*	DSOs	Total
Network operators (number)	8	875	883
Total circuit length (thousand km)	37.5	1,883.2	1,920.7
Extra-high voltage	37.3	0.2	37.5
High voltage	0.2	94.6	94.8
Medium voltage**		524.5	524.5
Low voltage**		1,263.9	1,263.9
Total final consumers (market locations) (thousand)	0.5	51,994.3	51,994.8
Industrial, commercial and other non-household customers	0.5	2,856.4	2,856.9
Household customers		49,137.9	49,137.9

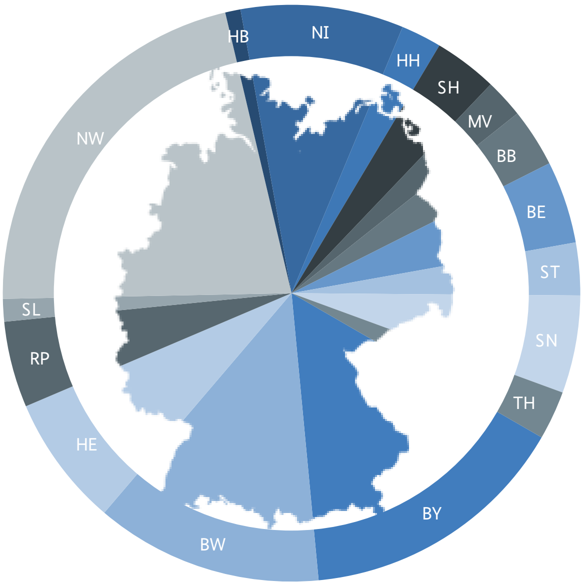
* Figures include offshore holding companies and Baltic Cable AB
** The 2019 total circuit length figures for medium and low voltage were not correct. The correct figures are 520.7 thousand km (medium voltage) and 1,241.4 thousand km (low voltage).

Table 5: 2020 network structure figures based on data from TSOs and DSOs

The circuit length at TSO level was 37,500 km in 2020. The total number of market locations of final consumers in the TSOs' networks was 528. Almost all of these market locations were interval-metered, in other words average consumption was recorded at least every quarter of an hour.

The DSOs' total circuit length at all network levels as at 31 December 2020 was around 1.88m km. As shown in the following figure, the majority of the DSOs included in the data analysis (708 or 84%) have networks with a short to medium circuit length (lines and cables) of up to 1,000 km. These DSOs serve 7.3m or 14% of all market locations in Germany. A total of 132 DSOs have networks with a total circuit length of more than 1,000 km. These network operators supply 44.7m market locations, about 86% of the total.

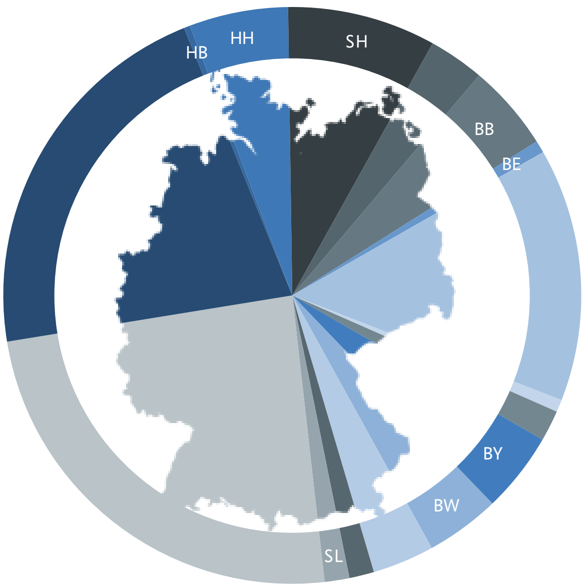
Electricity: market locations by federal state at DSO level 2020
(millions)



Hamburg	1.18
Lower Saxony	4.74
Bremen	0.45
North Rhine-Westphalia	11.25
Saarland	0.66
Rhineland-Palatinate	2.51
Hesse	3.83
Baden-Württemberg	6.62
Schleswig-Holstein	1.85
Mecklenburg-Western Pomerania	1.13
Brandenburg	1.70
Berlin	2.40
Saxony-Anhalt	1.53
Saxony	2.85
Thuringia	1.42
Bavaria	7.89

Figure 2: Market locations by federal state at DSO level based on data from DSOs

Electricity: market locations by federal state at TSO level 2020
(number)



Hamburg	16
Lower Saxony	62
Bremen	1
North Rhine-Westphalia	70
Saarland	4
Rhineland-Palatinate	4
Hesse	10
Baden-Württemberg	12
Schleswig-Holstein	24
Mecklenburg-Western Pomerania	9
Brandenburg	14
Berlin	2
Saxony-Anhalt	41
Saxony	2
Thuringia	5
Bavaria	13

Figure 3: Market locations by federal state at TSO level based on data from TSOs[15]

[15] Beginning this year, market locations for operational consumption and vehicle charging points are not counted as market locations at TSO level.

Electricity: DSOs by circuit length in 2020
(number and percentage)

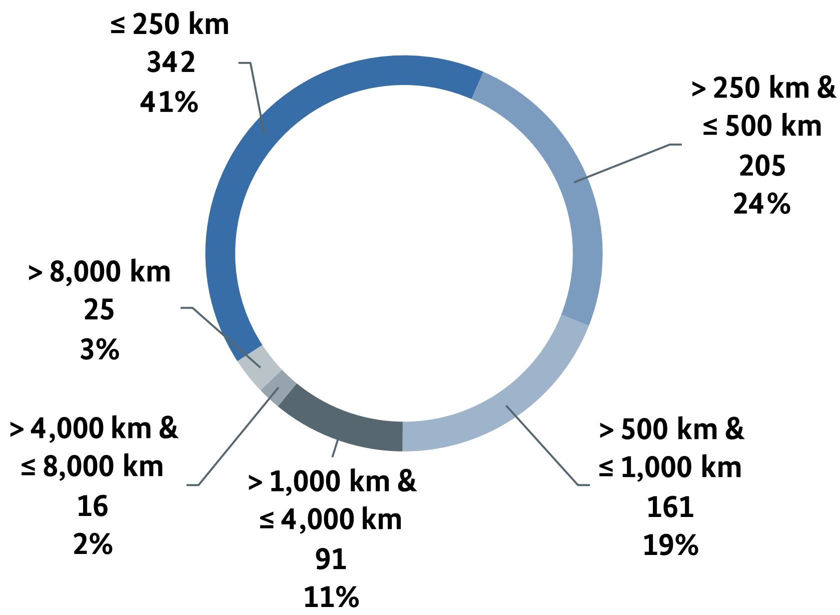


Figure 4: Number and percentage of DSOs by circuit length based on data from DSOs

Electricity: DSOs by number of market locations supplied in 2020 (number and percentage)

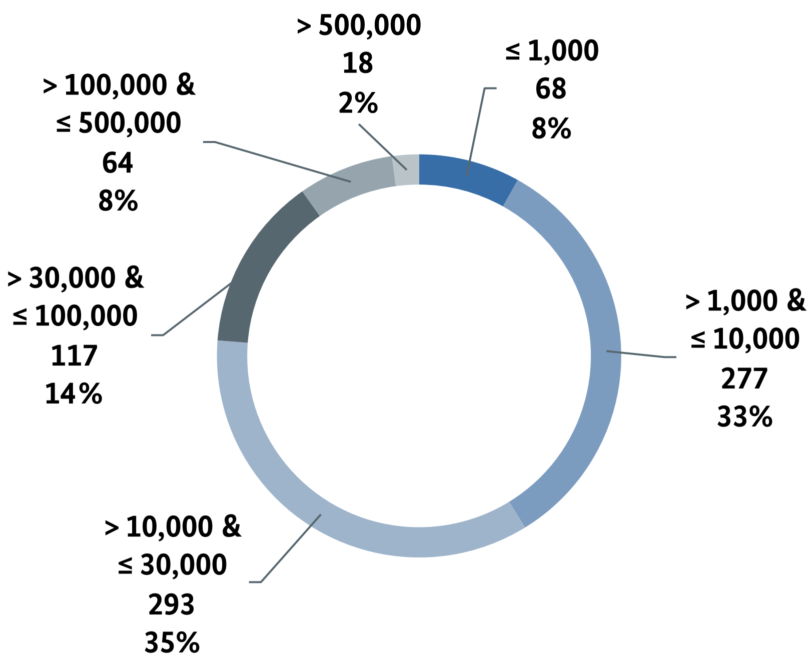


Figure 5: DSOs by number of market locations supplied based on data from DSOs

The number of market locations of final consumers in the DSOs' network areas was around 52.0m, of which about 49.1m were for household customers as defined in section 3 para 22 of the Energy Industry Act (EnWG). Around 395,679 meter locations were interval-metered.

As in the previous year, more than three quarters of the DSOs supply 30,000 or fewer market locations, while 10% of the companies supply more than 100,000 market locations. These 10% supply about 75% (39.2m) of all market locations.

3. Market concentration

As in the previous years, an extensive analysis of market power was not carried out since this would go beyond the scope of the monitoring report. A residual supply analysis, which is of essential importance in the Bundeskartellamt's practice for assessing market power in the electricity generation sector, is therefore not included in the report.[16] Instead this report will be based on indicators which are less complex to identify.

An extensive market power analysis is provided in the second report on competitive conditions in the electricity generation sector ("Market Power Report"), which the Bundeskartellamt published on 28 December 2020 in accordance with Section 53 of the German Competition Act, GWB. The analysis is largely based on data from the information system of the transmission system operators pursuant to the EU regulation on electricity transmission system operation (formerly energy information network) on the use of power plants over the year and on publicly available data. This is used to determine the so-called Residual Supply Index (RSI). This index shows to what extent a company's power plant fleet is indispensable for meeting the demand for electricity. It takes account of the fact that at every given period the amount of electricity produced has to match the amount required and that storage facilities are available only to a very limited extent. This index can thus be used to measure the extent of market power held by a company as the latter can significantly influence the amount of electricity available by the way it operates its power plants and – e.g. by strategically withholding capacity – can also significantly influence the electricity price.

The results of the analysis carried out in the assessment of the RWE/E.ON merger have shown, and both subsequently published market power reports have confirmed, that RWE's power plants are already pivotal during a significant number of hours in the year, i.e. they are indispensable for meeting the demand for electricity. However, the number of pivotal hours has still not yet reached the level necessary to presume a dominant position. Nevertheless, it cannot be ruled out that the extent of the indispensability of RWE's conventional power plant fleet will increase in future due to the general market shortages resulting from the last two stages in phasing out nuclear and coal power and RWE's prospective market power could expand to a degree in excess of the threshold above which market dominance is presumed.

For the purposes of this report the identification of possible market power will be based on the degree of market concentration, which in turn will be determined by the market share distribution of the players on the respective market. Market shares are generally a good reference point for estimating market power because they represent (for the period of reference) the extent to which demand in the relevant market was actually satisfied by a company.[17]

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[16] Cf. Bundeskartellamt, press release of 26 February 2019, B8-28/19 RWE/E.ON minority shareholding with background paper; Bundeskartellamt, report of 21 December 2019, Competitive conditions in the electricity generation market (Market Power Report) 2019, pp. 23 ff.; Bundeskartellamt, report of 28 December 2020, Competitive conditions in the electricity generation market (Market Power Report) 2020, pp. 20 ff., and previous to this, Bundeskartellamt, Sector Inquiry into Electricity Generation and Wholesale Markets, 2011, pp. 96 ff.

[17] Cf. Bundeskartellamt, 29 September 2019, Guidance on Substantive Merger Control, para. 25.

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 current reporting year – and also as a result of the historically evolved structure of the electricity markets – the points of reference for the analysis of electricity generation and first-time sale of electricity were the five largest electricity providers RWE AG, EnBW AG, LEAG GmbH, Vattenfall GmbH, E.ON SE (only first-time sale of electricity) and Uniper GmbH (only electricity generation capacities). At the same time, these businesses far surpassed other producers with regard to electricity generation capacities and electricity volumes fed into the grid (in the following CR5).

However, there are also major differences between the five largest electricity producers. With a clear market share lead of 25.3% (electricity sales volume) and 22.0% (electricity generation capacity), the market leader RWE is followed by four other electricity producers with market shares between 14.9% and 5.6% of the volume sold and between 10.4% and 7.9% of the generation capacity.

As in 2019, the points of reference for the analysis of end customer supply in 2020 were the four strongest suppliers, which, unlike previously, were only partly identical with the largest market players in the first-time sale of electricity. For instance, the sale of electricity to end customers has changed in that in the course of the RWE/E.ON transaction[18] many business activities were shifted from one company to the other, leading to RWE now concentrating on the generation and first-time sale of electricity as well as electricity wholesale whereas E.ON focuses on the operation of electricity distribution networks and the distribution of electricity.

Details on the calculation method: The report examines the market concentration on the economically significant market for the generation and first-time sale of electricity and on the two largest electricity retail markets. For reasons of simplicity, the market shares on the electricity retail markets are estimated using the “dominance method”. The market shares on the market for the first-time sale of electricity are on the other hand calculated using the group market share method under competition law, which produces more accurate results (for details on the differences between the two calculation methods see the box below).

[18] For further details see Monitoring Report 2019, pp.501 – 503.

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

In order to calculate the market shares it first has to be defined which companies (legal entities) are to be considered affiliated companies and consequently a corporate group. This implies that there is no (substantial) competition between the individual companies of a group.

Competition law uses the concept of "affiliated companies" (Section 36(2) 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 (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, interlocking management 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 affiliation 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 only one shareholder holds 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 sales 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 is 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 when applying 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 Electricity generation and first-time sale of electricity

In its normal practice the Bundeskartellamt defines a relevant product market for the generation and first-time sale of electricity with physical fulfilment (market for the first-time sale of electricity). Electricity generation volumes and the required generation capacities only belong to the market for the first-time sale of electricity as defined above if the volumes produced are fed into the general supply grid, are suitable to meet the general demand for electricity and are therefore interchangeable from the customers' perspective. This requirement is not fulfilled in the case of electricity generated for the producer's own consumption, traction current as well as balancing energy, reserve capacities and redispatching. On the supply side, electricity generation volumes which are subject to other market and competition conditions, e.g. due to specific legal obligations, are not to be included in the market for the first-time sale of electricity. Equally, electricity generation which is remunerated under the Renewable Energy Sources Act (EEG) is therefore also not considered part of the market for the first-time sale of electricity for the purpose of the monitoring report.

In its case practice the Bundeskartellamt has recently applied the following criteria for the calculation of market shares[19]:

The market shares are generally 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 the historically sometimes optional direct marketing is indirectly included in the residual supply analysis (see above) by way of the merit-order effect, but not in the calculation of the market shares on the market for the first-time sale of electricity applied here.[20] Electricity from renewable energy resources (EEG electricity) is generated and fed into the grid regardless of the demand situation and electricity wholesale prices. EEG plant operators are not exposed to competition from other suppliers whose electricity generation is not remunerated under the EEG system. 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 the latter decides on the use of the power plant and bears the risks and rewards of marketing the electricity.[21]

In geographical terms the Bundeskartellamt defined the market for Germany and Luxembourg as a single market after the bidding zone with Austria was split on 1 October 2018.[22] Data on electricity generation was collected from the five largest companies with a market share exceeding 5% based on the above definitions. In terms of the first-time sale of electricity these were RWE, LEAG, EnBW, E.ON and Vattenfall. However, in terms of the electricity generation capacities of their own power plants including drawing rights to other power plants, the five largest companies were RWE, EnBW, LEAG, Vattenfall and Uniper.

The results of the survey on volumes of electricity generated in 2020 are shown in the table below. Data from the previous year is shown for comparison.

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[19] Cf. Bundeskartellamt, case summary of 31 May 2019, B8-28/19 RWE/E.ON minority shareholding; explained in detail in the Bundeskartellamt's decision of 8 December 2011, B8-94/11, RWE/Stadtwerke Unna, paras. 22 ff.

[20] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, pp. 73 f.

[21] Cf. Bundeskartellamt, Sector Inquiry Electricity Generation and Wholesale Markets, pp. 93 f.

[22] Expressly outlined for the first time in the Bundeskartellamt's report of 21 December 2019, Competitive conditions in the electricity generation market (Market Power Report) 2019, p. 14.

Electricity: Electricity volumes generated by the five largest German electricity producers

Germany 2019			Germany 2020		
Company	**TWh**	**Share**	**Company**	**TWh**	**Share**
RWE	78.9	26.0%	RWE	67.8	25.3%
LEAG	49.0	16.2%	LEAG	39.9	14.9%
EnBW	38.3	12.7%	EnBW	26.6	9.9%
E.ON	26.6	8.8%	E.ON	25.7	9.6%
Vattenfall	19.5	6.4%	Vattenfall	15.0	5.6%
CR 5	212.2	**70.1%**	**CR 5**	175.0	**65.3%**
Other companies	90.6	29.9%	Other companies	92.8	34.7%
Total net electricity generation	302.8	100%	Total net electricity generation	267.8	100%

Table 6: 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 producers' own consumption)

The aggregate market share of the five strongest companies in the market for the first-time sale of electricity in the German market area including Luxembourg amounted to 65.3% in 2020. Their market share was still 70.1% in 2019. The total net electricity generation which was not entitled to payments under the EEG fell by 35 TWh to altogether 267.8 TWh compared to the previous year. One reason for this is that further capacities were withdrawn from the market and partly replaced by imports and – as a result of the Covid-19 pandemic – consumption decreased significantly. At the same time electricity generation from renewable energies entitled to payments under the EEG reached a new record level of around 221.9 TWh (211.0 TWh in the previous year), consequently continuing to replace electricity generation not remunerated under the EEG. Compared to the previous year, RWE's market share decreased slightly to 25.3%; the market shares of LEAG, EnBW and Vattenfall also fell considerably.

Regarding the comparison over time as illustrated below, it has to be taken into account that in 2017 E.ON and Uniper were considered a company group. Since 2018, E.ON and Uniper have been regarded as two separate companies following the sale of Uniper, including a large part of its plants, to the Finnish energy company Fortum. In spite of this, the volume of energy generated, in particular by the remaining E.ON nuclear power plants, still accounted for approx. 9.6%; this volume includes to a lesser extent the smaller generating units acquired from RWE via its shares in Innogy.

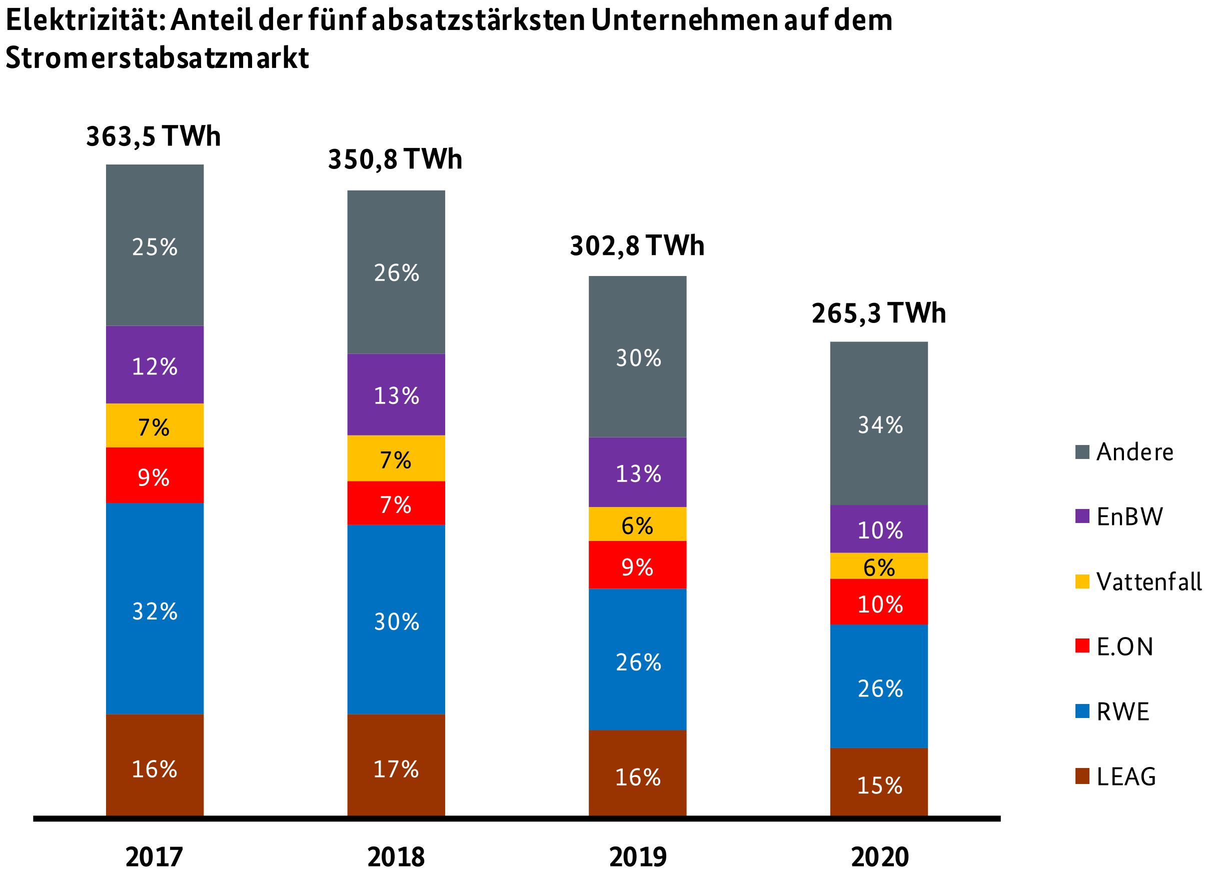

Figure 6: Shares of the five largest companies on the market for the first-time sale of electricity in the German market area

The total amount of electricity generation capacities available in 2020 was approx. 92.7 GW; compared to 2019, this increased by 2.5 GW due, among other things, to the commissioning of the Datteln 4 coal-fired power plant (Uniper). Consequently, the CR5's capacities also increased from 51.8 GW in 2019 to 52.6 GW in 2020. In spite of this, the five largest suppliers' share of the German non-EEG generation capacities available for use on the market for the first-time sale of electricity was 56.7% in 2020 and thus slightly below the 57.5% reached in the previous year. It has to be noted here that E.ON's remaining shareholdings in nuclear power plants (via its subsidiary PreussenElektra) were not included in the CR5 share of German non-EEG generation capacities because E.ON was not one of the five largest producers in terms of generation capacities. In addition, the capacities of the Innogy shareholdings, which were transferred to E.ON on 31 December 2019, have meanwhile been largely retransferred to RWE.

The joint market share of the five largest producers and consequently the degree of market concentration is likely to decrease further as a result of the planned shut-down and decommissioning of further nuclear power plants and coal-fired power stations. However, this deconcentrating effect caused by shut-downs will at the same time result in market shortages and in this way increase the competitive importance of the remaining capacities, which is manifested in the residual supply index. The RSI will be determined in the next market power report for 2021.

Elektrizität: Kapazitäten der fünf größten Stromerzeuger

Deutschland 31. Dezember 2019			Deutschland 31. Dezember 2020		
Unternehmen	**GW**	**Anteil**	**Unternehmen**	**GW**	**Anteil**
RWE	20,2	22,4%	RWE	20,4	22,0%
EnBW	11,0	12,2%	EnBW	9,6	10,4%
LEAG	7,8	8,6%	LEAG	7,8	8,4%
Vattenfall	7,5	8,3%	Vattenfall	7,5	8,1%
Uniper	5,4	6,0%	Uniper	7,3	7,9%
CR 5	51,8	**57,5%**	**CR 5**	52,6	**56,7%**
Andere Unternehmen	38,4	42,5%	Andere Unternehmen	40,0	43,3%
Kapazitäten insgesamt	90,2	100%	Kapazitäten insgesamt	92,6	100%

Table 7: Generation capacities of the five largest electricity producers

To sum up, it can be said that, in terms of generation volume, the market for the first-time sale of electricity in the German market area continued to be concentrated in 2020 with a CR5 of 65.3% (cf. Table 6). In the previous year, the CR5 had still amounted to 70.1% and in 2018 even to 73.9%. Hence the degree of market concentration in the German market area has decreased over the years.

In addition to the degree of market concentration which further decreased in 2020, other factors are also to be taken into account in assessing the market power situation. In the 2020 reporting year these factors suggested a downward trend in market power, which is, however, no longer the case. Currently, there are generally more electricity generation capacities in Germany than required to cover demand. In 2020 capacities expanded; however, this trend should be reversed following the first shut-downs of coal-fired power plants and the full decommissioning of nuclear power plants. An increased part of the electricity demand is covered by the feed-in of renewable energy with regard to which the market shares of the five large suppliers are substantially below those of conventional power generation. The demand for EEG electricity therefore no longer has to be satisfied on the market for the first-time sale of electricity.

This monitoring report contains surveys on the five producers' market shares in EEG electricity generation in order to provide a rough estimate of the effects which the exclusion of EEG electricity has on the degree of market concentration in the market for the first-time sale of electricity. ln line with the survey on the generation and first-time sale of electricity which is not remunerated under the EEG system, 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. In terms of the EEG subsidised generation volume (same companies as with regard to the generation volume, i.e. excluding Uniper) the share of the five largest companies in the German market area was around 5.5% in 2020. In the previous year it was still around 4.9%. In terms of EEG generation capacities, the share of the five largest producers (here including E.ON and excluding Uniper) was around 3.6% in 2020 compared to 4.0% 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 (see above). With regard to the future, it should ultimately also be borne in mind that the decommissioning of still existing German nuclear power plants, envisaged for the end of 2022 at the latest, and the shut-down of further coal-fired power plants are factors that will result in shortages on the market for the first-time sale of electricity and also bring about changes in the market structure I.B.1.8.3.

3.2 Electricity retail markets

In the electricity retail markets the Bundeskartellamt differentiates between customers whose consumption is measured on the basis of metered load profiles and customers with standard load profiles. Metered load profile customers are generally industrial or commercial customers. Standard load profile customers are generally consumers with relatively low levels of consumption such as 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. For the supply of electricity to standard load profile customers the Bundeskartellamt has so far differentiated between three product markets:

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

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

(iii) supply on the basis of special contracts (without heating electricity, defined as a national market)[23].

Since the Energy Industry Act (EnWG) no longer uses the term "special contract customers" in this sense, the relevant contracts are referred to as "special contracts" in the present monitoring report only in the context of defining the market under competition law. For the purpose of the monitoring report, these contracts are otherwise referred to as "non-default contract with the default supplier" or as "contract with a supplier other

[23] Cf. Bundeskartellamt, decision of 30 November 2009, B8-107/09, Integra/Thüga, paras. 32 ff.

than the local default supplier".[24] 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 heating electricity, default supply and supply under a special contract. The following analysis is based on data submitted by 1,413 electricity providers (legal entities) (2019: 1,429 electricity providers).

Based on the information provided by suppliers, in 2020 around 213.6 TWh of electricity were sold to metered load profile customers and around 133.8 TWh of electricity to standard load profile customers; 11.2 TWh of the total sales to standard load profile customers consisted of heating electricity. Of the remaining 122.6 TWh sales to standard load profile customers without electric heating, 25.1 TWh went to standard load profile customers with default supply contracts, i.e. around 20.5%; the remaining 97.4 TWh went to standard load profile customers with special contracts, i.e. around 79.5%. By comparison: In 2019, 257.2 TWh of electricity were sold to metered load profile customers and 156.9 TWh to standard load profile customers, which is significantly higher compared to the current reporting year. Approx. 13.5 TWh of the total sales to standard load profile customers consisted of heating electricity and 33.4 TWh went to standard load profile customers with default supply contracts and 110.1 TWh to standard load profile customers with special contracts. The significant decline in 2020 is presumed to be largely caused by the effects of the Covid-19 pandemic. In addition, there has been a slight shift from previous standard load profile customers with default supply contracts to standard load profile customers with special contracts.

Based on the data provided by the individual companies, it was determined which sales volumes were attributed to the four strongest companies in each market segment. The aggregate sales volumes were attributed to the four strongest companies using the "dominance method" according to the rules 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 and that some suppliers could not provide data on quantities so that only approximate market volumes were recorded. The quoted percentages therefore merely approximate the actual market shares.

When comparing the figures to those of 2019, it is to be noted that in 2020 there were considerable shifts in the retail markets, particularly due to the shift in business activities between RWE and E.ON (see above). For one thing, the market shares changed and as a consequence the ranking of the large electricity providers also changed, resulting in the fact that the current CR4 companies are only partly identical with those in 2019. For another, due to these shifts a distinction had to be made for the first time in 2020 between the CR4 companies for the individual market segments since the differences between the strongest companies had become significant. This also explains the partly considerable changes in the CR4 figures from 2020 compared to 2019; as a result, the figures for both years are comparable only to a limited extent.

In 2020 the four strongest companies (currently E.ON, RWE, EWE and N-Ergie) sold a total of around 60.8 TWh on the German market for **the supply of electricity to metered load profile customers**. Their

[24] The term "special contract" appears 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 (heating electricity). The terms "default (and fallback) supply" and "special contract" are appropriate for the purpose of market definition under competition law and will continue to be used because they are legally defined.

aggregated market share thus amounted to 28.5%. In the previous year, the four largest electricity providers still sold as much as 63.0 TWh, which was equivalent to a share of 24.5%. The market share of the CR4 companies on the market for metered load profile customers thus increased despite lower supply volumes in absolute terms. Nevertheless, this figure is still far below the statutory thresholds for the presumption of a (joint) dominant position (Section 18(4) and (6) GWB). The Bundeskartellamt assumes that there is currently no dominant supplier on the market for the supply of metered load profile customers.

In 2020 the cumulative sales of the four strongest companies (currently E.ON, EnBW, Vattenfall and EWE) on the German market for the supply of electricity to **standard load profile customers with special contracts** (non-default supply and excluding heating electricity) amounted to around 41.7 TWh – an increase from 37.5 TWh in the previous year. The CR4 on this market thus amounted to approx. 42.8% in 2020 (2019: 34.1%). This development shows that the four currently largest electricity providers were able to increase their supply volumes contrary to the general market trend (significant decline in supply quantities). Nevertheless, this CR4 figure is still far below the statutory thresholds for the presumption of a joint dominant position. The Bundeskartellamt assumes that there is currently no dominant supplier on the German market for the supply of electricity to standard load profile customers with special contracts (excluding default supply and heating electricity).

The cumulative sales of the four strongest companies[25] (currently E.ON, EnBW, Vattenfall and EWE) on the German market for the supply of electricity to **standard load profile customers with default contracts** amounted to around 13.2 TWh of the total default supply volume of around 25.2 TWh. The share of the CR4 companies was therefore around 52.6%. In 2019 this was around 41.6% with cumulative sales of the CR4 companies of 13.9 TWh and a total default supply volume of 33.4 TWh. The significant overall decline in the supply of electricity to customers with a default contract did not apply to the four largest electricity providers to the same extent.

In the exclusive supply of **heating electricity** to standard load profile customers, the currently four strongest companies still hold a relatively strong position. However, especially due to the sale of part of E.ON's heating electricity business to Lichtblick GmbH in 2020, the composition and the market shares changed within the CR4 group. The cumulative sales of the CR4 companies[26] in Germany were around 6.6 TWh of the total 11.2 TWh for heating electricity. The CR4's share thus amounted to 58.8%, which corresponds to an increase of 1.9 percentage points compared to 2019 (56.9% share).

The shares in sales to all standard load profile customers, i.e. including heating electricity 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 and geographical market but are nonetheless indicative of 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 currently four strongest companies to all standard load profile customers was around 60.8 TWh of a total of 133.8 TWh. This is equivalent to an aggregate share of around 45.5%. In 2019 the volume supplied by the CR4 companies was

[25] This is a fictitious value which only serves to illustrate the market conditions since in the Bundeskartellamt's decisional practice the market for the supply of electricity to customers with default contracts is not defined as national in scope.

[26] This is also a fictitious value, see above.

still 59.1 TWh and their market share was 37.6%. 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 heating electricity and default supply the four strongest companies – as illustrated above – tend to account for higher shares in the German sales volumes than in the area of standard load profile customers with special contracts (excluding heating electricity).

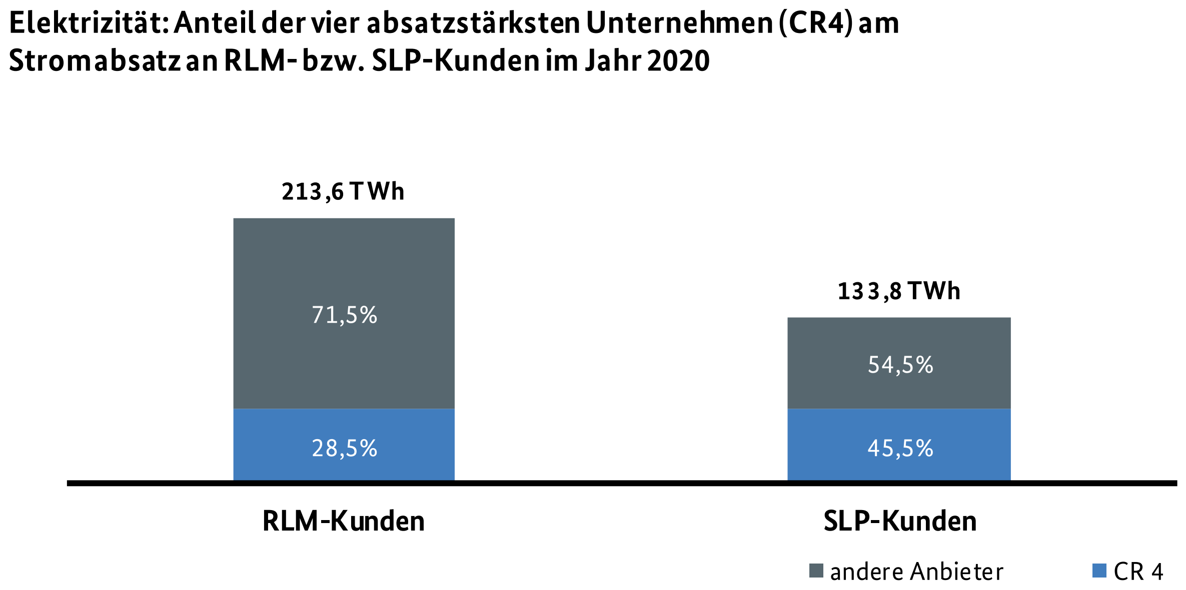

Figure 7: Shares of the four strongest companies (CR4) in the sale of electricity to final customers in 2020

4. Consumer advice and protection

The Bundesnetzagentur and its energy consumer advice service provide support to consumers. They offer comprehensive information on all issues relating to energy customers' rights and the obligations of energy suppliers, network operators and meter operators. They also provide information on dispute resolution and general developments on the energy market.

In the period up to 30 September 2021, the Bundesnetzagentur received a total of around 14,800 telephone, email, online and postal queries and complaints (compared with 13,400 in the same period in 2020). This represents a year-on-year increase of just over 10%.

Considering the total number of household customers served (49.1m electricity and 12.8m gas customers) and the number of customers who switched supplier in 2020 (around 5.4m electricity and 1.7m gas customers), the number of queries and complaints received by the Bundesnetzagentur is very low. These figures do not include complaints made in writing or by telephone about unsolicited marketing calls for electricity or gas supply contracts. In the first half of 2021, the number of written complaints alone about the energy sector was nearly 7,400.

In 2021, the energy consumer advice service have so far received nearly 8,000 telephone calls from consumers, 5,700 emails and 1,100 postal and online submissions.

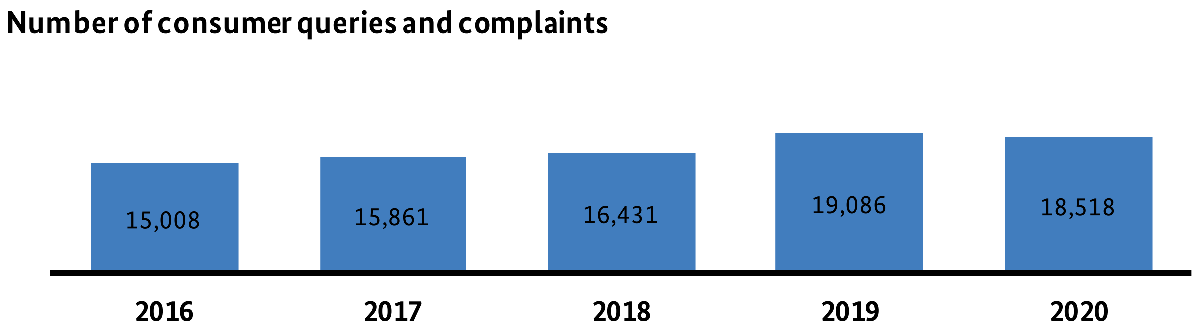

Figure 8: Number of consumer queries and complaints

Main subjects of queries and complaints

In the period up to 30 September 2021, 60% of the queries and complaints received were about electricity. The majority were again about contracts (default/fallback supply and competitive contracts), billing, renewable energy/CHP and supplier switching.

There is still a rising number of queries about "energy transition technologies" in private households. These include solar PV installations, and in particular "balcony installations", heat pumps and electric cars/wallbox chargers. This topic is closely linked to the issues relating to installing modern metering equipment and smart metering systems. Household customers also have increasingly specific questions as prosumers.

The coronavirus pandemic gave rise to relatively few queries from consumers about the special arrangements for the right to withhold performance, suspending electricity and gas disconnections, and reduced VAT rates for energy prices.

New FAQs were published online at www.bnetza.de/elektromobilitaet in response to the lively interest in electromobility, public charging infrastructure and private wallbox chargers.

Only 7% of all queries and complaints were specifically about gas issues. The small number of queries about gas networks reflects the very high level of information provided by network operators to customers affected by the conversion from L-gas to H-gas.

The remaining queries (33%) were not specifically about either electricity or gas. They included research-related questions, queries from consultancies, and matters not falling within the Bundesnetzagentur's remit.

At the end of July 2021, the revised EnWG transposing Directive (EU) 2019/944 led to an enhancement of consumers' rights, including those relating to the conclusion of contracts, the information to be specified in contracts, a summary of contractual conditions, and uniform rules for determining consumption, customers moving home and credit refunds. In light of this, the range of information provided by the energy consumer advice service and published online at www.bnetza.de/aktuelles-enwg was updated and supplemented.

Further information for consumers is contained in special boxes later on in the report.

5. Sector coupling

Sector coupling refers to interconnecting the electricity, heating, transport and industrial sectors. This sector coupling serves to make electricity usable in the other sectors as well and thus also to promote the defossilisation of the energy system as a whole. Defossilisation can occur directly through electrification, as in the case of electric vehicles. Applications that cannot be directly electrified, for example because of technical restrictions, can be defossilised through the use of synthetically produced gas (power-to-gas). One key application of sector coupling is the generation of heat from electricity (power-to-heat), for example to heat private households.

The concept of sector coupling means that the applications lead to an increase in load or consumption for the electricity system. Sector coupling is not to be seen as an end in itself, however, because the effects on carbon emissions need to be viewed across the whole energy system. Depending on the technology-specific efficiency and the level of the carbon emissions associated with meeting the additional electricity demand, the overall carbon effects should be positive.

5.1 Hydrogen

Section 3 para 10c EnWG defines the term biogas as "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)".

The biogas injection overview in II.B.4 includes separate figures for the injection of hydrogen and synthetically produced methane corresponding to this definition. In 2020, seven facilities injected hydrogen and two facilities injected synthetically produced methane (both figures as at 31 December 2020). With 2.8m kWh of hydrogen and 0.3m kWh of synthetically produced methane, however, these forms of injection accounted for only 0.031% of the total amount of biogas injected in 2020. The facilities injecting hydrogen have a total installed electric capacity of 11.3 MW and those injecting synthetic methane a total installed electric capacity of 8 MW.

In addition to these facilities, there are a number of other facilities which, however, do not inject the gas produced into the natural gas network. The majority of these facilities are demonstration and research facilities. In many cases, exact details of the technical specifications are not available. However, the total number of power-to-gas facilities currently in operation, including those injecting into the gas network, is estimated to be about 40, and the total installed electric capacity of these facilities is estimated to be more than 60 MW.

The scenarios set out in the approval of the electricity scenario framework for 2021-2035 and taken into consideration in the NDP 2035 (2021) take account of power-to-gas capacities of 3.5 GW (A 2035), 5.5 GW (B 2035), 8.5 GW (C 2035) and 10.5 GW (B 2040), in each case comprising 0.5 GW of power-to-methane capacity and the remaining capacity for power-to-hydrogen. The power-to-methane capacity potential is considered to be stable and comparatively small.

5.2 Electric vehicles

Following the entry into force of the Charging Station Ordinance (LSV) in March 2016, the Bundesnetzagentur records the notifications from recharging point operators with details of the charging infrastructure provided by the operators. All recharging points accessible to the public that have been taken into operation since the LSV entered into force are subject to the notification obligation. Recharging points not subject to the notification obligation may also be notified.

By 1 July 2021, the Bundesnetzagentur had been notified of a total of 23,363 charging stations with 45,369 recharging points; 38,876 recharging points had a power less than or equal to 22 kW (normal-power recharging points) and 6,493 were high-power recharging points (see https://www.bnetza.de/ladeinfrastruktur). In 2020, the number of charging stations increased by 5,270 and the number of recharging points by 10,521.

According to the Kraftfahrt-Bundesamt (KBA – Federal Motor Transport Authority), 865,142 externally rechargeable passenger vehicles were registered in Germany as at 1 July 2021, of which 438,950 were fully electric vehicles and 426,192 plug-in hybrids.

5.3 Electrical heat generation

Almost all of today's so-called controllable loads are for electrical heat generation, in particular using heat pumps or night storage heating systems. The network operators surveyed levy a reduced network charge for 1,777,852 controllable loads. This represents a year-on-year increase of 275,492 loads (see I.C.7.2). The increase is, however, almost solely due to one more DSO supplying data. Without these data, the number of controllable loads would only be 16,684 higher than the previous year.

B Generation

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

1.1 Net electricity generation in 2020

Net annual electricity generation since 2015 is shown in Figure 9 and Table 8 according to energy source.[27] Section I.B.2 "Development of renewable energiescontains a detailed analysis of the annual amount of energy supplied by installations eligible for payments under the EEG and its development. Renewable energies are therefore only shown in aggregated form in the following figure and table.

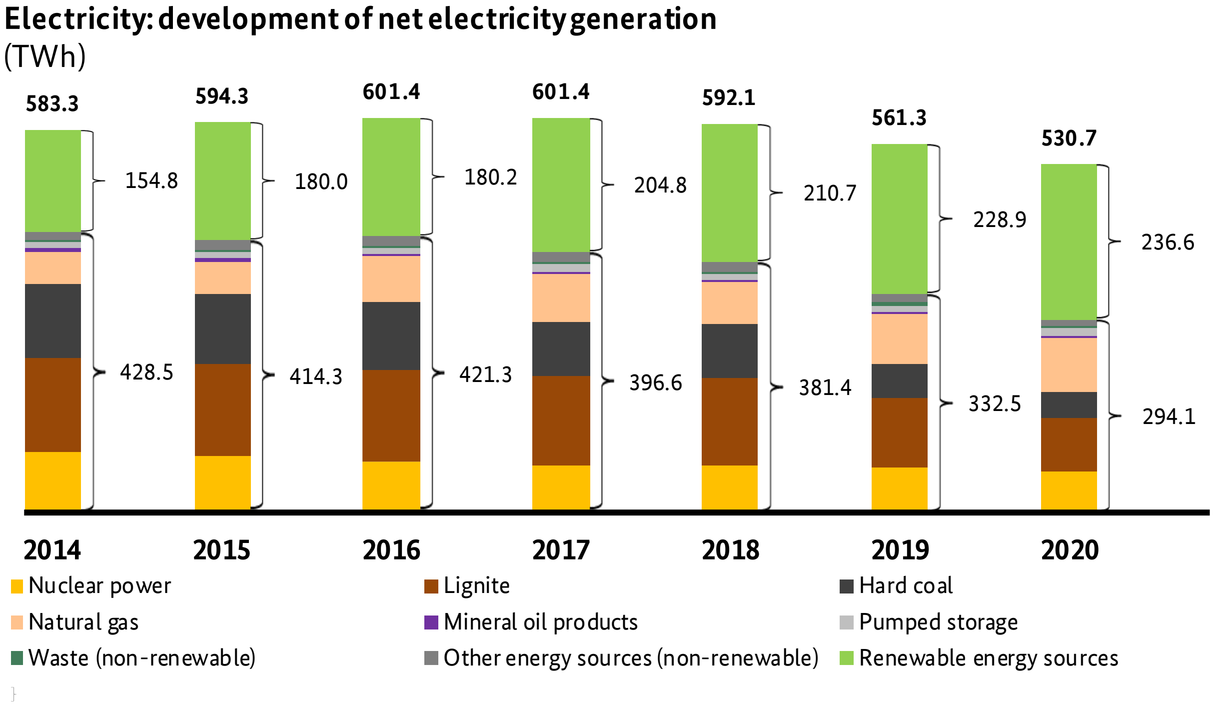

Figure 9: Net electricity generation since 2014

Total net electricity generation fell in 2020. Far less electricity was generated from nuclear power, lignite and hard coal in particular than in 2019[28]. Growth in the generation of electricity from renewable energy sources was low.

[27] Net electricity generation was determined on the basis of the Bundesnetzagentur's monitoring report and may differ from comparable figures published elsewhere.

[28] Thermal power generation units can be registered in the core energy market data register (MaStR). Typically, these units use heat that is generated by the combustion of a fuel or fuels. The time series has been updated by assigning the thermal power generation units to the energy sources used to date in the monitoring according to MaStR. Natural gas 1.3 GW, Coal: 0.2 GW, Waste: 0.2 GW, Biomass 0.2 GW, Other energy sources 0.3 GW.

Electricity: development of net electricity generation
(TWh)

	2014	2015	2016	2017	2018	2019	2020
Nuclear power	91.8	85.1	78.3	70.5	70.4	69.5	60.9
Lignite	144.5	142.5	139.9	137.5	135.9	104.2	83.6
Hard coal	111.6	106.1	103.3	83.5	80.3	53.4	40.0
Natural gas	50.0	48.7	68.0	72.7	64.4	75.5	81.0
Mineral oil products	3.8	4.3	3.9	3.5	3.5	3.1	4.3
Pumped storage	9.5	10.1	9.9	10.2	9.2	9.8	10.3
Waste (non-renewable)	4.3	4.2	4.3	4.3	4.2	4.1	3.9
Other energy sources (non-renewable)	12.9	13.4	13.6	14.3	13.6	12.9	10.0
Total of non-renewable energy sources	428.5	414.3	421.3	396.6	381.4	332.5	294.1
Renewable energy sources	154.8	180.0	180.2	204.7	210.7	228.9	236.6
Total	583.3	594.3	601.4	601.3	592.1	561.3	530.7

Table 8: Net electricity generation since 2014

The decrease in total electricity generation in 2020 can be mainly explained by the fall in electricity consumption compared to 2019 due to the Covid-19 pandemic. Lockdowns led to restrictions in public life and reduced economic activity[29]. As a result, less electricity was used in the industrial and manufacturing sectors in particular.

Apart from the Covid-19 pandemic, the sharp decline in the use of conventional energy is in part due to an increase in feed-in from renewables, the decommissioning of the Phillipsburg 2 nuclear power plant at the end of 2019, and the transfer of the two lignite-fired power plants Jänschwalde E and Neurath C to lignite security standby status at the end of October 2019. This resulted in a reduction compared to 2019 of around 20% in lignite-fired power generation and of around 25% in generation from hard coal.

[29] https://www.destatis.de/DE/Presse/Pressemitteilungen/2021/02/PD21_081_81.html

The increase in the prices for CO2 certificates led to a relative increase in the price of more CO2-intensive energy sources (and especially of lignite and hard coal) compared to natural gas power plants. This at least partly explains the increase in the amount of electricity generated in natural gas power plants. Despite the overall fall in electricity production in 2020 generation from natural gas power plants rose by 7.3% compared to 2019.

The following figure shows the sources of energy for net electricity generation in 2020 in percent.

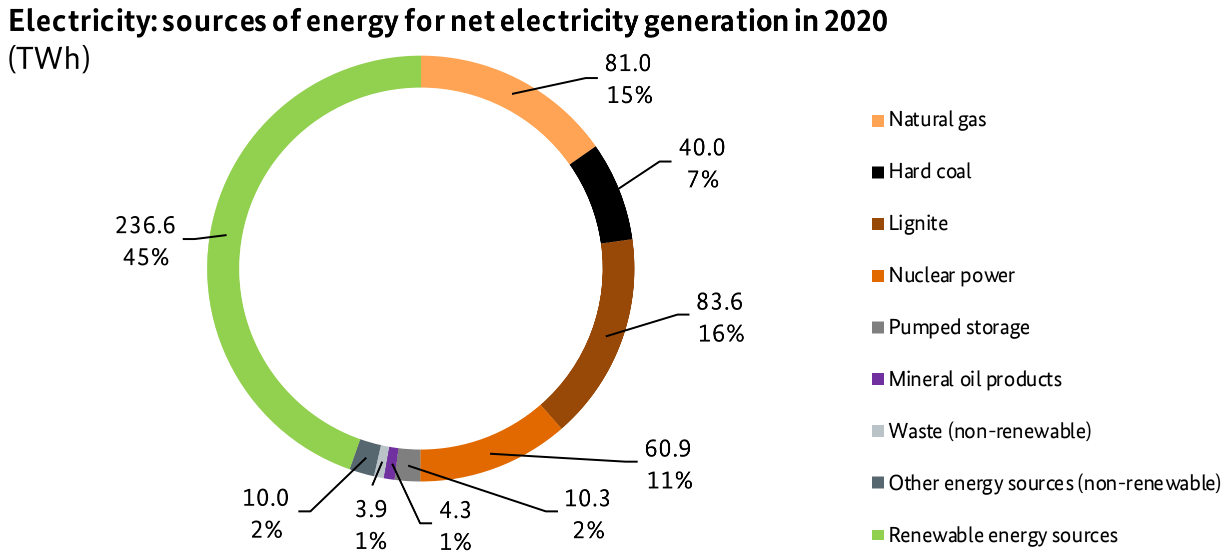

Figure 10: Sources of energy for net electricity generation in 2020

Trend: The amount of electricity generated from conventional energy sources will continue to fall over the next few years, in particular due to the phase-out of coal and the shutdown of nuclear power plants. Part of this reduction could be substituted with electricity generated in natural gas power plants.

1.2 CO2 emissions from electricity generation in 2020

The Bundesnetzagentur asked operators of power generation units with a net nominal capacity of at least 10 MW (per location) to supply data on CO2 emissions from electricity generation in 2020.[30] For CHP plants, operators only had to supply data on the share of CO2 emissions attributable to electricity generation.

The results of the survey of power plant operators are provided in Table 9.

[30] CO_2 emissions from electricity generation were determined on the basis of the Bundesnetzagentur's monitoring report and may differ from comparable figures published elsewhere.

Electricity: CO_2 emissions from electricity generation
(million tonnes)

	CO_2 emissions			Change on
	2018	2019	2020	2019
Lignite	152.8	117.0	93.4	-23.6
Hard coal	72.4	47.9	33.1	-14.8
Natural gas	22.5	26.3	29.8	3.5
Mineral oil products	2.3	1.3	3.0	1.7
Waste	7.5	8.0	7.0	-1.1
Other energy sources	17.2	17.1	10.4	-6.7
Total	274.7	217.7	176.7	-41.0

Table 9: CO2 emissions from electricity generation

The reduction in net electricity generation is reflected in lower CO2 emissions for power generation. The reasons for the decline in power generation are explained in I.B.1.1. Power plant operators reported that lignite-fired power plants emitted 93.4m tonnes of CO2 emissions in 2020, which accounted for over half of all CO2 emissions from electricity generation (52.8%). Hard coal-fired power plants emitted 14.8m tonnes of CO2 less than in the previous year. The remaining CO2 emissions originated, as shown in the table above, from natural gas-fired power plants, mineral oil-fired power plants and other energy sources.

1.3 Installed electricity generation capacity in Germany in 2020

The change in total (net) installed generation capacity since 2014 is shown in Figure 11 and Table 10 (including power plants that are not currently operating in the electricity market but that are, for example, grid reserve power stations, in lignite-fired power plant security standby or are temporarily shut down)[31].

[31] Power plant operators were not asked to provide capacity data for the Monitoring 2021 where such data must already be entered in the core energy market data register (MaStR). This means that the evaluations for 2020 in this report are based on capacity data taken from the MaStR and may differ from data in earlier monitoring reports.

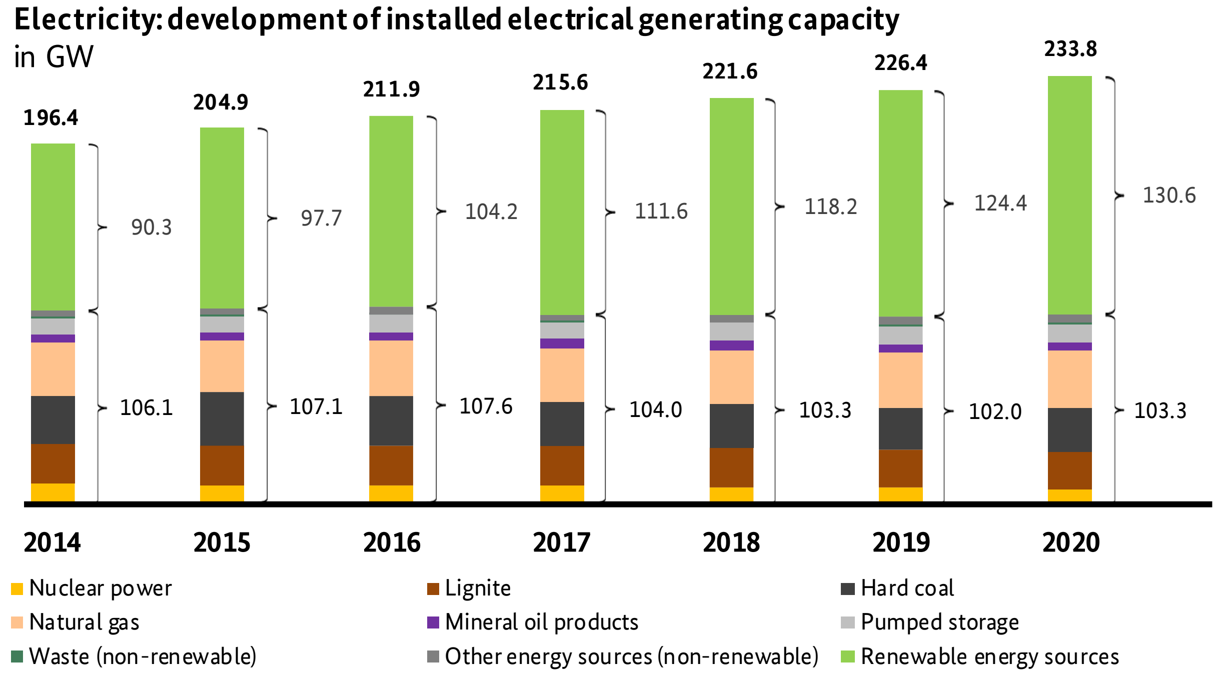

Figure 11: Development of installed generation capacity since 2014

Unlike in previous monitoring reports, the installed capacity figures are no longer based on the monitoring survey but on the core energy market data register. Previous monitoring surveys covered conventional power plants with a minimum installed capacity of 10 MW. Power generation units must be registered in the MaStR. In many cases, a generation system may consist of several smaller power generation units. Under the previous 10 MW threshold this meant that several or numerous power generation units entered in the MaStR were not included in the evaluations. The following evaluations therefore include all the conventional power generation units that, according to the MaStR (as at November 2021), have an on-site net nominal capacity of at least 10 MW.

Due to the new data basis and the methodology of the evaluation based on the market master data register described above, the figures are not entirely comparable with those from previous years. In particular, the values for conventional energy sources in 2020 include power generation units that were not covered by the monitoring in previous years.

Bearing this in mind, it must therefore be concluded that installed net generation capacity from renewable energy has increased by 6.1 GW. The increase in generation from conventional energy sources is mainly due to the commissioning of the Datteln 4 hard coal-fired power plant, which has a net nominal generating capacity of 1,052 MW, and the commissioning of other single systems

Total generation capacity in 2020 was therefore 233.8 GW. Of this, 103.3 GW was non-renewable and 130.6 GW renewable energy capacity.

Electricity: development of installed electrical generation capacity (GW)

	2014	2015	2016	2017	2018	2019	2020
Nuclear power	12.1	10.8	10.8	10.8	9.5	9.5	8.1
Lignite	21.1	21.4	21.3	21.1	20.9	20.9	20.6
Hard coal	26.2	28.7	27.4	24.0	23.8	22.7	23.8
Natural gas	29.0	28.4	29.7	29.8	30.1	30.1	31.7
Mineral oil products	4.2	4.2	4.6	4.4	4.4	4.4	4.8
Pumped storage	9.2	9.4	9.5	9.5	9.8	9.8	9.8
Waste (non-renewable)	0.9	0.9	0.9	0.9	0.9	0.9	1.0
Other energy sources (non-renewable)	3.4	3.4	3.5	3.5	3.5	3.7	3.6
Total of non-renewable energy sources	106.1	107.1	107.6	104.0	103.1	102.0	103.3
Renewable energy sources	90.3	97.7	104.2	111.6	118.2	124.4	130.6
Total	196.4	204.9	211.8	215.6	221.3	226.4	233.8
Renewables' share of total electricity generation	**46%**	**48%**	**49%**	**52%**	**53%**	**55%**	**56%**

Table 10: Development of installed generation capacity since 2014

The increase in capacity in 2020 was of the same order of magnitude as in the previous year, due in particular to the ongoing expansion of renewable energies. Compared to 2011 (the year in which figures were first recorded for comparison purposes) renewable energy generation capacity has increased by 64.3 GW. Section I.B.2 "Development of renewable energies" contains a detailed analysis of the installed capacity of installations eligible for payments under the EEG and its development.

Trend: The closures of nuclear and coal-fired power plants that are required by law will further intensify the decline in conventional generation capacity compared with previous years.

1.4 Current power plant capacity in Germany

On 15 November 2021, total (net) installed generating capacity amounted to 232.6 GW. Of this amount, 98.7 GW was sourced from non-renewables (as at November 2021) and 133.9 GW from renewables (as at 30 June 2021). Subsequent power plant closures and commissioning reduced non-renewable capacities compared to 2020 by 4.6 GW. The main reason for this is the marketing and operation bans that came into effect on 8 July 2021 for the coal-fired power stations that were awarded a tender under the Act to Reduce and End Coal-Fired Power Generation (KVBG).[32] A detailed breakdown of the development of the installed capacity by each renewable energy source can be found in section I.B.2.

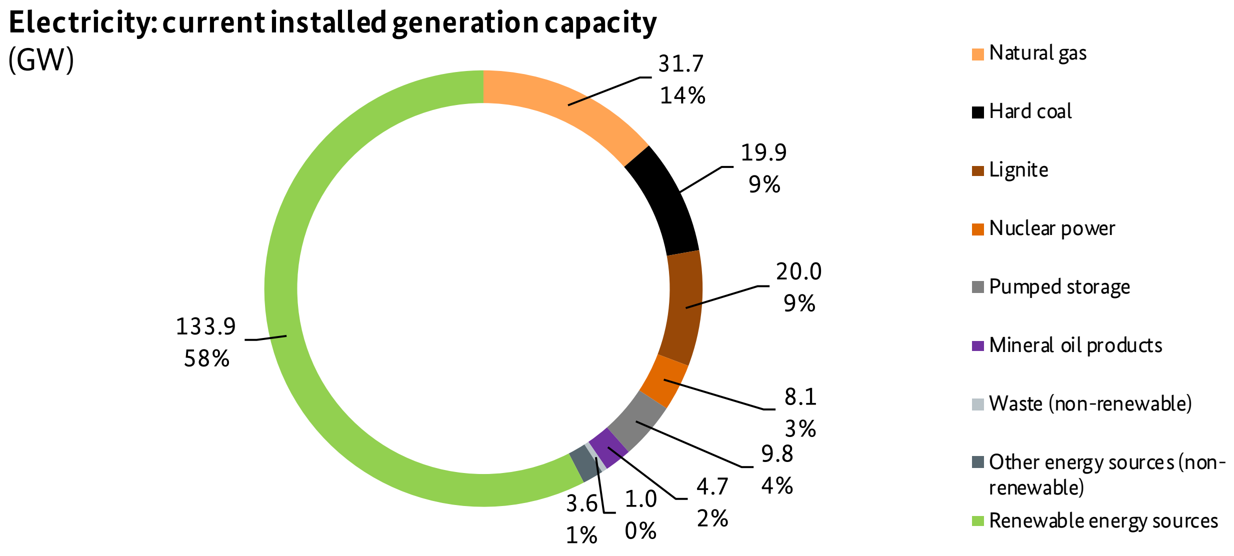

Figure 12: Current installed electrical generation capacity

[32] Plant operators have the option of converting plants for which they have been awarded a tender but which are subject to an operation and marketing ban to other energy sources or to close them permanently. They can also participate in a reserve capacity auction if the conditions for participation are met.

Electricity: closures of power plant capacity

Year		2015	2016	2017	2018	2019	2020	2021[1]	Total
Further closures during the year (MW)		3,563	4,025	6,920	2,826	3,912	800	11,643	31,972
of which final closure[2]	Capacity (MW)	1,377	1,687	2,764	1,767	1,753	78	372	9,798
	Average age in years at time	38	36	41	34	35	33	34	36
of which temporarily closed[2]	Capacity (MW)	661	301	78	0	0	0	0	730
	Average age in years at time	39	33	26	-	-	-	-	38
of which grid reserve under section 13b EnWG	Capacity (MW)	250	1,685	2,232	0	0	425	0	3,185
	Average age in years at time	50	29	38	-	-	38	-	34
of which grid reserve under section 26 KVBG	Capacity (MW)	0	0	0	0	0	0	1,565	1,565
	Average age in years at time	-	-	-	-	-	-	38	38
New capacity on security standby[3][4]	Capacity (MW)	0	352	562	1,059	757	0	0	2,730
	Average age in years at time	-	31	49	41	39	-	-	41
Closures under the Nuclear Phase-Out Amendment Act	Capacity (MW)	1,275	0	1,284	0	1,402	0	4,058	8,019
	Average age in years at time	33	-	33	-	34	-	36	33
Coal-fired electricity marketing bans and closures [5]	Capacity (MW)	0	0	0	0	0	297	5,648	5,945
	Average age in years at time	-	-	-	-	-	52	37	40

[1] Preliminary values, incl. statutory capacity up to 31 December 2021

[2] Includes all closed plants, under section 13b but excluding section 13b EnWG

[3] The power plants on security standby will be finally closed after four years and are currently outside of the electricity market. They are no longer shown as finally closed power plants.

[4] The installed capacity of power plants on security standby under section 13g EnWG is taken from the German government's draft electricity market legislation of 20 January 2016 (Bundtag Printed Paper: 18/7317) Rationale, Re Section 13g Page 102.

[5] Power plants with coal-fired electricity marketing bans and closures under section 52 (2) KVBG are prohibited from selling capacity or energy produced using coal on the electricity market.

Table 11: Power plant capacity that has exited the market since 2015

1.5 Current power plant capacity by federal state

Figure 13 shows the location of installed generation capacity in each federal state broken down by renewable and non-renewable energy sources, including power plants that are not currently operating in the electricity market. Figure 13 does not include generation capacity in Luxembourg, Denmark, Switzerland and Austria that feeds into the German grid (total of 4.4 GW). Only power plants using non-renewable energy sources with a capacity of 10 MW or more are shown. The Bundesnetzagentur records detailed data in the monitoring on smaller installations with a capacity of less than 10 MW that are not eligible for payments under the EEG in aggregated form and cannot therefore allocate this capacity (totalling 5.5 GW) to specific federal states.

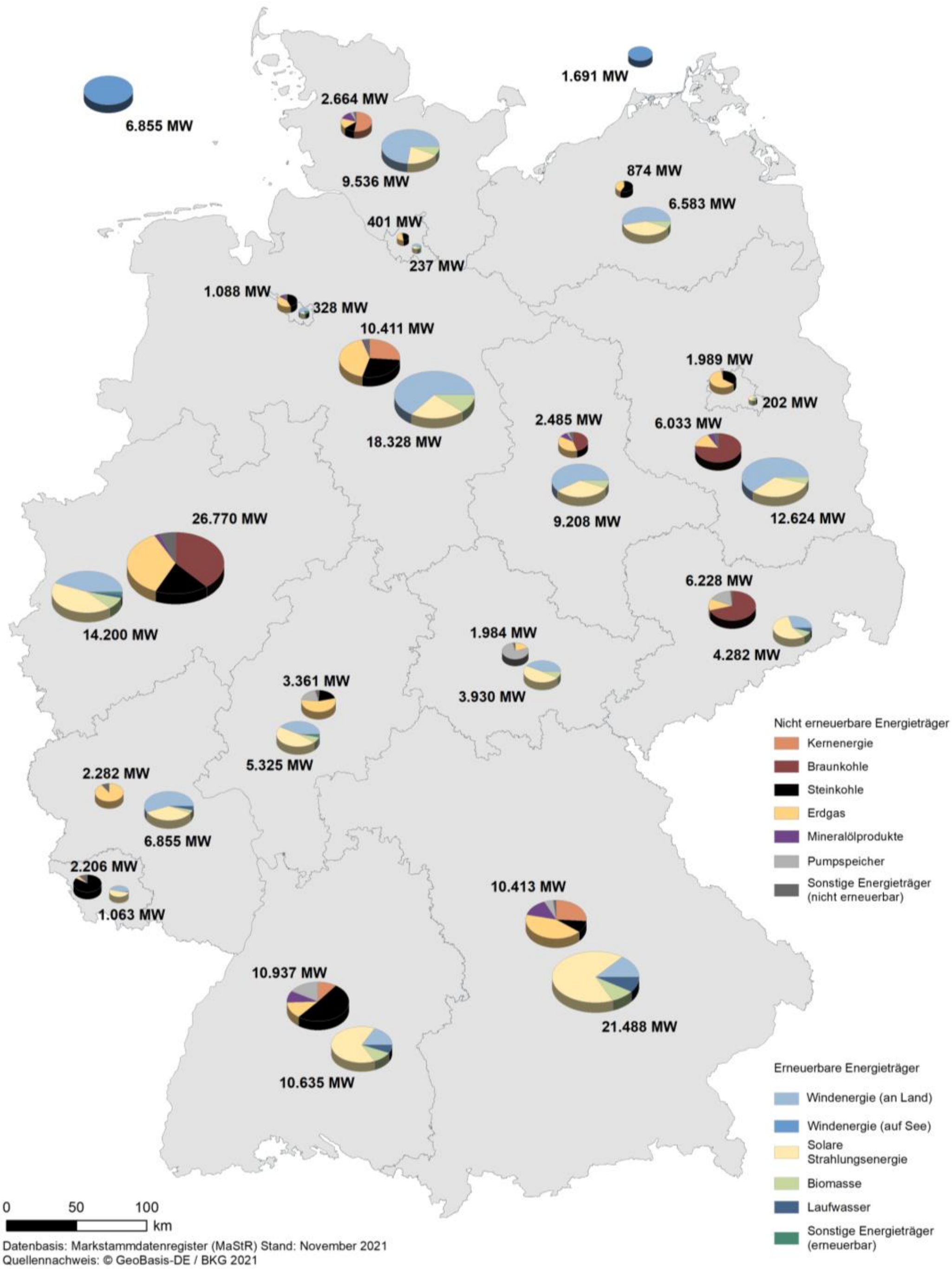

Figure 13: Generation capacity by energy source in each federal state

Electricity: generating capacity by energy source and federal state, including plants temporarily closed, grid reserve power plants 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	Other	Biomass	Run-of-river hydro	Offshore wind	Onshore wind	Solar	Others	Total
BW	0	5,517	1,259	1,310	1,966	813	72	1,093	615	0	1,709	7,172	45	**21,572**
BY	0	857	4,567	2,698	631	1,439	220	1,930	1,608	0	2,570	15,228	152	**31,901**
BE	0	653	1,267	0	0	51	18	44	0	0	12	128	18	**2,191**
BB	4,609	0	844	0	0	334	246	503	5	0	7,633	4,402	80	**18,657**
HB	0	469	459	0	0	86	74	14	10	0	198	52	56	**1,416**
HH	0	194	186	0	0	0	22	46	0	0	119	60	12	**638**
HE	34	687	1,835	0	645	25	136	321	63	0	2,284	2,547	111	**8,686**
MV	0	514	345	0	0	0	14	404	3	0	3,486	2,681	9	**7,457**
NI	19	3,021	4,114	2,696	0	140	421	1,888	65	0	11,493	4,844	38	**28,739**
NW	9,756	5,815	8,619	0	162	560	1,859	1,109	301	0	6,346	6,230	213	**40,970**
RP	0	0	2,019	0	0	26	237	201	230	0	3,768	2,604	51	**9,137**
SL	0	1,825	120	0	0	35	227	11	12	0	492	543	6	**3,269**
SN	4,403	0	614	0	1,085	27	98	314	212	0	1,256	2,489	11	**10,510**
ST	1,107	0	932	0	80	229	138	523	30	0	5,284	3,280	91	**11,693**
SH	0	342	354	1,410	119	334	104	617	5	0	6,928	1,953	34	**12,201**
TH	0	0	399	0	1,509	0	76	300	37	0	1,685	1,903	6	**5,915**
North Sea	0	0	0	0	0	0	0	0	0	6,083	0	0	0	**6,083**
Baltic Sea	0	0	0	0	0	0	0	0	0	1,691	0	0	0	**1,691**
Total	**19,927**	**19,895**	**27,934**	**8,114**	**6,197**	**4,099**	**3,962**	**9,319**	**3,195**	**7,774**	**55,262**	**56,117**	**932**	**222,726**

No detailed data is available for non-EEG installations with a capacity of less than 10 MW; the total capacity of these installations (5,496 MW) is therefore not included in the table.

The figures do not include generating capacity in Luxembourg, Denmark, Switzerland and Austria feeding into the German grid. (4,390 MW).

* This table includes the following plant statuses: operational, seasonal mothballing, temporarily shut down, grid reserve, reserve capacity, grid and reserve capacity, security standby.

Tabelle 12: generating capacity by energy source and federal state

1.6 Storage and pumped storage

The term electricity storage applies to facilities that consume electrical energy for the purpose of temporarily storing it electrically, chemically, mechanically or physically and release this again as electrical energy or in another form of energy (section 3 para 15d of the Energy Industry Act (EnWG)). The most common electricity storage technologies are battery-storage systems, compressed air energy storage or pumped storage. Electricity storage facilities play a dual function in the energy industry. Firstly, they are the final consumers of stored electricity. The electricity fed into an electricity storage facility is used up by converting it into a different form of energy. As a rule, storage facilities are considered final consumers of the electrical energy they receive from the grid (Decision of BGH EnVR 56/08 marginal note 9). At the same time, storage facility operators are also producers of the electricity that is returned to the grid from storage.

In accordance with this classification, storage facility operators are subject to regulations and obligations. This means that, in principle, network charges and levies are payable for the use of all electricity withdrawn from the grid, supplied or last consumed by electricity storage facilities. For various reasons, however, electricity storage facilities are subject to numerous special rules that drastically reduce the payment of charges and levies. These are highly diverse and range from the reimbursement of doubly-paid EEG surcharges through to reduction or total exemption. Exemptions from the EEG surcharge cover conversion losses, which may differ depending on the type of storage and state-of-the-art technology used.

In addition, existing pumped storage stations and other newly built electricity storage facilities are covered by exemption provisions under section 118 EnWG which, if certain statutory requirements are met, exempt these stations completely for a temporary period from network charges. In 2020, exemptions for storage facilities or pumped storage stations under section 118 EnWG amounted to €254.7m. In addition, pumped storage stations that are not completely exempt from network charges under section 118 EnWG may agree an individual network charge under section 19(4) and a discount for grid flexibility under section 19(2) sentence 1 of the Electricity Network Charges Ordinance (StromNEV).

Section 18 StromNEV also requires distribution system operators to distribute so-called "avoided network charges" to storage facility operators to the extent that the regulations concerning feed-in are met by the storage facilities at the moment of peak load. These payments – as with other electricity producers that benefit from the regulations (fossil installations, hydro power plants that no longer receive EEG payments) – are also made for the electricity that is generated and fed into the distribution network (capacity and power). The exemptions under section 118 EnWG and section 19 StromNEV do not reduce the payments of avoided network charges. It is possible for electricity storage facilities in the electricity distribution network to receive avoided network charges that exceed the cost of the network charges.

The Bundesnetzagentur has monitoring information on storage facilities with a capacity of at least 10 MW. This currently covers pumped storage stations and battery-storage systems.

Notification of battery-storage systems with a net nominal capacity of at least 10 MW was made for the Monitoring Report 2020. These systems have a total net nominal capacity of 580 MW.

All storage facilities must be registered in the Bundesneztagentur’s core energy market data register (MaStR) regardless of size. There are 267,000 storage facilities registered in the market data register (as at 1 September 2021).

In addition, pumped storage stations located in the Federal Republic of Germany and so-called border region power plants that are located outside Germany but which nonetheless feed electricity directly into the German public supply network were also notified. Pumped storage stations in the Federal Republic of Germany currently have a total capacity of 6,198 MW and generated 7.0 TWh of electricity in 2020. Other pumped storage stations in Luxembourg and Austria with a total capacity of 3,605 MW also fed an additional 3.3 TWh of electricity into Germany's public supply network in 2019.

A further pumped storage station with a planned net nominal capacity of 16 MW is currently under construction and is due to go into operation in 2023.

Pumped storage stations therefore generated a total of 10.3 TWh of electricity. A total of 11.8 TWh electricity was removed from the grid by pumping operations. The difference of 1.5 TWh is the amount of electricity produced when water is being pumped uphill and which exceeds later generation (energy consumed by power plants for their own use).

1.7 Power plants outside of the electricity market

The total generation capacity of 98.7 GW from non-renewables (as at November 2021) can be divided into power plants operating within the electricity market (88.3 GW) and power plants operating outside of the electricity market (10.4 GW). Within these two categories, the following subsets can be classified with regard to power plant status:

Power plants operating in the electricity market:

- 88.3 GW: plants in operation;

Plants operating outside of the electricity market:

- 6.8 GW: grid reserve power plant capacity (power stations systemically relevant and now only operated when requested by the TSOs)
    - of which under sections 13b(4) and 13b(5) EnWG: 5.9 GW
    - of which under section 26(2) KVBG: 0.9 GW Heyden power station (grid reserve ends on 30 September 2022 to be followed by conversion to rotating phase-shift system for reactive power purposes)

- 1.8 GW: Power plants in security standby status in accordance with 13g EnWG[33][34]
- 1.8 GW: Temporarily closed plants (not included in grid reserve under sections 13b(4) EnWG).

The grid reserve power stations referred to above are stations that were notified as scheduled for temporary or final closure but which may not be closed for supply security reasons (see also I.C.5.1.6 "Deployment of grid reserve capacity"). These plants currently comprise power stations using natural gas (1.6 GW), hard coal (3.6 GW) and mineral oil products (1.6 GW).

In accordance with section 13g EnWG, the lignite-fired power plants listed in the table below have been transferred to so-called security standby status[35]. 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 table does not include the Buschhaus or Frimmersdorf F and Q power stations, which at the time of publication of this report were permanently closed after four years on security standby.

Lignite-fired power plants in security standby status in accordance with section 13g EnWG

Name of power plant	Net nominal capacity in MW	Entry into security standby status	Final closure on
Niederaußem F	299	2018	1 October 2022
Niederaußem E	295	2018	1 October 2022
Jänschwalde F	465	2018	1 October 2022
Jänschwalde E	465	2019	1 October 2023
Neurath C	292	2019	1 October 2023

Table 13: Lignite-fired power plants in security standby status in accordance with section 13g EnWG

The plants temporarily closed are power stations using natural gas (1.5 GW) and mineral oil products (0.2 GW).

The following figure shows the location of power plants operating outside of the electricity market. The map shows power plants that have been notified as scheduled either for temporary ("grid reserve power stations" under section 13b EnWG) or final closure but which may not be closed for supply security reasons. The EnWG distinguishes between temporary and final closure: A power plant is defined as temporarily closed if the operator is able to put it back into operation again within 12 months of a request by transmission system operators. A power plant is defined as permanently shut down if it would take longer than 12 months to restore its operational readiness. The category of "power plants providing reserve capacity" under section 26(2)

[33] The costs for these power plants were between €400m and €450m in 2020. More detailed information is unobtainable as the operators of these facilities classify this information as operating and business secrets.

[34] The installed capacity of power plants on security standby under section 13g EnWG is taken from the German government's draft electricity market legislation of 20 January 2016 (Bundestag Printed Paper: 18/7317) Rationale re section 13g page 102.

[35] The installed capacity of power plants on security standby under section 13g EnWG is taken from the German government's draft electricity market legislation of 20 January 2016 (Bundestag Printed Paper: 18/7317) Rationale re section 13g page 102.

KVBG covers power plants that have been awarded a public contract but, for reasons of supply security, may not be immediately shut down.

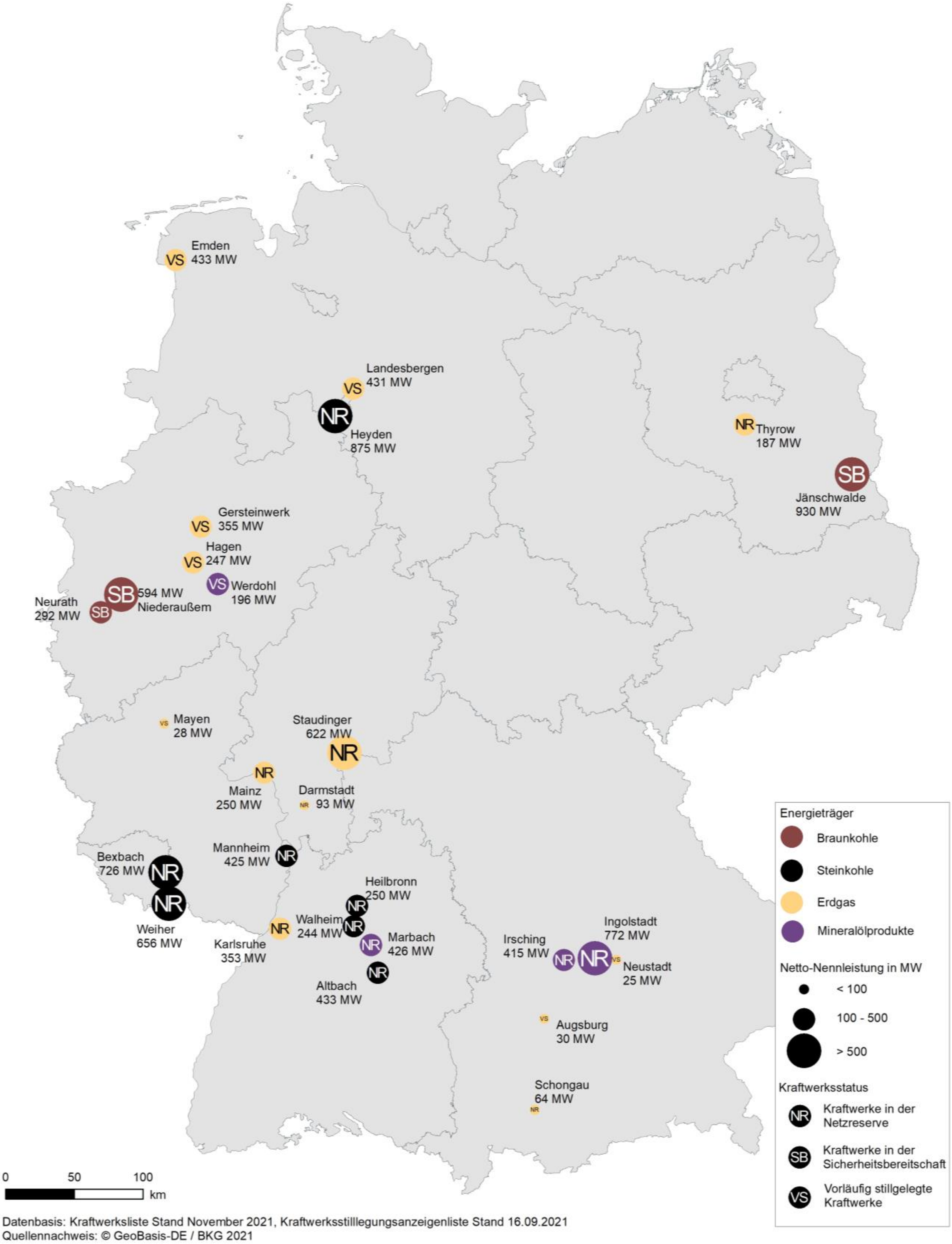

Figure 14: Power plants outside of the electricity market

1.8 Future development of non-renewable energy sources

1.8.1 Projected power plant construction

In addition to information on existing power plants, the Bundesnetzagentur also requests information on the future development of power plant capacity. The following section first examines the construction of new power plants. Section I.B.1.8.3 complements the assessment of the future development of the generation system by including power plant closures. The analysis of the future generation system focuses exclusively on non-renewable energy sources. The analysis of newly constructed power plant capacity is restricted to power generating facilities currently in trial operation or under construction with a minimum net nominal capacity of 10 MW up to the year 2024. In such cases, the probability of projects being implemented is considered sufficiently high.

Generation capacity totalling 3,633 MW is currently in trial operation or under construction and will likely be completed in the next three years (Figure 15). The power plants projects in Germany relate to natural gas (3,567 MW), other energy sources (50 MW) and pumped storage (16 MW).

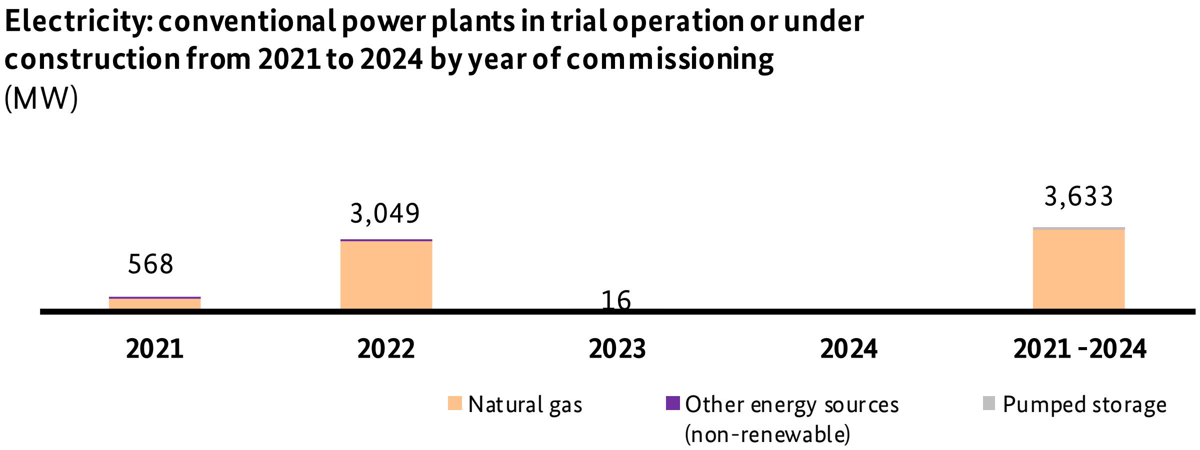

Figure 15: Power plants in trial operation or under construction

1.8.2 Auctions and reductions by law to end the production of electricity from coal

The Act to Reduce and End Coal-Fired Power Generation (KVBG) came into effect on 14 August 2020. While large lignite-fired power plants will be phased out under public contracts between operators and the federal government, hard coal-fired power plants and smaller lignite-fired power plants (with a net nominal capacity of up to 150 MW) will be subject to auctions and statutory reduction.

1) Legally stipulated capacity reduction path for lignite-fired power plants

The KVBG provides for the following capacity reduction path:

Capacity reduction path for large lignite-fired power plants (KVBG)

Name of block	Net nominal capacity in MW_{el}	Final closure date	Date of transfer to phased closure
Niederaußem D	297	31 December 2020	
Niederaußem C	295	31 December 2021	
Neurath B	294	31 December 2021	
Weisweiler E	321	31 December 2021	
Neurath A	294	1 April 2022	
Neurath D	607	31 December 2022	
Neurath E	604	31 December 2022	
Frechen/Wachtberg	120	31 December 2022	
Weisweiler F	321	1 January 2025	
Weisweiler G or H *	663 or 656	1 April 2028	
Jänschwalde A	465	31 December 2028	31 December 2025
Jänschwalde B	465	31 December 2028	31 December 2027
Jänschwalde C	465	31 December 2028	
Jänschwalde D	465	31 December 2028	
Weisweiler H or G *	656 or 663	1 April 2029	
Boxberg N and P	465 (each)	31 December 2029	
Niederaußem G or H *	628 or 648	31 December 2029	
Niederaußem H or G *	649 or 628	31 December 2033	31 December 2029
Schkopau A and B	450 (each)	31 December 2034	
Lippendorf R and S	875 (each)	31 December 2035	
Niederaußem K	944	31 December 2038	
Neurath F (BoA 2)	1,060	31 December 2038	
Neurath G (BoA 3)	1,060	31 December 2038	
Schwarze Pumpe A and B	750 (each)	31 December 2038	
Boxberg R and Q	640 or 857	31 December 2038	

* Option

Table 14: Capacity reduction path for large lignite-fired power plants (KVBG)

2) Tendering procedure for hard coal-fired power plants and small lignite-fired power plants

The Bundesnetzagentur organises auctions to achieve voluntary reductions in the generation of electricity from hard coal-fired power stations and smaller lignite-fired power plants. Plant operators can tender bids for the coal-fired capacity volumes that they are willing to take offline. The legal consequence when a bid is awarded a tender is a ban on coal-fired generation. This means that power plants do not necessarily have to be closed, but can switch away from coal to other energy sources instead.

Bids in the first of these auctions to take 4,000 MW offline could be submitted by 1 September 2020. The Bundesnetzagentur made awards in the first tendering procedure on 1 December 2020 and published the results on its website.

The auction volume was significantly oversubscribed. Eleven bids with a total volume of 4,787,676 MW were awarded a tender. The first bid to result in oversubscription is granted a tender.

Overview of bids awarded a tender on the tendering date 1 September 2020

Name of bidder	Name of installation	Awarded bid volume (MW)
STEAG GmbH	Kraftwerk Walsum 9	370.000
Pfeifer & Langen GmbH & Co. KG	HKW Werk Jülich	22.860
swb Erzeugung AG & Co. KG	Kraftwerk Hafen Block 6	303.000
Infraserv GmbH & Co. Höchst KG	Kohleblock HKW	50.945
RWE Generation SE	Kraftwerk Westfalen	763.700
RWE Generation SE	Kraftwerk Ibbenbüren	794.000
Vattenfall Heizkraftwerk Moorburg GmbH	Heizkraftwerk Moorburg Block B	800.000
Vattenfall Heizkraftwerk Moorburg GmbH	Heizkraftwerk Moorburg Block A	800.000
Uniper Kraftwerke GmbH	Kraftwerk Heyden	875.000
Südzucker AG	Kraftwerk der Zuckerfabrik Brottewitz	3.571
Südzucker AG	Kraftwerk der Zuckerfabrik Brottewitz	4.600

Table 15: Overview of bids awarded a tender on the tendering date 1 September 2020

The prices of the bids awarded a tender ranged from €6,047 per MW to €150,000 per MW. The maximum price set on the first tendering date was €165,000 per MW. Every successful bidder was paid the individual price that they had bid. The plants that were awarded a tender were no longer allowed to offer their capacity or energy produced using coal on the electricity market from 1 January 2021 onwards. The ban on coal-fired power generation came into effect on 8 July 2021 after a six-month operational readiness phase.

The second tendering date for a volume of 1,500 MW was 4 January 2021. The awards in this procedure were published on 1 April 2021.

Overview of bids awarded a tender on the tendering date 4 January 2021

Name of bidder	Name of installation	Awarded bid volume (MW)
Uniper Kraftwerke GmbH	Kraftwerk Wilhelmshaven	757.000
Kraftwerk Mehrum GmbH	Kraftwerk Mehrum (KWM), Block 3	690.000
Mitteldeutsche Braunkohlengesellschaft mbH	Kraftwerk Deuben	67.000

Table 16: Overview of bids awarded a tender on the tendering date 4 January 2021

Eleven bids for a total capacity of 1,514 MW were awarded a tender. As the tender was oversubscribed, the bid that resulted in an auction volume of 1,500 MW being exceeded was awarded a tender. The prices of the bids awarded ranged from €0 per MW to €59,000 per MW. The maximum possible price was €155,000.

The auction volume in the first two auctions was stipulated by law (round 1: 4,000 MW, round 2: 1,500 MW). In contrast to the first two auctions, the auction volume for the tendering dates from the third round onwards will be determined by the Bundesnetzagentur. The auction volume that will be determined in megawatts of net nominal capacity is the difference between the base level (section 7 KVBG) for the relevant target date and the target level for hard coal-fired power stations on the electricity market under section 4 KVBG for the relevant target date. On this basis, the auction volume for the third auction round was 2,480.826 MW. In the third auction round, eleven bids with a total volume of 2,132.682 MW were awarded a tender. As this auction round was undersubscribed, every admissible bid was awarded a tender. The price of the bids awarded a tender ranged from €0 per MW to €155,000 per MW; this corresponds to the maximum price.

Overview of bids awarded a tender on the tendering date 30 April 2021

Name of bidder	Name of installation	Awarded bid volume (MW)
STEAG GmbH	Kraftwerk Bergkamen A	717.000
STEAG GmbH	Modellkraftwerk Völklingen	179.000
STEAG GmbH	Heizkraftwerk Völklingen	211.000
Venator Germany GmbH	Heizkraftwerk Venator Germany – Block 1	19.377
Henkel AG & Co. KGaA	Anlage 80 – Kohleblock	36.000
Sappi Stockstadt GmbH	Gesamt–Sammelschienenkraftwerk – Konventionelles HKW	27.405
Fernwärme Ulm GmbH	Heizkraftwerk Magirusstraße – Kohleblock	8.400
Onyx Kraftwerk Farge GmbH & Co. KGaA	Onyx Steinkohlekraftwerk Farge	350.000
Smurfit Kappa Zülpich Papier GmbH	K06	14.383
Evonik Operations GmbH	Kraftwerk I	225.117
Uniper Kraftwerke GmbH	Kraftwerk Scholven Block C	345.000

Table 17: Overview of bids awarded a tender on the tendering date 30 April 2021

On 23 July 2021 the fourth auction was announced for 1 October 2021. The volume in this auction will be 433.016 MW and the maximum possible price €116,000 per MW.

3) Reductions by law in the production of electricity from coal

The KVBG provides for a total of seven auction rounds. If the auction volume is undersubscribed after the target year 2024, ie as of the fifth auction round, the auction volume that is not awarded will be subject to the statutory reduction. For this purpose, the Bundesnetzagentur will announce on the day notice is given of the award in the relevant auction round, to which hard coal-fired power stations that are not small plants the statutory reduction of coal-fired power generation will apply. Plant operators affected by the statutory reduction will then no longer be eligible for financial compensation in the form of a hard coal award. After the final auction round, which is set for 2026, coal-fired power generation will be decommissioned by law only (target date 2027). As with tendering procedures, the legal impact of an imposed reduction will be a ban on coal-fired generation and marketing by the relevant power plant. The relevant power plant does not necessarily have to be closed, but can switch away from coal to other energy sources instead.

4) Network and supply security

The Bundesnetzagentur will continue to assess the impact of the reduction of coal-fired power generation on the security and reliability of the electricity supply system throughout the coal exit process. These assessments will be performed as part of the accompanying network analysis under section 34(2) KVBG and ongoing monitoring of security of electricity supply under section 51(3) EnWG.

The TSOs will continue to carry out system relevance tests on all power plants that are scheduled for closure. If necessary, power plants can be transferred to the grid reserve.

1.8.3 Expected power plant closures

The legally stipulated capacity reduction path for lignite-fired power plants outlined in section I.B.1.8.2 and the tendering procedures for the voluntary termination of coal-fired power generation under the KVBG will result in substantial coal-fired power plant capacity being shut down in the years ahead. As well as the closure of coal-fired power plants in connection with the coal exit, more power stations will be closed by 2024. These will be

- the nuclear power plants that must be closed by law,
- lignite-fired power stations that at the end of the four-year security standby status will not be allowed to return to the market (see I.B.0) and
- market-driven closures by plant operators.

These latter include power plants that have been notified to the Bundesnetzagentur and scheduled for final or temporary plant closure. Unlike temporarily closed grid reserve power plants, once a grid reserve power plant has been permanently closed it cannot return to the electricity market after it has left the grid reserve. For this reason the following table only includes power plants notified as scheduled for final closure. Not included are coal-fired power plants whose scheduled final closure has been notified to the Bundesnetzagentur as these power plants can take part in tendering procedures for the voluntary termination of coal-fired power generation.

The following table provides an overview of the power plant capacity that is expected to be withdrawn from the market by 2024.

Power plant capacity expected to be withdrawn from the market 2021 - 2024

	2021	2022	2023	2024	Total
Coal phase-out under KVBG	**2,424**	**3,758**			**6,182**
of which legally stipulated capacity reduction path for lignite-fired power plants	910	1,625			2,535
of which auctions for black coal-fired power stations and black coal-fired power plants	1,514	2,133			3,647
2. auction round[1]	1,514				1,514
3. auction round		2,133			2,133
4. auction round		Not yet determined			
Closures after termination of the security standby status of lignite-fired power stations[2]		**1,059**	**757**		**1,816**
Power stations under section 7(1) AtG	**4,058**	**4,049**			**8,107**
Notification for final closure under section 13b(1) EnWG	**15**				**15**
Natural gas	15				15
Total	**6,497**	**8,866**	**757**		**16,120**

[1]The first auction round under KVBG has not been included as a coal-fired electricity marketing ban had already taken effect on 8 July 2021 for awarded power plant capacity under sections 51 and 52 KVBG. This is 4,787.7 MW, of which part has already been finally closed.

[2]Frimmersdorf F and Q, with a total of 562 MW, are not included as these were finally closed in October 2021.

Table 18: Power plant capacity expected to be withdrawn from the market as at 31 December of each year

In Germany as a whole, 16,120 MW of capacity is planned for withdrawal from the market by 2024[36]. This exceeds the planned expansion of 3,633 MW by 12,487 MW.

It should be noted that the above figures are subject to a degree of uncertainty. The auction volumes for the fourth auction rounds under the KVBG are not yet known and it is therefore not possible to provide a precise figure in the above table for the exact number of coal-fired power plants that will be closed between now and 2024. However, the end of coal-fired electricity generation at a particular plant does not necessarily mean that

[36] The installed capacity of power plants on security standby set out in section 13g EnWG is taken from the German government's draft electricity market legislation of 20 January 2016 (Bundestag Printed Paper: 18/7317) Rationale re section 13g page 102.

all the plant's capacity will be removed from the market since it is possible for plant operators to convert their plants to other energy sources (see I.B.1.8.2).

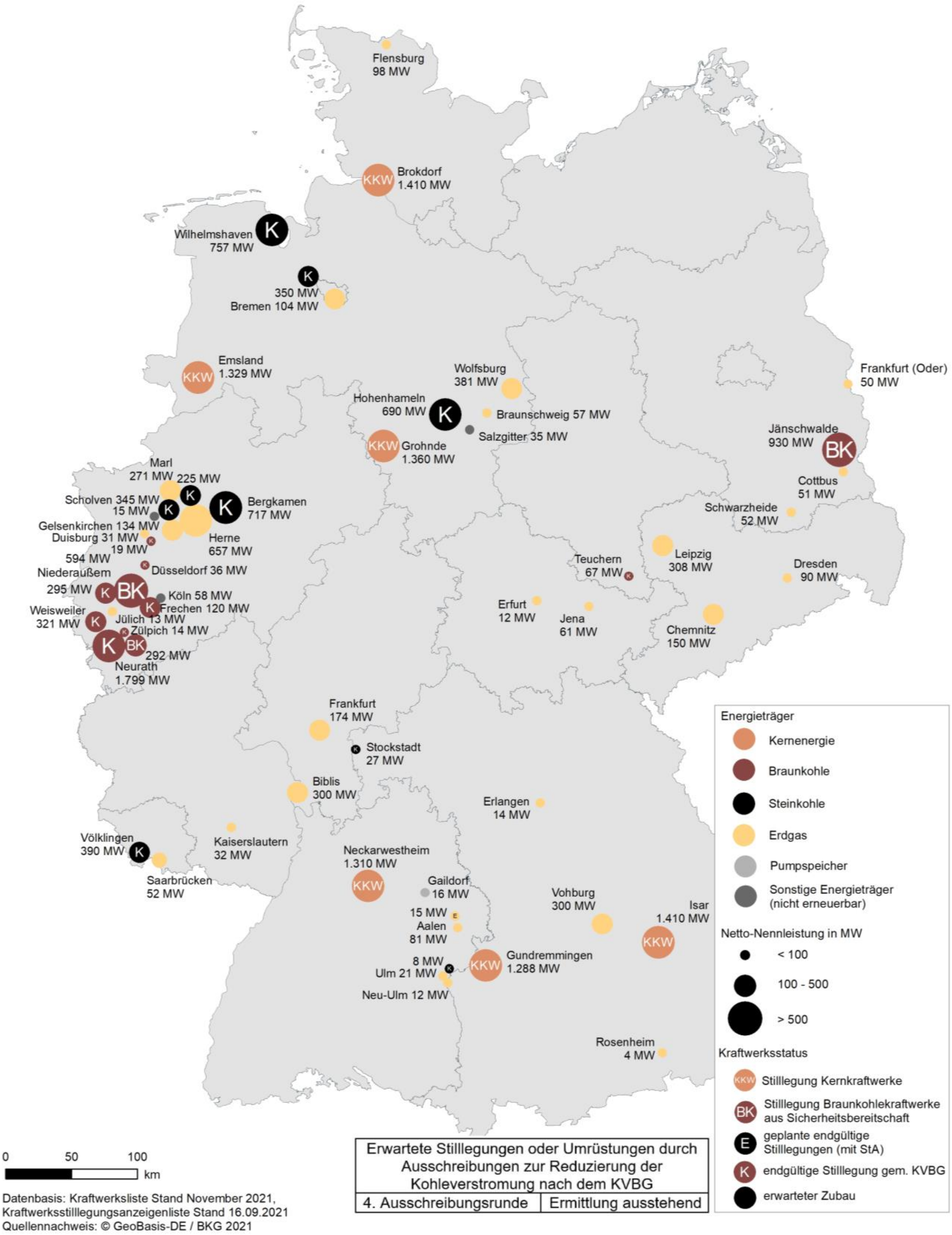

Figure 16: Locations with an expected increase in or withdrawal of generation capacity by 2024

In addition to the above-mentioned formal notifications of planned final closures, the Bundesnetzagentur was also informed of further planned closures of power generating units through its monitoring activities. These planned closures that were communicated during the monitoring process are not included in the table above. The final closure of a total additional capacity of 213 MW can thus be expected by 2024. This concerns specifically natural gas power plants with a capacity of 86 MW, mineral oil-fired power plants with a capacity of 93 MW and other energy sources with a capacity of 34 MW.

The capacity of power plants scheduled for closure by the year 2024 therefore totals 16,333 MW.

Consequently, the overall national anticipated balance of the increase and decrease of power generation capacity by 2020 is -12,700 MW.

1.9 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.

CHP plants with an electrical capacity of more than 1 MW and up to and including 50 MW may participate in auctions provided they meet the requirements stated in section 5(1) para 2 Combined Heat and Power Act (KWKG). CHP payments are only paid on electricity fed into the general supply grid to plant operators who have taken part successfully in a CHP auction. The same applies to innovative CHP systems under section 5(2) KWKG. The first auction for CHP plants was held on 1 December 2017 and for innovative CHP plants on 1 June 2018. Two auctions will be held every year for both types up to the year 2021.

For the first time, the capacity assessments are based on data taken from the core energy market data register (see also 1.3). Since 1 July 2017, all CHP plants must be registered in the Bundesnetzagentur's core energy market data register regardless of size.

1.9.1 CHP plant capacity with a minimum capacity of 10 MW net nominal capacity (electrical)

The evaluations presented in this chapter include CHP-capable German power generation units with a net nominal electrical capacity of at least 10 MW per location (see also I.B.1.3). The Bundesnetzagentur continues to collect data from plant operators on power generation units that do not have to be entered in the core energy market data register (eg net electricity generation, CO2 emissions for power generation).

The installed capacity of these CHP installations is shown in MW in Figure 17. The installed electrical and useful heat capacity of CHP installations are shown separately.

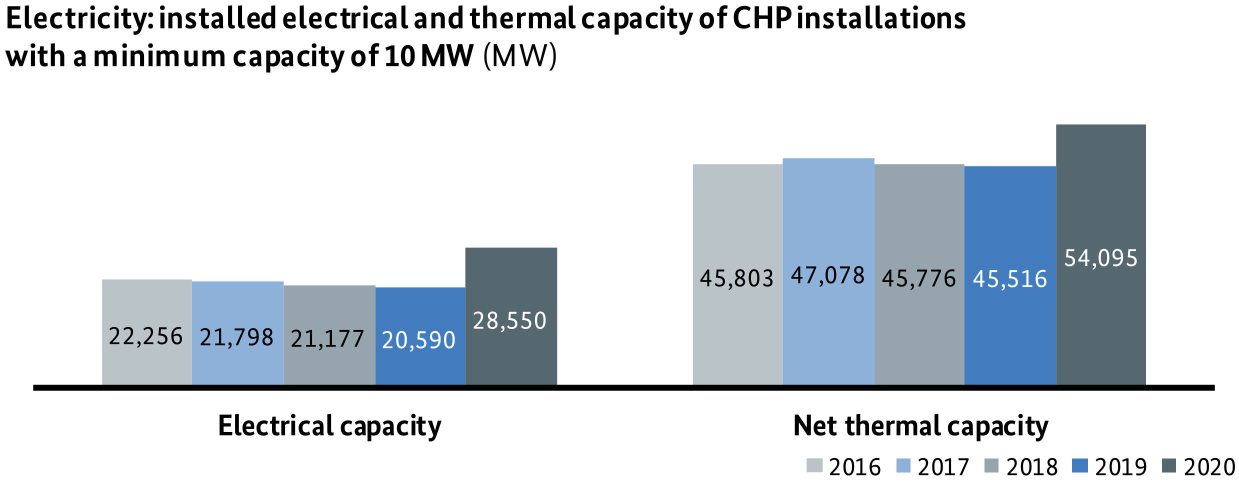

Figure 17: Installed electrical and net thermal capacity of CHP installations with a minimum capacity of 10 MW

The installed (electrical and useful heat) capacity is sourced as set out in Table 19. The table clearly shows that natural gas and hard coal in particular are used in CHP power plants. Numerous smaller CHP power plants in Germany, particularly in the field of natural gas, have an installed net electrical capacity of less than 10 MW per location. These are not captured by the monitoring survey performed by the Bundesnetzagentur and are therefore not included in the capacities shown in the following table.

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

	Electrical capacity		Net thermal capacity	
	2019	2020	2019	2020
Waste	748	1,214	3,605	3,668
Biomass	466	871	1,862	3,737
Lignite	1,107	1,783	4,974	5,461
Natural gas	11,161	13,829	19,701	23,709
Other	1,290	1,628	4,334	4,464
Hard coal	5,818	9,225	11,040	13,057
Total	20,590	28,550	45,516	54,095

Table 19: Installed electrical and useful heat capacity of CHP power plants by energy source with a minimum capacity of 10 MW (MW)

Figure 18 shows the electrical and thermal energy generated since 2016.

Electricity: amount of electricity and useful heat produced by CHP plants (TWh)

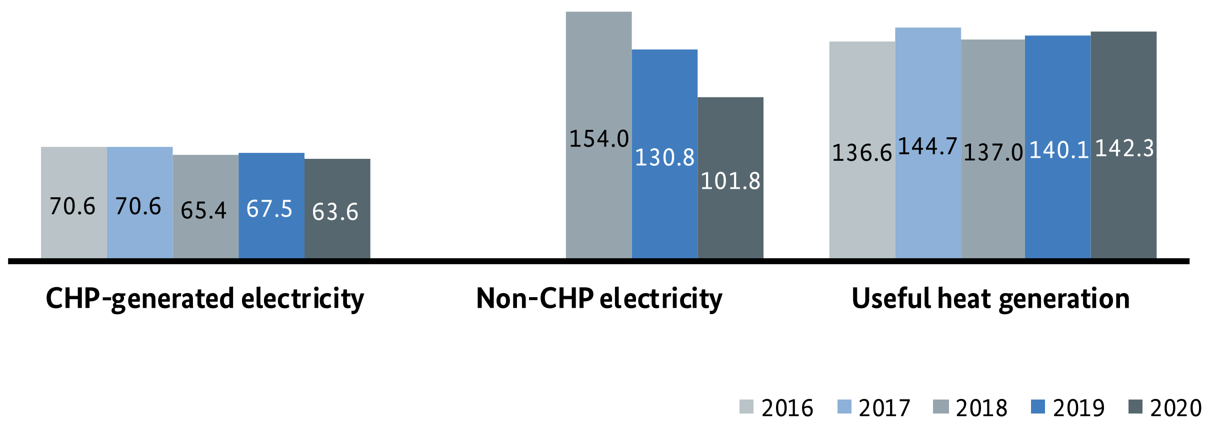

Figure 18: Amount of electricity and useful heat produced by CHP plants with a minimum capacity of 10 MW

The CHP-capable power generation units on which this evaluation is based produced 142.3 TWh useful heat and 63.6 TWh of electricity in 2020. The amount of electricity produced by CHP plants decreased by around 4 TWh compared to 2019 (-6%). The amount of useful heat generated in 2020 rose by around 2 TWh (+2%) between 2019 and 2020. In 2020, 29 TWh less of non-CHP electricity was generated, or the equivalent of 22% less than in the previous year. Non-CHP electricity is one element of the net electricity generated by CHP plants. It is generated using the steam produced in the power plant without heat recovery. The fall in generation of non-CHP electricity primarily results from the energy sources hard coal (-41%), lignite (-22%) and natural gas (-12%). This means that overall non-CHP electricity generation was in line with the drop in electricity generation from non-renewable sources.

Electricity: amount of electricity and useful heat produced by CHP plants by energy source with a minimum capacity of 10 MW (TWh)

	CHP-generated electricity		Non-CHP electricity		Useful heat generation	
	2019	2020	2019	2020	2019	2020
Waste	2.9	2.8	2.3	2.2	12.0	11.9
Biomass	2.2	2.5	1.3	1.9	9.3	9.1
Lignite	3.2	2.4	72.3	56.4	13.7	12.7
Natural gas	45.2	43.7	16.1	14.1	60.0	60.7
Other	3.9	3.6	4.4	6.9	17.5	30.2
Hard coal	10.2	8.6	34.4	20.4	27.6	17.7
Total	67.6	63.6	130.8	101.9	140.1	142.3

Table 20: Amount of electricity and useful heat produced by CHP plants with a minimum capacity of 10 MW by energy source

The most important energy sources for the generation of CHP electricity and useful heat are natural gas and hard coal (see Table 20). Natural gas is a particularly important energy source for electricity generated by CHP plants through heat extraction and accounted for 69% of total generation in 2020. Whereas for useful heat, 43% of useful heat is generated from natural gas and 12% from hard coal.

1.9.2 CHP plants newly registered in the core energy market data register in 2020

Since 1 July 2017, under the Core Energy Market Data Register Ordinance (MaStRV) CHP plants must be registered with the Bundesnetzagentur. Approval information and technical core energy data for the plant – such as main fuel and capacity – must be provided as well as plant operator and plant location data. The date on which the installation was put into operation, the operator to whose grid the plant is connected, the voltage level and information about the ability to control the installation remotely must also be provided.

In the calendar year 2020, 6,180 CHP power generation units with a total net nominal capacity of 2,389 MW were registered. The significantly higher figures compared to the previous year (2019: 5,212 units, 3,588 MW) are mainly due to the fact that net nominal capacity of 1,052 MW from the Datteln 4 anthracite-fired power station went online for the first time. There was also a general increase, however, in net nominal capacity in all capacity classes of at least 11% compared with the previous year. In addition to plant classes above 10 MW, the net nominal capacity of the plant class between 50 and 250 kW also increased particularly strongly compared to the previous year (increase of 30%).

Most commissioned units in CHP plants run on natural gas (5,212) followed by plants which run on biomass (759). These sources of energy are used by over 95% of the units in CHP plants and account for just under 50% of net nominal capacity. Year on year the net nominal capacity of natural gas rose by 60% and of biomass by 27%. Due to the commissioning of Datteln 4, hard coal now accounts for 44% of net nominal capacity.

Electricity: CHP plants newly registered in 2020

Month	Net nominal capacity in MW	Number
January	49	480
February	27	423
March	39	483
April	106	385
May	1,352	459
June	89	486
July	51	516
August	88	401
September	96	515
October	115	588
November	94	704
December	283	740
Total	**2,389**	**6,180**

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

Table 21: Commissioning of power generation units in CHP plants

Electricity: commissioning by energy source in 2020

Capacity class	Net nominal capacity in MW	Number
Other gases	22	145
Biomass	417	759
Natural gas	769	5,212
Sewage sludge	0	2
Mineral oil products	1	50
Non-biogenic waste	5	2
Hard coal	1,052	1
Heat	123	9
Total	**2,389**	**6,180**

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

Table 22: Commissioning by energy sources

Electricity: commissioning by capacity class in 2020

Capacity class	Net nominal capacity in MW	Number
≤ 50 kW	50	5,110
50 kW - 250 kW	64	414
250 kW - 1 MW	277	511
1 MW - 10 MW	323	133
> 10 MW	1,675	12
Total	**2,389**	**6,180**

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

Table 23: Commissioning by capacity classes

Electricity: commissioning by federal state in 2020

Federal state	Net nominal capacity	Number
Baden-Württemberg	145	1,200
Bavaria	103	1,005
Berlin	264	102
Brandenburg	25	168
Bremen	1	30
Hamburg	4	86
Hesse	24	453
Mecklenburg-Vorpommern	23	90
Lower Saxony	133	759
North Rhine-Westphalia	1,174	1,149
Rhineland-Palatinate	112	304
Saarland	3	56
Saxony	28	241
Saxony-Anhalt	280	138
Schleswig-Holstein	56	258
Thuringia	15	141
Total	**2,389**	**6,180**

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

Table 24: Commissioning by federal state

Most (5,110) of the commissioned units in CHP plants produced up to 50 kW. This accounts for over 82% of all newly registered plants. The largest net nominal capacity is attributable to the 1 to 10 MW plant classes, which at 1,675 MW account for around 70% of new capacity.

Most plants were commissioned in Baden-Württemberg (1,200), North Rhine-Westphalia (1,149) and Bavaria (1,005). In terms of net nominal capacity, the highest share (1,174 MW) was installed in North Rhine-Westphalia.

1.9.3 CHP auctions

In order to receive funding for CHP electricity, combined heat and power plants with a capacity of more than 1 MW and up to and including 50 MW must have participated successfully in an auction The capacity range for innovative CHP systems is between 1 MW and up to an including 10 MW.

Bids are accepted on the basis of the rate specified in the respective bid ("pay as bid"). The highest amount for bids is 7.0 ct/kWh for CHP plants and 12 ct/kWh for innovative CHP systems (iCHP systems). The following tables show the outcomes of previous auctions:

Electricity: auction results for CHP systems

Tendering date	1 Dec 2017	1 Jun 2018	3 Dec 2018	3 Jun 2019	2 Dec 2019	2 Jun 2020	1 Dec 2020	1 Jun 2021
Auction volume in MW	100	93	77	51	80	75	75	59
Number of bids	20	15	18	13	13	22	17	16
Bid volume in MW	225	96	126	87	58	71	60	112
Number of awards	7	14	12	4	12	21	15	13
Volume awarded in MW	82	91	100	46	53	69	56	58
Excluded bids	0	1	3	0	3	1	2	1
Volume of excluded bids in MW		4	8		8	2	4	1
Average award price* (ct/kWh)	4.05	4.31	4.77	3.95	5.12	6.22	6.75	5.64

*volume weighted

Table 25: CHP auctions

Electricity: auction results for CHP systems

Tendering date	1 Dec 2017	1 Jun 2018	3 Dec 2018	3 Jun 2019	2 Dec 2019	2 Jun 2020	1 Dec 2020	1 Jun 2021
Auction volume in MW		25	29	30	25	29	28	26
Number of bids		7	3	5	10	13	12	9
Bid volume in MW		23	13	22	43	44	31	29
Number of awards		5	3	5	5	8	10	7
Volume awarded in MW		21	13	22	20	26	27	25
Excluded bids		2	0	0	1	1	2	1
Volume of excluded bids in MW		2			9	2	4	2
Average award price* (ct/kWh)		10.27	11.31	11.17	10.25	10.22	10.8	11.57

*volume weighted

Table 26: Innovative CHP auctions

2. Development of renewable energies

An essential cornerstone of the energy transition is the continuous expansion of renewable energies. For this purpose, ambitious annual development corridors for the renewable technologies of onshore wind, offshore wind, solar and biomass technologies have been legally anchored in the EEG.

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 tariffs, that is, receive payments under the EEG for the electricity produced without having to sell the electricity themselves. All other operators with installations having a capacity of 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 largest share (81%) of renewable electricity generated in Germany in 2020 was sold directly either by the operator or by a service provider.

2.1 Development of renewable energies (eligible for payments under the EEG)

Not all renewable energy generating facilities are eligible for payments under the EEG. A distinction is therefore made between renewable energy generating facilities with and without eligibility for payments. The majority of installed renewable energy capacity falls under the EEG payment regime (market premium or feed-in tariff). Of the 130.6 GW of capacity installed at the end of 2020, 126.7 GW was eligible for EEG payments. This section therefore examines renewable energies eligible for payments in more detail.

The 3.8 GW of renewable energy capacity not eligible for payments is primarily accounted for by the energy sources hydropower (2.6 GW) and waste (1.0 GW). For the energy source waste, only half of the biogenic share of the waste is considered a non-eligible renewable energy source. The remaining 1.0 GW of generation capacity for the energy source waste is assigned to the non-renewable energy sources. A total of 14.7 TWh of electricity was generated from non-eligible renewable sources in 2020. The majority of that energy was generated in hydropower plants (run-of-river and dammed water) in an amount of 10.8 TWh and in waste-fired power plants totalling 3.9 TWh.

In the publication "EEG in Numbers 2020"[37], 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.

2.1.1 Installed capacity

As at 31 December 2020, the total installed capacity of installations eligible for payments in accordance with the EEG was approximately 126.7 GW. Around 6.6 GW of the total additional plant capacity entitled to payments was installed in 2020, representing an increase of around 5.5%.

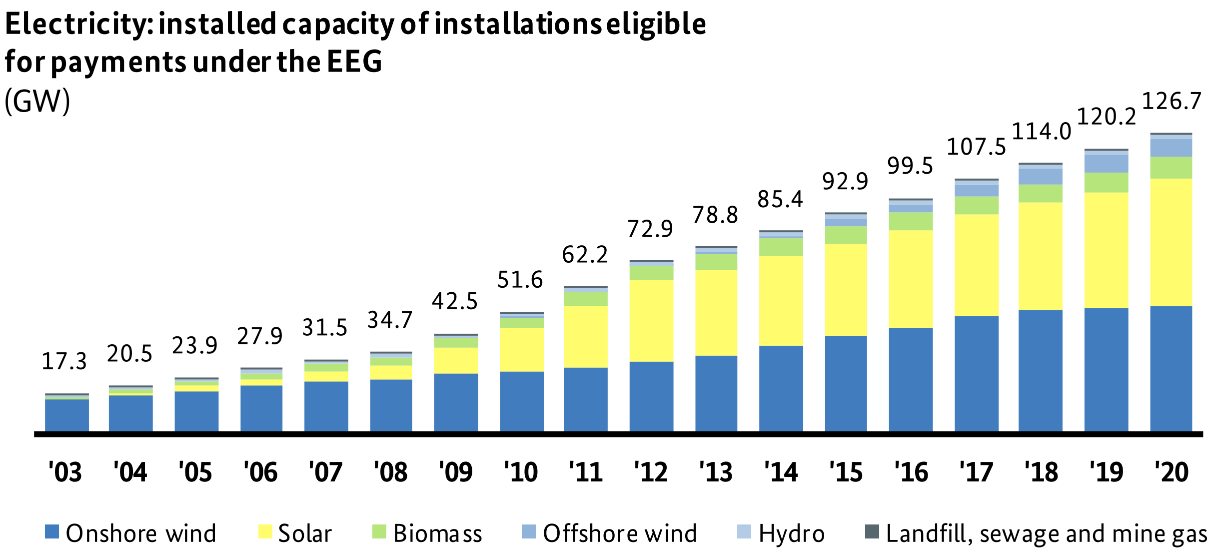

Figure 19: Installed capacity of installations eligible for payments under the EEG up to 2020

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

Solar capacity rose sharply again in 2020. Some 4.8 GW of new capacity was installed in 2020, compared to an average of 2.2 GW annually over the previous five years. Offshore and onshore wind energy also continued to grow. In contrast to previous years, there was again a small increase of 1.2 GW in net new capacity from onshore wind power plants in 2020 (2019: 0.9 GW, 2018: 2.2 GW, 2017: 4.9 GW). Installed new capacity was, however, well below the long-term average. The expansion of offshore wind energy power plants with a capacity of 0.2 GW is dependent on the completion of the grid connection lines by the transmission system operators (2019: approximately 1.1 GW). The 0.4 GW expansion in biomass installations was also again slightly higher than in the previous year (2019: 0.3 GW).

Electricity: installed capacity of installations eligible for payments under the EEG by energy source

	Total 31 December 2019	Total 31 December 2020	Increase / decrease in 2020	Increase / decrease compared to 2019
	in MW	in MW	in MW	in %
Hydro	1,613.2	1,624.5	11.3	0.7%
Gases[1]	413.9	376.5	-37.4	-9.0%
Biomass	8,336.8	8,748.4	411.6	4.9%
Geothermal	47.1	47.1	0.0	0.0%
Onshore wind	53,187.1	54,413.8	1,226.7	2.3%
Offshore wind	7,555.3	7,774.2	218.9	2.9%
Solar	48,913.6	53,720.7	4,807.1	9.8%
Total	120,067.0	126,705.2	6,638.2	5.5%

[1] Landfill, sewage and mine gas

Table 27: Installed capacity of installations eligible for payments under the EEG by energy source (as at 31 December)

Some 184,794 new facilities were installed in 2020. Solar installations accounted for 97.4% of new installations, onshore wind installations for 1.3% and biomass installations for 0.7%; the remainder is shared among other technologies. For 2020, the figures as of June 2021 indicate a steady trend.

Electricity: changes in the installed capacity of installations eligible for payments under the EEG

	2014	2015	2016	2017	2018	2019	2020	Jun 21
Hydro	6,947	7,078	7,041	7,138	7,172	7,192	7,243	7,250
Gases[1]	627	630	612	600	593	567	566	565
Biomass	14,024	14,113	14,186	14,271	14,496	14,535	14,699	14,767
Geothermal	8	9	10	9	10	11	11	12
Onshore wind	23,593	24,696	26,057	27,406	28,131	28,310	28,579	28,730
Offshore wind	241	789	945	1,167	1,307	1,467	1,499	1,499
Solar	1,521,365	1,572,922	1,622,405	1,686,993	1,760,396	1,863,684	2,047,963	2,145,564
Total	1,566,805	1,620,237	1,671,256	1,737,584	1,812,105	1,915,766	2,100,560	2,198,387

[1] Landfill, sewage and mine gas

Table 28: Changes in the installed capacity of installations eligible for payments under the EEG

Electricity: growth rates of installations by energy source

	Total 31 December 2019	Total 31 December 2020	Increase / decrease in 2020	Increase / Decrease compared to 2019
	Number	Number	Number	in %
Hydro	7,192	7,243	51	0.7%
Gases[1]	567	566	-1	-0.2%
Biomass	14,535	14,699	164	1.1%
Geothermal	11	11	0	0.0%
Onshore wind	28,310	28,579	269	1.0%
Offshore wind	1467	1499	32	2.2%
Solar	1,863,684	2,047,963	184,279	9.9%
Total	1,915,766	2,100,560	184,794	9.6%

[1] Landfill, sewage and mine gas

Table 29: Growth rates of EEG installations eligible for payments by energy source (as at 31 December)

2.1.2 Development corridors

The EEG 2014 introduced capacity-based development corridors for onshore wind, offshore wind, solar and biomass to meet the goals of an increasingly renewable, cost-efficient and grid-compatible energy supply by the years 2025, 2035 and 2050. These development corridors were adjusted in the EEG 2017 and EEG 2021. These goals are summarised in the following table.

Electricity: development corridors

	Onshore wind	Offshore wind	Solar	Biomass
EEG 2014	2.5 GW net increase per year	6.5 GW increase in 2020	2.5 GW gross increase per year	100 MW gross increase per year
EEG 2017	2.8 GW gross increase for 2017 to 2019; 2.9 GW gross increase as of 2020	20 GW increase in 2030		150 MW gross increase for 2017 to 2019 200 MW gross increase for 2020 to 2022
EEG 2021	57 GW in 2022 62 GW in 2024 65 GW in 2026 68 GW in 2028 71 GW in 2030	20 GW in 2030 40 GW in 2040	63 GW in 2022 73 GW in 2024 83 GW in 2026 95 GW in 2028 100 GW in 2030	8.4 GW in 2030

Table 30: Development corridors

The following figures show the annual net new build compared to the expansion targets defined in the EEG. With around 848 MW of net new build in the first half of 2021, a total of 55.3 GW of onshore wind power is now installed. In the last half year, the most wind energy power plants were commissioned in Lower Saxony (200 MW), Brandenburg (159 MW) and North Rhine-Westphalia (143 MW). According to the new expansion targets in the EEG 2021, installed capacity is to be increased to 57 GW by 2022, resulting in a development corridor of around 580 MW per half-year for the next year and a half.

Electricity: expansion of onshore wind capacity up to June '21
(GW)

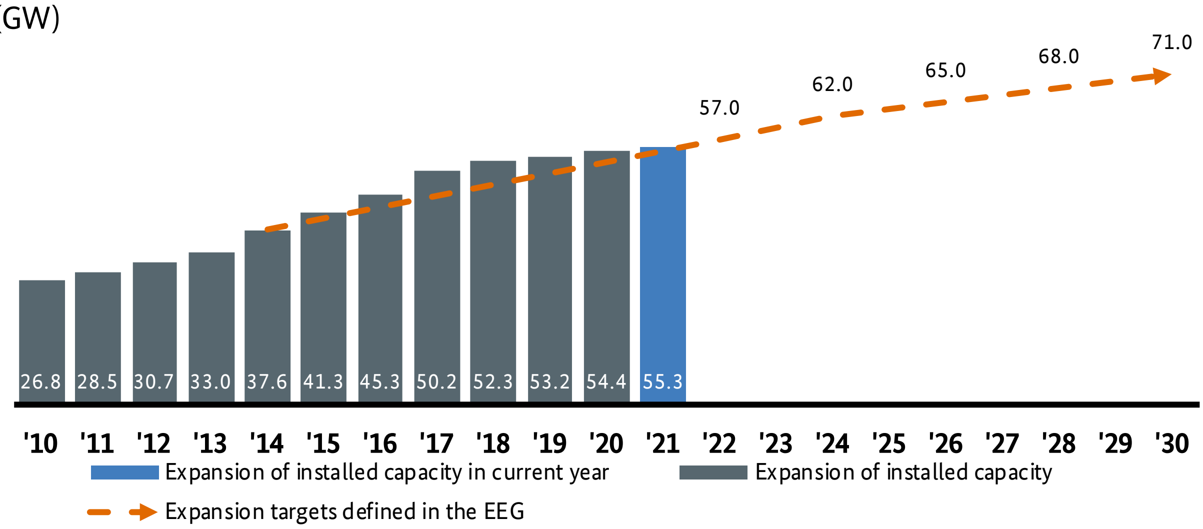

Figure 20: Onshore wind development targets

Net new build of solar in the first half of 2021 was 2.4 GW. In total, 2.1 million solar installations with 56 GW capacity are in operation in Germany. The most solar power in the past half year was newly installed in Bavaria (560 MW), North Rhine-Westphalia (297 MW) and Baden-Württemberg (275 MW). Measured against the expansion targets in the EEG 2021, a half-yearly expansion of 2.3 GW would still be necessary to achieve the expansion target of 63 GW in 2022.

Electricity: expansion of solar capacity up to June '21
(GW)

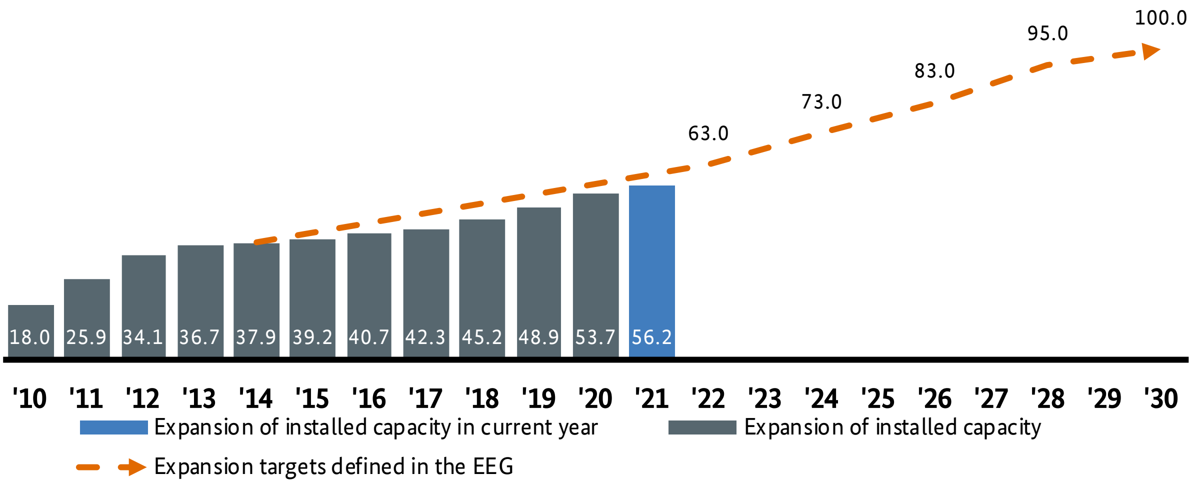

Figure 21: Solar development targets

Net new build of biomass was at a relatively lower level of 68 MW in the first half of 2021. A total of 8.8 GW biomass capacity receives EEG payments, of which 8.4 GW will be retained under the expansion targets in the EEG 2021 until 2030.

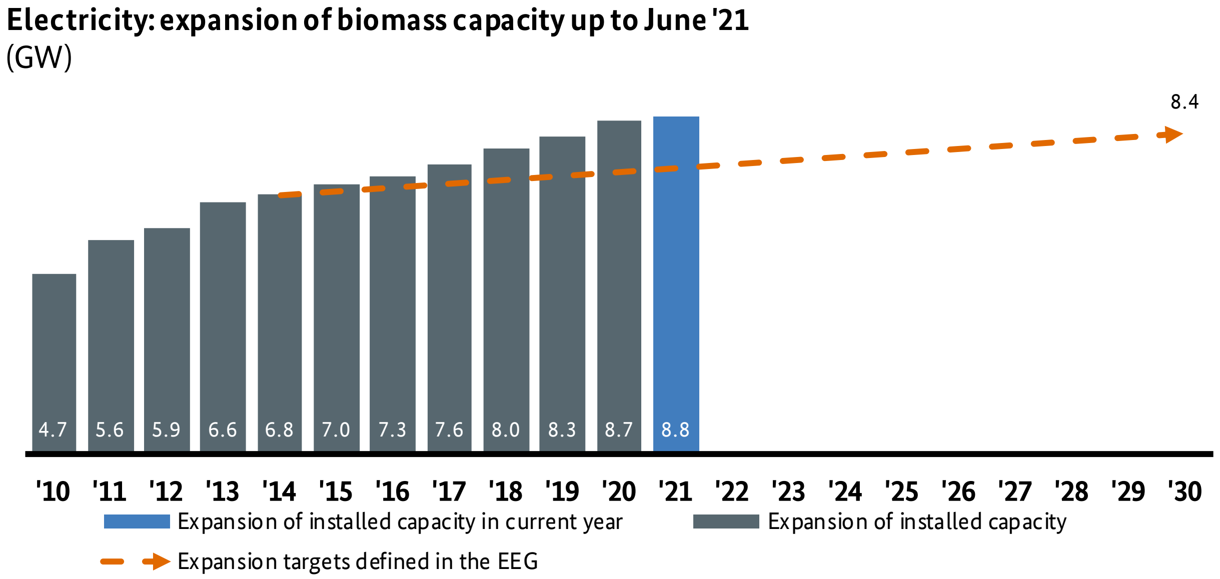

Figure 22: Biomass expansion targets

The expansion target in the EEG and Offshore Wind Energy Act (WindSeeG) of 6.5 GW in 2020 was exceeded with an installed capacity of 7.7 GW (this corresponds to the maximum installed capacity possible under the previous legal regime which could be realised within the framework of the capacity allocated by the Bundesnetzagentur). As a result, no further net new build has taken place in the offshore wind energy sector since July 2020. The most recent grid connection lines to go into operation are the NOR-8-1 (2019) in the North Sea and the OST-1-2 and OST-1-3 grid connection lines in the Baltic Sea.

Tenders have already been submitted to the Bundesnetzagentur (see previous monitoring reports) for the interim system between 2021 and 2025. As of the year 2023, further offshore lines and offshore wind parks will go into operation. These are the OST-2-1, OST-2-2 and OST-2-3 (each with 250 MW in the Baltic Sea) and the NOR-3-3 (900 MW in the North Sea).

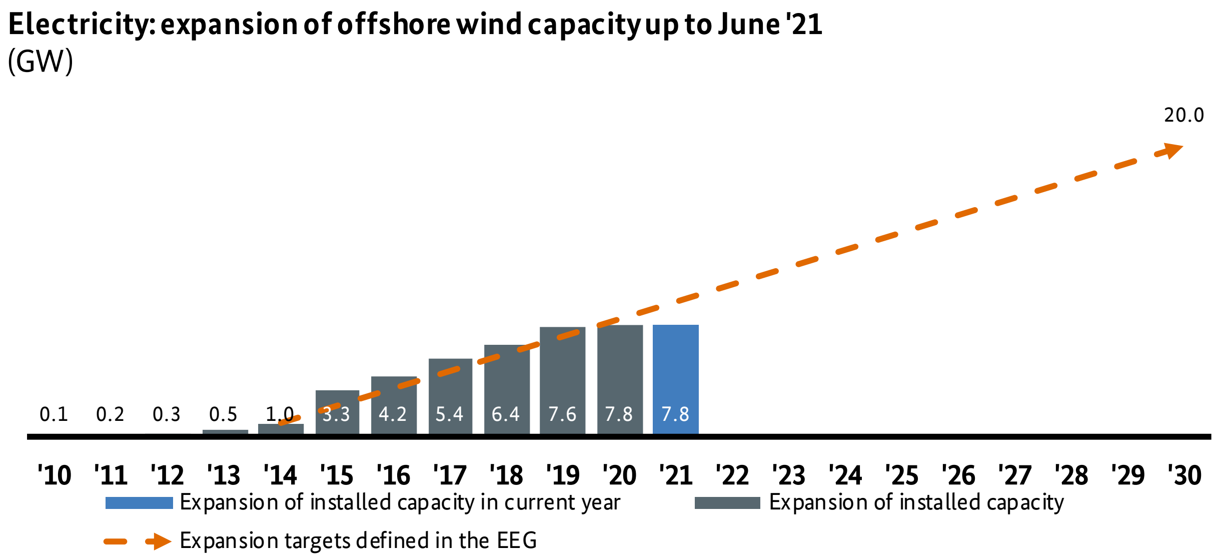

Figure 23: Offshore wind development targets

All scenarios in the approved scenario framework are based on the assumption that the 65% target will be met by 2030, as stipulated in the current EEG. The development corridor for reaching the target varies, however, depending on the different rates of growth of gross electricity consumption assumed in the scenarios. For this reason, the assumed average annual gross rise of 3.78 GW to 4.37 GW for onshore wind and of 5.03 GW to 5.65 GW for solar installations is higher than the EEG targets. A target value for biomass plants of between 6.8 GW and 8.7 GW has been defined for the year 2035. In line with the targets in the Offshore Wind Energy Act, a capacity of 28.0 GW to 34.0 GW was assumed for offshore wind for the year 2035. Except in the A2035 scenario, all the scenarios are based on the assumption that coal-fired power generation will have come to a complete end by the year 2035. Scenario A2035 is based on an assumed coal-fired power plant capacity of 7.8 GW, which is based on the coal-fired power plant reduction path in the Act to Reduce and End Coal-Fired Power Generation.

The stated expansion requirements, which are higher than the current target figures, are not yet based on the targets in the amended Climate Change Act (KSG) of 24 June 2021.

2.1.3 Annual feed-in of electricity

In 2020 the total annual energy feed-in of electricity from installations eligible for payments under the EEG was 222.0 TWh. Total annual electricity feed-in has increased by 4.8% compared to the previous year (2019: 211.9 TWh). At 102.7 TWh or 46%, the largest share of this electricity was generated by onshore wind installations, followed by solar installations with a share of 45 TWh (20%) and biomass installations with a share of 40.9 TWh (18%).

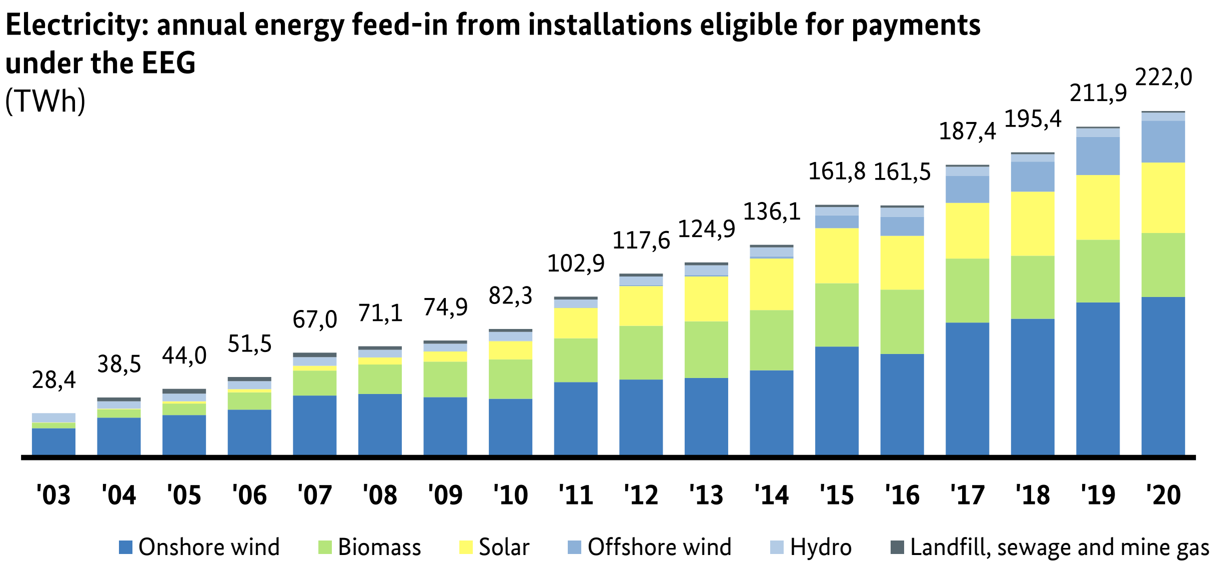

Figure 24: Changes in annual feed-in of electricity from installations eligible for payments under the EEG

Annual feed-in from solar installations rose sharply by 8.8%. This strong increase is due in part to the expansion in new build in this area (see Table 31) and in part to the fact that 2020 was the fourth sunniest year since measurements began in 1951[38].

Electricity: annual feed-in from installations eligible for payments under the EEG by energy source

	Total 31 December 2019	Total 31 December 2020	Increase / decrease compared to 2019
	in GWh	in GWh	in %
Hydro	5,548	5,048	-9.0%
Gases[1]	1,063	1,089	2.4%
Biomass	40,152	40,948	2.0%
Geothermal	187	197	5.3%
Onshore wind	99,166	102,741	3.6%
Offshore wind	24,379	26,903	10.4%
Solar	41,383	45,030	8.8%
Total	211,879	221,956	4.8%

[1] Landfill, sewage and mine gas

Table 31: Annual energy feed-in from EEG installations eligible for payments by energy source (as at 31 December)

Maximum feed-in from wind power and solar installations

The maximum feed-in from wind power and solar installations increased significantly compared with previous years. In 2020, the maximum feed-in from wind power installations and solar installations of 72.7 GW was recorded on 21 April 2020 whereby 56% of this peak feed-in was due to wind power. On this day, wind installations fed up to 40.7 GW into the grid. This coincided with a high level of feed-in from solar installations (32.1 GW).

[38] Source: DWD press release: The weather in Germany 2020 at https://www.dwd.de/EN/press/press_release/EN/2020/20201230_the_weather_in_germany_in_2020.pdf?__blob=publicationFile&v=2.

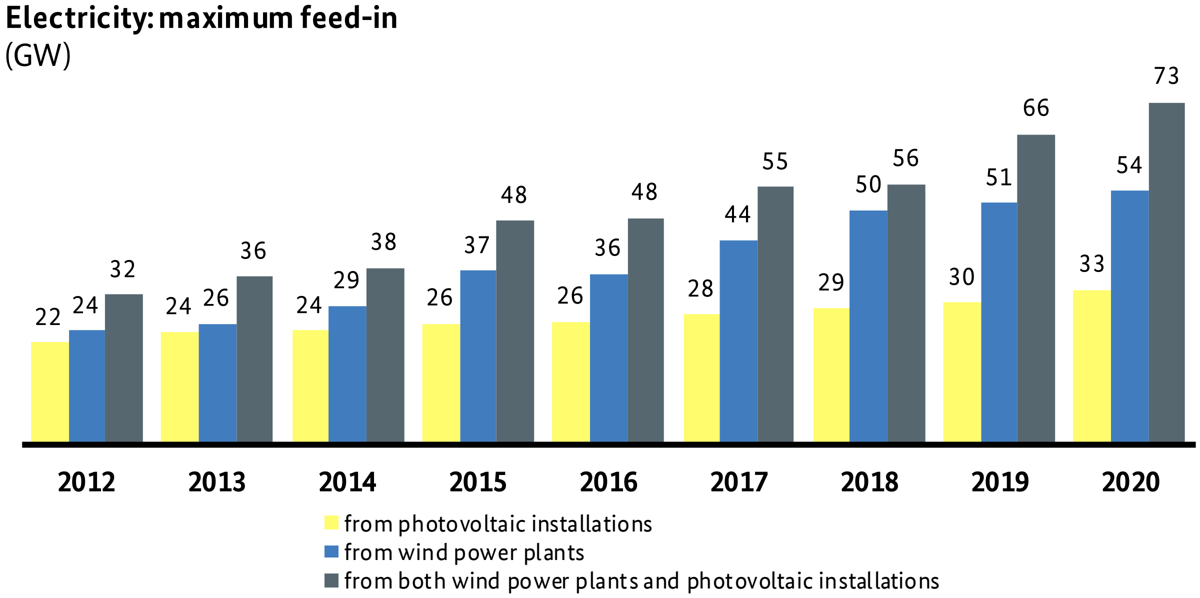

Figure 25: Maximum feed-in

In 2020, the maximum feed-in from solar installations alone of 33.2 GW was recorded on 1 June 2020. The year's highest feed-in values for wind power (onshore and offshore) were recorded in February 2020. The peak level of 54.1 GW achieved on 11 February 2020 was due primarily to the storm SABINE. Several peak values were also observed in the course of the year as a result of various storm systems.

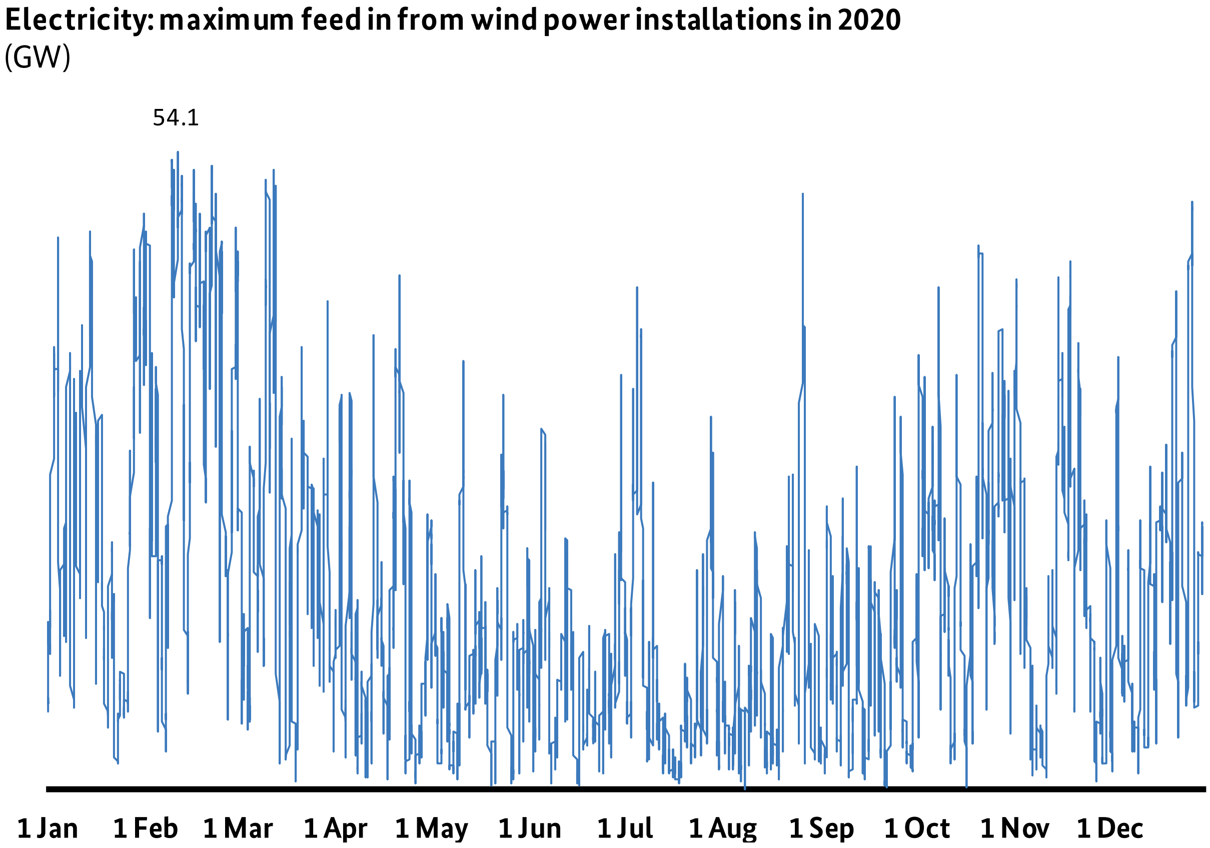

Figure 26: Maximum feed-in from wind power installations in 2020

2.1.4 Form of selling

Under section 33b 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: claiming a market premium (as an EEG-based payment in addition to market profits), a reduction to the EEG surcharge through energy utilities (green electricity privilege), or another form of direct selling (sales of EEG electricity without benefiting from additional payments under the EEG). Subsequent amendments to the EEG all stipulate direct selling and the market premium as standard forms of selling. Only existing installations or new installations with a capacity of up to 100 kW can still opt for fixed feed-in tariffs or payment of a tenant electricity supplement. Another form of direct selling, ie selling without receiving payment under the EEG, also remains possible.

In 2020, 81% of annual energy feed-in is already remunerated under the EEG in the form of the market premium. This is the case for 100% of offshore wind farms and at 96% the number of onshore wind turbines receiving market premiums is also approaching the 100% mark. At 34% (2019: 31%), the proportion of electricity from solar installations paid a market premium is still relatively low but growing continually. This small increase is due to the fact that the large number of small solar installations with a capacity of less than 100 kW continue to take advantage of the feed-in tariff.

Electricity: annual energy feed-in from installations with a fixed feed-in tariff or direct selling
(%)

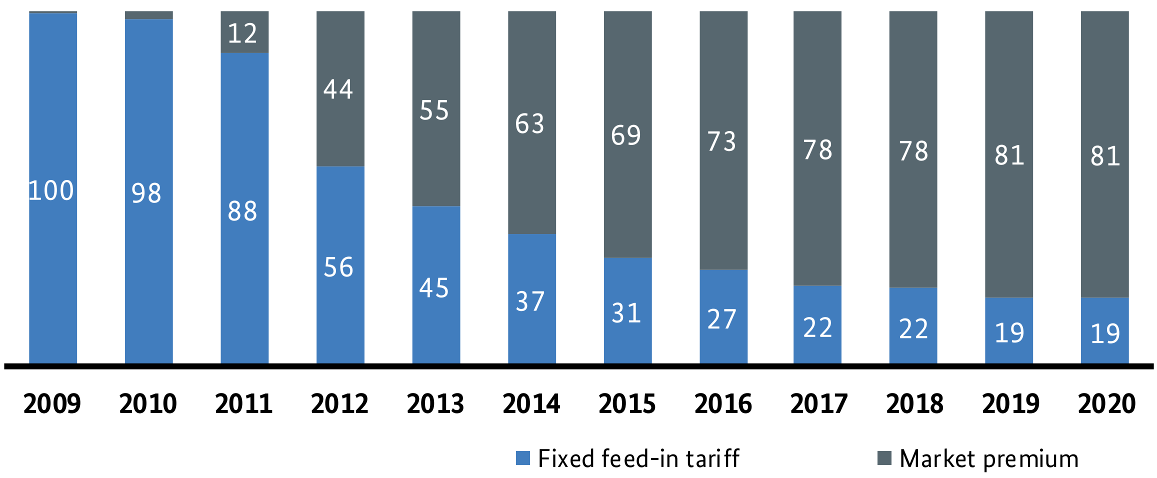

Figure 27: Annual energy feed-in of electricity from installations eligible for payments under the EEG by feed-in tariff or market premium

Electricity: annual feed-in of electricity from installations with a fixed feed-in tariff and market premium for 2020

	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 in %
Hydro	5,048	1,824	3,224	64%
Gases[1]	1,089	203	887	81%
Biomass	40,948	6,293	34,655	85%
Geothermal	197	12	185	94%
Onshore wind	102,741	3,329	99,412	97%
Offshore wind	26,903	0	26,903	100%
Solar	45,030	29,555	15,469	34%
Total	**221,956**	**41,216**	**180,734**	**81%**

[1] Landfill, sewage and mine gas

Table 32: Annual feed-in of electricity from installations by feed-in tariff and market premium

As in previous years, the main energy source for direct selling in 2020 was onshore wind power, which accounted for a share of 55% (2019: 56%), followed by biomass with a share of 19.2% and offshore wind power at 14.9%.

Electricity: breakdown by energy source of annual feed-in from installations with market premium for 2020 (%)

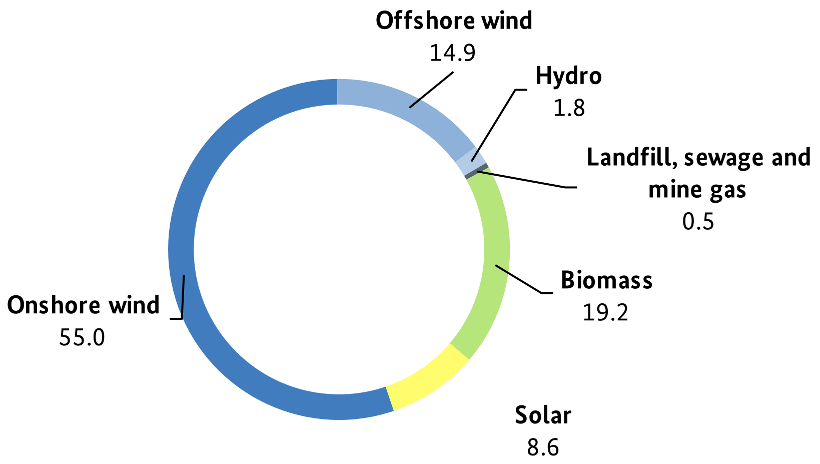

Figure 28: Breakdown by energy source of annual feed-in from installations with market premium

2.2 Changes in payments under the EEG

The EEG surcharge finances green electricity payments to the operators of solar, wind, hydro or biogas and biomass installations. The surcharge is paid for by all electricity customers although certain commercial and industrial customers receive 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 renewable energy operators play a key role in the calculation of the EEG surcharge. All the renewable electricity entitled to a fixed feed-in tariff (approximately 18%), which is mainly produced by small-scale and existing installations, is sold by the transmission system operators on the power exchange. The larger share of renewable electricity supported under the EEG (82%) is sold directly by installation operators or via direct sellers on the market, eg the power exchange. In both cases the market revenue is not sufficient to cover the actual payments made.

This difference is passed on to all electricity consumers in the form of the surcharge. Since the 2021 EEG surcharge the difference is also partly financed by federal subsidies.

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 networks the generating installations are connected in accordance with technology-specific payment rates (values to be applied) as defined in the EEG. Payments are usually made from the year in which the installation is commissioned and for a subsequent period of 20 years.

In 2020 a total of €29.8bn was paid to installation operators by the operators to whose networks the installations are connected. This includes payments to installation operators who sell their electricity through transmission system operators (feed-in tariff) as well as premium payments to installation operators who market their electricity themselves (market premium). In 2020 the majority of payments were made to installation operators entitled to the market premium (feed-in tariff: 37.5%, market premium: 62.5%). Market premiums again rose in comparison with the previous year (2019: 59.5%).

Solar installations (€11.5bn), biomass installations (€7.0bn) and onshore wind installations (€6.7bn) accounted for significant shares of these payments. Overall, payments were 8% higher in 2020 than in the previous year.

Electricity: payments by energy source

	Total 31 December 2019 (€ million)	Total 31 December 2020 (€ million)	Increase / decrease compared to 2019 (%)
Hydro	400	386	-3.3%
Gases[1]	45	51	13.0%
Biomass[2]	6,603	6,984	5.8%
Geothermal	40	43	7.7%
Onshore wind	5,817	6,674	14.7%
Offshore wind	3,731	4,246	13.8%
Solar	10,996	11,456	4.2%
Total	27,633	29,841	8.0%

[1] Landfill, sewage and mine gas

[2] Including support for flexibility

Table 33: Payments under the EEG by energy source (as at 31 December)

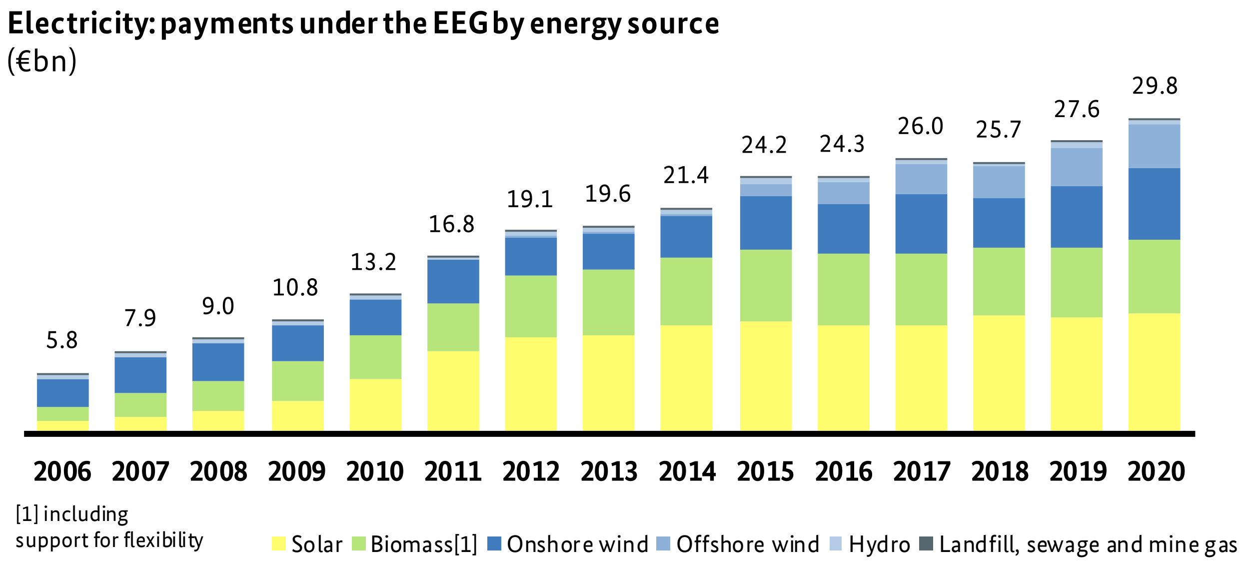

Figure 29: Changes in payments under the EEG by energy source

Renewable energy operators received an average of 13.4 ct/kWh in payments under the EEG[39] in 2020. Payments for the different energy sources varied significantly, however. As shown in Figure 31, operators of solar installations received an average of 25.4 ct/kWh in 2020, while operators of onshore wind installations received an average of 6.5 ct/kWh. These average values include both existing installations, which receive very high payments under the EEG, and new installations, which receive much lower EEG payments. Installation

[39] 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.

operators have also received additional revenue since 2012 from direct marketing on power exchanges. These revenues are not included in the payments shown.

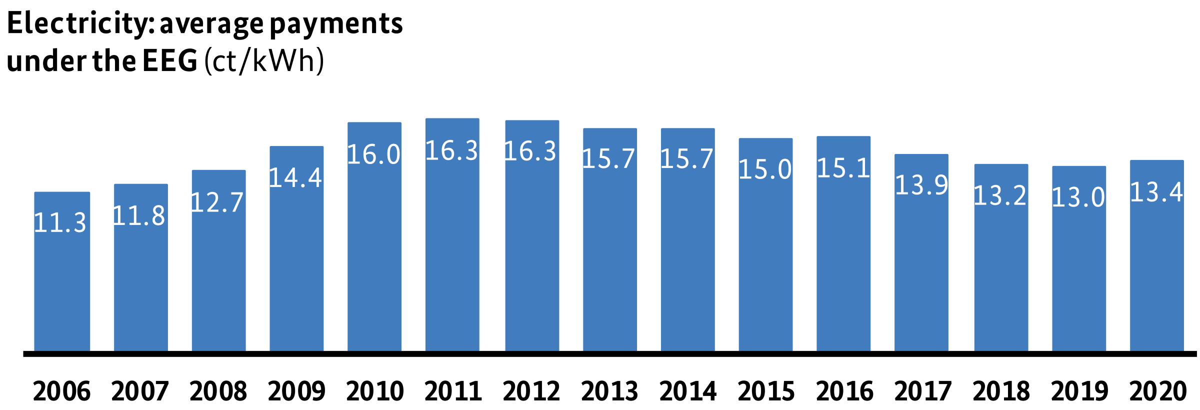

Figure 30: Changes in average payments under the EEG

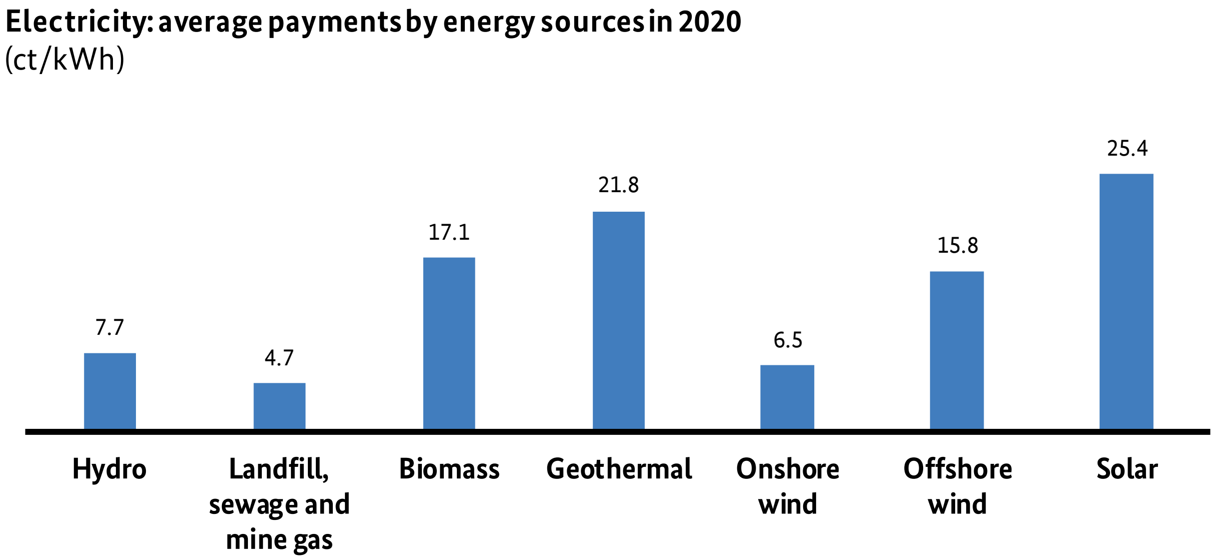

Figure 31: Average payments by energy source in 2020

2.2.2 Changes in the EEG surcharge

Payments under the EEG are for the most part refinanced through the EEG surcharge. The EEG surcharge for 2022 is 3.72 ct/kWh, almost 43% lower than in the previous year (6.5 ct/kWh). The last time the surcharge was lower than 4 ct/kWh was in 2012.

The main reason for the sharp drop in the 2022 EEG surcharge is the substantial increase in prices on power exchanges. The increase in market revenues from renewable electricity significantly reduces the need for support. As in the previous year, the 2022 surcharge will also be reduced by a federal subsidy, which will be financed from revenues derived from the national CO2 price.

The surcharge has been comparatively stable at between 6.2 and 6.9 ct/kWh since 2014. Falling payment entitlements for new installations have slowed the rate of increase of payments to installation operators substantially in recent years.

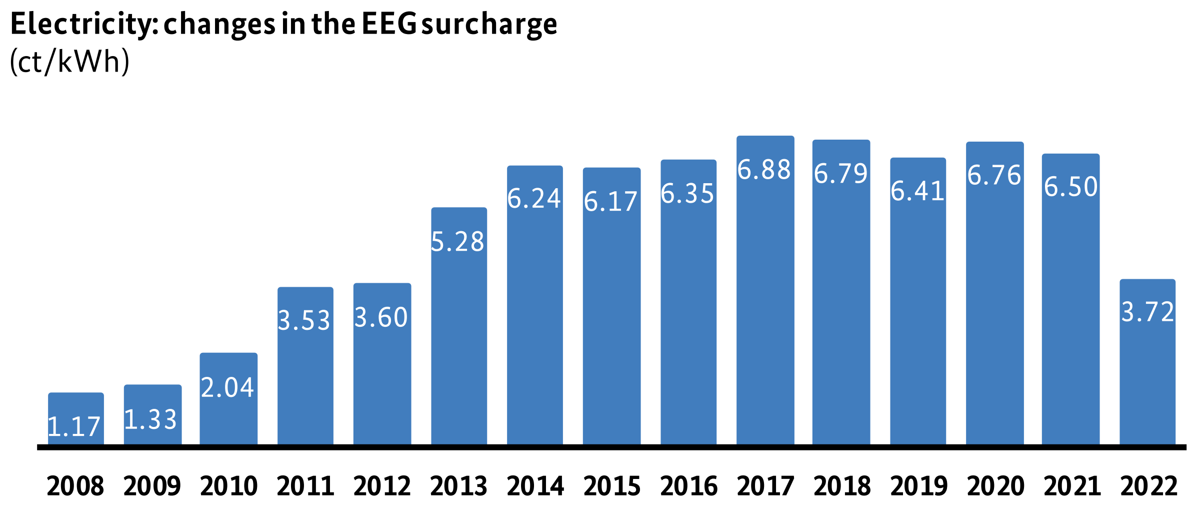

Figure 32: Changes in the EEG surcharge

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 derived from technological advancements. Thus, as of September 2014, the values to be applied for solar energy are reduced by a set percentage each month. 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 development 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 installation data recorded in the core energy market data register.

In 2018, 2019, 2020 and 2021, a substantial rise in solar was recorded and the target corridor in the respective reference periods was consequently exceeded. The value to be applied was therefore reduced by 1.4% in almost every month from May 2019. The only exceptions are the months November 2019 to January 2020, during which expansion was only slightly above the target corridor and resulted in a small reduction of 1.0%. In the months November 2020 to January 2021, expansion significantly exceeded the target corridor and resulted in a reduction of 1.8%. The 2021 EEG raised the development corridors for the calculation of the degression rate and this means that, despite increasing expansion, the value to be applied will again be reduced by 1.4%.

Since 1 January 2019, the remuneration for electricity from onshore wind installations that are not required to participate in auctions (installations with an installed capacity of up to 750 kW and pilot wind turbines) has been calculated on the basis of the bids awarded in previous auctions using the average of award prices from the year before last (section 46b(1) EEG). The value of 4.63 ct/kWh was thus applied for wind installations commissioned in 2019 and 6.04 ct/kWh for installations commissioned in 2020 and 6.20 ct/kWh for installations commissioned in 2021.

Electricity: lowering of the values to be applied
Solar energy

Relevant reference period for calculating actual reduction	Growth corridor (MW)	Actual growth in reference period (MW)	Applied reduction	Reduction cycle	Period of validity of reduction
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

Table 34: Lowering of the values to be applied – solar energy

Electricity: lowering of the values to be applied
Solar energy

Relevant reference period for calculating actual reduction	Growth corridor (MW)	Actual growth in reference period (MW)	Applied reduction	Reduction cycle	Period of validity of reduction
Fixed in EEG 2017	2.500 (gross)	-	0.0%	monthly	Jan 17
(Jul 2016 - Dec 2016) x2		2,025	0.0%		Feb 17 - 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
(Jul 2018 - Dec 2018) x2		2,570	1.0%		Feb 19 - Apr 19
(Oct 2018 - Mar 2019) x2		3,625	1.4%		May 19 - Jul 19
(Jan 2019 - Jun 2019) x2		3,662	1.4%		Aug 19 - Oct 19
(Apr. 2019 - Sep 2019) x2		2,878	1.0%		Nov 19 - Jan 20
(Jul 2019 - Dec 2019) x2		2,936	1.4%		Feb 20 - Apr 20
(Oct 2019 - Mar 2020) x2		3,242	1.4%		May 20 - Jul 20
(Jan 2020 - Jun 2020) x2		3,800	1.4%		Aug 20 - Oct 20
(Apr 2020 - Sep 2020) x2		3,975	1.8%		Nov 20 - Dec 20
Fixed in EEG 2021		-	-		Jan 21
(Oct 2020 - Dec 2020) x4		4,355	1.4%		Feb 21 - Apr 21
(Jan 2021 - Mar 2021) x4		4,379	1.4%		May 21 - Jul 21
(Apr 2021 - Jun 2021) x4		3,846	1.4%		Aug 21 - Oct 21

Table 35: (Continued from Table 34): Lowering of the values to be applied – solar energy

2.3 Auctions

Operators of new onshore wind, offshore wind and biomass plants only receive EEG payments if they have successfully participated in an auction. The only exceptions are for onshore wind installations, ground-mounted solar installations (first segment solar installations) with an installed capacity of up to and including 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 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 must pay penalties if installations are not commissioned within the defined period.

In addition to separate technology-specific auctions for onshore wind energy, offshore wind energy, solar and biomass, the first innovation auction was carried out in 2020. The 2021 EEG abolished cross-technology auctions for onshore wind and solar. Auctions were introduced for rooftop solar systems (second segment solar installations) and biomethane installations.

There were 35 auction rounds in the January 2020 to September 2021 period with the following results:

Electricity: technology-specific auctions for solar and onshore wind installations 2020 - 2021

Technology	Tendering date	Award price (ct/kWh)*
Solar (1st segment)	01.02.2020	5.01
	01.03.2020	5.18
	01.06.2020	5.27
	01.07.2020	5.18
	01.09.2020	5.22
	01.10.2020	5.23
	01.12.2020	5.1
	01.03.2021	5.03
	01.06.2021	5.00
Solar (2nd segment)	01.06.2021	6.88
Onshore wind	01.02.2020	6.18
	01.03.2020	6.07
	01.06.2020	6.14
	01.07.2020	6.14
	01.09.2020	6.20
	01.10.2020	6.11
	01.12.2020	5.91
	01.02.2021	6.00
	01.05.2021	5.91
	01.09.2021	5.79

*Volume-weighted average award price (sliding market premium); for solar power, the award price is applied prior to receipt of second securities.

Table 36: Auctions held in 2020 and 2021 for solar and onshore wind installations with sliding premium

Electricity: other auctions in 2020 - 2021 with sliding market premium

Technology	Tendering date	Award price (ct/kWh)*
Biomass	01.04.2020	13.99
	01.11.2020	14.85
	01.03.2021	17.02
	01.09.2021	17.48
Onshore wind and solar across all technologies	01.04.2020	5.33
	01.11.2020	5.33

* Volume-weighted average award price. In these auctions, and for wind and solar, incentives are paid in the form of sliding market premiums based on exchange prices.

Table 37: Auctions held in 2020 and 2021 with sliding premium

Electricity: other auctions in 2020 - 2021 with fixed market premium

Technology	Tendering date	Award price (ct/kWh)*
CHP	01.06.2020	6.23
	01.12.2020	6.75
	01.06.2021	5.64
Innovative CHP systems	01.06.2020	10.63
	01.12.2020	10.8
	01.06.2021	11.57
Innovation auction: single systems	01.09.2020	2.65
Innovation auction: system combinations	01.09.2020	4.50
Innovation auction: system combinations	01.04.2021	4.29
	01.08.2021	4.55

* Volume-weighted average award price. In these auctions incentives are paid in the form of fixed market premiums that take no account of exchange prices.

Table 38: Auctions held in 2020 and 2021 with fixed premium.

The figures in Table 36 and Table 37 are not comparable with Table 38 as in Table 36 and Table 37 they include a sliding premium minus potential revenues on the power exchange, while the figures in Table 38 reflect fixed premiums that generally flow as subsidies without deduction.

2.3.1 Solar photovoltaic auctions, first segment

Following the pilot auction for ground-mounted installations in the years 2015 to 2016, auctions have been held for all solar installations with an installed capacity of over 750 kilowatts since the beginning of 2017. 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 happened in Baden-Württemberg, Bavaria, Hesse, Rhineland-Palatinate and Saarland). In 2020, seven auction rounds were held for 1,299 MW. A total of 270 solar projects (bids) with a volume of 1,320 MW were awarded a tender. In 2021, 1,637 MW will be put out to tender, although the volumes for the auction scheduled for November may still change as required by law. In the March and June auction rounds, tenders for1,133 MW were awarded to 198 solar projects.

The bid volumes for all photovoltaic auctions have so far been significantly oversubscribed. The initial sharp decline in the award price in the first four auction rounds between February 2017 and February 2018 (6.58 ct/kWh to 4.91 ct/kWh) was not sustained in subsequent rounds. A bid volume of 500 MW for this special auction and a maximum permitted price of 8.91 ct/kWh resulted in a significantly higher average award price of 6.59 ct/kWh in 2019. An adjustment of the permissible maximum price to 7.50 ct/kWh successfully slowed this upward movement in 2020. In the course of 2020, award prices generally rose slightly up to October, oscillating between 5.01 ct/kWh (February 2020) and 5.23 ct/kWh (October 2020). The average volume-weighted winning bid in 2020 was 5.10 ct/kWh.

Since 2021, only bidders who wish to install ground-mounted solar installations or other structures that are neither buildings nor noise barriers may participate in auctions for first segment solar installations. At 5.03 ct/kWh (March 2021) and 5.00 ct/kWh (June 2021), the winning bids in the first two auctions in 2021 were also in the lower 5-ct range.

Average award prices have fallen by 21% since auctions were introduced for all solar installations in 2017. The highest award price in the period under review was 6.59 ct/kWh (March 2019) and the lowest award price was 4.33 ct/kWh (February 2018). The current average payment (in October 2020) for new solar installations determined by auction up to 2022 is 5.23 ct/kWh. This price realistically reflects average solar power generation costs.

Electricity: implementation rates for solar installations from solar auctions with expired implementation periods

Tendering date	Implementation status in %	Commissioning period (exclusion deadline)	Basis of tender
15.04.2015	99	06.05.2017	FFAV
01.08.2015	90	20.08.2017	FFAV
01.12.2015	92	18.12.2017	FFAV
01.04.2016	100	18.04.2018	FFAV
01.08.2016	96	12.08.2018	FFAV
01.12.2016	73	15.12.2018	FFAV
01.11.2016	99	05.12.2018	GEEV
01.02.2017	99	15.02.2019	EEG
01.06.2017	97	21.06.2019	EEG
01.10.2017	35	23.10.2019	EEG
01.02.2018	44	27.02.2020	EEG
01.06.2018	83	21.12.2020	EEG
01.10.2018	55	26.04.2021	EEG

Table 39: Implementation rates for all solar auctions

Awards must be implemented within 18 to 24 months. From the previous 25 rounds (including FFAV and GEEV) in addition to the six completed auction rounds under the Ground-mounted PV Auction Ordinance (FFAV), the implementation periods for the first seven solar photovoltaic auction rounds under the EEG and the Cross-Border Renewable Energy Ordinance (GEEV) have expired. These all have high rates of implementation (Table 39), which is regarded as a success. The only auction rounds to deviate from this success are those completed in October 2017, February 2018 and October 2018, which had implementation rates of 35%, 44% and 55% respectively. The main reason for this was the failure to implement two very large solar projects. As a result of the Covid-19 pandemic, the implementation periods for all tenders awarded prior to 1 March 2020, and for those whose implementation periods have not yet expired, have been extended by six months. This means that the ultimate rates of implementation for the 2019 auction rounds will only be apparent at the end of 2021. The implementation periods for all other auction rounds have not yet expired either.

Electricity: solar auctions, first segment 2020

	Feb	Mar	Jun	July	Sep	Oct	Dec
Volume put up for auction (MW)	100	300	96	193	257	96	257
Submitted bids	98	190	101	174	163	87	186
Submitted bid volume (MW)	493	838	447	779	675	393	936
Winning bids*	18	51	21	30	75	30	45
Volume awarded (MW)*	101	301	100	193	258	103	264
Excluded bids	12	9	9	18	22	9	42
Volume of excluded bids (MW)	77	35	18	70	73	37	196
Maximum rate (ct/kWh)	7.50	7.50	7.50	7.50	7.50	7.50	7.50
Average volume-weighted award price (ct/kWh)	5.01	5.18	5.27	5.18	5.22	5.23	5.10
Lowest bid (awarded) (ct/kWh)	3.55	4.64	4.90	4.69	4.80	4.98	4.88
Highest bid (awarded) (ct/kWh)	5.21	5.48	5.40	5.36	5.39	5.36	5.26

*Prior to receipt of the second security deposit.

Table 40: Solar auctions, first segment 2020

Electricity: solar auctions, first segment 2021

	Mar	Jun	Nov
Volume put up for auction (MW)	617	510	510**
Submitted bids	288	242	not available
Submitted bid volume (MW)	1,504	1,130	not available
Winning bids*	103	95	not available
Volume awarded (MW)*	620	513	not available
Excluded bids	6	11	not available
Volume of excluded bids (MW)	38	36	not available
Maximum rate (ct/kWh)	6	6	6
Average volume-weighted award price (ct/kWh)	5	5	not available
Lowest bid (awarded) (ct/kWh)	5	5	not available
Highest bid (awarded) (ct/kWh)	5	5	not available

*Prior to receipt of the second security deposit.

**The actual volume put up for auction may change based on statutory provisions

Table 41: Solar auctions, first segment 2021

Figure 33 shows that over 50% of the bids awarded for solar photovoltaic auctions in 2019 and 2020 were concentrated in Bavaria, in part due to the increase from 70 to 200 bids awarded following the amendment of the ordinance in Bavaria that opens up disadvantaged areas for solar farms.

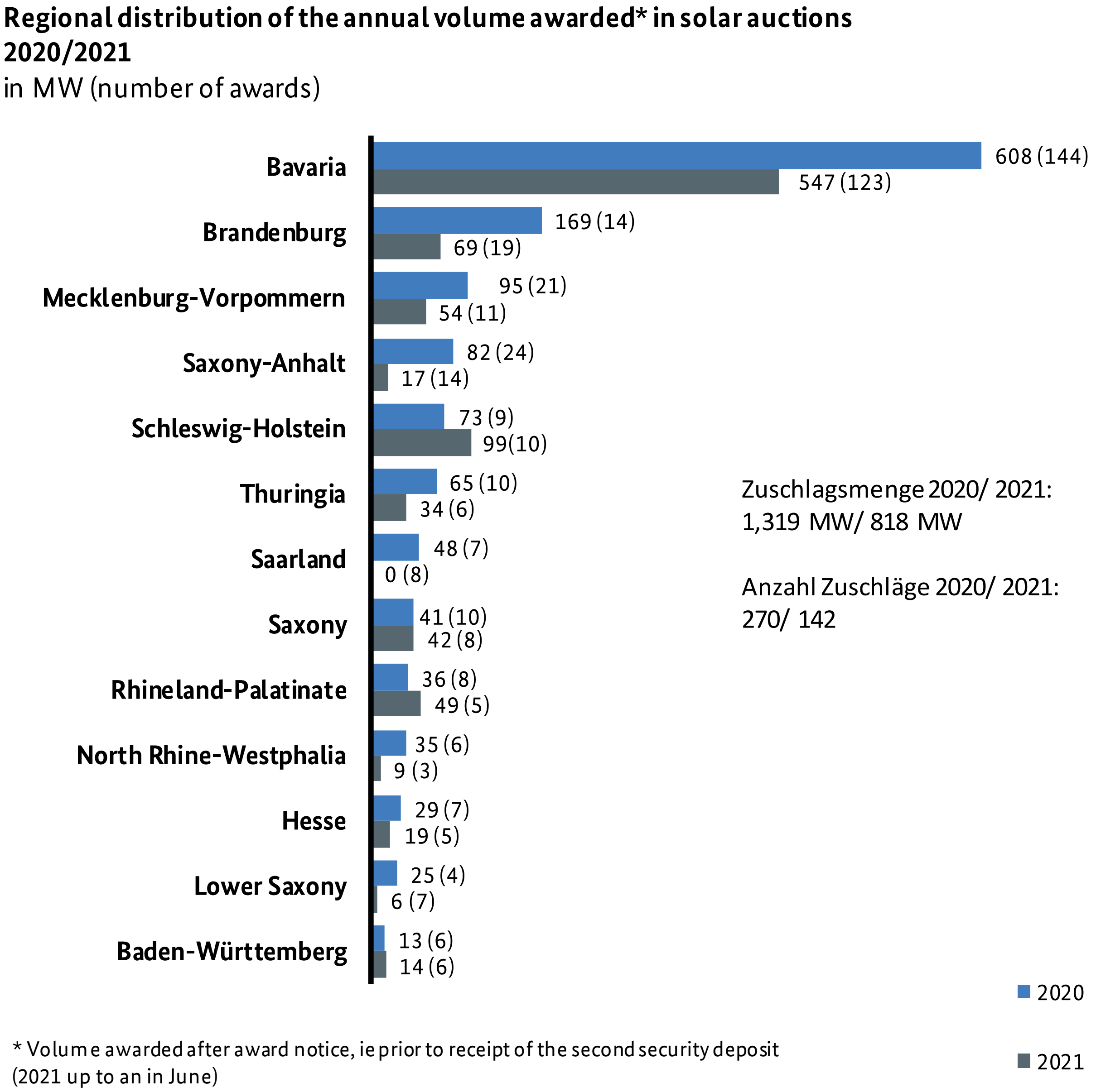

Figure 33: Regional distribution of the annual volume awarded in EEG solar auctions 2020/2021

2.3.2 Onshore wind auctions

Since the beginning of 2017 payments for onshore wind plants have also been determined by auction. All onshore wind turbines with an installed capacity of at least 751 kW must participate in such auctions. Bids are submitted for the value to be applied to an installation at a defined 100% reference site; however the actual payments may diverge from this.

In 2020, auctions were held for 3,869 MW in seven different auction rounds. In 2021, three auctions were held for 4,500 MW. Six of seven rounds in 2020 were significantly undersubscribed. A volume of just 2,672 MW was awarded and the envisaged development corridor was consequently not reached. Only the last round in December was slightly oversubscribed (Table 42 and Table 43). The picture remained unchanged in 2021. Some of the rounds in February and May were largely oversubscribed. Only the round in September 2021 was slightly oversubscribed. The lack of competition was reflected by the high award prices, all of which were just below the highest bid of 6.2 or 6 ct/kWh.

Electricity: onshore wind auctions 2020

	Feb	Mar	Jun	July	Sep	Oct	Dec
Volume put up for auction (MW)	900	300	826	275	367	826	367
Submitted bids	67	25	62	26	25	89	96
Submitted bid volume (MW)	527	194	468	191	310	769	657
Submitted bid volume (MW) in grid expansion area (NAG)	115	85	148	57	72	349	286
Winning bids	66	20	61	26	25	74	58
Volume awarded (MW)	523	151	464	191	287	659	400
Volume awarded in the NAG (MW)	115	56	148	57	87	268	197
Excluded bids	1	2	1	0	2	3	3
Excluded bids in MW	4	18	4	0	23	48	20
Maximum rate (ct/kWh)	6.20	6.20	6.20	6.20	6.20	6.20	6.20
Average volume-weighted award price (ct/kWh)	6.18	6.07	6.14	6.14	6.20	6.11	5.91
Lowest bid (awarded) (ct/kWh)	5.76	5.74	5.90	6.00	5.99	5.60	5.59
Highest bid (awarded) (ct/kWh)	6.20	6.20	6.20	6.20	6.20	6.20	6.07
Highest bid in the NAG (awarded) (ct/kWh)	Not relevant	5.98	Not relevant				

Table 42: Onshore wind auctions 2020

One major reason for the lack of participation in the tenders for onshore wind is the lack of federal immission control permits, which must be submitted for participation in the tendering procedure. Based on the experience with citizens' energy companies in 2017, it would not be helpful to move away from making participation dependent on permits; at that time, such companies were able to bid without a permit. This resulted in highly-speculative bids being made. The implementation rates for the awards made in 2017 are extremely low for precisely this reason. Decision-making in approval procedures for wind power plants is subject to various nature conservation and species protection regulations, construction planning and regional planning law, as well as aviation law. Nature conservation and species protection law, in particular, require intensive examination and a complex weighing-up process.

Electricity: onshore wind auctions 2021

	Feb	May	Sep
Volume put up for auction (MW)	1,500	1,243	1,492
Submitted bids	91	137	210
Submitted bid volume (MW)	719	1,161	1,824
Winning bids	89	127	166
Volume awarded (MW)	691	1,110	1,494
Excluded bids	2	10	6
Excluded bids in MW	27	51	34
Maximum rate (ct/kWh)	6.00	6.00	6.00
Average volume-weighted award price (ct/kWh)	6.00	5.91	5.79
Lowest bid (awarded) (ct/kWh)	5.15	5.68	5.20
Highest bid (awarded) (ct/kWh)	6.00	6.00	5.92

Table 43: Onshore wind auctions 2021

From a regional perspective (Table 44), 74% of the volume awarded in wind energy auctions in 2020 was concentrated on the four federal states of Schleswig-Holstein (22%), Lower Saxony (19%), North Rhine-Westphalia (17%) and Brandenburg (16%). In September 2021, 74% of the volume awarded was also concentrated in these federal states.

Electricity: distribution of bids and awards for onshore wind energy per federal state 2020 - 2021*

	Number of bids		Capacity bids in kW		Number of awards		Awarded capacity in kW	
Federal state	**2020**	**2021**	**2020**	**2021**	**2020**	**2021**	**2020**	**2021**
Baden-Württ.	9	5	92,100	58,200	8	4	79,500	54,000
Bavaria	2	8	27,000	68,000	1	6	13,500	51,400
Berlin	1	0	4,200	0	1	0	4,200	0
Brandenburg	46	63	505,400	531,060	37	50	434,100	459,110
Bremen	0	1	0	3,600	0	1	0	3,600
Hesse	6	16	80,300	206,480	5	15	71,900	171,980
Meckl.-Vorp.	15	13	147,000	157,200	8	13	114,800	157,200
Lower Saxony	52	52	557,350	593,800	46	49	503,350	574,400
N. Rhine-W.	80	109	512,150	707,740	69	90	456,300	553,290
Rhinel.-Pal	18	21	125,900	157,800	13	20	95,500	152,200
Saarland	0	2	0	17,850	0	1	0	3,450
Saxony	8	10	64,200	48,400	6	5	49,400	23,300
Saxony-Anhalt	14	12	160,600	136,100	12	11	149,300	123,500
Schlesw.-Holst.	116	107	714,540	895,300	99	100	582,690	869,850
Thuringia	23	19	124,750	122,500	22	17	117,700	98,500
Total	**390**	**438**	**3,115,490**	**3,704,030**	**327**	**382**	**2,672,240**	**3,295,780**

*Auction rounds in February, May, September 2021

Table 44: Distribution of bids and awards per federal state

2.3.3 Other auctions (offshore wind, biomass, joint and innovation auctions)

Offshore wind auctions

The offshore wind auctions for existing projects in 2017 and 2018 were followed on 1 September 2021 by the first "central model" offshore wind auction, which will in future take place every year. An award in this auction is linked to the right to a grid connection – financed by the electricity consumer via the offshore network surcharge – and the option to operate the offshore wind farm for 25 years. The holder of the award also receives the right to apply to the German Maritime and Hydrographic Agency (BSH) for planning approval to build the offshore wind park.

The auctions for a total volume of 958 MW were for three sites, which had already been pre-assessed by the BSH on behalf of the Bundesnetzagentur. Two sites, designated N-3.7 and N-3.8, are in the North Sea and one site, designated O-1.3, is in the Baltic. The award price for all three sites is 0 cent/kWh. The offshore wind parks are set to go into operation in 2026.

Several bids, each for a bid value of 0 cent/kWh, were submitted for the site N-3.8 and O-1.3. Awards were allocated by the Bundesnetzagentur for both areas by drawing lots, as provided for by law. The project developers who had originally planned offshore windparks also have the right to participate at sites N-3.8 and O-1.3. These project developers exercised their right to take part in the award in good time on 2 November 2021.

Electricity: offshore wind auctions; tendering date 1 September 2021

Designation of area	N-3. 7	N-3. 8	O-1. 3
Volume put up for auction (MW)	225	433	300
Volume awarded (MW)	225	433	300
Maximum rate for bids (ct/kWh)	7.30	7.30	7.30
Award price (ct/kWh)	0.00	0.00	0.00
Lottery	No	Yes	Yes
Right to participate	No	Yes	Yes
Offshore transmission link	NOR-3-3	NOR-3-3	OST-1-4

Table 45: Auction for offshore wind energy; tendering date 1 September 2021

Biomass auctions

The Bundesnetzagentur has held eight auctions since the auction procedure was introduced for biomass installations in 2017. Initially rounds were held annually; in 2019 through to 2020 bi-annual rounds were held in April and November. Since 2021, rounds have been held in March and September. In each of the two rounds 100 MW will be put out to tender; this volume is adjusted upwards largely due to the bid volumes not awarded in the previous year. As a result, 335 MW were auctioned in 2020 and a total of 575 MW in 2021.

One particular feature of this procedure is that installations that are already in operation are also able to take part in auctions if they are only eligible for payments under the EEG for a maximum of a further eight years.

So far all auction rounds have been significantly oversubscribed. This trend continued in 2020 and 2021. The volume-weighted average for all winning bids was 14.42 ct/kWh in 2020 and 17.25 ct/kWh in 2021. The medium winning bids for new installations were 14.44 ct/kWh in 2020 and 14.91 ct/kWh in 2021. On average, bids for existing installations with installed capacity exceeding 150 kW were awarded at 14.66 ct/kWh in 2019 and 16.39 ct/kWh in 2021. Bids for existing installations with installed capacity equal to or less than 150 kW were, on average, awarded at 16.40 ct/kWh in 2019 and 17.76 ct/kWh in in March 2021. Regardless of the actual price at which awards were made, the value to be applied for existing installations is limited to the average in the three years preceding the auction.

Electricity: biomass auctions in 2020

	1 April 2020			1 November 2020		
	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)		168			168	
Submitted bids	5	5	31	3	2	16
Submitted bid volume (MW)	43	0	49	22	0	29
Winning bids	5	5	28	2	2	15
Volume awarded (MW)*	43	0	47	19	0	9
Excluded bids	0	0	3	1	0	1
Volume of excluded bids (MW)	0	0	2	2	0	20
Maximum rate (ct/kWh)	14.44	16.40	16.40	14.44	16.40	16.40
Average volume-weighted award price (ct/kWh)	14.44	16.40	13.56	14.43	16.40	15.75

Table 46: Biomass auctions in 2020

Electricity: biomass auctions in 2021

	1 May 2021			1 September 2021		
	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)		300			300	
Submitted bids	7	8	45	7	10	83
Submitted bid volume (MW)	14	1	29	21	1	65
Winning bids	5	5	28	7	7	59
Volume awarded (MW)*	12	1	21	21	1	48
Excluded bids	0	2	6	0	0	6
Volume of excluded bids (MW)	0	0	3	0	0	5
Maximum rate (ct/kWh)	16.40	18.40	18.40	16.40	18.40	18.40
Average volume-weighted award price (ct/kWh)	15.09	18.79	18.09	14.72	16.73	14.68

Table 47: Biomass auctions in 2021

Innovation auctions for individual renewable energy sources (onshore wind, solar, biomass) or system combinations

The Bundesnetzagentur held its first innovation auction under the Innovation Auction Ordinance (InnAusV) in September 2020. In the first round of this new type of tendering procedure, bids could either be submitted for individual renewable technologies (onshore wind, biomass and solar) or for combinations of several installations using different renewable energies or of combined renewable generation and storage systems.

In addition to the new target group of system combinations, one of the key innovative elements in the auction design was the introduction of the payment of a fixed instead of a sliding premium as well as endogenous volume management in the absence of competition (subscription to the auction volume). While the sliding premium system pays the amount determined in the tenders minus potential market revenues, the fixed premium provides for a fixed amount that is paid as support regardless of potential market revenue. The reference yield model and special arrangements for citizens' energy companies do not apply to onshore wind installations.

The first auction round for 650 MW in September 2020 was substantially oversubscribed, with 133 bids for a bid volume of 1,095 MW. Most bids were for system combinations (785 MW for 83 bids). The remaining bids

(310 MW for 50 bids) were for individual solar installations. Renewable onshore wind and biomass technologies and biomass played no role at all for individual installations. A total of 73 bids with a total capacity of 677 MW were successful, including 394 MW for 28 system combinations. The selection of system combination was dominated by the combination of solar installations with storage.

The highest bids were 3.0 ct/kWh for single systems and 7.5 ct/kWh for system combinations. The average award price corresponding to a fixed payable premium was 2.65 ct/kWh for single systems (for awards of between 0.96 ct/kWh and 3 ct/kWh) and 4.50 ct/kWh for system combinations (for awards of between 1.94 ct/kWh and 5.52 ct/kWh).

Since 2021, only system combinations may take part in innovation auctions. A total of 250 MW was auctioned in April 2021. As in the previous year, the auction was substantially oversubscribed at a bid volume of 509 MW. Once again, onshore wind and biomass technologies did not play a major role and bids were submitted almost exclusively for system combinations of solar installations with storage. A total of 18 bids for a capacity of 258 MW were awarded a tender. The average price of bids in this round was 4.29 ct/kWh, which is slightly lower than in the previous year. A total of 250 MW was also auctioned in August 2021. The submitted bid value was just under 250 MW and in this case the legally stipulated volume management consequently applied. Accordingly, awards may only be made up to the amount of 80% of the auction volume. Overall, 16 bids with a total capacity of 156 MW were successful. The volume-weighted average winning bid was 4.55 ct/kWh; the lowest winning bid was 3.99 ct/kWh and the highest 5.48 ct/kWh. The winning bids were slightly higher than in the previous year.

Electricity: auctions for innovative technologies 2020 - 2021

	Sep 20	Apr 21	Aug 21
Volume put up for auction (MW)	650	250	250
Submitted bids	133	43	23
of which single systems	50	-	-
of which system combinations	83	43	23
Submitted bid volume (MW)	1095	509	250
of which single systems	310	-	-
of which system combinations	785	509	250
Winning bids	73	18	16
of which single systems	45	-	-
of which system combinations	28	18	16
Volume awarded (MW)	677	258	156
of which single systems	283	-	-
of which system combinations	394	258	156
Excluded bids	14	1	6
Volume of excluded bids (MW)	71	3	67
Maximum rate fixed market premium (ct/kWh) (single systems)	3.00	-	-
Maximum rate fixed market premium (ct/kWh) (system combinations)	7.50	7.50	7.50
Average volume-weighted award price (ct/kWh) (single systems)	2.65	-	-
Average volume-weighted award price (ct/kWh) (system combinations)	4.50	4.29	4.55
Lowest bid (awarded) (ct/kWh) (single systems)	0.96	-	-
Lowest bid (awarded) (ct/kWh) (system combinations)	1.94	3.33	3.99
Highest bid (awarded) (ct/kWh) (single systems)	3.00	-	-
Highest bid (awarded) (ct/kWh) (system combinations)	5.52	4.88	5.48

Table 48: Auctions for innovative technologies 2020 – 2021

Solar auctions, second segment

The 2021 EEG introduced solar auction for second segment solar installations. Bidders who wish to install a solar installation on or in a building or noise barrier and whose systems have an installed capacity of more than 300 kW may participate in this auction. The first auction was held in June 2021. A volume of 150 MW was put up for auction and 168 bids for a capacity of 213 MW were submitted. The auction round was thus substantially oversubscribed. Awards were made to 114 bids for a capacity of 153 MW. The volume-weighted average winning bid was 6.88 ct/kWh; the highest bid in this round was for 9.00 ct/kWh.

Electricity: auctions for photovoltaic installations, second segment 2021

	Jun	Dec
Volume put up for auction (MW)	150	150*
Submitted bids	168	n.a.
Submitted bid volume (MW)	213	n.a.
Winning bids	114	n.a.
Volume awarded (MW)	153	n.a.
Excluded bids	15	n.a.
Volume of excluded bids (MW)	21	n.a.
Maximum rate (ct/kWh)	9.00	n.a.
Average volume-weighted award price (ct/kWh)	6.88	n.a.
Lowest bid (awarded) (ct/kWh)	5.35	n.a.
Highest bid (awarded) (ct/kWh)	7.89	n.a.

* The actual volume put up for auction may change based on statutory provisions

Table 49: Solar auctions, second segment 2021

C Networks

1. Current status of grid expansion

As part of its monitoring, the Bundesnetzagentur provides quarterly updates on the progress in planning and construction for individual projects in the transmission system during the previous three months. This covers the projects from the Federal Requirements Plan Act (BBPlG) and the Power Grid Expansion Act (EnLAG). The Bundesnetzagentur publishes the updates on its website at www.netzausbau.de/vorhaben.

As at the second quarter of 2021, 101 projects were listed in the BBPlG and the EnLAG: 21 projects had already been completed and eight had been at least fully approved; 48 projects were still at the approval stage; and 24 projects were waiting for submission of the initial applications for federal sectoral/spatial planning.

The total length of the EnLAG and BBPlG projects as at the second quarter of 2021 was some 12,239 km:

- around 2,901 km were about to start the approval procedure;
- around 920 km were in the federal sectoral/spatial planning procedure;
- around 6,045 km were in or about to start the planning approval or notification procedure;
- 602 km had been approved/were under construction; and
- 1,771 km had been completed.

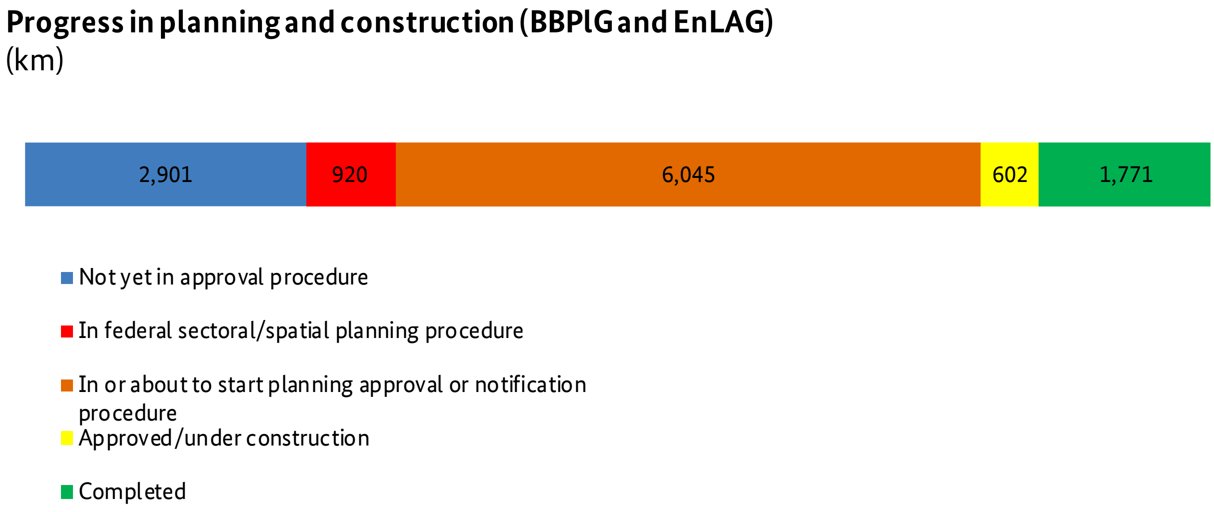

Figure 34: Progress in planning and construction (BBPlG and EnLAG)

1.1 Monitoring of EnLAG projects

The EnLAG listed 24 expansion projects as at the second quarter of 2021. Six of these projects are designated as pilot projects for underground cabling. These projects are earmarked as feasible for partial undergrounding under certain conditions. The spatial planning and planning approval procedures are the responsibility of the relevant federal states.

The total length of the EnLAG projects as at 30 June 2021 was some 1,827 km:

- around 8 km were in the spatial planning procedure;
- around 266 km were in or about to start the planning approval procedure;
- 466 km had been approved/were under construction; and
- 1,087 km had been completed.

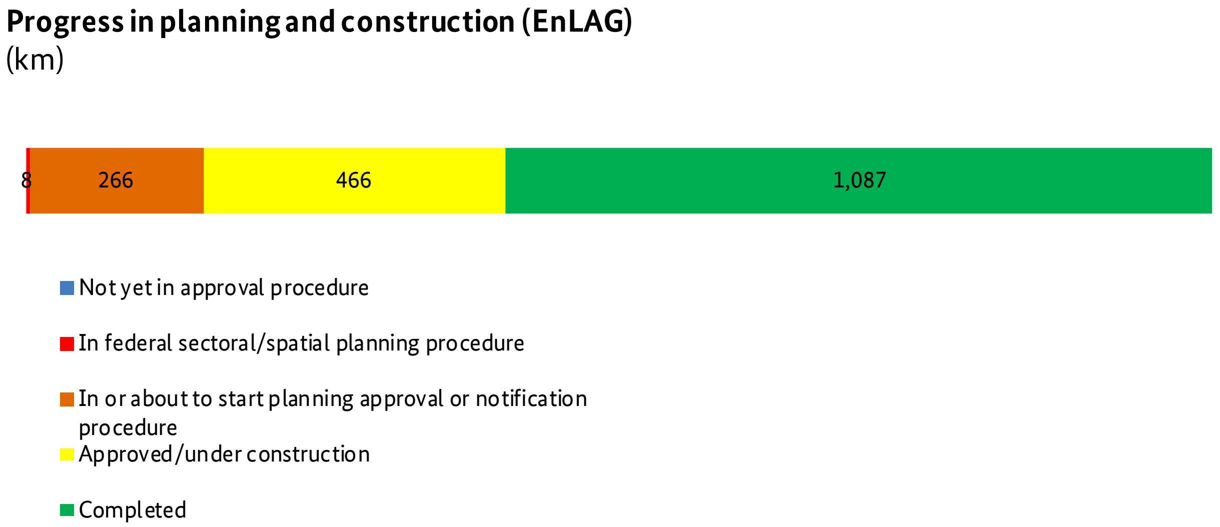

Figure 35: Progress in planning and construction (EnLAG)

The following map shows the status of the EnLAG projects in the second quarter of 2021.

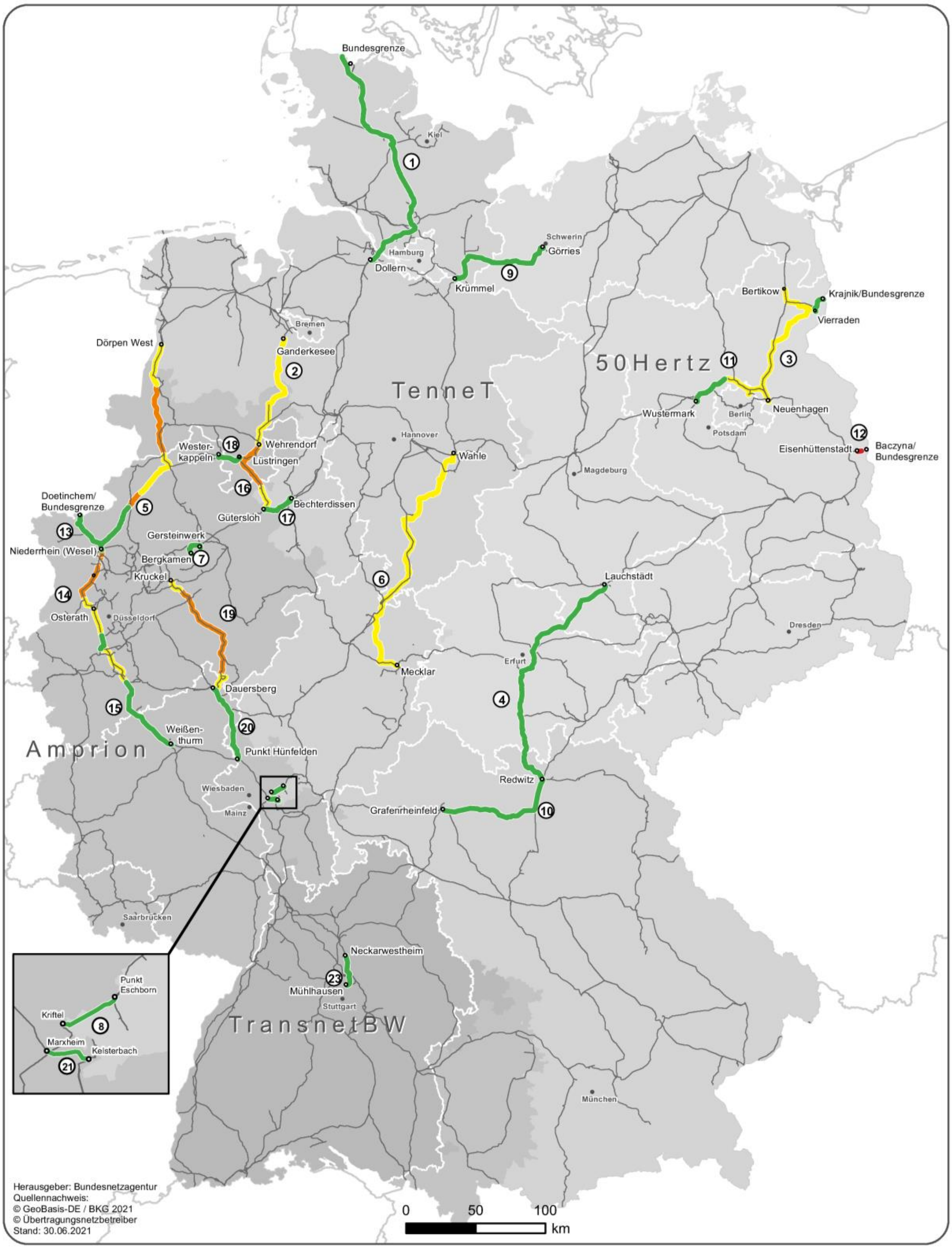

Figure 36: Status of EnLAG projects: 2nd quarter 2021

1.2 Monitoring of BBPlG projects

The revised BBPlG entered into force on 4 March 2021. The new Federal Requirements Plan (the annex to the BBPlG) includes 36 new and eight updated grid expansion projects. The total number of projects in the BBPlG has increased from 43 to 79 and the total length of the projects by around 4,400 km.

A total of 16 of the 79 expansion projects in the current BBPlG are designated as pilot projects for low-loss transmission over long distances (HVDC transmission). Ten DC projects are earmarked for priority underground cabling and five AC projects for possible partial undergrounding. In addition, one project is a pilot project using high-temperature superconductors and two are submarine cable projects.

A total of 29 projects and two project sections are designated as crossing federal state or national borders. The Bundesnetzagentur is responsible for the procedures for these projects. The total length of the projects as at the second quarter of 2021 was around 6,397 km. However, the total length largely depends on the route of the north-south corridors and will not be definite until a later stage of the procedure. Most of the other projects (around 3,797 km) are the responsibility of the federal states, as with the EnLAG projects. The procedures for a further 218 km are carried out by the Federal Maritime and Hydrographic Agency (BSH).

The total length of the BBPlG projects as at the second quarter of 2021 was some 10,412 km:

- around 2,901 km were about to start the approval procedure (including 2,550 km from the new BBPlG);
- around 912 km were about to start the federal sectoral/spatial planning procedure (including 95 km from the new BBPlG);
- around 5,779 km were in or about to start the planning approval/notification procedure (including 1,795 km from the new BBPlG);
- 136 km had been approved/were under construction; and
- 684 km had been completed.

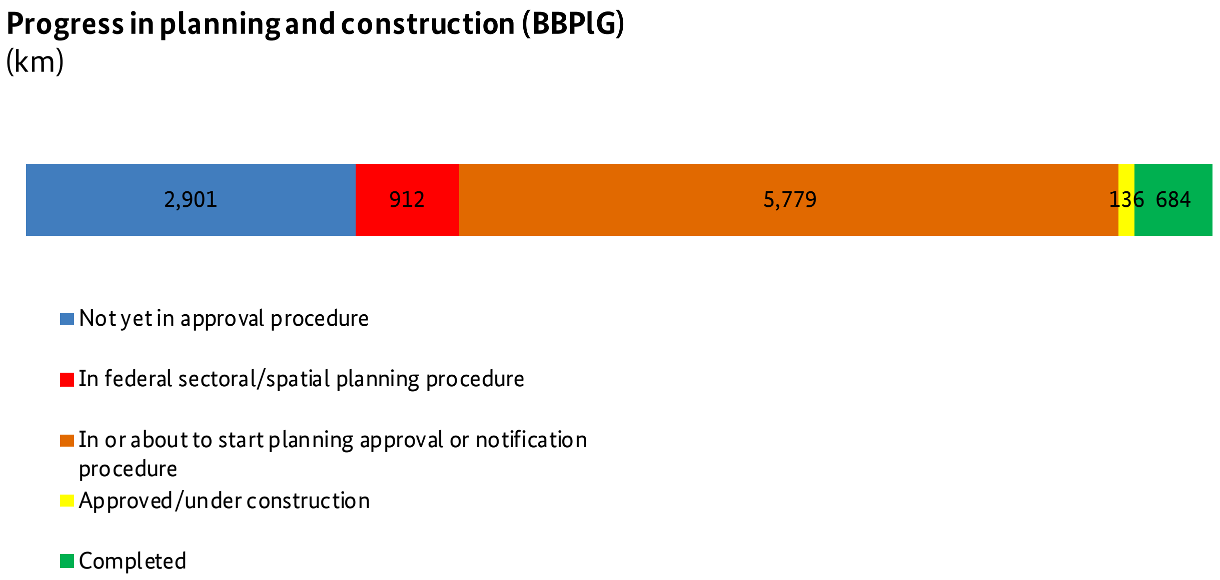

Figure 37: Progress in planning and construction (BBPlG)

The following map shows the status of the BBPlG projects in the second quarter of 2021.

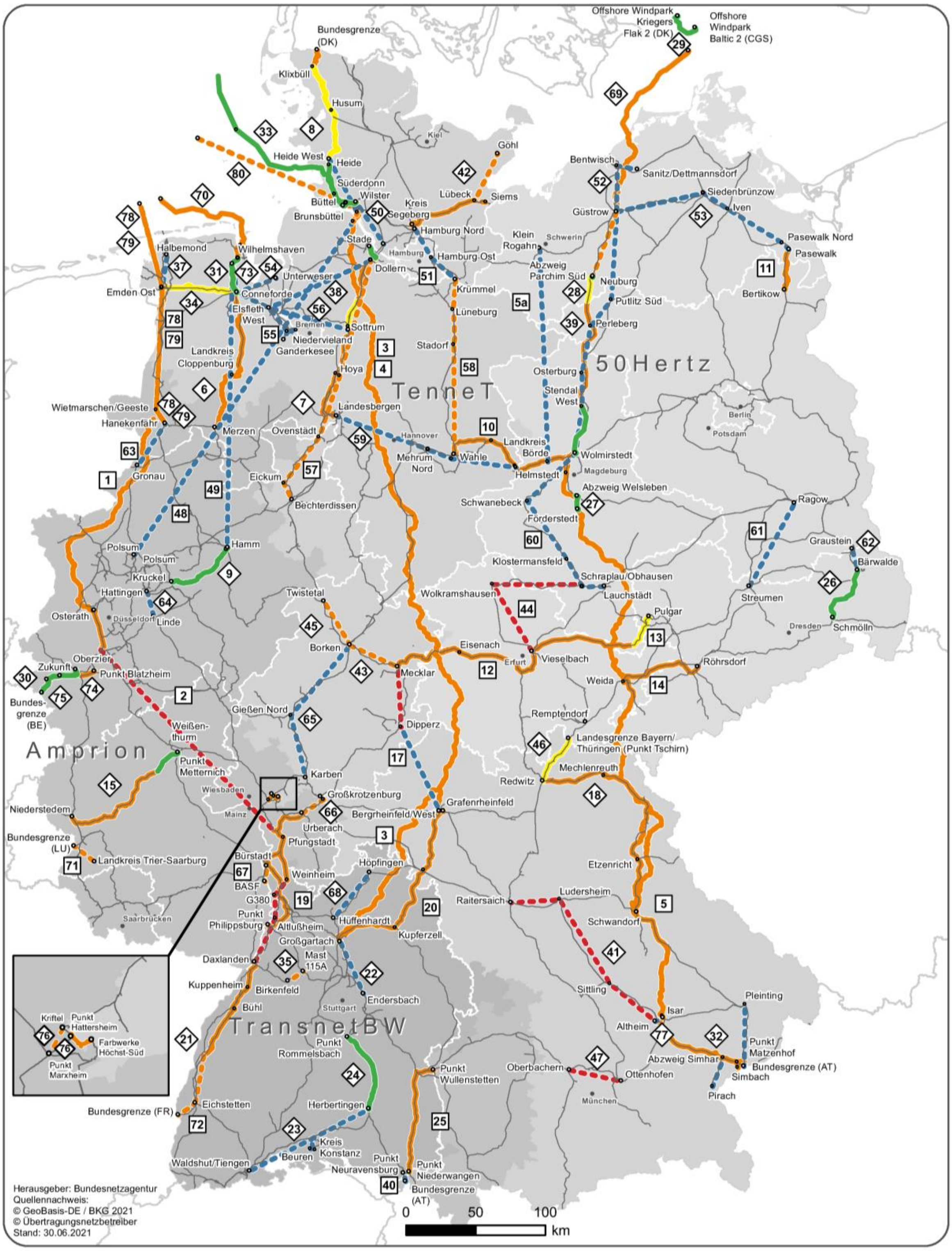

Figure 38: Status of BBPlG projects: 2nd quarter 2021

1.3 Electricity network development plan status

The TSOs published the first draft of the electricity NDP 2021-2035 based on the scenario framework 2021-2035 on 29 January 2021 for public consultation until 4 March 2021. The second draft of the NDP 2035 (2021) was submitted to the Bundesnetzagentur on 26 April 2021. The preliminary assessment results were published on 9 August 2021 for consultation until 20 October 2021.

The TSOs have proposed 96 measures for expansion of the transmission network for the period up to 2035. The Bundesnetzagentur considers 85 of these to be eligible for confirmation. Current assessments indicate that the projects already listed in the BBPlG are as important as before.

The TSOs have proposed two additional HVDC corridors for the period up to 2035.

They have proposed the construction of two additional onshore HVDC lines in the period up to 2035. However, the Bundesnetzagentur's current assessments indicate that only one HVDC line, between Rastede and Bürstadt (DC34), will be necessary. The TSOs have also proposed to reinforce existing or construct new conventional AC lines. The assessment took into account an increase in the level of utilisation of existing networks, for example through dynamic line monitoring and flow management measures (PSTs).

Electricity: kilometre overview

	NDP 2021-2035 (as proposed)	Currently eligible for confirmation	Currently not eligible for confirmation	Federal Requirements Plan (for comparison)
AC new builds	500 km	450 km	50 km	200 km
DC new builds	2,150 km	1,950 km	200 km	1,450 km
AC interconnectors	50 km	50 km	-	-
DC interconnectors	250 km	250 km	-	200 km
AC reinforcements	3,700 km	3,400 km	300 km	2,800 km
Total	6,650 km	6,100 km	550 km	9,900 km[1]

[1] Including 5,250 km in the start network

Table 50: Kilometre overview

The NDP 2035 (2021) includes both onshore measures and the planning for offshore transmission links. This planning is based on the provisions of the site development plan, which determines the order in which sites are to be auctioned for offshore wind farms as well as the years in which the transmission links need to go into operation for the sites to be connected on time. On the basis of these provisions, the NDP defines the necessary offshore transmission links including the commissioning years and onshore grid connection points. Since the energy generated offshore is not consumed there – in the sense of the uptake of electricity – almost all of it has to be transported to land. The NDP must include all measures necessary for the expansion of offshore transmission links in line with demand, including the timing for the planned completion and the onshore grid connection points. The assessment is therefore based not only on the criteria of necessity and effectiveness, but also on the expansion in offshore wind capacity that needs to be connected to the onshore grid.

The scenario framework proposes an expansion in offshore wind capacity in the North Sea and Baltic Sea up to 2035 of between 28 GW and 34 GW, depending on the scenario.

1.4 Optimisation and reinforcement in the transmission networks

The "NOVA" principle ensures that all possible measures to optimise or reinforce the existing grid are taken before an expansion measure is confirmed. The principle sets a certain order for identifying which measures are needed to ease restrictions: as a rule, all possible optimisation measures should be taken before reinforcement or, if necessary, expansion measures are considered.

Optimisation measures comprise a range of measures that can be carried out in the existing grid. One example is increasing the voltage of an overhead line that is capable of operating at 380 kV but is only operated at 220 kV. Another example is dynamic line monitoring, which enables the carrying capacity of existing lines to be varied depending on the weather, as conductors are capable of transmitting more electricity when it is windy or cool. Flow management measures (such as PSTs) can also be taken to optimise the use of existing networks.

Dynamic line monitoring allows the carrying capacity of overhead line conductors to be increased, depending on the weather. Conductors heat up as electrical current flows along them. The maximum permissible operating temperature of standard lines is usually 80°C. The maximum operating temperature of some lines in the 50Hertz network area is only 40°C because the lines were designed to technical standards and regulations applicable in the former German Democratic Republic. Dynamic line monitoring involves recording the weather conditions at the conductor. This allows the current carrying capacity of a conductor to be increased in certain situations, for instance when the ambient temperature is lower than the standard temperature at which the conductor has been designed to operate.

Dynamic line monitoring is an integral part of the NDP planning and approval process; its application is modelled nationwide to exploit the potential for minimising network expansion requirements. Dynamic line monitoring does not make economic and technical sense in all network areas and is therefore not used on some overhead line circuits. The operators regularly review when and where it makes sense to use dynamic line monitoring. The operation of overhead line circuits using dynamic line monitoring also needs to take account of adjacent or intersecting infrastructures, such as pipes, for other energy sources (for instance gas or oil). Additional measures to protect these pipes (including earthing) may be necessary when dynamic line monitoring is used across the country.

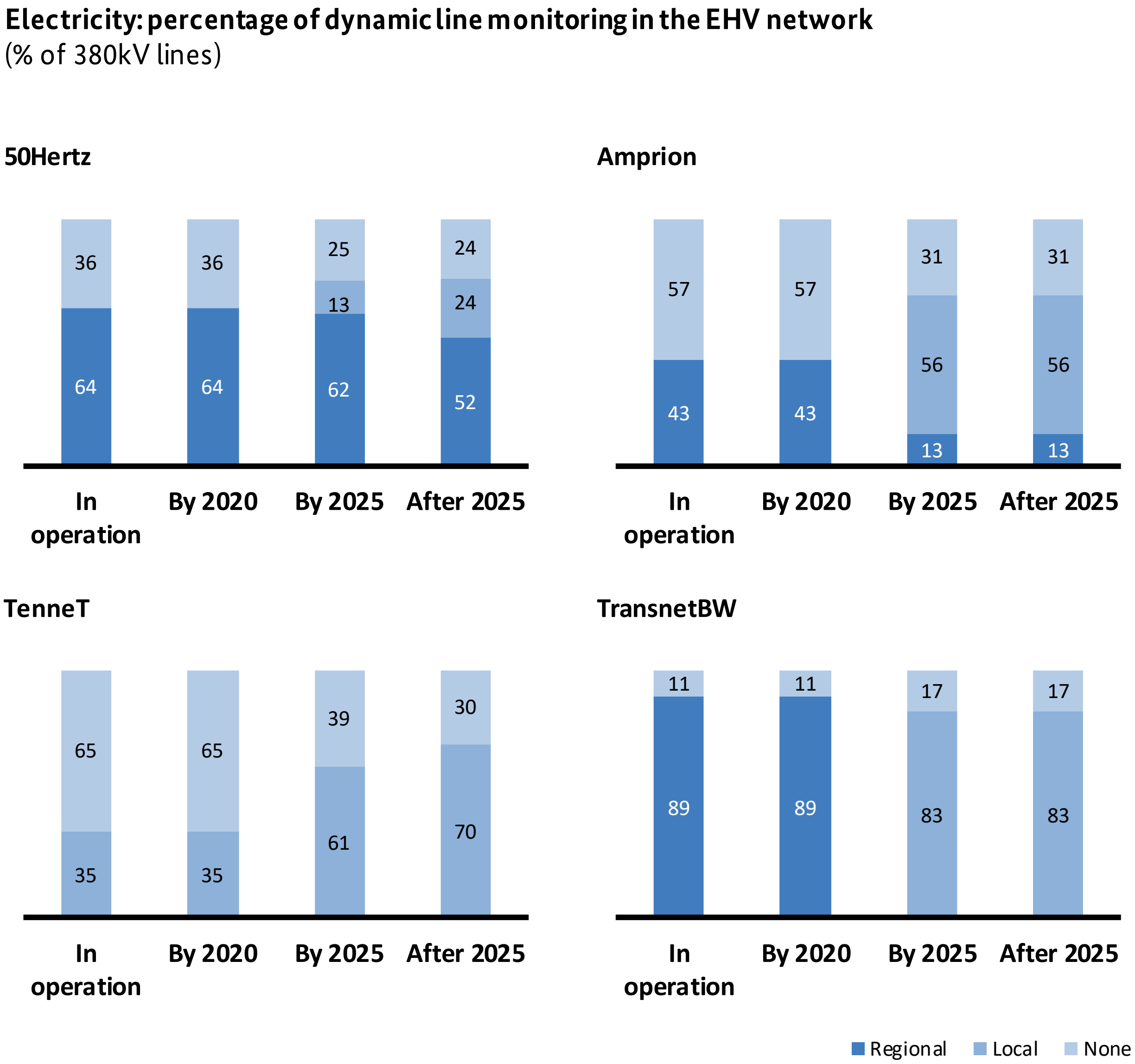

Figure 39: Percentage of dynamic line monitoring in the EHV network (380 kV)[40]

[40] A distinction is made between two measurement methods for dynamic line monitoring. Regional: account is taken of regional weather conditions; fixed summer/winter periods with a different current carrying capacity (ampacity) for all circuits (deviations can be made depending on the weather conditions); general assumption for optimised line operation (following corresponding upgrading). Local: account is also taken of local weather conditions. (Definitions based on CIGRE.)

Electricity: percentage of dynamic line monitoring in the EHV network
(% of 220kV lines)

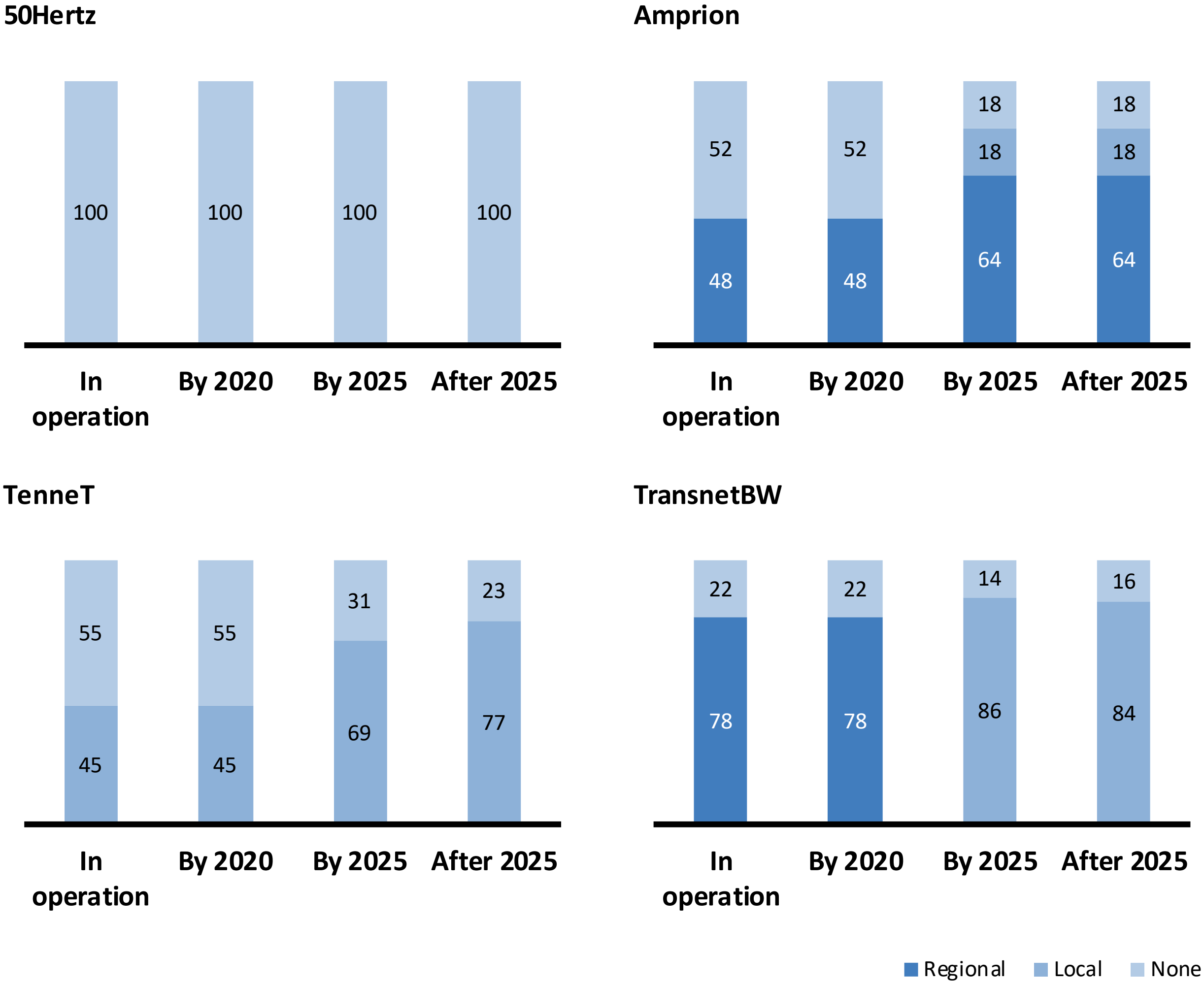

Figure 40: Percentage of dynamic line monitoring in the EHV network (220 kV)[41]

High-temperature superconductors are capable of operating at a higher temperature because of the special materials used. While standard conductors are only designed for a maximum operating temperature of 80°C, high-temperature superconductors can operate at temperatures of 150°C to 210°C. This means that high-temperature superconductors have a higher ampacity than standard conductors with comparable cross-sections. Their use needs to be assessed on a case-by-case basis.

Another option is the use of high-current cables. These cables have a larger conductor cross-section and therefore a higher permanent ampacity compared to standard conductors (3,600 A to 4,000 A compared to a

[41] A distinction is made between two measurement methods for dynamic line monitoring. Regional: account is taken of regional weather conditions; fixed summer/winter periods with a different current carrying capacity (ampacity) for all circuits (deviations can be made depending on the weather conditions); general assumption for optimised line operation (following corresponding upgrading). Local: account is also taken of local weather conditions. (Definitions based on CIGRE.)

maximum of 2,000 A). The advantages of high-current cables compared to high-temperature superconductors are lower network losses and lower noise levels.

2. Distribution system expansion

2.1 Optimization, reinforcement and expansion in the distribution networks

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 approve and integrate the installations and the energy generated regardless of grid 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 strategies for accommodating future energy developments and achieving efficient network operation. A new legal framework has been created for this with section 14d of the revised EnWG.

A total of 841 DSOs (837 in the previous year) provided information about the measures they had taken to optimise their networks. A total of 638 companies reported network optimisation measures. Figure 41 shows the measures implemented by the DSOs to optimise their networks.

Electricity: overview of optimisation and reinforcement measures
(number of DSOs)

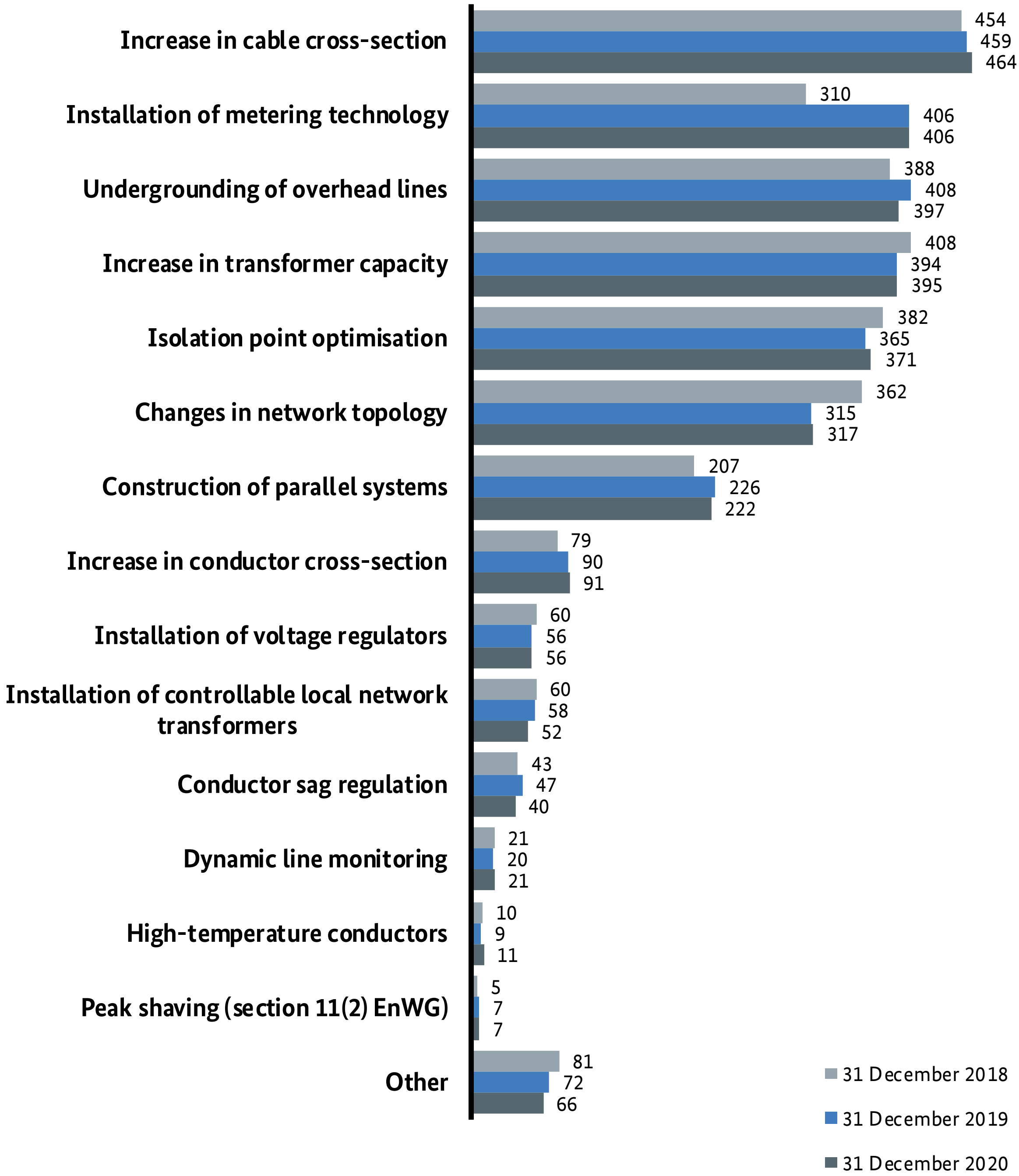

Figure 41: Overview of network optimisation measures

2.2 Future grid expansion requirements

The Bundesnetzagentur requests information from the DSOs about the status of their networks and their expansion plans for the next ten years on an annual basis pursuant to section 14(1a) and (1b) EnWG (old version) in order to be able to assess the DSOs' future grid expansion requirements.[42] The results of the annual data collections are published on the Bundesnetzagentur's website in a report on the status and expansion of the distribution systems.[43] In 2021, 58 DSOs operating HV (110 kV) networks were asked to report information pursuant to section 14(1a) and (1b) EnWG. One additional DSO particularly affected by feed-in management measures was also asked for information pursuant to section 14(1a) EnWG. The information reported by the DSOs on the status of their networks and their expansion plans was current as at 31 December 2020. The reports submitted by the DSOs in 2021 cover about 99.11% of Germany's total circuit length at HV level, about 73.20% at MV level and about 67.27% at LV level.

The lower the voltage level (from HV down to LV), the shorter the planning timescales. This means that long-term expansion plans are not usually made for the lower network levels. Any necessary expansion measures at these levels are implemented within a short-term timescale. In the 2021 survey, the DSOs were therefore allowed for the first time to report more generalised ten-year plans for the MV, MV/LV and LV levels. Most of the DSOs surveyed calculated their ten-year investment requirements from an average investment per year based on historical data and new challenges (such as integrating recharging points). This new information enables a better assessment of investment requirements for the lower network levels in the next ten years. However, it also means that the previous year's figures are not fully comparable with those from the 2021 survey.

The following figures only cover expansion measures that are designed to increase transmission capacity. These include all reinforcement, optimisation and replacement measures designed to increase transmission capacity as well as new builds. They do not include one-to-one replacement, dismantling or disposal measures. These measures are not covered by the reporting requirement under section 14(1a) and (1b) EnWG (old version); any measures reported as such by the DSOs have been excluded from the figures.

[42] As a result of the revision of the EnWG, from next year the information will be collected pursuant to section 14(2) and section 14d EnWG (new version).

[43] www.bundesnetzagentur.de/netzausbaubericht2020

Electricity: expansion at distribution level designed to increase transmission capacity
- new builds, replacements increasing transmission capacity, reinforcements and optimisations (€bn)

	Total 10-year expansion	Expansion based on measures plan	Expansion based on 10-year plans for lower levels
HV	8.05	8.05	--
HV/MV	1.52	1.52	--
MV	7.86	1.71	6.14
MV/LV	3.41	0.07	3.33
LV	6.63	0.27	6.36
Other	0.14	0.14	--
Total	**27.61**	**11.77**	**15.84**

Table 51: Ten-year expansion plans at distribution level

The above table shows that the 2,375 expansion measures reported by the DSOs to be envisaged, at the planning stage or under construction amount to an investment volume of around €11.77bn. There is an additional expansion investment volume of €15.84bn based on the more generalised ten-year plans for the lower (MV to LV) levels. The total expansion investment volume reported for all the network levels for the next ten years is therefore €27.61bn.

A total of 30% of the 2,375 individual measures reported are under construction, 28% are at the planning stage, and 42% are "envisaged".

The DSOs were also asked to give the expansion resulting from the measures in kilometres. However, the data provided were incomplete to such an extent that figures derived from the data do not allow a representative conclusion to be drawn about actual expansion and therefore no kilometre figures are being published for the year under review. The Bundesnetzagentur will aim to ensure a better quality of survey data to enable kilometre figures for expansion to be published in future.

The changes in the questions on expansion requirements – in particular for the lower network levels – mean that the total investment volume is not fully comparable with the figure of €16.1bn published in last year's report. It is only possible to compare the expansion investment volume for the HV level over the years. The HV investment volumes for 2018 to 2020 have been made comparable by excluding any expansion measures not designed to increase transmission capacity. As the chart below shows, there has been a continual increase in the ten-year expansion investments at HV level. The total expected ten-year expansion investment volume as at 31 December 2020 was up around €1.17bn (17%) on the previous year at €8.05bn. The increase is smaller than that between the two previous reports: the expected investment volume for HV expansion measures designed to increase grid capacity previously rose by 22.5% from €5.62bn in 2018 to €6.89bn in 2019.

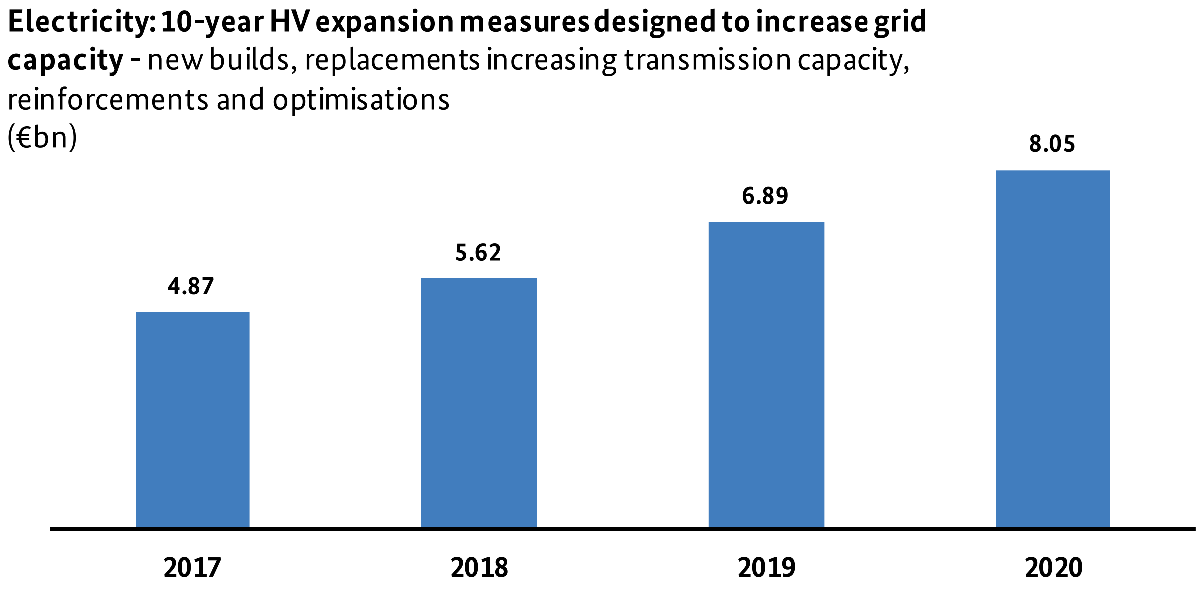

Figure 42: Ten-year HV expansion

In the 2021 survey covering 2020, 283 new HV measures were reported. The DSOs surveyed reported a total of 1,081 HV measures designed to increase grid capacity and either under construction, at the planning stage or envisaged. The table below shows the HV expansion investment volume for each DSO with an expected investment exceeding €100m. Ten of the 17 DSOs listed have an expected HV expansion investment volume exceeding €250m. These DSOs' network areas are coloured dark blue on the map below, and the seven DSOs' network areas with an expected HV expansion investment volume of between €100m and €250m are light blue.[44]

[44] For reasons of clarity and simplicity, the map does not show the DB Energie GmbH network because it extends across the whole of the country.

Electricity: HV expansion designed to increase transmission capacity - new builds, replacements increasing transmission capacity, reinforcements and optimisations

HV network operator	Expected expansion investment (€m)
Avacon Netz GmbH	1,450.3
DB Energie GmbH	1,172.2
E.DIS Netz GmbH	796.6
Westnetz GmbH	628.6
Stromnetz Berlin GmbH	449.9
Stromnetz Hamburg GmbH	417.7
Bayernwerk Netz GmbH	389.9
Schleswig-Holstein Netz AG	335.7
MDN Main-Donau Netzgesellschaft mbH	254.0
NRM Netzdienste Rhein-Main GmbH	250.3
Rheinische NETZGesellschaft mbH	233.0
Mitteldeutsche Netzgesellschaft Strom mbH	230.1
WEMAG Netz GmbH	208.0
Netze BW GmbH	207.2
LEW Verteilnetz GmbH	144.2
Syna GmbH	134.6
TEN Thüringer Energienetze GmbH & Co. KG	100.4

Table 52: HV expansion – DSOs with an expected expansion investment exceeding €100m

Electricity: HV network expansion
Network areas with an expected HV expansion investment volume exceeding €100m

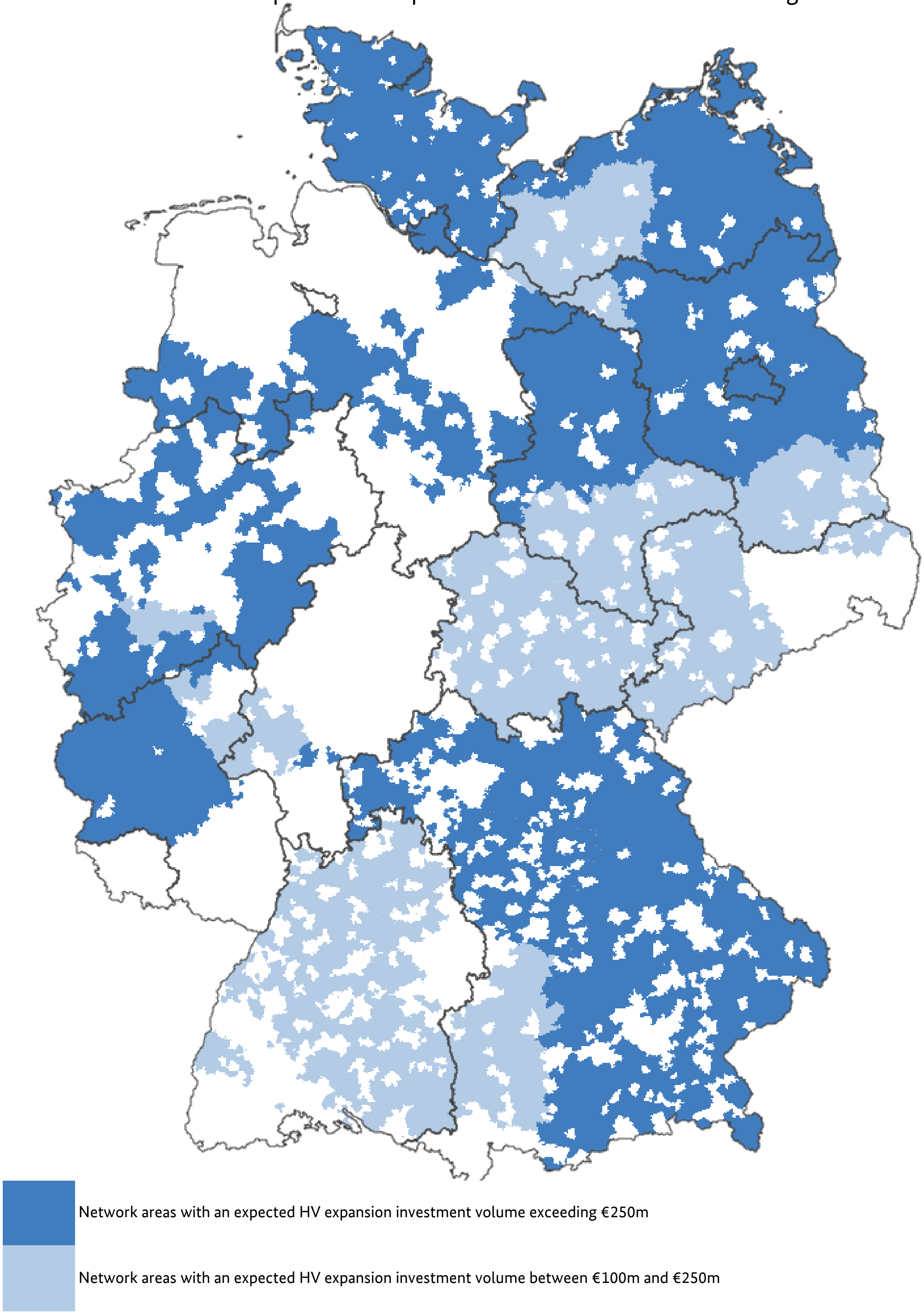

Figure 43: Network areas with an expected HV expansion investment volume exceeding €100m

An analysis of the DSOs' expected investment volumes across all network levels shows that just ten of the 59 DSOs surveyed account for around 65% of the total volume of €27.61bn. As the table below shows, these ten DSOs each expect a ten-year investment volume exceeding €1bn. A further 26 of the DSOs surveyed each expect to invest between €100m and €1bn. The ten DSOs with the highest expansion requirements as at 31 December 2020 are Avacon Netz GmbH, Bayernwerk Netz GmbH, DB Energie GmbH, E.DIS Netz GmbH, Mitteldeutsche Netzgesellschaft Strom mbH, Netze BW GmbH, Rheinische NETZGesellschaft mbH, Stromnetz Berlin GmbH, Stromnetz Hamburg GmbH, and Westnetz GmbH.[45] The highest investment volume expected by one single DSO is €2.75bn. The average investment volume is €0.47bn per DSO surveyed.

Electricity: expansion at distribution level designed to increase transmission capacity
- new builds, replacements increasing transmission capacity, reinforcements and optimisations

	Number of DSOs	Total (€bn)
All DSOs surveyed	59	27.61
DSO > €1bn	10	18.05
€1bn ≥ DSO > €100m	26	8.32
€100m ≥ DSO > €50m	13	0.97
€50m ≥ DSO	10	0.28

Table 53: Breakdown of distribution network expansion

3. Investments

For the purposes of the monitoring survey, investments are defined as the gross additions to fixed assets capitalised in 2020 and the value of new fixed assets newly rented and hired in 2020. 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 balance sheets of the transmission system operators (TSOs) and distribution system operators (DSOs). 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).

3.1 Transmission system operators' investments and expenditure

In 2020, investments in and expenditure on network infrastructure by the four German TSOs amounted to approximately €4,244m, up 37% on the previous year's figure of €3,089m. The difference between actual investments and expenditure in 2020 and the figure of €5,309m forecast for the 2019 monitoring survey is about €1,065m. The TSOs thus realised 75% of their planned investments and expenditure.

The individual categories for network infrastructure investments and expenditure are shown in Table 54:

45 In alphabetical order.

Electricity: TSOs' network infrastructure investments and expenditure

	2019	2020
Investments (€m)	**2,727**	**3,862**
New build, upgrade and expansion projects other than for cross-border connections	1,922	2,930
New build, upgrade and expansion projects for cross-border connections	511	506
Maintenance and renewal excluding cross-border connections	287	424
Maintenance and renewal of cross-border connections	7	3
Expenditure (€m)	**362**	**382**
Expenditure excluding cross-border connections	359	376
Expenditure on cross-border connections	3	6
Total	**3,089**	**4,244**

Table 54: TSOs' network infrastructure investments and expenditure

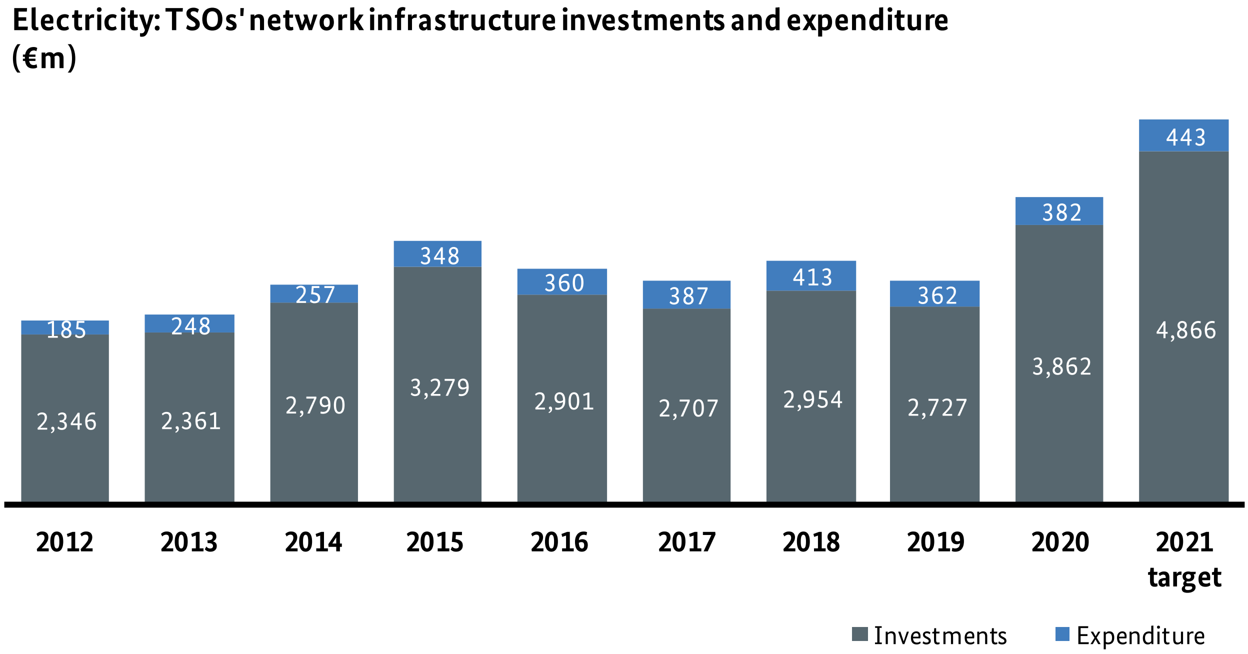

Figure 44: TSOs' network infrastructure investments and expenditure (including cross-border connections)

Total investments of around €4,866m and total expenditure of €443m are currently planned for 2021. The planned total for investments and expenditure of about €5,013m is considerably higher than the total amount realised in previous years. This shows that refinancing conditions continue to be seen as very favourable by investors for the future.

3.2 Distribution system operators' investments and expenditure

In 2020, investments in and expenditure on network infrastructure by the 841 DSOs that provided data in the monitoring amounted to around €8,088m, up about 7% on the previous year's figure of €7,540m. Investments and expenditure for metering systems amounted to around €371m in 2020, compared to €418m in 2019.

Detailed information on investments in metering systems can be found in I.H.7. The planned total for investments and expenditure in 2021 is €8,705m.

Figure 45 shows the figures for investments, expenditure and combined investments and expenditure since 2012 and the planned figures for 2021. The noticeable peak of investment in 2016 is likely to be related to the incentive regulation. This year was used as a base year that was 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.

Electricity: DSOs' network infrastructure investments and expenditure (€m)

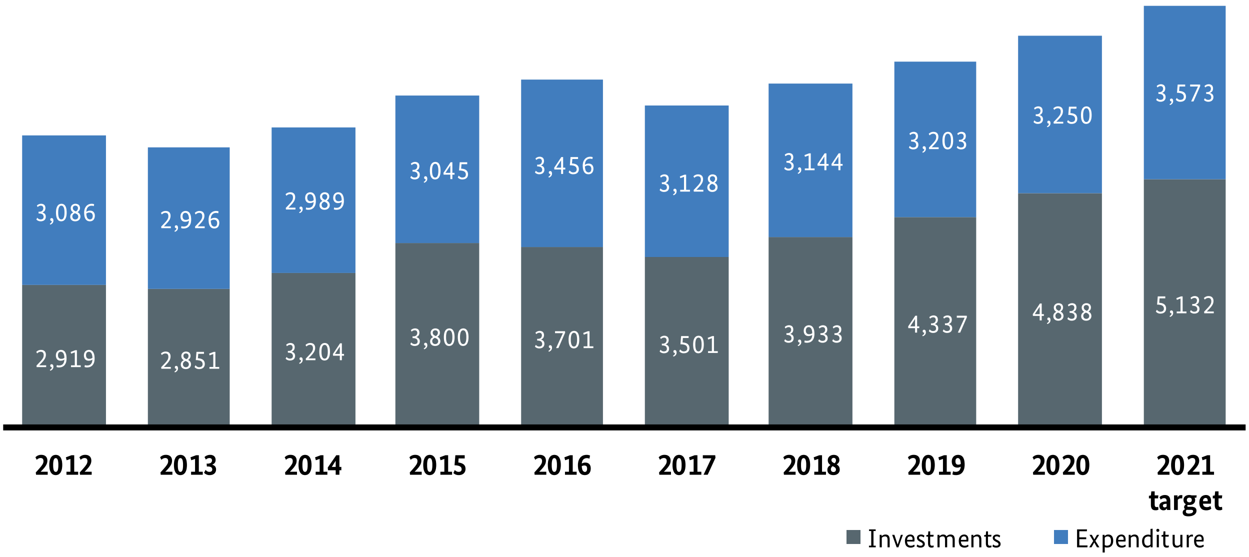

Figure 45: DSOs' network infrastructure investments and expenditure

The level of investment by DSOs depends on circuit lengths, the number of meter locations served, and other individual structural parameters, especially geographical factors. DSOs with longer circuits tend to have higher investments. In the distribution networks, too, the network operators' observable behaviour confirms the very attractive present and future refinancing options.

A total of 88 of the DSOs, or 10%, are in the top category with investments exceeding €10m per network area and account for 85% of the investments. Figure 46 shows investment categories by the total number of DSOs and the investment and expenditure amounts.

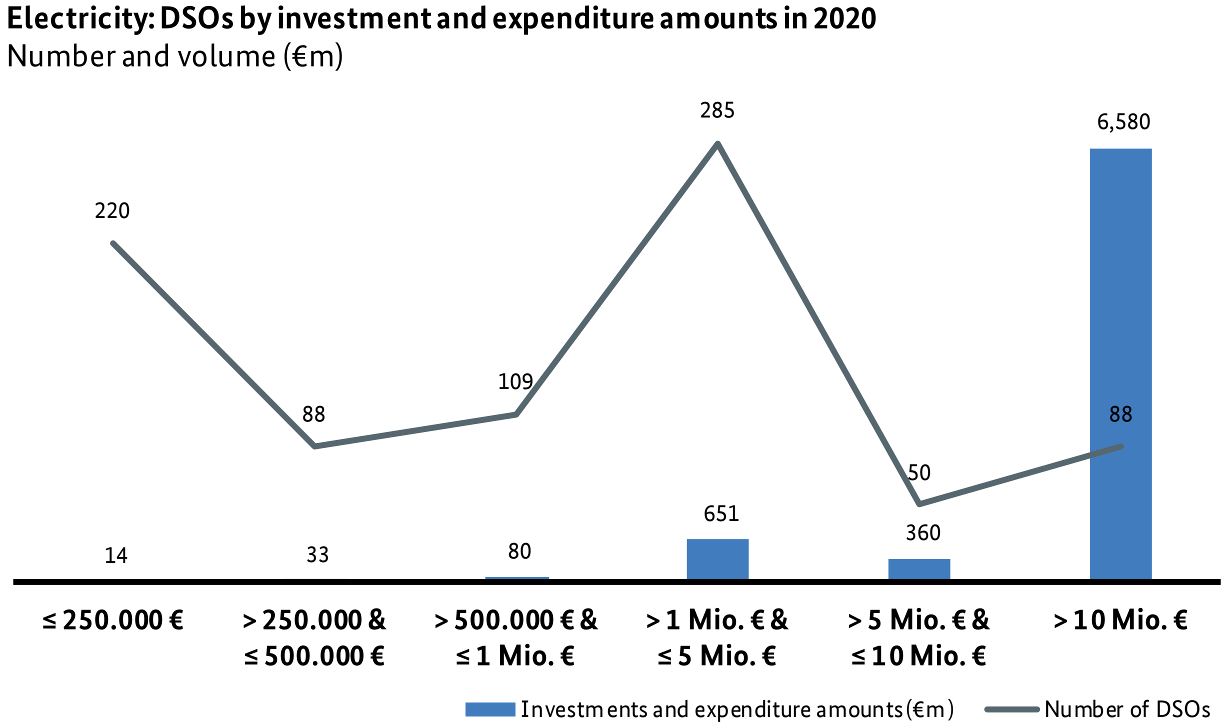

Figure 46: Number of distribution system operators by investment and expenditure amounts

3.3 Investments and incentive regulation

The ARegV 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. Based on section 23 ARegV, upon application the Bundesnetzagentur grants approval for individual projects if the prerequisites stated in the ARegV have been met. Section 23 ARegV generally applies to TSOs and, if the high voltage network level is affected, to DSOs as well. However, this investment measure tool was removed for DSOs in 2019 when the adjustment of capital expenditure was introduced at the beginning of the third regulatory period. Once approval has been given, the operator concerned 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 costs budgeted are checked by the Bundesnetzagentur in an ex-post control.

3.3.1 Expansion investments by TSOs

As of 31 March 2021, 34 new applications for investment projects had been submitted by TSOs to the competent Ruling Chamber. Costs of acquisition and production of about €1.9bn are linked to these investment measures. Compared to 2020, the number of applications submitted by the TSOs has decreased minimally, while the costs linked to the projects applied for have been well more than halved.

3.3.2 Capital expenditure mark-up and monitoring of the adjustment of capital expenditure for DSOs

The Bundesnetzagentur introduced the capex mark-up for electricity distribution systems for the first time as from 1 January 2019. DSOs are able to apply for mark-ups on the revenue cap approved by the Bundesnetzagentur to take account of investments in network infrastructure, software and other fixed assets that qualify for capitalization.

These adjusted revenue caps cover all network costs plus a return on equity, which companies may pass on to consumers through the network charges. The capex mark-up already includes a pre-financing element as the companies can factor in planned investments.

By the deadline of 30 June 2021, 170 applications for capex mark-up approvals for 2022 had been received (105 under the Bundesnetzagentur's own responsibility and 65 under the regulatory authorities of the federal states of Schleswig-Holstein and Brandenburg). The figure below shows an annual comparison of the planned acquisition and production costs.

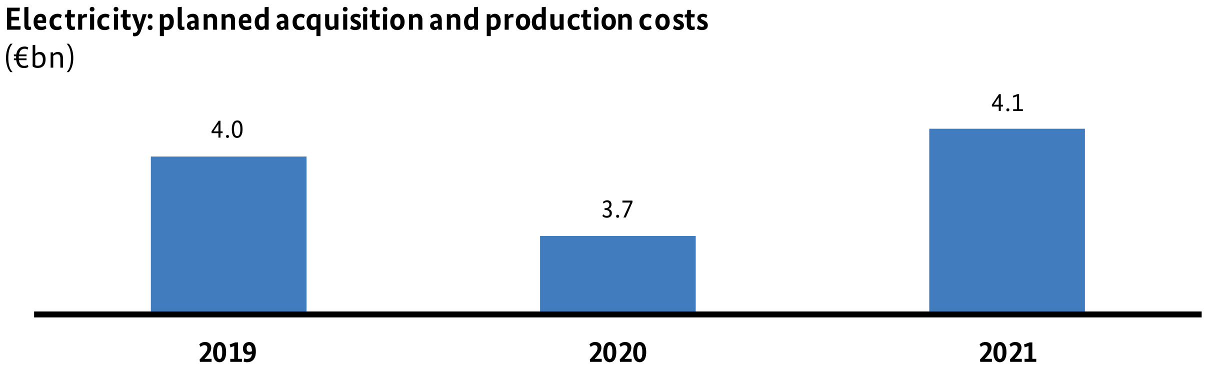

Figure 47: Planned acquisition and production costs

By 30 June 2021, the Bundesnetzagentur had approved capex mark-ups for distribution network expansion amounting to around €3.3bn for the years 2019 to 2021. This corresponds to past or planned investments totalling some €11.8bn. Through the capex mark-up, only the annual capital costs of investments, including a return on equity, feed into the revenue caps for a given calendar year.

The capex mark-ups approved by the Bundesnetzagentur are in addition to further investments of the 700 companies falling under the regulatory responsibility of the federal states as having fewer than 100,000 connected customers.

For the first time, approval of the incentive regulation account balance also made it possible to reconcile the forecasted and actual 2019 capex mark-up. This makes it clear whether or not the network operators have followed through completely with their planned investments. For 2019 the Bundesnetzagentur approved capex mark-ups totalling around €780m. The cost examination of actual expenditure showed that investments made in network infrastructure amounted to around €810m.

Electricity: top 20 DSOs on investment according to the 2020 grid expansion report
Investments in 2021 in accordance with capex mark-ups under ARegV

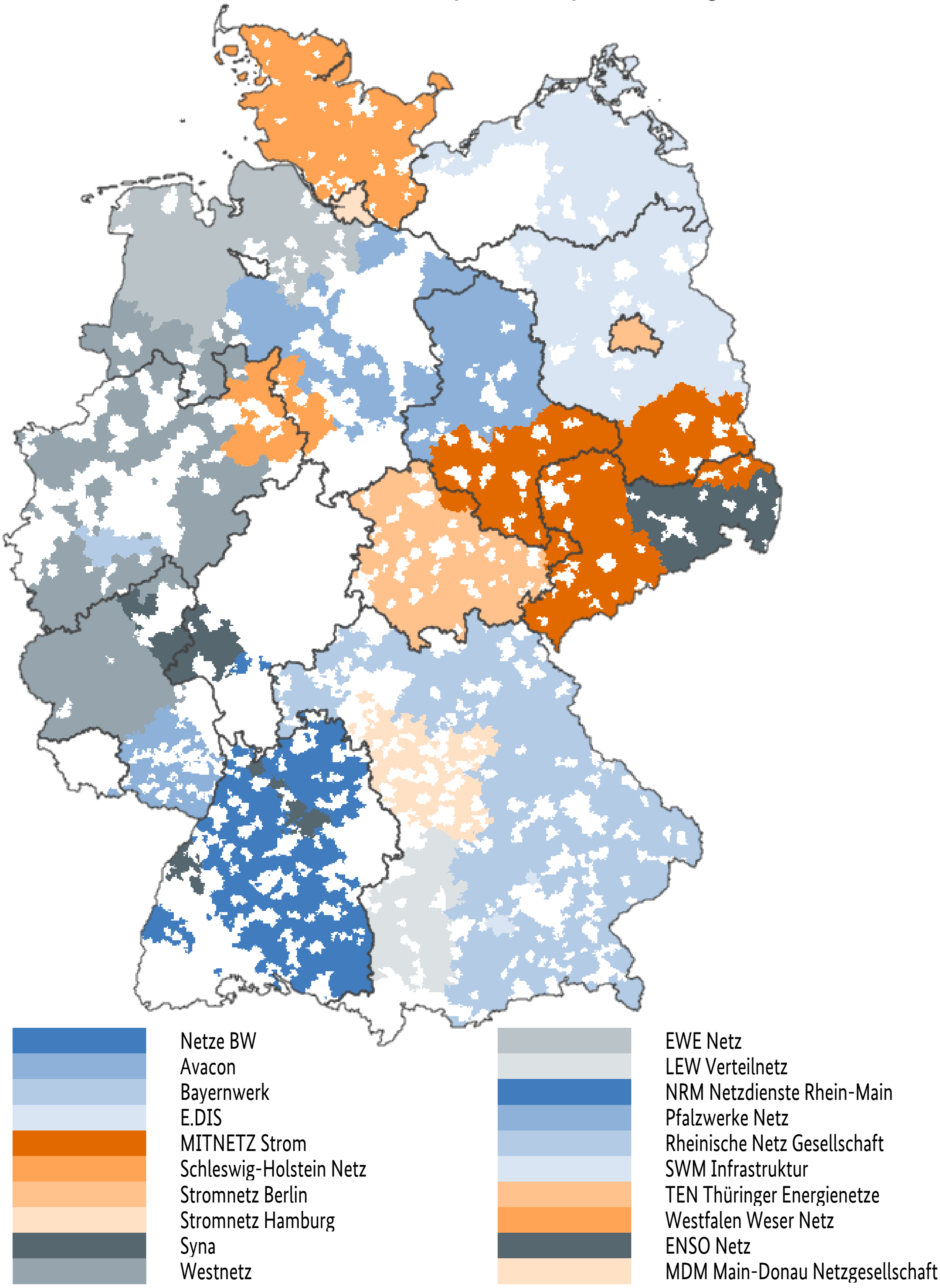

Figure 48: Top 20 DSOs on investment according to the 2020 grid expansion report. Investments in 2021 in accordance with capex mark-ups under ARegV.

3.4 Rates of return for capital stock

Investments in electricity and gas networks are extremely capital-intensive. The capital stock formed provides the key assessment basis for calculating the corporate gain, the return on equity and any interest on debt necessary through equity substitution, and the imputed corporate tax. Together with the imputed depreciation, these figures form what is known as the regulatory allowed capital costs.

3.4.1 Rate of return on equity

The assessment basis for the capital costs is essentially determined by the costs of acquisition and production, or the depreciable residual values, of the regulatory asset base (RAB). The cost of equity is obtained by adding the necessary current assets and deducting the borrowed capital. The rate of return on equity is determined on the basis of a risk-free base rate supplemented by a risk premium. The risk-entailing return on securities in the market balance can be expected to derive from the sum of the risk-free return and the risk premium (capital asset pricing model – CAPM). The risk premium is the product of the market price for the risk (market risk premium) and the risk that cannot be eliminated by diversification compared with the market as a whole (beta).

The level of the rate of return on equity is a key figure in regulated markets. The following chart shows the regulatory rates of return on equity allowed under the ARegV or through actual determinations. Separate appeals that were lodged with the Higher Regional Court of Düsseldorf for both gas and electricity supply networks against the procedure used to determine the rate of return on equity for the third regulatory period were initially successful. However, in its ruling of 9 July 2019 the Federal Court of Justice confirmed the legality of the Bundesnetzagentur's determination in its entirety.

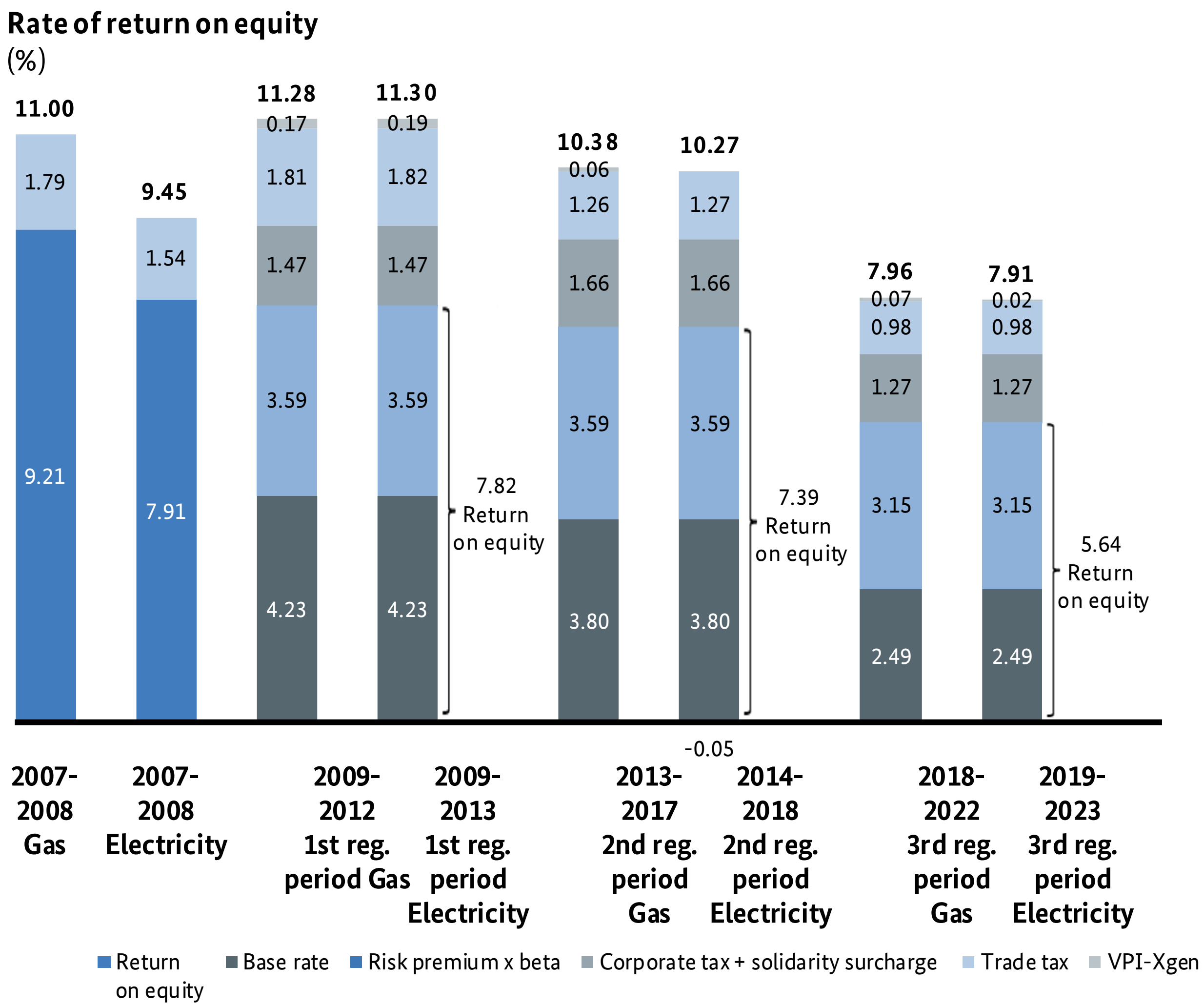

Figure 49: Rate of return on equity

3.4.2 Equity II interest rate

Equity can be substituted by the use of borrowed capital. Completely substituting equity with leverage is practically not possible since no debt capital provider would likely be willing to supply capital without any recoverable assets. The higher the equity investment is, the lower the stipulated interest rate on borrowings tends to be. When the equity investment is more than 40%, however, a regulatory thesis is applied whereby the equity investment is no longer worthwhile since an effect from lowering the interest rate on borrowings is missing. If the equity ratio is more than 40%, the portion beyond 40% is therefore treated just like borrowed capital. That is to say, any available equity capital in the capital structure earns the interest rate (averaging over 10 years) stipulated under section 7(7) of the Electricity and Gas Network Charges Ordinances (StromNEV and GasNEV) and referred to as the "equity II interest rate".

3.4.3 Interest rate on borrowings

In the various regulatory areas, borrowings are generally recognised in the amount of the actual financing conditions unless interest rates typical for the market are exceeded. The individual assessment is defined, however, by a different threshold, depending on the form of regulation. As of the third regulatory period the adjustment of capital expenditure for DSOs has been in effect. Here the interest rate on borrowings is calculated as is done with leverage using the normal incentive regulatory regime. For the third regulatory period this was set to 3.03% and 2.72% for gas and electricity respectively.

4. Electricity supply disruptions

The System Average Interruption Duration Index (SAIDIEnWG) is the average length of supply interruption experienced per connected final 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 SAIDIEnWG for 2020 is 10.73 minutes.

Operators of energy supply networks are required under section 52 of the Energy Industry Act (EnWG) 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. Network operators must also provide information on the measures required to avoid supply interruptions in the future.

The System Average Interruption Duration Index value (SAIDIEnWG [46]) does not take into account planned interruptions or those that 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 2020, 860 operators reported 162,224 interruptions in supply for 868 networks for the calculation of the SAIDIEnWG. This is a slight increase of around 2,400 compared with 2019.

The figure of 10.73 minutes of supply disruptions per final consumer for the low-voltage and medium-voltage levels is below the average from 2010 to 2020 of 14.05 minutes per year. The security of supply thus remained at a consistently high level in 2020.

[46] 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).

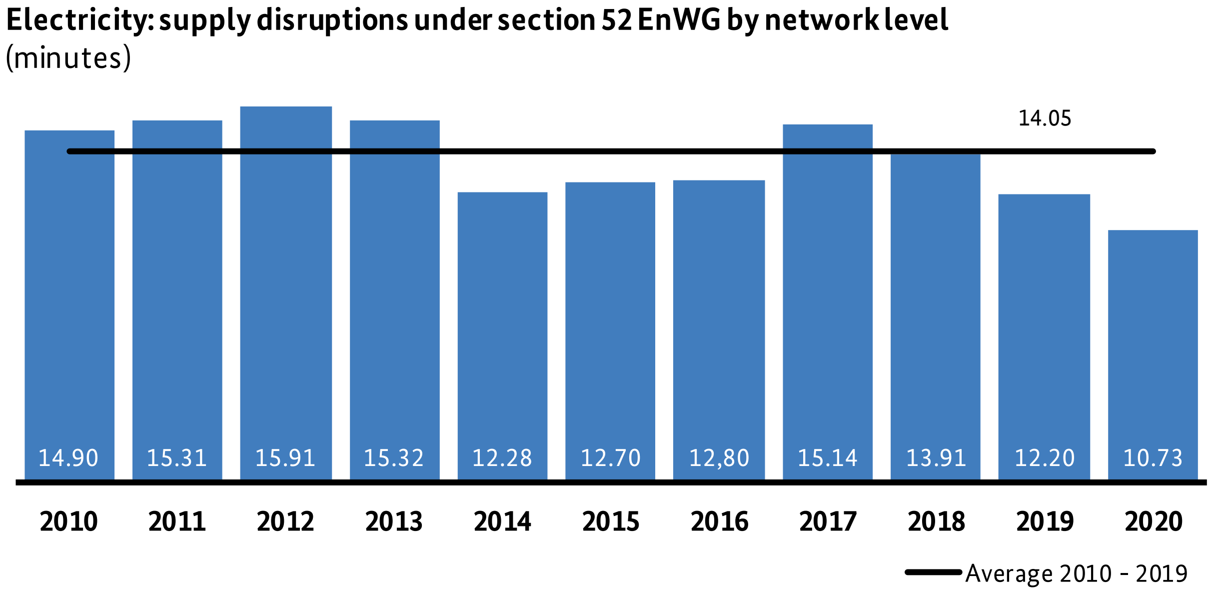

Figure 50: SAIDIEnWG from 2010 to 2020

The decrease in the average interruption duration is due to a decrease of 1.4 minutes at the medium-voltage level to 8.62 minutes. Last year's SAIDIEnWG also registered a slight decrease of 0.08 minutes to 2.11 minutes at the low-voltage level. For interruption causes used for calculating SAIDIEnWG in the 2020 reporting year, there was a decline in nearly all the effects of supply interruptions at both the low-voltage and the medium-voltage levels. Only disruptions at the low-voltage level that were "caused by third parties" registered an increase over last year. Those disruptions result, for example, from live electrical components being touched or approached by people, animals, trees, diggers, fire or flying objects.

The energy transition and the associated growth in more distributed and smaller-scale generation far from load centres again do not appear to have had a significant impact on the quality of supply in 2020.

5. Congestion management

Network operators are legally entitled and obliged to take certain measures to maintain the security and reliability of the electricity supply system. These include both network-related and market-related measures such as topological measures, interruptible and increasable loads, redispatching and countertrading, and grid reserve deployment. The following analysis does not cover network-related, or topological, measures. Market-related measures and grid reserve deployment are grouped and analysed together as congestion management.

Redispatching: reducing and increasing electricity feed-in from power plants under a contractual arrangement with, or a statutory obligation to, the network operator, with the 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 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. These volumes are still usually balanced by the balance responsible party. However, as with redispatching, economic balancing can be carried out by the network operator as well. Balancing by the requesting network operator became compulsory on 1 October 2021. This balancing can lead to costs and revenues (for example 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 the balancing.

Adjustment measures: adjusting electricity feed-in and/or offtake at the network operator's request without compensation, where other measures are insufficient.

These congestion management measures and the associated costs are reported to the Bundesnetzagentur. There was a relevant change in the structures in 2021 as a result of what is known as "Redispatch 2.0". The revised NABEG (NABEG 2.0) changed the rules for redispatching and feed-in management. Sections 13, 13a and 14 EnWG were revised with effect from 1 October 2021. The new rules affect all operators with plants with a capacity of 100 kW or more in their networks. The rules make it possible for upstream operators to involve these operators in Redispatch 2.0 measures even if no measures to ease restrictions are actually needed in the downstream operators' networks.

5.1 Overall development in 2020

The tables below summarise the regulatory content, primary mechanisms and scope of measures (redispatching with operational and grid reserve power plants, feed-in management and adjustment measures). The figures are continually updated and so may differ from the figures published in the Bundesnetzagentur's quarterly reports. These quarterly figures are published online at www.bundesnetzagentur.de/systemstudie.

The total volume of network congestion management measures was higher in 2020 than the year before. The total costs are provisionally put at around €1.4bn and are thus also slightly higher (2019: €1.3bn).

Electricity: congestion management measures under section 13 EnWG in 2020

	Redispatching	Feed-in management	Adjustment measures
Legal basis and regulatory content	Sections 13(1), 13a(1) and 13b(4) EnWG Network-related and market-related measures: topological measures such as balancing energy, interruptible loads, redispatching, countertrading, use of grid reserve	Section 13(2) and (3) sentence 3 EnWG in conjunction with sections 14 and 15 EEG, for CHP installations Feed-in management: reduction in feed-in from renewable energy, mine gas and CHP installations	Section 13(2) EnWG 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: sections 13(1), 13a(1) and 13c EnWG	Measures at network operator's request with reimbursement of costs: section 13(2) and (3) sentence 3 in conjunction with sections 14 and 15 EEG, for CHP installations in conjunction	Measures at network operator's request without reimbursement of costs: section 13(2) EnWG
Scope in reporting period	Total redispatching volume, increases and reductions of operational power plants, and increase of reserve power plants (not including test starts and test runs): **16,795 GWh**	Curtailed energy of installations remunerated under EEG (TSOs and DSOs): **6,146 GWh**	Curtailed volume from adjustment measures (TSOs and DSOs): **16.1 GWh**
Estimated costs in reporting period	Preliminary cost estimate for redispatching, countertrading, and use and contracting of grid reserve power plants: **€637.4m**	Preliminary estimated claims for compensation from installation operators under section 15 EEG (TSOs and DSOs): **€761.2m**	No entitlement to compensation for installation operators for adjustment measures under section 13(2) EnWG

Table 55: Congestion management measures under section 13 EnWG in 2020

Electricity: congestion management measures

		2018	2019	2020
Redispatching				
Total volume[1] of operational plants	GWh	14,875	13,323	16,561
Cost estimate[2] for redispatching	€m	388	227	221
Cost estimate for countertrading	€m	37	64	134
Grid reserve power plants				
Volume[3]	GWh	904	430	635
Cost estimate for activation	€m	137	82	88
Capacity[4]	MW	6,598	6,598	6,596
Annual costs of holding in reserve[5]	€m	279	197	195
Feed-in management				
Volume of curtailed energy[6]	GWh	5,403	6,482	6,146
Estimated compensation	€m	635	710	761
Feed-in adjustments				
Volume	GWh	8	9	16

[1] Amounts (reductions and increases) including countertrading measures according to monthly reports to the Bundesnetzagentur.
[2] TSOs' cost estimate based on actual measures.
[3] Activation 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] Plus other costs not dependent on deployment.
[6] Reduction of installations remunerated in accordance with the EEG or KWKG.

Table 56: Overview of congestion management measures

5.2 Development of redispatching in 2020

Section 13(1) 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.

Figure 51 shows that the majority of the redispatching measures were taken by the TSOs. Out of the around151 GWh at DSO level, a total of about 61 GWh is accounted for by DSOs' own measures requested by 18 DSOs. The following figures, tables and descriptions therefore relate to redispatching by the TSOs, as presented in the Bundesnetzagentur's quarterly reports.

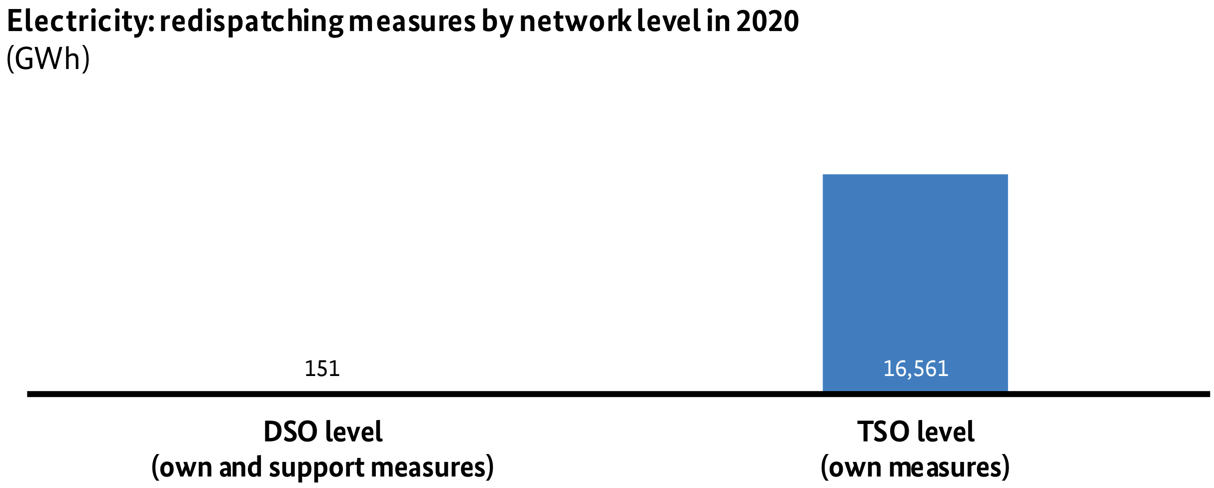

Figure 51: Redispatching measures by network level in 2020

The table below shows a breakdown of the redispatching measures taken in 2020.

Redispatching within the meaning of section 13(1) EnWG in 2020
in GWh

	2019	2020
Total	13,521	16,795
Breakdown into reductions/increases	13,521	16,795
Reductions	6,958	8,522
Increases	6,563	8,273
Operational power plants	6,365	7,891
Grid reserve power plants (without test runs/test starts)	198	382
Breakdown by type of measure	13,521	16,795
Individual overloading measures	10,800	11,561
4-TSO measures	2,721	5,235
Breakdown by reason for measure	13,521	16,795
Voltage-related	1,792	2,926
Electricity-related	11,730	13,869
Breakdown by geography	13,521	16,795
Non-cross-border	7,881	7,837
Cross-border	5,640	8,958
Countertrading	3,210	5,671

Table 57: Redispatching within the meaning of section 13(1) EnWG in 2020

The reductions and increases in feed-in from conventional operational and grid reserve power plants requested as part of the redispatching process amounted in 2020 to about 16,795 GWh (8,522 GWh of reductions and 8,273 GWh of increases). The total volume of requested reductions and increases in feed-in from power plants was therefore higher than in 2019 (13,521 GWh). The largest changes are due to the following reasons:

- In particular, the volume of voltage-related measures was higher in the second quarter than in the previous year due to the reduced load caused by the lower electricity consumption during the pandemic.

- There was a further increase in the volume of countertrading, data on which is combined with redispatching. The increase is largely due to the bilateral agreement between Germany and Denmark. This agreement provides for minimum trading capacities across the border between western Denmark and Germany as well as for cooperation between the TSOs on countertrading measures.

The costs for redispatching measures using operational and grid reserve power plants and for countertrading measures are provisionally put at around €443m in 2020 and are thus about 19% higher than the previous year's level (2019: €373m).

There are various steps to operational redispatch planning. This report makes a distinction between individual overloading measures that can be attributed to a network element 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 at an early stage.

5.2.1 Advance measures by the four TSOs

A total of 2,739 GWh was curtailed and 2,496 GWh increased on the basis of advance measures by the four TSOs (5,235 GWh overall). These measures make up 31% of the total redispatching and grid reserve volume.

According to the TSOs, it is not currently possible to allocate the jointly requested volumes of measures to the individual network elements that cause them. However, it is clear that the network elements that trigger the majority of advance measures by the four TSOs are also the ones listed in 5.2.2.

5.2.2 Individual overloading measures

The volume of reductions in feed-in through individual overloading measures in the whole of 2020 amounted to around 5,783 GWh. Increases in feed-in for balancing were around 5,778 GWh. The total volume of these redispatching measures was thus approximately 11,561 GWh, which represents an increase of 7% compared with 2019.

Electricity-related individual overloading measures

Electricity-related individual overloading measures can be attributed to specific network elements and are best illustrated on a map. The numbering of the network elements in Tables 58 and 59 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 the tables, were included. The numbers serve to identify the network elements on the map (Figure 52), which shows the location of the critical network elements from the tables (at least 50 hours of overload per line).

Electricity: electricity-related redispatching on the most heavily affected network elements in 2020

No	Network element	Control area[1]	Duration (hours)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)
1	Dollern-Sottrum	TenneT	1264	751	746
2	Altheim (Altheim-Sittling, Altheim-Simbach-Sankt Peter (AT))	TenneT	955	420	419
3	Landesbergen (Landesbergen-Wechold-Sottrum)	TenneT	322	163	162
4	Lehrte - Mehrum circuit	TenneT	303	32	31
5	Mecklar - Dipperz	TenneT	246	94	92
6	Daxlanden area (Daxlanden-Maximiliansau-Goldgrund, Daxlanden-Weingarten)	TransnetBW/ Amprion	215	52	53
7	Dipperz - Großkrotzenburg	TenneT	204	71	71
8	Ovenstädt-Bechterdissen (Ovenstädt-Eickum-Bechterdissen)	TenneT	166	44	44
9	Dörpen (Dörpen-Niederlangen-Meppen-Hanekenfähr)	TenneT/ Amprion	131	35	34
10	Kontek (DK - Zealand island)	50Hertz	129	8	8

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

Table 58: Electricity-related redispatching on the most heavily affected network elements in 2020

Electricity: electricity-related redispatching on the most heavily affected network elements in 2020

No	Network element	Control area[1]	Duration (hours)	Volume of feed-in reductions (GWh)	Volume of feed-in increases (GWh)
11	Neuenhagen - Vierraden - Pasewalk line	50Hertz	124	34	34
12	Borken - Waldeck - Twistetal circuit	TenneT	116	56	56
13	Bergshausen - Borken circuit	TenneT	109	31	31
14	Pleinting - Sankt Peter/APG circuit	TenneT	97	43	43
15	Landesbergen - Ovenstädt circuit	TenneT	78	43	42
16	Bürstadt-Lambsheim	Amprion	76	20	20
17	Sottrum - Huntorf - Conneforde	TenneT	73	23	21
18	Krümmel - Hamburg line	50Hertz/ TenneT	58	23	23
19	Audorf - Flensburg	TenneT	57	17	17

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

Table 59: (continuation of Table 58) Electricity-related redispatching on the most heavily affected network elements in 2020

Elektrizität: Dauer von strombedingten Redispatch Einzelüberlastungsmaßnahmen auf den am stärksten betroffenen Netzelementen im Gesamtjahr 2020

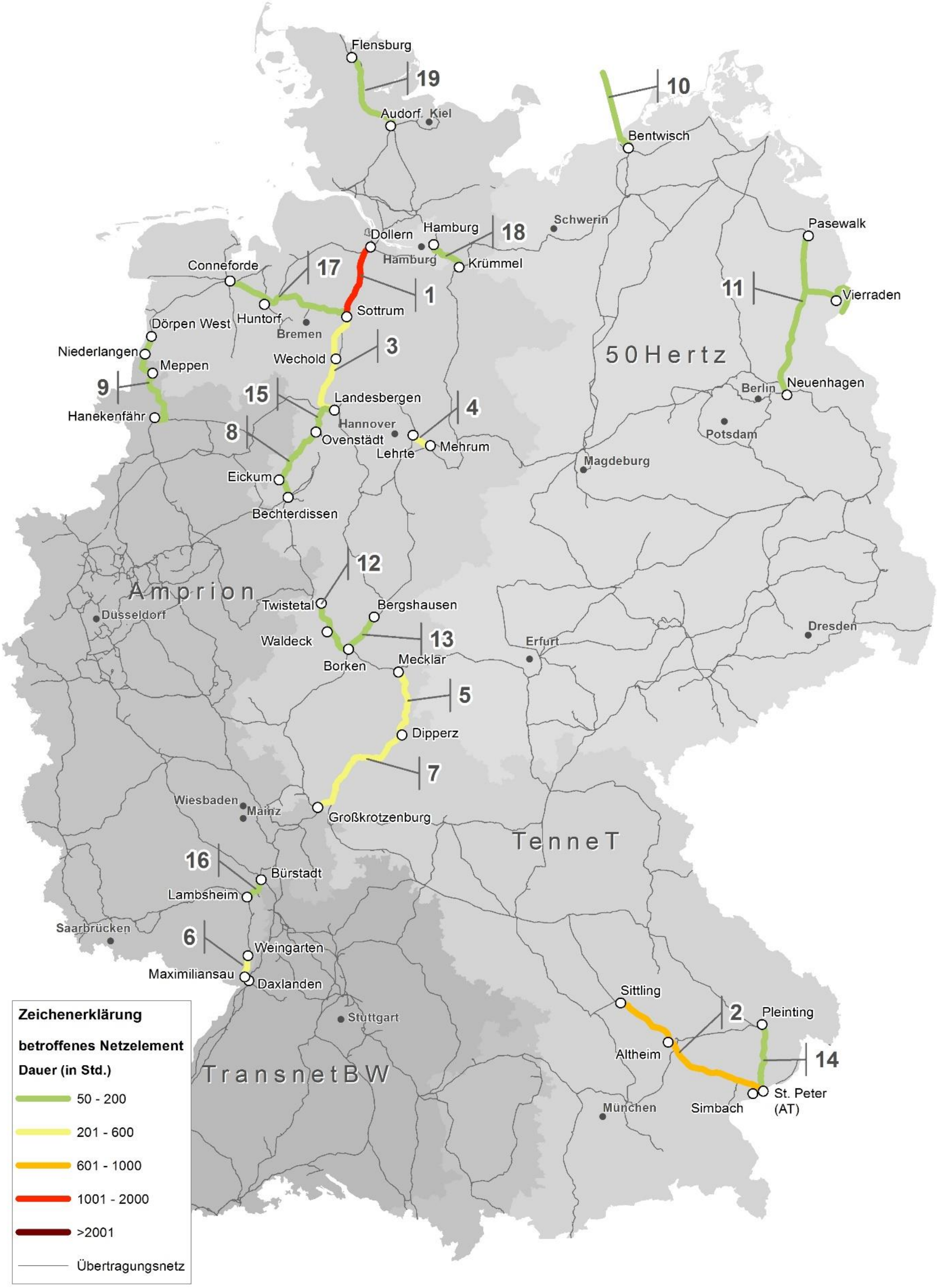

Figure 52: Duration of electricity-related redispatching measures in cases of individual overloading of the most heavily affected network elements in 2020

Voltage-related individual overloading measures

In addition to electricity-related redispatching, the TSOs reported voltage-related redispatching measures with a total volume of around 2,926 GWh in 2020. Voltage-related measures are balanced by countertrades on the exchange. The need for voltage-related redispatching measures was much greater than in the previous year (2019: 1,792 GWh).[47] The need for reactive power largely depends on the level of utilisation of the lines. Additional reactive power (voltage-related redispatching) may be needed with both a high and a low level of utilisation.

Table 60 shows the duration and volume of the measures required in the individual control and network areas.

Electricity: voltage-related redispatching in 2020[1]

Network area	Duration (hours)	Volume (GWh)
TenneT control area	**4,138**	**1,529**
Oberbayern network area (voltage)	1,393	454
Dipperz - Großkrotzenburg	1,247	552
Ovenstädt-Bechterdissen-Borken network area (voltage)	1,217	455
Mehrum-Grohnde-Borken	174	34
Borken/Gießen	81	26
Conneforde	16	7
Lehrte-Helmstedt-Krümmel network area (voltage)	7	1
Göttingen-Hardegsen-Erzhausen-Lehrte	1	4
TransnetBW control area	**1,253**	**574**
Altbach Daxlanden network area	942	444
Mittlerer Neckar, Obere Rheinschiene	310	130
50Hertz control area	**782**	**690**
Amprion control area	**313**	**132**
No network area information	233	104
Mittelbexbach	80	28

[1] Since voltage-related redispatching measures relate to larger network regions (and not individual lines or transformer stations), the measures are not illustrated on a map.

Table 60: Voltage-related redispatching in 2020

47 Voltage-related redispatching involves adjusting the feed-in from power plants in order to make adjustments to the reactive power provided. Voltage-related measures often do not need to be balanced locally and are therefore usually balanced via the intraday market.

5.2.3 Deployment of power plants in redispatching

In 2020, a total volume of 11,085 GWh (4,048 GWh of reductions and 7,037 GWh of increases in feed-in) was provided by operational plants within Germany and grid reserve power plants both in and outside Germany to ease network restrictions.

Figure 53 shows a breakdown of the power plants deployed for redispatching by energy source. Some redispatching takes place on the exchange and is classed as "unknown" since it cannot be allocated to any one energy source. These transactions on the exchange are mainly for voltage-related redispatching. 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".

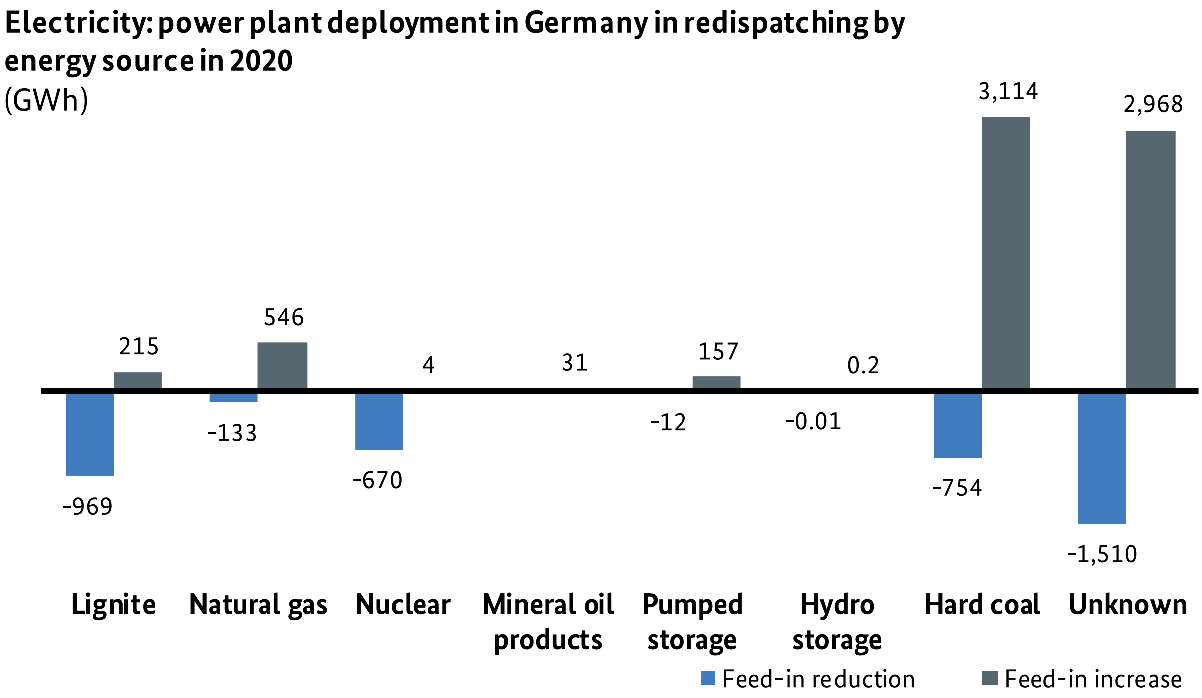

Figure 53: Power plant deployment in redispatching by energy source in 2020

Table 61 shows power plant deployment across the individual federal states.

Breakdown of power plant deployment by German TSOs by federal state in 2020

Federal state	Reduction	Increase
Baden-Württemberg	Up to 10 GWh	More than 1,000 GWh
Bavaria	Up to 100 GWh	Up to 500 GWh
Brandenburg	Up to 500 GWh	Up to 50 GWh
Bremen	Up to 100 GWh	0 GWh
Hamburg	Up to 250 GWh	0 GWh
Hesse	Up to 10 GWh	Up to 1,000 GWh
Mecklenburg-Western Pomerania	Up to 50 GWh	Up to 50 GWh
Lower Saxony	Up to 1,000 GWh	Up to 100 GWh
North Rhine-Westphalia	Up to 500 GWh	Up to 1,000 GWh
Rhineland-Palatinate	Up to 50 GWh	Up to 100 GWh
Saarland	Up to 1 GWh	Up to 250 GWh
Saxony	Up to 250 GWh	Up to 250 GWh
Saxony-Anhalt	Up to 10 GWh	Up to 50 GWh
Schleswig-Holstein	Up to 500 GWh	0 GWh
Thuringia	Up to 10 GWh	Up to 10 GWh

Table 61: Breakdown of power plant deployment by German TSOs by federal state in 2020 (GWh)

5.2.4 Redispatching measures duration curve

The curve illustrates the redispatching measures required in Germany in each hour over the course of the year in decreasing order of the volume of energy reduced. The curve shows in how many hours of the year the volume of redispatched energy was above or below a certain level.

Electricity: redispatched energy (reductions) in decreasing order per hour in Germany in 2020 (MW)

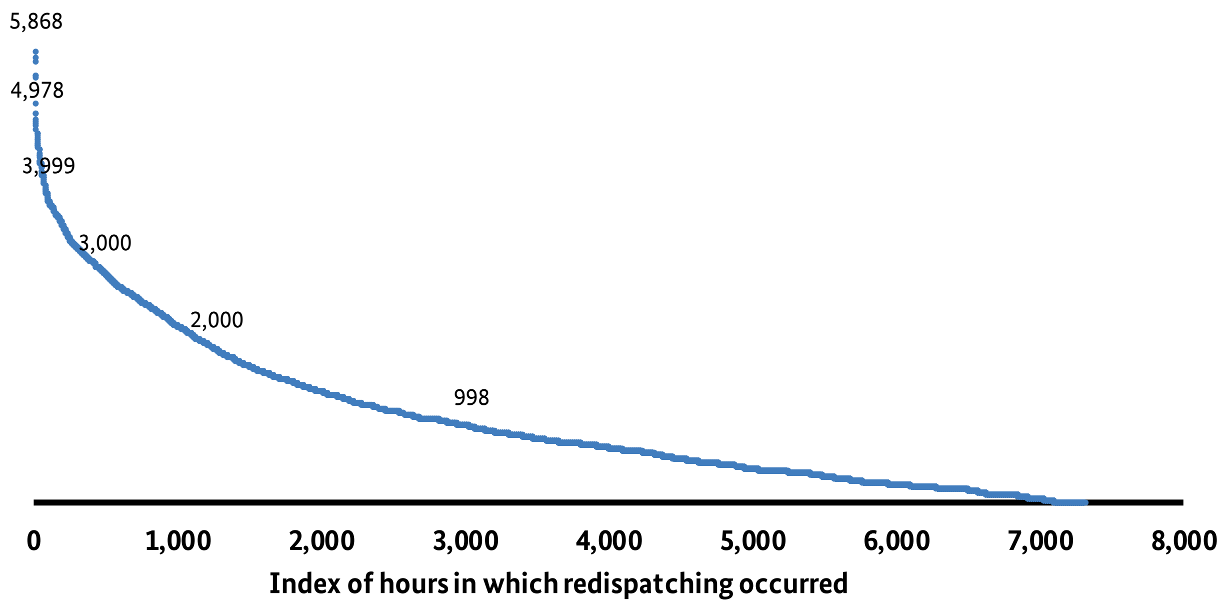

Figure 54: Redispatched energy (reductions) in decreasing order per hour in Germany in 2020

In 2020, the largest required reduction was 5,868 MW. The volume of redispatched energy was higher than 5,000 MW in 132 individual hours. No redispatching measures were carried out in 1,596 hours.

5.2.5 Countertrading

Cross-border countertrading, which forms part of the individual overloading measures, made up about 5,671 GWh of the total redispatching volume in the whole of 2020 (2019: 3,210 GWh). Countertrading incurred costs of around €134m, which also represents a large year-on-year increase (2019: €64m).

The increase is largely due to the bilateral agreement between Germany and Denmark and to antitrust proceedings by the European Commission against the TSO TenneT TSO GmbH. Both provide for minimum trading capacities across the border between western Denmark and Germany as well as for cooperation between the TSOs on countertrading measures. The antitrust proceedings involved TenneT TSO GmbH committing to make an incremental increase in the minimum trading capacity up to the target of 1,300 MW in the year under review. It is planned to gradually increase the minimum trading capacity further in line with grid expansion.

5.2.6 Deployment of grid reserve capacity

In 2020, the grid reserve was used on 191 days to provide a total of around 635 GWh of energy. Grid reserve power plants can be called upon both as a 4-TSO advance measure or as an individual overloading measure. The TSOs estimate the costs of using them at about €88m. The preliminary costs of holding them in reserve plus other costs not dependent on their deployment amounted to €194.8m.

Table 62 summarises the use of the grid reserve. The average deployment in MW shows the average volume of reserve requested per day of deployment.

Electricity: summary of grid reserve deployment in 2020

	Number of days	Average deployment (MW)	Maximum volume of use (MW)	Total (MWh)
January	9	148	622	12,832
February	14	228	1,145	41,638
March	8	121	342	10,147
April	14	183	872	31,022
May	22	232	930	85,851
June	24	246	560	95,267
July	20	208	912	58,588
August	19	226	745	71,112
September	21	297	990	71,576
October	10	156	385	18,324
November	17	322	1,049	95,149
December	13	231	740	43,569
Total	**191**			**635,074**

Source: TSOs' reports of redispatching power plant deployment to the Bundesnetzagentur

Table 62: Grid reserve deployment in 2020

5.3 Feed-in management measures and compensation

Feed-in management is a special congestion management 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.

5.3.1 Curtailed energy

The chart and table below show the amount of unused energy as a result of feed-in management measures for the energy sources most affected by such measures since 2011.

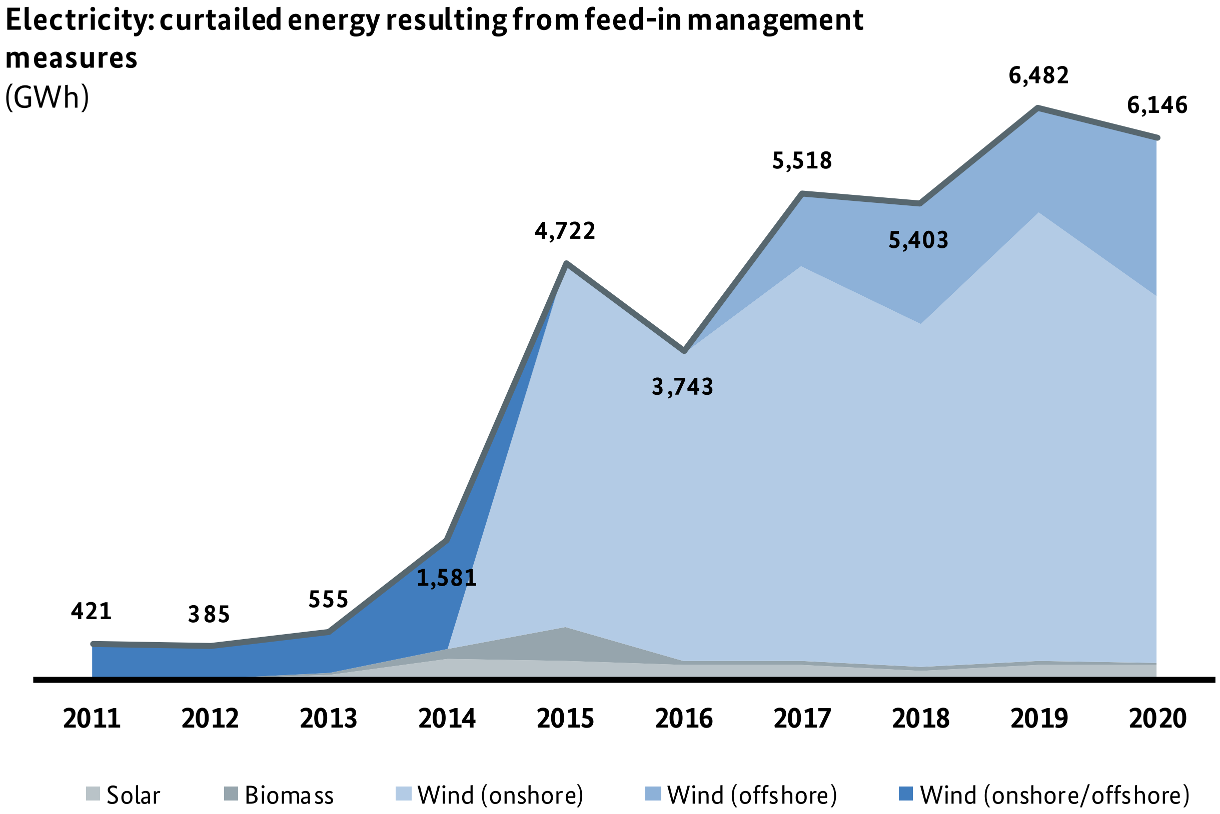

Figure 55: Curtailed energy resulting from feed-in management measures

Electricity: curtailed energy resulting from feed-in management measures
(GWh)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wind	409.7	358.5	480.3	1,221.5	4,124.9	3,530.1	5,287.2	5,246.9	6,272.5	5,942.2
Wind (onshore)					4,110.6	3,498.0	4,461.2	3,890.5	5,084.8	4,145.0
Wind (offshore)					14.3	32.0	826.0	1,356.3	1,187.6	1,797.3
Solar	2.6	16.1	65.5	245.2	227.7	184.1	163.1	116.5	177.6	164.8
Biomass	5.9	9.4	8.8	112.1	364.4	26.5	61.1	35.7	30.2	34.9
Other	2.4	0.8	0.2	1.8	21.1	2.6	6.6	3.6	2.3	4.1
Total	**420.6**	**384.8**	**554.8**	**1,580.6**	**4,722.3**	**3,743.2**	**5,518.0**	**5,402.7**	**6,482.5**	**6,146.0**

Table 63: Curtailed energy resulting from feed-in management measures

The amount of energy curtailed as a result of feed-in management measures decreased by a good 5% from 6,483 GWh in 2019 to 6,146 GWh. The decline was probably due to the network expansion projects in Schleswig-Holstein successively going into operation.[48]

[48] These include the "central axis" with the line between Hamburg/Nord and Dollern and the west coast line.

The amount of energy curtailed as a result of feed-in management measures corresponds to 2.8% of the total amount of electricity generated by installations eligible for payments under the EEG (including direct selling) (2019: 2.9%).[49] Thus around 97% of the renewable energy marketed in 2020 was produced and made available to users.

The level of feed-in management measures is essentially due to various factors, including the weather and the increase in renewable capacity. Given the level of curtailed energy and assuming that there will be a further steady increase in renewables, the measures required for network optimisation, reinforcement and expansion need to be implemented without delay. Detailed and up-to-date information on feed-in management measures is included in the Bundesnetzagentur's quarterly reports on congestion management measures.[50]

The table below shows a breakdown of curtailed energy by energy source.

Electricity: curtailed energy resulting from feed-in management measures by energy source in 2020

Energy source	Curtailed energy (GWh)	Percentage of total (%)
Wind (onshore)	4,144.95	67.4
Wind (offshore)	1,797.25	29.2
Solar	164.77	2.7
Biomass, including biogas	34.91	0.6
CHP electricity	3.39	0.1
Run-of-river	0.46	< 0.1
Other	0.21	< 0.1
Landfill, sewage and mine gas	0.07	< 0.1
Total	**6,146.02**	**100**

Table 64: Curtailed energy resulting from feed-in management measures by energy source in 2020

The network operators' reports on congestion management measures provided the following details of the use of feed-in management: the operators' monthly reports to the Bundesnetzagentur show that the TSOs were responsible for the majority of the feed-in management measures taken in 2020. Overall, restrictions in the transmission networks accounted for around 79% of the energy curtailed, although installations connected to transmission networks accounted for only around 31% of the energy curtailed and compensated. The remaining amount – approximately 69% – was accounted for by installations connected to distribution networks.

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

[50] https://www.bundesnetzagentur.de/systemstudie

Electricity: network levels of curtailments and cause of feed-in management measures in 2020

	Curtailed energy (GWh)	Percentage of total curtailed energy (%)
Measures taken by TSOs (cause in transmission network)	**1,881**	**31**
Measures taken by DSOs	**4,265**	**69**
DSOs' own measures (cause in distribution network)	1,276	21
DSOs' support measures (cause in transmission network)	2,989	49
Total feed-in management measures	**6,146**	**100**

Table 65: Network levels of curtailments and cause of feed-in management measures in 2020

Although many regions in Germany now require feed-in management measures, around 81% of curtailed energy from such measures occurs in the federal states of Schleswig-Holstein and Lower Saxony, with Schleswig-Holstein being particularly affected (about 58%, see Figure 56).

Electricity: curtailed energy by federal state in 2020

(GWh)

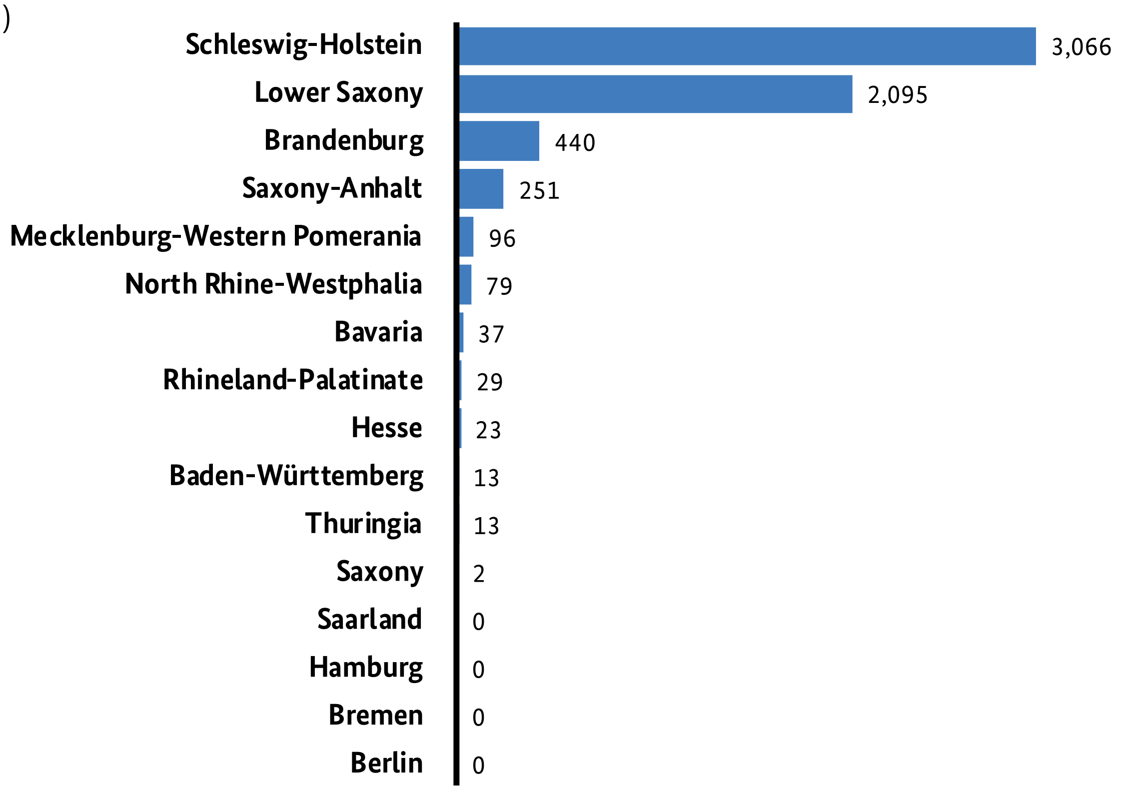


Figure 56: Curtailed energy by federal state in 2020

5.3.2 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 monthly basis. The costs incurred can therefore be directly compared with the amount of curtailed energy.

The actual compensation paid is the amount of compensation paid by the TSOs and DSOs to installation operators during the year under review. This is reported once a year in the monitoring survey. It includes the costs of compensation for measures taken up to three years previously. Consequently, the compensation paid in one year does not reflect the actual costs incurred for curtailments in that year. The questionnaire 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.[51]

The amount of compensation paid to installation operators in 2020 was about €919m, down around €139m on 2019 (2019: €1,058m). Around 1.9% (€17.8m) comprises compensation for feed-in management measures taken because of restrictions caused by remedial or maintenance measures. Most of the compensation paid in 2020 came under the EEG payments, with about €78,000 coming under the CHP payments. The costs of the compensation paid to the installation operators are borne by the network charges paid by final customers, adding an average of around €17.67 per final customer in 2020 (2019: €20.43; 2018: €13.98; 2017: €11.37; 2016: €10.13; 2015: €6.26; 2014: €1.65). The additional costs are higher for final customers in regions particularly affected by feed-in management measures. These higher costs are offset by lower surcharges payable by the customers in all network areas under the EEG, since no payments have to be paid for the electricity generated but not fed in from the renewable and CHP installations. The chart below shows the compensation paid each year since 2011 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 2020 therefore does not reflect the actual amounts payable for the curtailments in 2020. The compensation paid in 2020 also includes amounts payable for curtailments in previous years.

[51] 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 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.

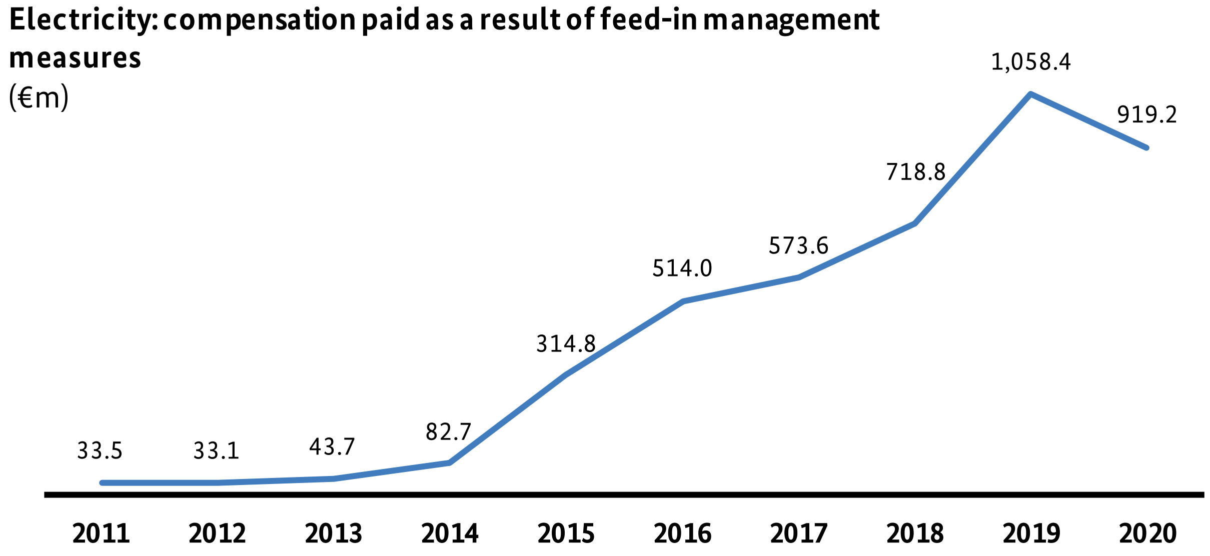


Figure 57: Compensation paid as a result of feed-in management measures

The claims for compensation from installation operators in 2020, based on the network operators' monthly estimates, amounted to around €761m, some €51m higher than in 2019.[52] This rise, which amounts to about 7%, was caused by the greater curtailment of offshore wind turbines.

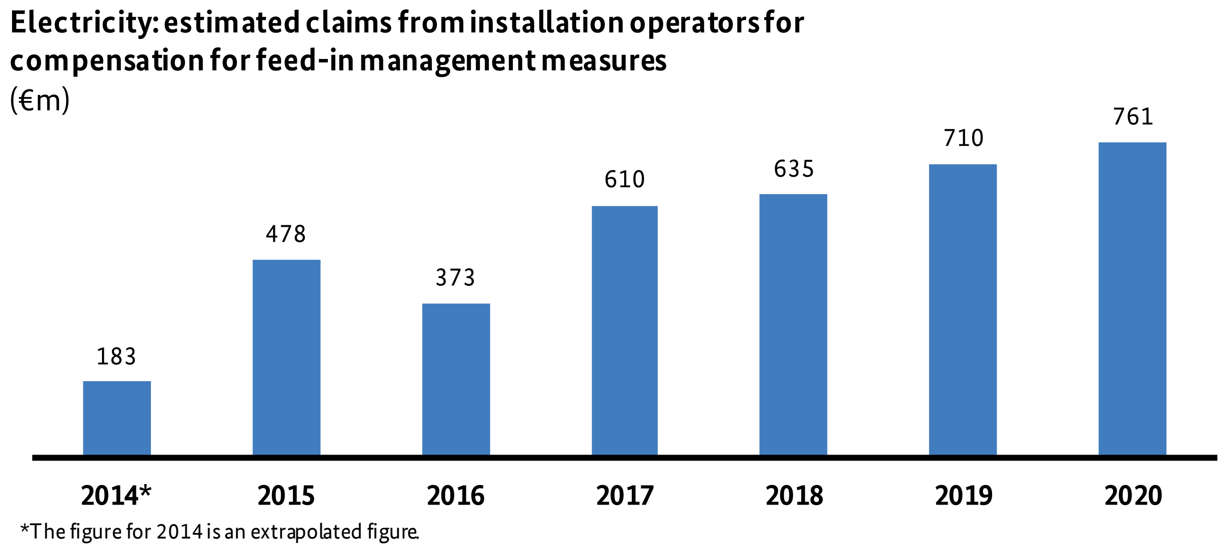


Figure 58: Estimated claims from installation operators for compensation for feed-in management measures

In 2020, the network operators paid a total of around €919m in compensation to the installation operators. Approximately €576m was compensation for curtailments actually occurring in 2020, while the remaining amount of around €343m was compensation for curtailments in previous years. This means that some 76% of the claims from installation operators for compensation for curtailments in 2020, as estimated by the network operators, have already been settled. At the time of the survey, around 24% (€185m) of the estimated compensation claims had not yet been settled; this will have a knock-on effect on the amount of

[52] See the Bundesnetzagentur's quarterly reports available at https://www.bundesnetzagentur.de/systemstudie.

compensation paid in subsequent years. The table below shows the detailed figures for the network operators' estimates of compensation claims and the actual compensation paid.

Electricity: compensation claims and payments by measures taken and causes of feed-in management measures according to network operators' reports in 2020

	Estimated claims for compensation from installation operators (€m) (for measures in 2020)		Total compensation paid (€m) (in 2020)		Compensation for measures in previous years (€m)
Measures taken and compensation paid by TSOs (cause in transmission network)	**367**	**48%**	**339**	**37%**	**129**
Measures taken and compensation paid by DSOs	**394**	**52%**	**581**	**63%**	**214**
DSOs' own measures (cause in distribution network)	120	15.7%	141	15.3%	59
DSOs' support measures (cause in transmission network)	274	36.0%	440	47.8%	155
Total feed-in management measures	**761**	**100%**	**919**	**100%**	**343**

Table 66: Compensation claims and payments by measures taken and causes of feed-in management measures according to network operators' reports in 2020

5.4 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.

In 2020, a total of six DSOs took adjustment measures. Brandenburg accounted for the majority of the adjustment measures with some 85%, followed by Saxony-Anhalt with about 14% and Thuringia with around 1%. The table below shows a breakdown by energy source.

Electricity: feed-in and offtake adjustments by energy source in 2020

Energy source	Adjustments under section 13(2) (GWh)	Percentage of total (%)
Waste (non-biodegradable)	16.32	97%
Natural gas	0.43	3%
Total	**16.75**	**100%**

Table 67: Feed-in and offtake adjustments by energy source in 2020

6. Network charges

Network charges make up 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 made up around 23% of the price in 2021 for household customers with an annual consumption of between 2,500 kWh and 5,000 kWh. Following an increase in 2020, the network charges for household customers remained largely stable in 2021, increasing from 7.50 ct/kWh in 2020 to 7.52 ct/kWh in 2021.

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 between a small number of network users.
- Differences in the costs of feed-in management measures.
- Network age: older networks with a low residual value entail lower network costs than new networks.
- Network quality: this has a direct influence on the revenue cap through the quality element.

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). Network charges are based on the costs incurred by the network operators for the efficient operation, maintenance and expansion of their networks. These regulated costs are the basis for the rates 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. Producers of electricity (and thereby those 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 as set out below.

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 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 cost examination for the currently ongoing third regulatory period (2019–2023) 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 economically proven and necessary for network operation, which in turn form the basis for setting the current revenue caps. The fourth regulatory period begins on 1 January 2024 on the basis of the costs of the year 2021.

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 ARegV. The revenue cap stipulates the revenue each operator is allowed to generate over the years of a regulatory period. 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 the third regulatory period, a relative generic network analysis to measure efficiency is applied for TSOs.[53] Any inefficiencies revealed in the analysis are to be remedied over the course of the 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 I.C.6.4) or for the use of upstream network levels; costs for redispatch and feed-in management (see I.C.5.2 and I.C.5.3). For TSOs, there is an array of costs for means to ensure security of supply and grid expansion, in particular costs for investment measures

[53] According to section 22(2) ARegV, a relative generic network analysis establishes relative divergencies between the costs of actual plant volumes and the costs of a generic network as a result of a comparison of a number of operators. The operator with the least divergence from the generic network is taken as the efficiency benchmark for establishing the efficiency levels; the efficiency level of this operator is stated at 100%.

pursuant to section 23 of the ARegV (see section I.C.3.3), costs for redispatching with grid reserve power plants (see section I.C.5.2.6) and costs of procuring balancing reserves (see chapter I.D.1).

- The retail price index, which reflects general inflation.

- The capex mark-up (see I.C.3.3.2), which ensures adjustment of the DSOs' revenue caps in line with the (projected) cost of capital of investment in new assets as from the beginning of the third regulatory period on 1 January 2019. No distinction is made here between replacement and enhancement or expansion expenditure.

- 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. This applies particularly in the case of differences between forecast and actual consumption quantities leading to higher or lower revenues. Various other permanently non-controllable cost items (including costs for approved investment measures and for the necessary use of upstream network levels) as well as the approved capex mark-up figures are initially taken into account in the revenue cap as planning figures. Then the difference to the costs actually incurred is 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.

Until now, the revenue caps allowed for the individual network operators were to be published by the competent regulatory authority in accordance with section 31 ARegV. The obligation to publish now comes from section 23b EnWG, the section explicitly transferring publication requirements from section 31 ARegV to the EnWG and partially supplementing it. In light of the Federal Court of Justice (BGH) ruling[54], the entry into force in 2021 of section 23b of the amended EnWG created a new legal basis for publication requirements directly in the EnWG.

Deriving the network charges

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

The specific annual costs in euros per kilowatt ("postage stamp" tariff) are then calculated beginning with the highest network or substation level operated. They result from dividing the assigned level's total costs by the concurrent annual peak load of the level. The "coincidence function" (section 16 StromNEV) is applied to derive four charges from these specific annual costs: a capacity charge and a unit charge for less than 2,500 hours and for 2,500 hours or more of network usage. The basic idea of the coincidence function 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. This probability is reflected in a network user's hours of usage and is shown in the

[54] BGH, ruling of 11 December 2018 - EnVR 21/18.

charging scheme by the different charges for more than or equal to 2,500 hours and less than 2,500 hours of network usage. Network users with a small number of usage hours thus have to pay a relatively low capacity charge and a high unit charge, while network users with a large number of usage hours have to pay a relatively high capacity charge and a low unit charge. A unit charge and, in some cases, a standing charge is to be set for non-interval-metered network users at low-voltage level (those with an annual offtake of less than 100,000 kWh from the low-voltage network – mainly household customers and smaller commercial customers). In this case, there is no general rule, but under section 17(6) StromNEV the unit charge and the standing charge must be "in reasonable proportion" to each other, which allows for a certain margin.

The expected revenues of the network level are determined on the basis of the planned sales volumes and the derived network charges. The difference between the costs allocated to the network level and the expected network charge revenues of the level (in other words the block of costs not covered at that level) is passed on to the next network level and added to the costs of that next level. 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 costs allocated to the level 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) StromNEV 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.

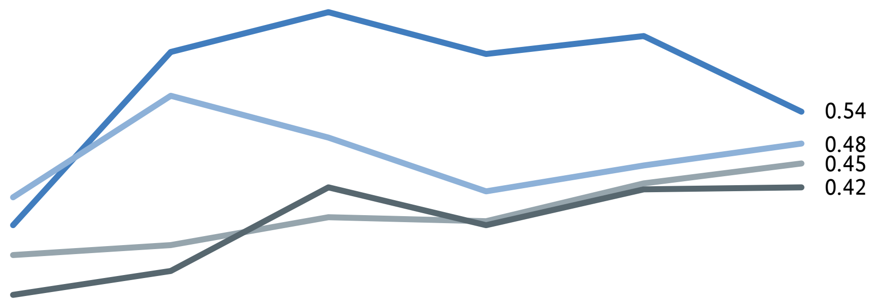
Other surcharges that form components of the final consumer price are detailed in I.G.4.3.

6.2 Development of network charges in Germany

6.2.1 Development of network charges at TSO level

The following chart shows the four TSOs' network charges from 2016 to 2021 for an example large industrial customer connected to the extra-high voltage level with an annual consumption of 850 GWh, an annual maximum load of 190 MW and around 4,500 usage hours, assuming a network charge reduction of 75% pursuant to section 19(2) sentence 1 StromNEV.

Electricity: TSOs' network charges
(ct/kWh)



	2016	2017	2018	2019	2020	2021
TenneT	0.35	0.64	0.70	0.63	0.66	0.54
50Hertz	0.40	0.56	0.50	0.41	0.45	0.48
TransnetBW	0.31	0.32	0.37	0.36	0.42	0.45
Amprion	0.24	0.28	0.41	0.35	0.41	0.42

Figure 59: Transmission network charges

Network charge trends in the individual control areas are influenced in particular by the changes to a given TSO's revenue cap and as from 2019 also by the regional effect of the gradual harmonisation of transmission network charges throughout Germany. The level of each revenue cap is, in turn, determined primarily by the grid expansion costs, as well as by the costs for feed-in management and redispatching, and also by the costs for grid reserve and security standby. The network charge increases at the beginning of the 2016-2021 period are due in particular to rising grid expansion costs and cost increases for grid reserve, but also due to rising costs for redispatching and feed-in management measures. The decrease in the network charge in the 50Hertz control area in 2018 was, however, largely due to the costs saved through redispatching and feed-in management measures in the commissioning of the "Thuringia power bridge". The main reason for the decrease in the network charges in all four control areas in 2019 was the implementation of the Network Charges Modernisation Act (NEMoG), on the basis of which in 2019 the offshore connection costs were removed from the transmission network charges for the first time and transferred to the new offshore network surcharge. (If the offshore costs in 2018 and 2019 were presented in such a way that the offshore cost items are comparable, the decreases in the charges in 2019 appear significantly less than in 2018. In the TransnetBW control area there is even an increase in network charges for the sample customer[55]). The increase in transmission network charges in 2020 is largely the result of a revenue cap increase at all four TSOs, which is due, among other things, to rising costs of grid expansion and increased predicted costs for procuring balancing energy caused by higher balancing energy prices in the reference period 2018/19. The

[55] For a breakdown of the offshore network surcharge and an analysis of the comparability of the network charges with and without a surcharge see also the Monitoring Report 2019 Chapter 6.3.1.

increase in the control areas Amprion, 50Hertz and TransnetBW is a result of the ongoing process to gradually harmonise transmission network charges in Germany.

Only the TenneT control area saw a decrease in transmission network charges in 2021. This decrease is due, among other things, to a decreasing revenue cap and the relieving effect for TenneT of the step-by-step harmonisation of the transmission network charges in Germany, which has already led to a recovery of 60% of the respective network charges nationwide in 2021. Although Amprion's revenue cap is also decreasing, the transmission network charge harmonisation process leads to transmission network charge increases. Overall, other factors offset the effect of the lower revenue cap and the transmission network charges increase slightly. This year, 50Hertz will be able to benefit for the first time from the gradual harmonisation of the transmission network charges in Germany. However, there is overcompensation for the effect by, among other things, a revenue cap increase. By contrast, at TransnetBW the effect of a revenue cap increase is further amplified by, for instance, rising charges associated with the equalisation of network charges that is gradually being implemented throughout Germany.

In the next few years it is assumed that there will be an upward trend in the TSOs' network charges as a result of expected continued investment in grid expansion and the costs for the emergency power stations (referred to as special grid facilities under section 11(3) of the old version of the EnWG) that were contractually bound by the TSOs in 2021. The trend, however, depends strongly on the costs for redispatching, which are not predictable and depend on, among other things, the level of actual volatile feed-in.

6.2.2 Development of average network charges

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 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 maximum load 50 kW, annual usage period 1,000 hours, low-voltage supply (0.4 kV);

- industrial customers: annual consumption 24 GWh, annual maximum 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 StromNEV.

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.

In the period up to 2011, the first cost examinations since the introduction of regulation led to falling network charges. Various factors have influenced the rise in network charges since 2012 as well as the consistently high level. For instance there was an increase in distributed feed-in, which led to higher costs from paying what are called 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 power stations made further grid expansion necessary. All of these factors pushed up network costs. A turning point occurred in 2018, and in the period from 2017 to 2018 the volume-weighted average network charge fell by around 2%. The main reason for the drop was the effect of the NEMoG bringing down costs for avoided network charges. Despite the exclusion of the offshore connection costs from the network charges and a further reduction in the avoided network charges under the NEMoG, this trend did not continue for reasons including increasing grid expansion costs and projected high costs for system security measures. However, the national average network charge for household customers only rose marginally in 2021 by 0.2% from 7.50 ct/kWh to 7.52 ct/kWh, and is thus on a stable level.

Electricity: average volume-weighted network charges (incl. meter operation) for household customers
(ct/kWh)

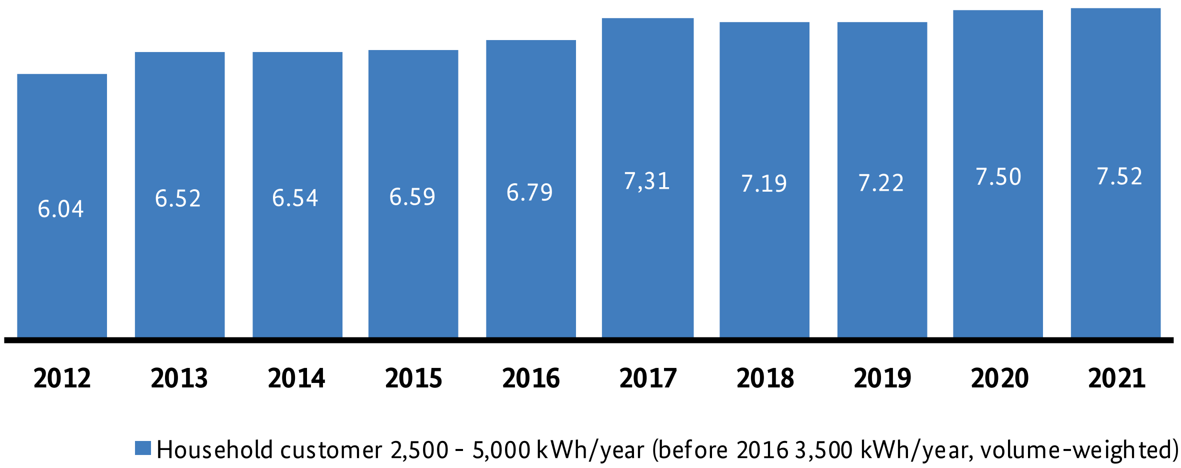


Figure 60: Average volume-weighted network charges for household customers from 2012 to 2021

According to information from distribution system operators under the responsibility of the Bundesnetzagentur on the provisional network charges for 2022, the average network charge in Germany will increase noticeably. Reasons include higher upstream network costs in the control areas of Amprion and TransnetBW, investments in the networks, rising non-wage labour costs for many network operators and increasing costs for the procurement of energy to cover transmission losses due to higher electricity prices on the power exchange.

For non-household customers the arithmetic mean charges are both higher and slightly lower than the previous year's level: with regard to consumption by commercial customers, network charges rose by 0.18 ct/kWh or almost 3% to 6.64 ct/kWh, while the arithmetic mean charges for consumption by industrial customers fell again slightly by 0.03 ct/kWh or around 3% to 2.67 ct/kWh.

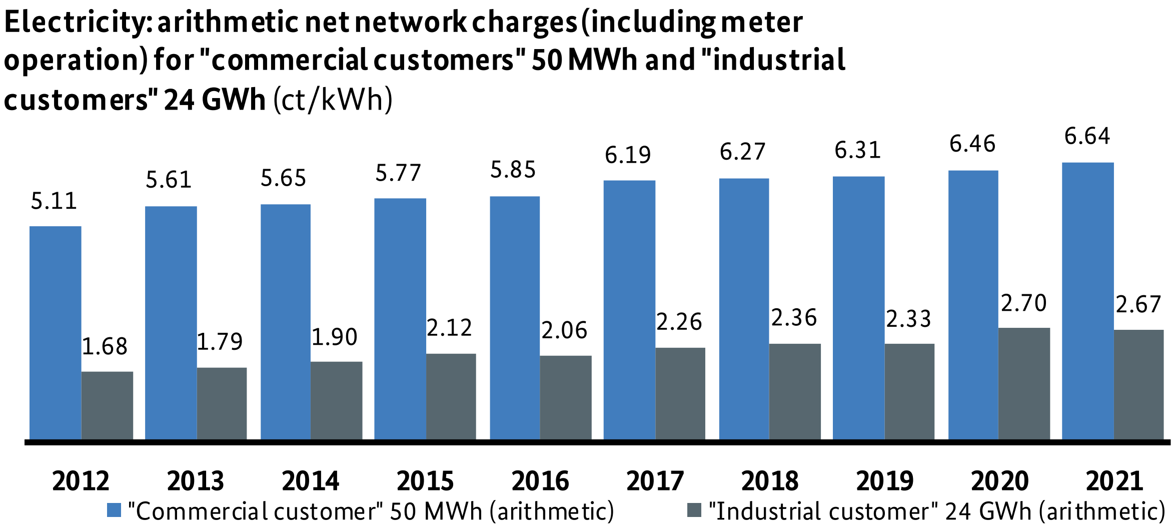


Figure 61: Arithmetic net network charges[56] (including meter operation) for "commercial customers" (50 MWh) and "industrial customers" (24 GWh)

6.2.3 Standing charges

For non-interval-metered customers, the network charges are replicated either by just the unit charge or by a combination of unit and standing charge components. There are large differences in the standing charges for SLP customers in Germany (see Figure 62). However, Table 68 shows a nationwide trend towards increasing standing charges in recent years. The maximum standing charge in 2021 remained at the previous year's level (2020: €105 per year).

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

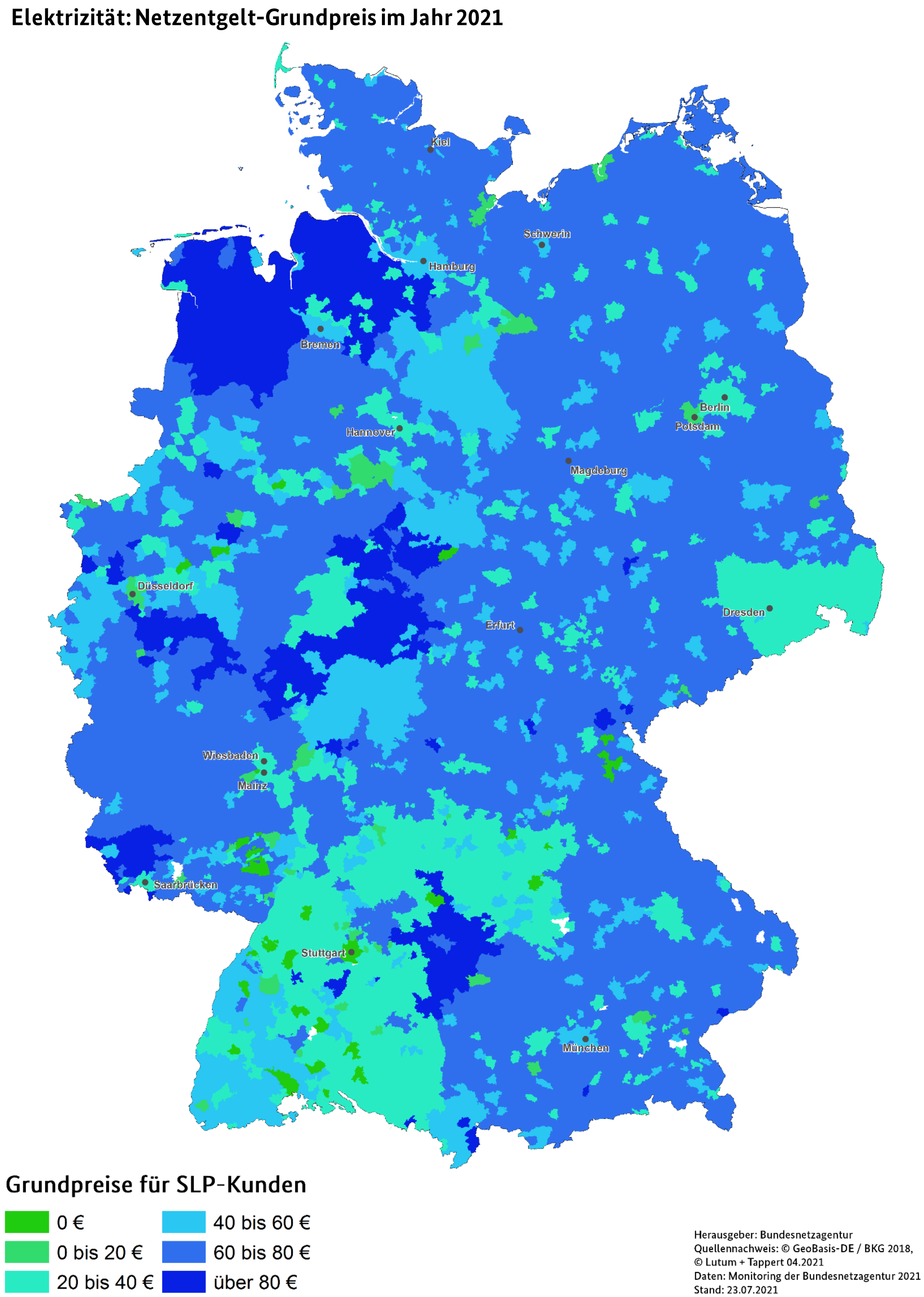


Figure 62: Network operators' standing charges per year for SLP customers

Electricity: standing charges
(€/year)

	2017	2018	2019	2020	2021
Average standing charge	35	37	40	52[2]	57[2]
Maximum standing charge	95	100	105	105	105
Minimum standing charge [1]	6	4	7	8	8
DSOs without standing charge	46	36	42	40	31

[1] Minimum standing charge levied by DSOs.
[2] The standing charge for 2020 was weighted by DSO delivery volumes. The unweighted average in 2020 was €42 per year and in 2021 it was €45 per year.

Table 68: Standing charges

The level of standing charges is the subject of public discussion. Here, the Bundesnetzagentur continues to be in favour of a reasonable standing charge as a fixed component. The reasonableness of the standing charge is based on a comparison with the tariffs for interval-metered customers at the low-voltage level and on the costs incurred for providing network infrastructure, which very largely do not depend on actual network usage. The Bundesnetzagentur acknowledges that the standing charge also has a social component and that it must be aligned with energy saving incentives.

6.3 Regional distribution of network charges

There are large regional differences in the network charges. To compare network charges across Germany, the monitoring report collects information from the DSOs about the current network charges in their network areas. This information can then be compiled relating to the three consumption groups of household, commercial and industrial customers (see I.C.6.2). Section 21(3) EnWG 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 2021. The figures do not include the meter operation charges or VAT. 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 requested 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 consumption quantity to obtain the average network charge in each federal state.[57]

Results of the monitoring survey show that the DSOs' network charges for household customers range from 1.29 ct/kWh to 25.06 ct/kWh. The following tables and maps show the network charges in the federal states and individual network areas.

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[57] Quantity weighting according to consumption group: household customers = consumption quantity for household customers within the meaning of section 3 para 22 EnWG; commercial customer = consumption quantity for standard load profile (SLP) final consumers excluding household customers; industrial customer = consumption quantity of interval-metered final consumers. The quantities for DSOs operating in more than one federal state were weighted using the relevant market location distribution.

Electricity: net network charges for household customers in Germany in 2021
(ct/kWh)

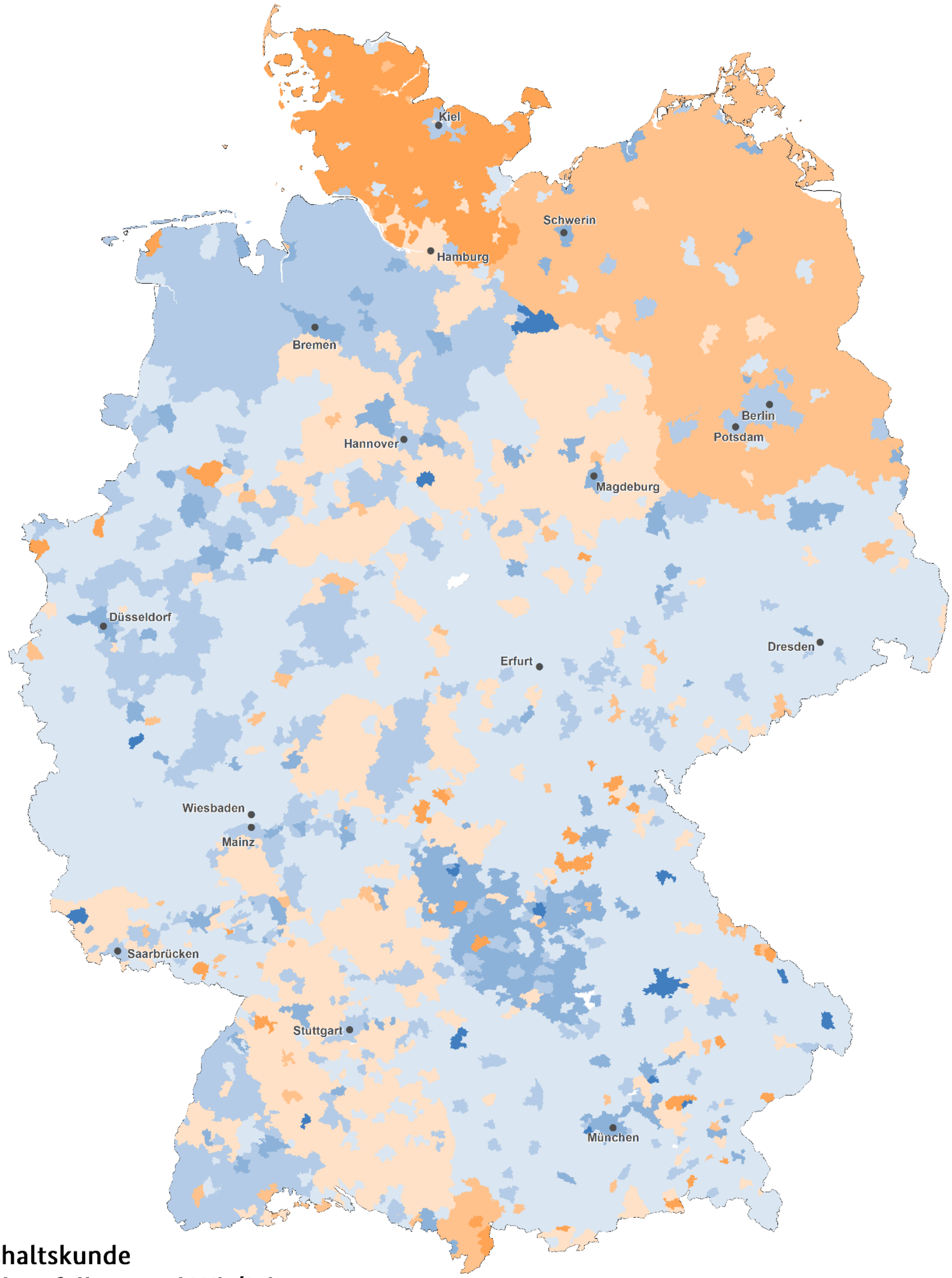
Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	9.47	5.46	11.61	47
Brandenburg	8.56	1.29	14.86	39
Hamburg	8.45	5.46	11.20	10
Mecklenburg-Western Pomeran	8.31	5.32	9.94	21
Saarland	7.79	4.99	15.61	19
Saxony-Anhalt	7.59	5.42	10.63	34
Baden-Württemberg**	7.53	4.28	11.07	133
Thuringia	7.52	5.86	9.96	40
Rhineland-Palatinate	7.34	5.16	11.75	56
Saxony	7.29	5.23	9.58	43
Lower Saxony	7.21	4.54	25.06	77
Hesse	7.16	5.46	9.80	65
North Rhine-Westphalia	7.05	3.04	10.85	115
Bavaria	6.80	2.94	19.97	240
Berlin	6.40	5.46	14.30	12
Bremen	5.13	5.05	9.07	10

* The weighting was based on the total consumption volumes in each network area.
** Includes the coverage area of the German enclave of Büsingen within Switzerland.

Table 69: Net network charges for household customers in Germany[58] 2021

[58] The underlying data also include several operators of closed distribution systems that supply final customers with electricity, claim network charges for transmitting electricity and participated in the monitoring survey in accordance with section 35 EnWG.

Elektrizität: Verteilung der Nettonetzentgelte für Haushaltskunden in Deutschland für das Jahr 2021



Haushaltskunde
Abnahmefall: 3.500 kWh/Jahr

- unter 5 Cent/kWh
- 5 bis < 6 Cent/kWh
- 6 bis <7 Cent/kWh
- 7 bis <8 Cent/kWh
- 8 bis < 9 Cent/kWh
- 9 bis < 10 Cent/kWh
- über 10 Cent/kWh

Herausgeber: Bundesnetzagentur
Quellennachweis: © GeoBasis-DE / BKG 2018, © Lutum + Tappert 04.2021
Daten: Monitoring der Bundesnetzagentur 2021
Stand: 21.07.2021

Figure 63: Spread of net network charges for household customers in Germany in 2021

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 1.52 ct/kWh to 23.07 ct/kWh. Overall, however, charges are lower than for household customers.

Electricity: net network charges for commercial customers in Deutschland in 2021
(ct/kWh)

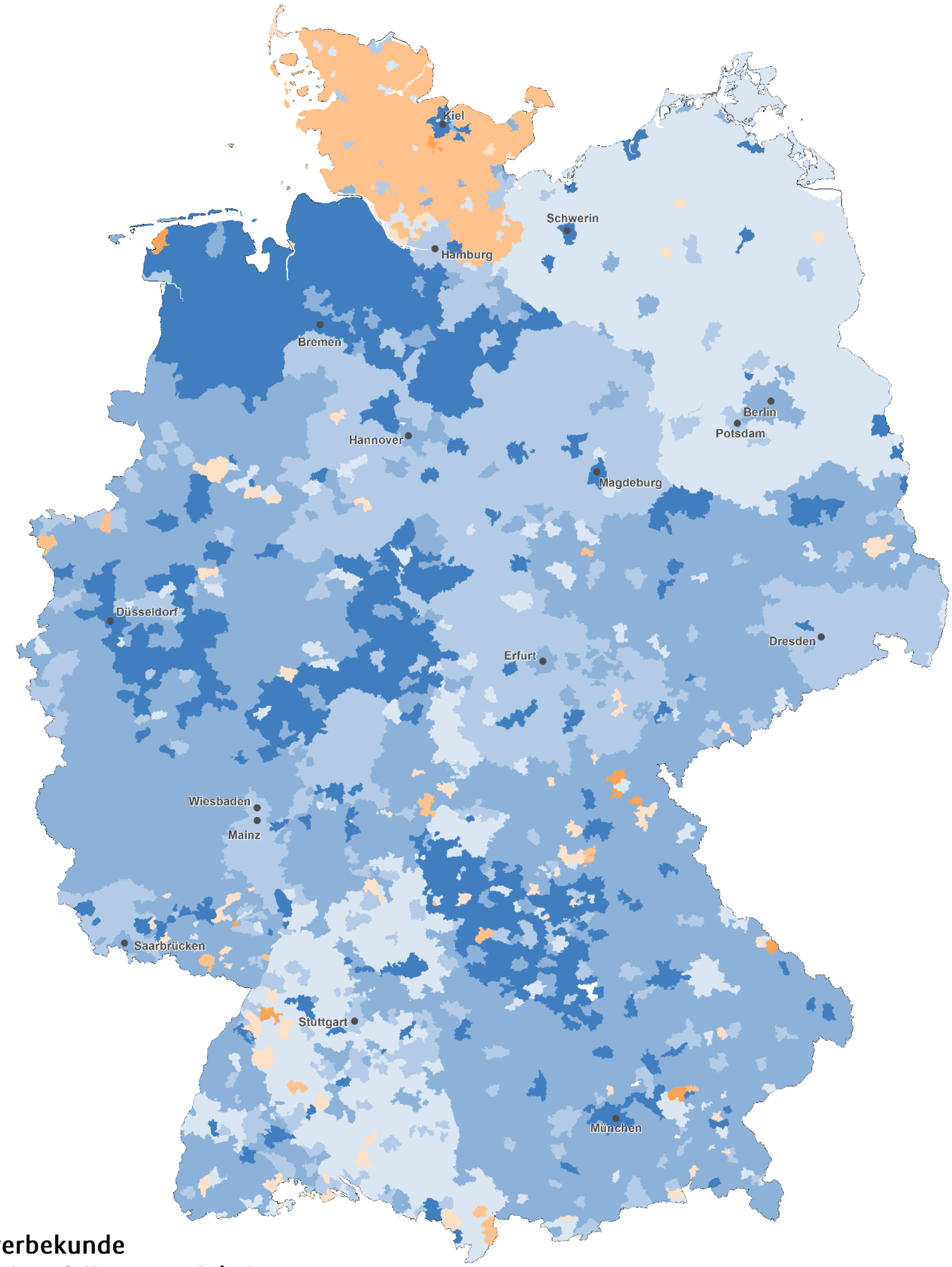
Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	7.95	4.40	10.02	47
Brandenburg	6.89	1.02	14.66	39
Hamburg	6.83	4.40	9.36	10
Baden-Württemberg**	6.46	1.52	10.27	133
Mecklenburg-Western Pomeran	6.41	3.88	8.67	21
Saarland	6.38	1.63	14.34	19
Saxony	5.93	3.37	8.34	43
Rhineland-Palatinate	5.87	3.61	10.42	56
Thuringia	5.87	4.10	8.16	40
Saxony-Anhalt	5.81	4.09	9.56	34
Hesse	5.67	4.02	8.55	65
Berlin	5.52	4.40	13.37	12
Bavaria	5.38	1.59	18.05	240
North Rhine-Westphalia	5.37	3.01	9.79	115
Lower Saxony	5.29	3.78	23.07	77
Bremen	3.94	3.78	8.43	10

* The weighting was based on the total consumption volumes in each network area.
** Includes the coverage area of the German enclave of Büsingen within Switzerland.

Table 70: Net network charges for commercial customers (annual consumption 50 MWh) in Germany[59] in 2021

[59] The underlying data also include several operators of closed distribution systems that supply final customers with electricity, claim network charges for transmitting electricity and participated in the monitoring survey in accordance with section 35 EnWG.

Elektrizität: Verteilung der Nettonetzentgelte für „Gewerbekunden" (Abnahmefall 50 MWh/Jahr) in Deutschland für das Jahr 2021



Gewerbekunde
Abnahmefall: 50 MWh/Jahr

- unter 5 Cent/kWh
- 5 bis < 6 Cent/kWh
- 6 bis < 7 Cent/kWh
- 7 bis < 8 Cent/kWh
- 8 bis < 9 Cent/kWh
- 9 bis < 10 Cent/kWh
- über 10 Cent/kWh

Herausgeber: Bundesnetzagentur
Quellennachweis: © GeoBasis-DE / BKG 2018,
© Lutum + Tappert 04.2021
Daten: Monitoring der Bundesnetzagentur 2021
Stand: 21.07.2021

Figure 64: Spread of net network charges for commercial customers (annual consumption 50 MWh) in Germany in 2021

The spread of network charges for the 24 GWh annual consumption group (industrial customers) is different. The volume-weighted average network charges are also higher in Schleswig-Holstein than anywhere else in the country. The lowest average network charges are in Saarland. The network charges for industrial customers range from 0.74 ct/kWh to 8.41 ct/kWh. These charges do not take account of possible reductions through individual network charges pursuant to section 19(2) StromNEV. In some cases, the charges for industrial customers entitled to individual network charges may be lower.

Electricity: net network charges for industrial customers in Germany in 2021
(ct/kWh)

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks included
Schleswig-Holstein	3.28	1.28	4.63	46
Mecklenburg-Western Pomeran	3.15	1.67	3.94	21
Brandenburg	3.13	1.15	3.94	39
Hesse	3.04	1.36	8.41	67
Saxony-Anhalt	2.92	1.88	4.24	34
Hamburg	2.81	2.38	8.41	10
Saxony	2.79	1.94	4.03	43
Thuringia	2.76	1.96	3.54	37
Berlin	2.73	2.40	3.76	11
Baden-Württemberg	2.70	0.80	8.41	133
Lower Saxony	2.54	1.40	8.41	76
Rhineland-Palatinate	2.48	1.57	3.76	56
Bavaria	2.40	0.74	8.41	232
North Rhine-Westphalia	2.37	1.40	8.41	116
Bremen	2.36	2.08	3.22	10
Saarland	2.32	1.52	4.52	19

* The weighting was based on the total consumption volumes in each network area.

Table 71: Net network charges for industrial customers (annual consumption 24 GWh) in Germany[60] in 2020

[60] The underlying data also include several operators of closed distribution systems that supply final customers with electricity, claim network charges for transmitting electricity and participated in the monitoring survey in accordance with section 35 EnWG.

Elektrizität: Verteilung der Nettonetzentgelte für „Industriekunden" (Abnahmefall 24 GWh/Jahr) in Deutschland für das Jahr 2021

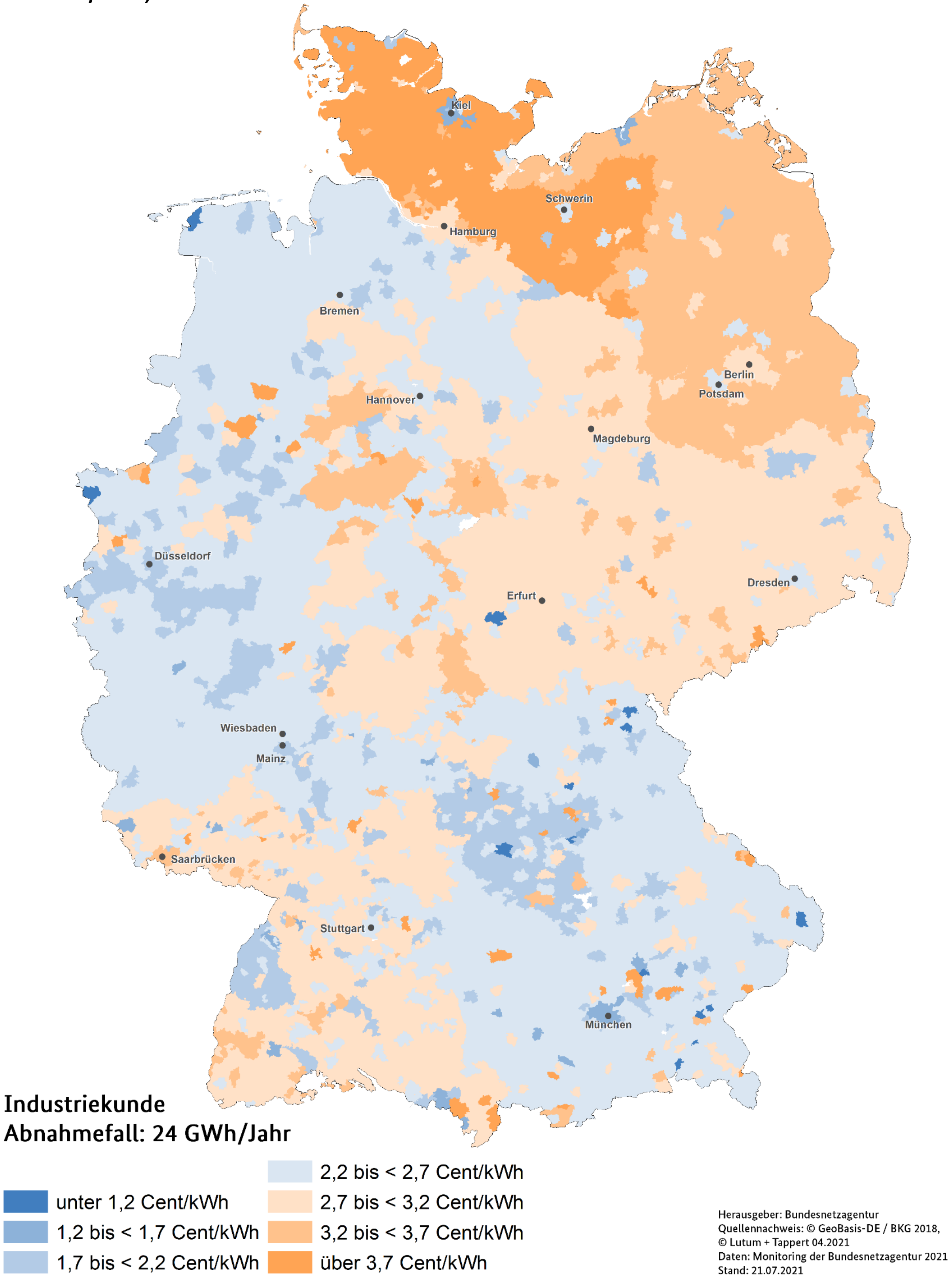


Figure 65: Spread of net network charges for industrial customers (annual consumption 24 GWh) in Germany in 2021

The regional differences in network charges are due to a complex range of factors.[61] 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 among a small number of network users, while in more densely populated areas the costs are shared among a high number. The costs for feed-in management measures originating in the distribution network have also become a factor contributing to differences in network charges. 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 revenue caps through the quality element. 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 investments in grid expansion and an increase in congestion management measures such as redispatching and reserving 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. 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 borne by all network users.

6.4 Avoided network charges

Under section 18(1) StromNEV, operators of distributed generation plants 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 network or substation level. Combined heat and power (CHP) plants that participate in an auction with the intention of receiving payments for CHP electricity may not already be receiving avoided network charges. In 2017 the NEMoG came into force.[62] Among other things, it adjusted the group of recipients and the amount of the avoided network charges.

The initiated changes concerning the avoided network charges can be divided into four stages.[63]

In stage I effective from 1 January 2018 the avoided network charges per kW of output and per kWh of work are "capped" for all distributed generators at the level of the adjusted charges for 2016. A detailed description of the capping process is available in the 2020 Monitoring Report.[64] The general network charges for a given year are to be applied (stage I) if they are below the reference price.

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

[62] The Network Charges Modernisation Act of 17 July 2017, Federal Law Gazette Part I page 2503; Bundestag Printed Paper 18/11528 of 15 March 2017 contains the draft bill by the Federal Government with reasoning, the response by the Bundesrat and the counter-response by the federal government.

[63] For detailed explanations (in German) of the changes see https://www.bundesnetzagentur.de/DE/Service-Funktionen/Beschlusskammern/BK08/BK8_61_Archiv/BK08_ALT/BK8_99_Downloads/Downloads/EOG_Hinweise_2018.pdf, page 11 et seq.

[64] https://www.bundesnetzagentur.de/SharedDocs/Mediathek/Berichte/2020/Monitoringbericht_Energie 2020.pdf?__blob=publicationFile&v=8, page 173 et seq.

Moreover, no avoided network charges are payable as from 2018 for new facilities with volatile generation[65] (see section 120(1) para 2 EnWG). This also applies to volatile generation facilities that are "resized" to a different voltage level (stage II).

Starting in 2018 the avoided network charges for volatile facilities already in existence were gradually reduced. Whereas in 2018 two-thirds and in 2019 one-third of the avoided network charges were still remunerated, beginning with the 2020 calendar year the avoided network charges for volatile generation facilities were eliminated entirely (stage III).

For the final stage (stage IV) beginning on 1 January 2023 new, non-volatile generation facilities will be excluded from the payment of avoided network charges. The non-volatile facilities already in existence will remain under the provision with no time limit.

Positive effects of the NEMoG on network charges nationwide

The information in the following section refers to avoided network charges paid by the network operators under the responsibility of the federal states. In the years prior to the introduction of the NEMoG, the amount of avoided network charges paid was continually on the rise and reached its peak in 2017 at €2.5bn.[66] The NEMoG had the effect of reducing the amount of avoided network charges paid in 2018 to €1.3bn. Actual costs fell to €1.2bn in 2019. A further decrease in avoided network charges was expected in 2020 when payments to volatile generation facilities ended. The network operators planned avoided network charges of €1,028m for 2020. Avoided network charges were actually beneath the €1bn mark for the first time in 2020, totalling around €942m. Projected avoided network charges for 2021 total €1,063m.

[65] Volatile generation within the meaning of section 3 para 38a EnWG is the generation of electricity from wind power plants and solar installations. Avoided network charges continue to be determined and remunerated for other facilities under the Renewable Energy Sources Act.

[66] These figures each relate to the network operators under the responsibility of the Bundesnetzagentur. The avoided network charges paid by the network operators under the responsibility of the federal states are not reported to the Bundesnetzagentur and therefore cannot be taken into account.

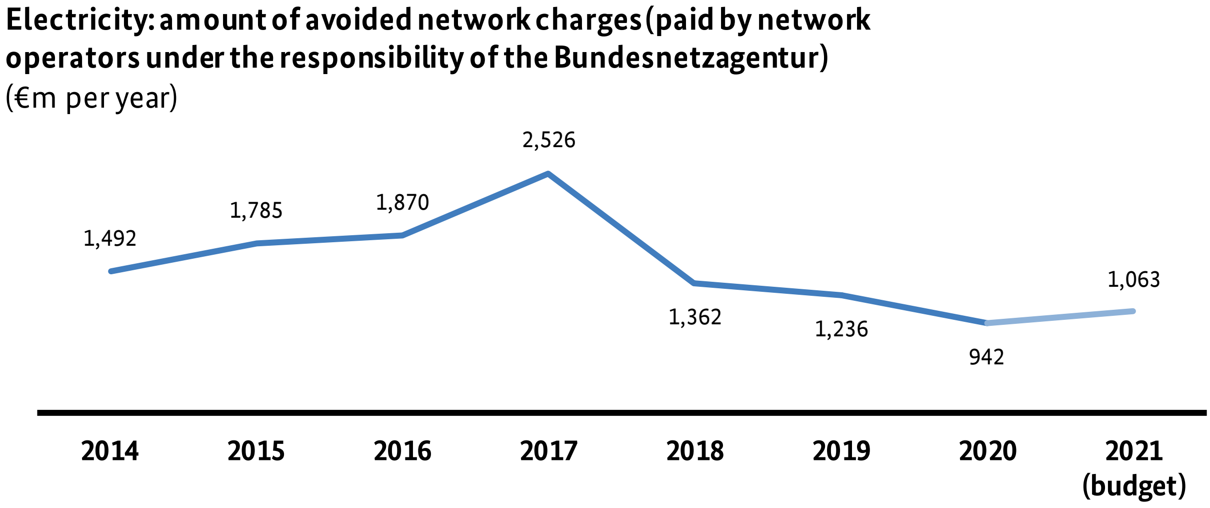


Figure 66: Amount of avoided network charges (paid by network operators under the responsibility of the Bundesnetzagentur)[67]

The Monitoring Report 2020 provides a detailed look at the relieving effect of the third stage of the NEMoG in general and with regard to regional differences.[68]

Remaining burden from avoided network charges

Non-volatile facilities that went into operation before 1 January 2023 will continue to receive payments from avoided network charges. Continuing payment of avoided network charges to operators of non-volatile facilities will continue to cause an uneven burden on network users in individual network areas. This is evident when looking at the minimum and maximum values of the avoided network charges paid per network operator.

Only a very small number of the approximately 180 public supply network operators within the responsibility of the Bundesnetzagentur submitted actual figures for avoided network charges of €0 for 2020. Thus no generation facilities entitled to receive payment of avoided network charges feed into these network areas. Table 72 shows the maximum burden from avoided network charges in 2021:

[67] Due to the termination of administrative agreements, figures of the network operators under the responsibility of the federal states of Mecklenburg-Western Pomerania and Thuringia are no longer included as from 2020. Figures from the federal state regulatory authorities are currently not available.

[68] https://www.bundesnetzagentur.de/SharedDocs/Mediathek/Berichte/2020/Monitoringbericht_Energie2020.pdf?__blob=publicationFile&v=8 page 175 et seq.

Electricity: maximum burden from avoided network charges in 2021

Maximum cost of avoided network charges for a DSO in % of the total revenue cap	34%
Maximum cost of avoided network charges for a DSO in absolute figures	€125m
Average avoided network charges	€6m

Table 72: Maximum burden from avoided network charges in 2021 (budget values)

The highest budgeted amount measured in absolute figures for avoided network charges was reported by a large, national network operator. The highest budgeted percentage amount of the revenue cap set by the Bundesnetzagentur was submitted by a municipal network operator whose avoided network charges amount to 34% of the revenue cap.

Stage III's effect on the overall costs for electricity customers

Gradually excluding the operators of volatile generation facilities from the mechanism of avoided network charges as a result of the NEMoG did not lead directly to relief for electricity customers overall. Renewable power plant operators, including operators of wind plants and solar installations, did not receive payment for avoided network charges prior to their elimination in accordance with section 18(1) StromNEV. The avoided network charges for the volatile generators were paid by the DSO in accordance with section 57(3) EEG to the TSOs' EEG account, from which the renewable energy input was and continues to be remunerated. The elimination of the avoided network charges for operators of volatile wind plants and solar installations did not lead to a change in the revenue situation for the operators. The removal of the avoided network charges only led to an EEG surcharge increase because the network operators were no longer sending payments to the TSOs' EEG accounts. Thus the NEMoG actually has no direct effect for operators of volatile generation facilities.

As already described, the customers of each distribution network connected to the distributed generator bear the costs for avoided network charges. However, final customers nationwide bear the higher costs for the EEG surcharge. In this respect one objective of the NEMoG was met, which was to reduce the uneven regional burden that avoided network charges place on network costs.

The Monitoring Report 2020 contains a detailed analysis of the incentive effect that section 18(1) sentence 1 StromNEV has had on the addition of conventional generation plants.[69]

No reduction in network expansion measures through payments to generators of distributed feed-in
The concept of avoided network charges assumed that distributed feed-in would reduce consumption from, and thus use of, the upstream network, thereby saving network infrastructure costs.[70] The operators of the

[69] https://www.bundesnetzagentur.de/SharedDocs/Mediathek/Berichte/2020/Monitoringbericht_Energie 2020.pdf?__blob=publicationFile&v=8, page 179.

[70] See most recently, for example, the statement in Bundestag Printed Paper 18/11528 of 15 March 2017, page 12.

distributed generation plants would receive the resulting savings as remuneration. Since the actual amount of remuneration avoided cannot be determined, the remuneration that would otherwise be paid by the upstream network operator is used for provisionally setting the level of remuneration.

The introduction of the principle of avoided network charges was based on the assumption that electricity flows from the highest to the lowest voltage level. The assumption of avoided network charges, that distributed feed-in would lead to a reduction in network expansion measures in the medium to long-term, originated around the turn of the millennium and is, at least now, unfounded.

The network is generally dimensioned so that the peak load of the year for electricity can be met solely by taking from the upstream transmission network. Distributed feed-in is not taken into account here because it is uncertain as to whether these installations actually provide feed-in at the time of the annual peak load. This means that network dimensioning as a key cost driver remains unchanged. The reduction of the remuneration to be paid to upstream operators as a result of distributed feed-in should not be confused with a reduction of infrastructure costs. On the contrary: infrastructure costs rise when the feed-in from distributed generation plants exceeds the annual peak load and the network dimensions must be increased accordingly to transport the electricity.

Networks dimensioned too small due to distributed feed-in

Less than ten DSOs under the Bundesnetzagentur's authority have dimensioned their networks smaller in the past due to distributed feed-in from conventional power stations and proportionately saved network infrastructure costs.

However, this approach requires that a sufficient amount of capacity can still be provided at times when there is scheduled maintenance, an unexpected outage or a plant closure, and also when there is simply no feed-in for reasons having to do with the market because electricity can be produced cheaper elsewhere. First and foremost, the operation of power generation plants must be economically sustainable, which for a long time has often not been the case.

Due to the development of wholesale electricity prices in recent years, continuous feed-in from conventional power stations is often no longer economical. DSOs who were unable to meet their entire grid load from the upstream network due to inadequate network dimensioning have to fear high costs for local power stations that are essential for the system so that those power plants can constantly provide enough capacity.

Consequently, these DSOs then also expanded their grid connection to the upstream network operator, which in turn is reflected in the number of investment measure requests submitted to the Bundesnetzagentur.

This shows that DSOs cannot rely on distributed feed-in when planning long-term network dimensioning. There are no contractual commitments for the payment of avoided network charges in the current rules of section 18 StromNEV that would require, for example, a distributed power station to provide continual or selective feed-in. A preliminary assessment tells us that introducing such a rule would also not be helpful because a generation plant's profitability cannot be secured through avoided network charges and therefore further long-term (more than 10 years) financing of such facilities through the network users' local network charges would be necessary. Adequately dimensioning the network has regularly proven to be more efficient than constantly having to maintain reserve capacity.[71]

Conclusion

The changes to avoided network charges introduced by the NEMoG have been effective. Capping the avoided network charges and eliminating them for volatile generators reduced avoided network charges from around €2.5bn in 2017 to around €942m in 2020. As from 2023, newly commissioned conventional distributed power stations will not receive avoided network charges. Accordingly, the avoided network charges will continue to decline from that time onward.

Nevertheless avoided network charges paid to distributed power stations still make up 5% of electricity customers' network charges over the long term.

After 15 years of regulation and 10 years of network development planning it cannot be ascertained that distributed power stations, either renewable or conventional, save network infrastructure costs.

6.5 Transfer of electricity networks

Section 26(2) to (5) of the ARegV 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 (EnWG)). 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 ARegV has led to substantial changes in the procedure for splitting the revenue caps. According to section 26(3-5) ARegV as applicable since September 2016, when an energy supply network is partly transferred to a different network operator the regulatory authority must define ex officio the shares of the revenue caps for the part of the network being transferred if the affected parties do not come to an agreement.

As at 31 December 2020, the Bundesnetzagentur had received 42 applications for electricity network transfers in 2020. The following graph shows the number of applications made in the last six years.

[71] It was in this context that the Enervie Vernetzt GmbH case became publicly known in 2014. Since it was no longer possible to provide security of supply in the Enervie distribution network without operation of the distributed power stations, which had become economically unfeasible, these Enervie power stations were supposed to maintain reserve capacity. In addition, Enervie's network area could not be fully supplied through Amprion's transmission system. A search for other solutions for the network charges ensued due to the dramatic economic consequences. As a result, Enervie also expanded its connection to the grid to the upstream network operator, see https://www.energate-messenger.de/news/148029/enervie-und-bundesnetzagentur-skizzieren-loesung-fuer-versorgungssicherheit.

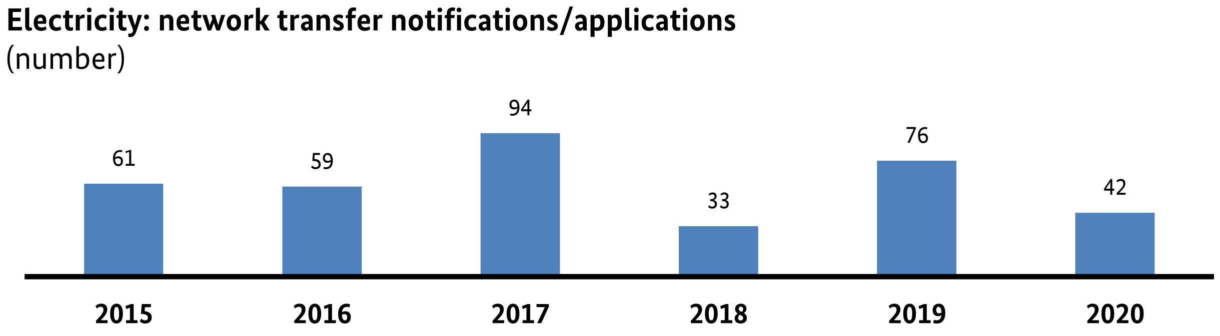


Figure 67: Network transfer notifications/applications

In 2020, Ruling Chamber 8 took decisions on 60 electricity network transfers, including network transfers from previous years.

6.6 Individual network charges – StromNEV section 19(2)

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.

Revenue missed due to the conclusion of individual network charge agreements may be passed on to the final customers as a pro-rata surcharge on the network charges (surcharge under section 19 StromNEV).

Individual network charges are granted as a reduction on the general network charge to network users meeting certain defined criteria. Section 19(2) StromNEV 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) sentence 1 StromNEV and electricity-intensive network users as per section 19(2) sentence 2 StromNEV. While atypical network users shift their peak load to outside the network's peak load period, electricity-intensive network users have at the same time even and permanent consumption patterns. The criteria for determining these individual network charges were 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) StromNEV (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) StromNEV 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 2021.

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7. Electric vehicles/charging stations and load control

7.1 Electric vehicles/charging stations

The federal government's target in its programme to promote electromobility is for there to be one million electric vehicles on Germany's roads by 2022. To enable this target to be met, incentives have been created both for the purchase of electric vehicles and for the deployment of the required private and public infrastructure nationwide. For the operators of electricity supply networks, the programme to promote electromobility means a large number of new consumption units that need to be connected to and supplied by the existing distribution networks. The charging capacities, which are high compared to normal household applications, and the potentially high simultaneous demand in the evenings are creating new challenges for the network operators.

The network operators are therefore reliant on sufficient information about the number and location of electric vehicle recharging points in their networks in order to be able to guarantee forward-looking capacity planning and the safe operation of their networks at all times. Recharging points installed in private households could theoretically be connected without involving the network operator because the capacity of some existing building connections is sufficient. Because of this, a provision was incorporated into section 19 of the Low Voltage Connection Ordinance (NAV) in March 2019 requiring all electric vehicle charging infrastructure to be notified to the network operator. In addition, the operation of charging infrastructure with a capacity exceeding 12 kVA requires the prior agreement of the network operator, with the network operator having two months to investigate and respond to a request for agreement. If agreement is refused, the network operator must give the reasons in writing and must specify any remedial measures that could be taken by the network or infrastructure operator and the time needed for these measures.

In 2020, the network operators were notified of a total of 50,372 recharging points in accordance with section 19(2) NAV.[72] This figure includes both public recharging points and all private recharging points that are to be notified to the network operators and so is not identical to the number of recharging points published by the Bundesnetzagentur.[73] In view of the large number of electric vehicles registered in 2020 (194,163 fully electric vehicles and 200,469 plug-in hybrids), it can be assumed that more recharging points, in particular private recharging points, were connected than are known to the network operators.[74] In the 2020 report on the status and expansion of the distribution systems the network operators stated that they assumed there were a large number of private recharging points that had not been notified. In 412 cases, it was not immediately possible for network operators to agree to the charging infrastructure being connected.

The most common reasons for network operators refusing agreement were:

- inadequate capacity and fuse capacity of the existing building connection;
- lack of capacity in the network;
- risk of voltage limits being exceeded;
- lack of short-circuit capacity in the network; and
- lack of agreement with the property/premises owners.

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[72] A recharging point is defined in section 2 para 6 LSV as infrastructure that is suitable and intended for charging electric vehicles and that is capable of charging only one electric vehicle at a time. The number of recharging points accessible to the public is therefore equal to the number of electric vehicles that can be charged at public points at any one time.

[73] According to section 2 para 9 LSV, a recharging point is accessible to the public if it is located either on public street space or on private property, provided that the parking space belonging to the recharging point can actually be used by an indeterminate group of persons or a group that can only be defined on the basis of general characteristics.

[74] Kraftfahrt-Bundesamt (2021), press release no 02/2021, vehicle registrations in December 2020 and annual figures, last accessed on 26 October 2021 at https://www.kba.de/DE/Presse/Pressemitteilungen/Fahrzeugzulassungen/2021/pm02_2021_n_12_20_pm_komplett.html (in German).

The most common measures proposed to charging infrastructure operators to remedy the reasons for not being able to connect infrastructure were:

- modernising and upgrading the building connection;
- installing a new building connection;
- installing load management/restricting the charging capacity;
- recommending smaller-scale charging infrastructure; and
- reinforcing (transformer station, conductor cross-section) and expanding the network.

The average time needed for the network operators' remedial measures was said to be between one and two months. Delays were longer in the few instances in which expansion measures were necessary.

Key to the success of electromobility alongside successful integration into the electricity networks is the nationwide deployment of interoperable and publicly accessible charging infrastructure. At EU level, requirements for the operation of charging infrastructure accessible to the public and for the interoperability of the technology used were therefore introduced in 2014 in Directive 2014/94/EU on the deployment of alternative fuels infrastructure. Germany was the first country to transpose the requirements into national law with the Charging Station Ordinance (LSV), which entered into force on 17 March 2016. The LSV specifies minimum technical requirements for the safe and interoperable deployment and operation of electric vehicle recharging points accessible to the public. These include binding provisions on the charging plugs used and an obligation to notify the Bundesnetzagentur.

The Bundesnetzagentur has been recording the notifications from operators of normal and high-power recharging points since July 2016 with a view to assessing the safety and interoperability requirements applicable to publicly accessible recharging points. All recharging points accessible to the public that have been taken into operation since the ordinance entered into force as well as all high-power recharging points with a capacity of more than 22 kW 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/ladeinfrastruktur.

Since the first revision of the LSV in June 2017, operators of publicly accessible recharging points are also required to enable electric vehicle users to charge their vehicles on an ad hoc basis without entering into a long-term contract for authentication and use. The second revision of the LSV is due to introduce stricter requirements, including for ad hoc recharging, in 2021. Operators are required to enable payment using standard debit and credit cards by 1 July 2023. The revised version also sets out additional requirements for the availability of digital interfaces and strengthens the Bundesnetzagentur's responsibilities.

The Bundesnetzagentur was notified of a total of 23,363 charging stations with 45,369 recharging points by 1 July 2021, of which 38,876 recharging points had a power less than or equal to 22 kW (normal-power recharging points) and 6,493 were high-power recharging points. A total of 5,270 of these charging stations and 10,521 of these recharging points were taken into operation in 2020.

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

Electricity: notified charging infrastructure by federal state

Federal state	Charging stations	Recharging points	High-power recharging points
Baden-Württemberg	3,885	7,484	1,185
Bavaria	4,900	9,436	1,125
Berlin	744	1,411	158
Brandenburg	485	962	163
Bremen	198	385	51
Hamburg	702	1,401	174
Hesse	1,571	3,042	441
Mecklenburg-Western Pomerania	246	481	76
Lower Saxony	2,644	5,070	765
North Rhine-Westphalia	4,046	7,848	845
Rhineland-Palatinate	966	1,862	410
Saarland	174	359	52
Saxony	929	1,893	340
Saxony-Anhalt	421	821	175
Schleswig-Holstein	953	1,885	283
Thuringia	499	1,029	250

As at 1 July 2021

Table 73: Notified charging infrastructure by federal state (as at July 2021)

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 can be found at https://www.bundesnetzagentur.de/ladesaeulenkarte.

Electricity: charging stations in Germany notified pursuant to the LSV

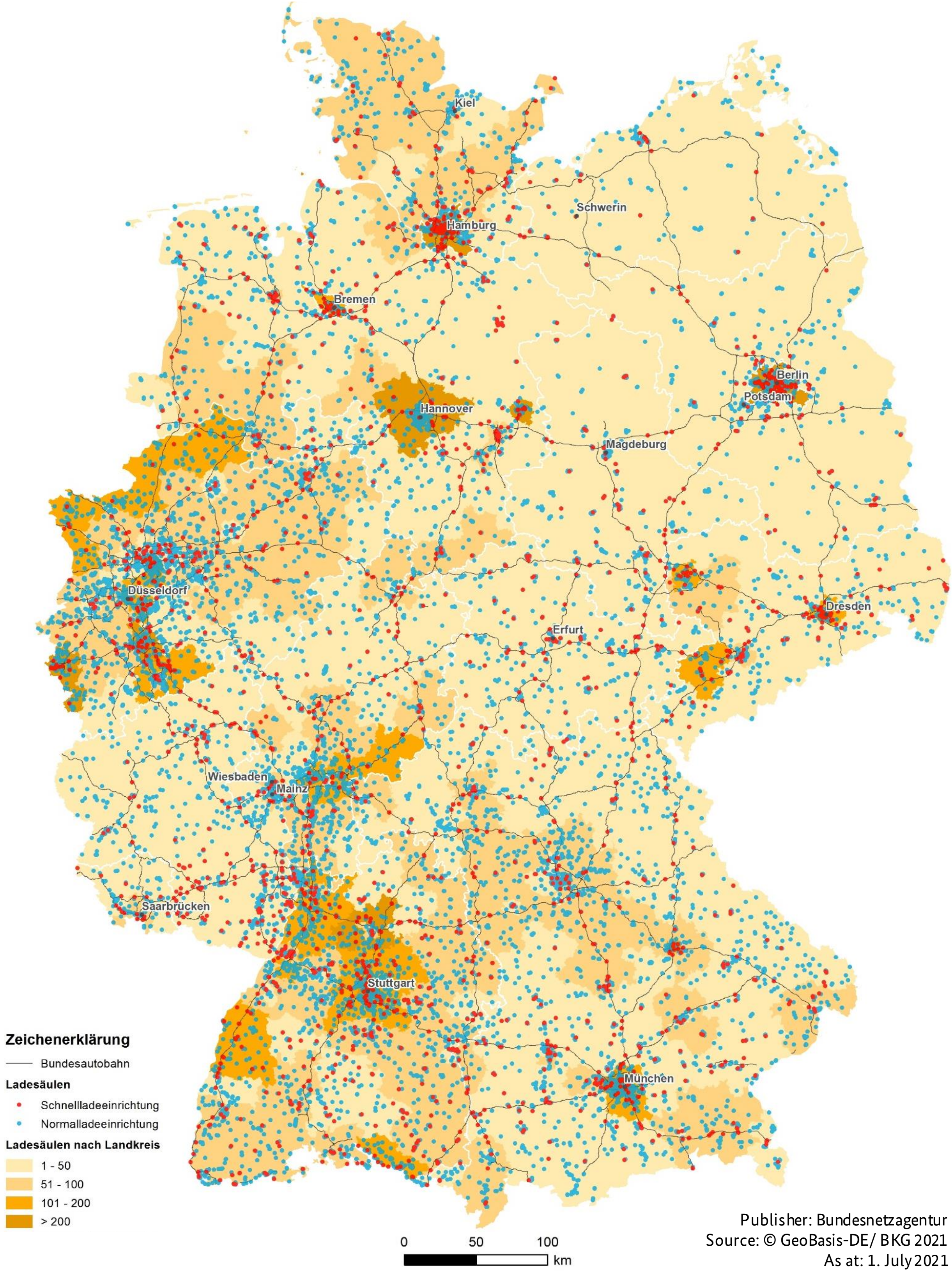
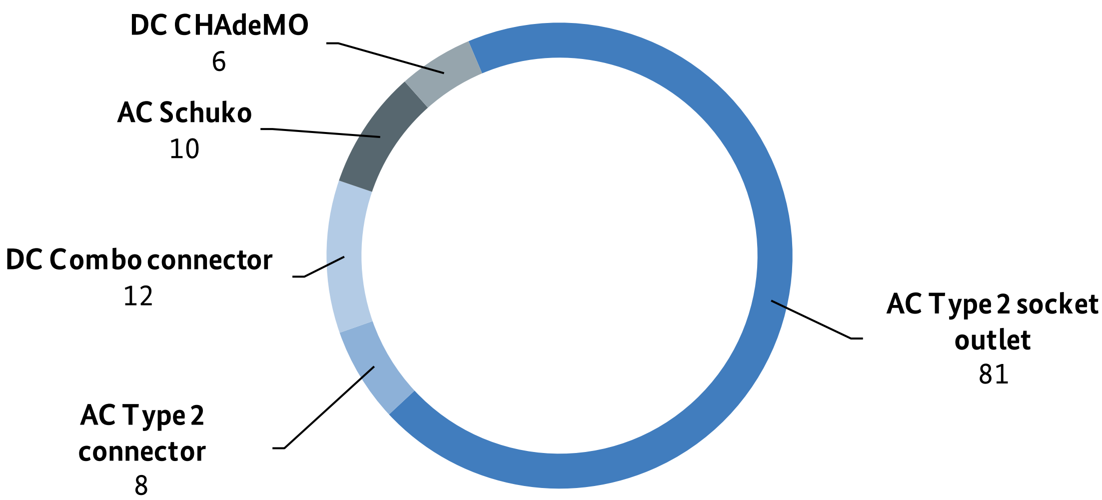


Figure 68: Charging stations in Germany notified pursuant to the LSV, as at July 2021

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 "Combo 2" vehicle connector. Alternating current recharging points require a "Type 2" plug system. There are still differing requirements for alternating current recharging points, depending on their charging capacity. 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 the 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 percentages relate in each case to all charging plugs at notified recharging points.

Electricity: breakdown of charging plugs by type in Germany
(%)



As at July 2021

Figure 69: Breakdown of charging plugs by type in Germany

The charging capacities of the recharging points are distributed as shown in Figure 70. 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 capacity most frequently mentioned in the recharging point notifications to the Bundesnetzagentur was 22 kW. There are also a large number of publicly accessible recharging points with 3.7 kW (AC Schuko), 11 kW/22 kW (AC Type 2), 43 kW/150 kW (DC Combo connector) and 50 kW (DC CHAdeMO). An increasing number of high-power charging stations with "DC Combo connector" plugs and a power less than or equal to 350 kW are now being installed.

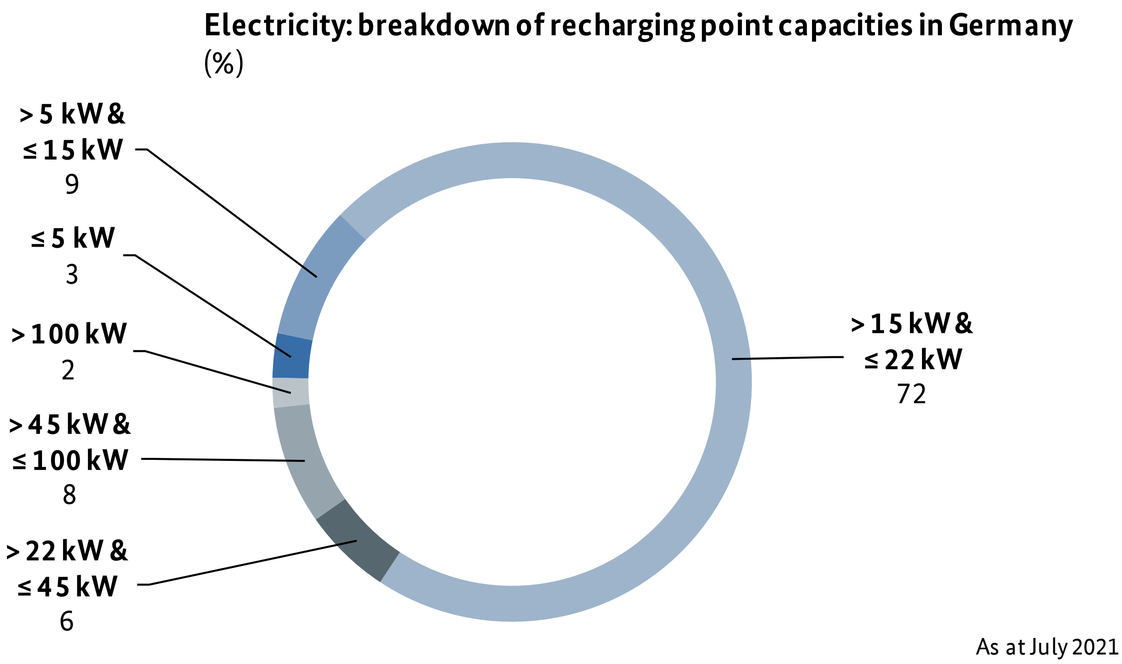


Figure 70: Breakdown of recharging point capacities in Germany

Since 2018, the Bundesnetzagentur has been working together with the PTB (Physikalisch-Technische Bundesanstalt – National Metrology Institute) and now also records the public keys for the notified recharging points. The user can enter the verification key on the metering equipment into verification software provided by the e-mobility provider.

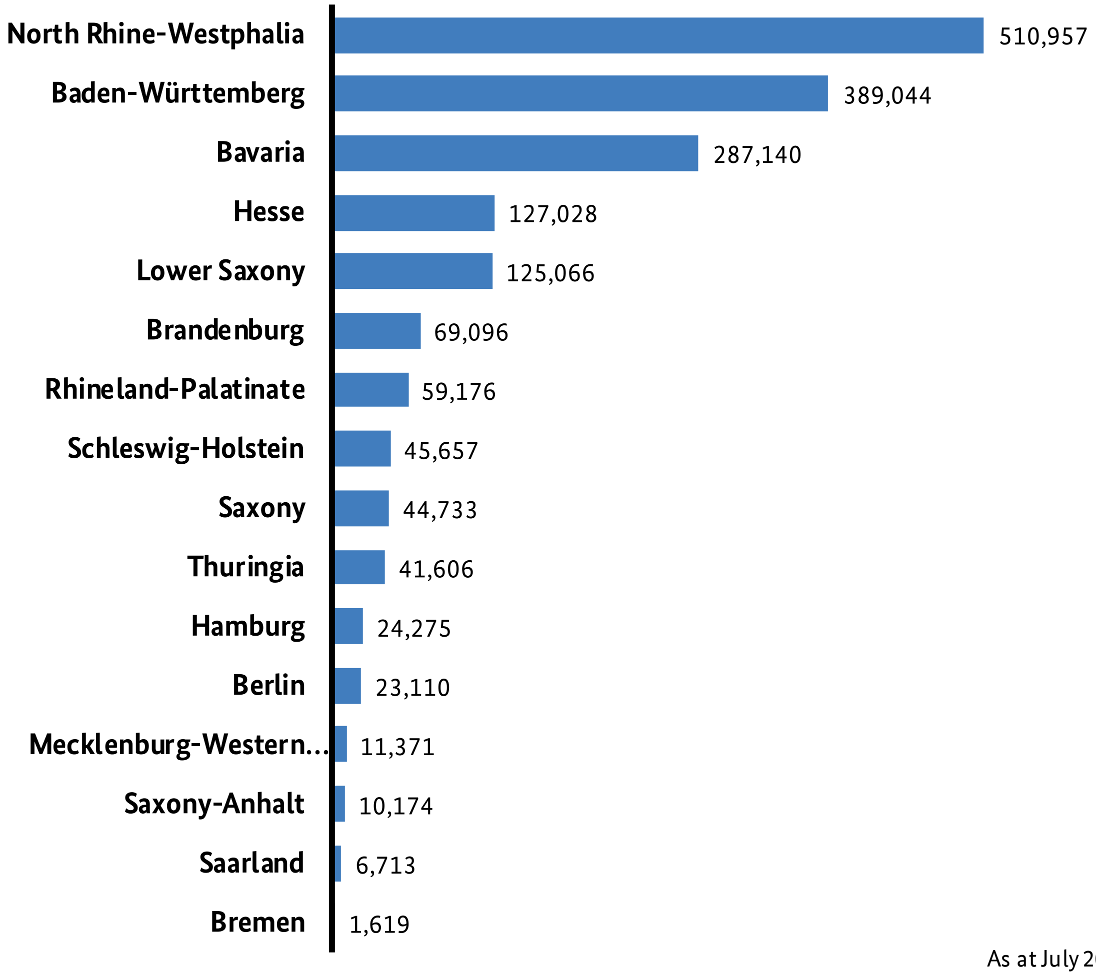
With this software, the user can verify whether the meter data given in the invoice are identical to the actual meter results and are also actually from the recharging point at which the vehicle was charged. The charging station information published on the Bundesnetzagentur's website now includes the public keys for the charging stations concerned.

No reliable picture emerged from the data supplied by the providers surveyed on the prices payable for charging electric vehicles at publicly accessible recharging points (406 out of about 1,400 providers did not give any information). The data supplied suggest – with all due caution – that, on average, there are significant differences between the prices charged by providers to their own customers (users of the providers' recharging point access schemes), ad hoc customers (section 4 LSV) and third-party e-mobility providers. The Bundeskartellamt is currently carrying out a sector inquiry into the provision and marketing of publicly accessible charging infrastructure for electric vehicles; one aim is to examine the conditions and prices at public charging facilities from a competition perspective. The results of the inquiry will be summarised and published in a report. (See also III.C "Selected activities of the Bundeskartellamt".)

7.2 Load control

Section 14a EnWG 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 with final consumers with controllable (previously interruptible) loads in return for a reduction in the network charge. The aim is to prevent these loads from consuming a large amount of electricity from the low-voltage network at times when consumption is already high and from thus causing localised overloading. The arrangement is essentially designed for loads such as night storage heating systems, heat pumps and electric vehicles.

Electricity: market locations with load control by federal state
(number)



As at July 2021

Figure 71: Market locations with load control by federal state

A total of 699 out of the 840 network operators surveyed stated that they took advantage of the provision and levied reduced network charges for a total of 1,776,765 market locations with load control. The number of market locations with load control is 274,405 higher than in the previous year, but this is due to data being provided by one additional DSO that had not reported data in previous years. Without these additional data, the number would be around 15,597 higher than in the previous year. The regional distribution is shown in Figure 71. As in previous years, the chart shows a high concentration in Baden-Württemberg, Bavaria and North Rhine-Westphalia, with considerably more than half of all the market locations with load control in these three southern and western federal states. The reason for this is likely to be historical, since the provision was originally intended to create stable demand for the constant production by nuclear and coal-fired power plants.

Electricity: breakdown of market locations with reduced network charges by load type
(%)

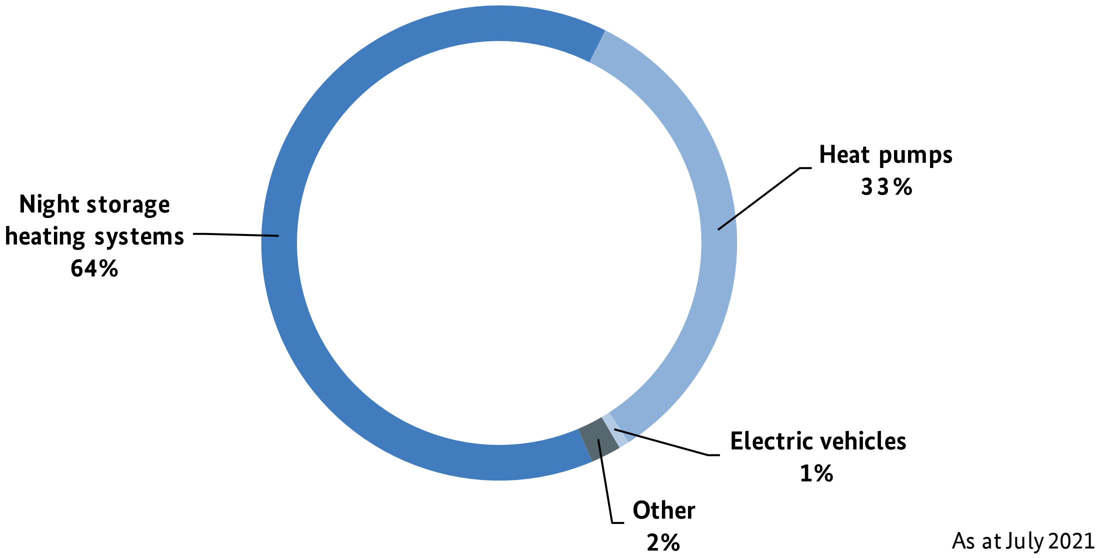


Figure 72: Breakdown of market locations with reduced network charges by load type

It is still the case that almost all the market locations with load control are for heating systems (see Figure 72), 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. It should be noted that, due to incorrect data being reported by a network operator in the previous year, the share of "Other" loads is five percentage points lower than in the previous reporting period and the share of heat pumps is five percentage points higher. There are also other, normal changes in the shares accounted for by the different types of load, as seen in the previous year. For example, the share of night storage heating systems is down by more than two percentage points compared with the previous year, while the share of heat pumps is actually up by two percentage points or, taking into account the incorrect data, up by a total of seven percentage points. The share of electric vehicle charging infrastructure is now 0.61% (previous year: 0.38%).

The average reduction in the network charge given by network operators in return for load control is about 57%, which corresponds to an average discount of 3.76 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 84% of the general charge for the use of the network, while the lowest is just 5%. By contrast, the differences between the various types of load are negligible. Developments compared with the previous years are also hardly noticeable.

It is still 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, while just 1% use the more modern remote control technology. Between 2% and 5% of the network operators do not use any control technology at all, while about a third use time switching. The use of control technology for charging infrastructure for electric vehicles is very different. Ripple control accounts for only about a third, remote control technology here again accounts for only around 2%, but only just over 14% of network operators use time switching. What is striking, however, is that no control technology at all is used by around 43% of network operators for electric vehicle charging infrastructure, which accounts for a very small proportion of controllable loads. Figure 73 shows a more detailed breakdown of the control technologies used.

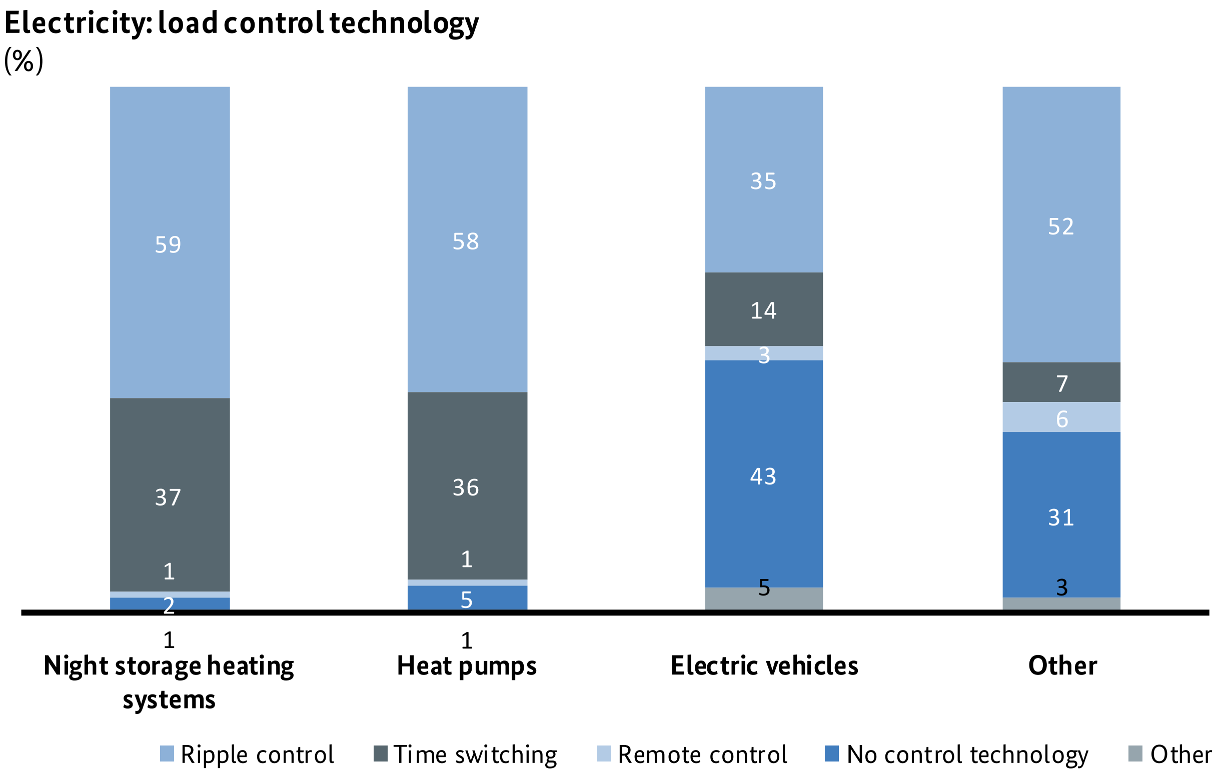


Figure 73: Load control technology

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 EnWG must be fitted with smart meters. This applies as soon as the BSI has determined the technical feasibility. 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.

D System services

Guaranteeing system stability is one of the core tasks of the TSOs and is performed using system services. System services include maintaining the system frequency by contracting and using the three types of balancing services: frequency containment reserves (FCR), automatic frequency restoration reserves (aFRR) and manual frequency restoration reserves (mFRR). They also include procuring energy to cover losses, maintaining voltage stability in particular by means of reactive power, providing black start capability, system restoration, inertia, and other technical requirements immediately related to network operation. National and cross-border redispatching and countertrading, TSOs' and DSOs' feed-in management measures, and contracting and using grid reserve plant capacity are, technically speaking, also system services. These are looked at separately in I.C.5. Interruptible loads under the Interruptible Loads Ordinance (AbLaV) and the provision of the capacity reserve and special grid facilities are also part of the range of tasks.

1. Costs for system services

The net costs for the above-mentioned services that are **recovered through the network charges** amounted to around €2,018.3m in 2020 (2019: €1,931.2m).[75] Major costs in 2020 were the costs of reserving and using grid reserve power plants at around €282.8m (2019: €278.1m; up 2%), national and cross-border redispatching at €220.5m (2019: €227.2m; down 3%), the estimated claims for compensation for feed-in management measures at €761.2m (2019: €709.5m; up 12%) and loss energy at about €398.8m (2019: €321.2m; up 24%). The increase in the costs for loss energy is due to the increase in procurement prices. The reference price for loss energy under the determination on volatile costs for loss energy rose from €37.90/MWh in 2019 to €51.01/MWh in 2020.

There was a considerable decrease in the costs for contracting FCR, aFRR and mFRR, which totalled €152.4m (2019: €285.7m; down 47%). The decrease is due to the following reasons. There was a decrease in the costs for contracting FCR (2020: €35.7m; 2019: €46.4m) because of the increase in competition within the international FCR cooperation scheme. There was a decrease in the costs for contracting aFRR (2020: €82.6m; 2019: €118.6m) and mFRR (2020: €34.2m; 2019: €120.7m) because of the abolition of the mixed price procedure. The application of the mixed price procedure in the tendering for aFRR and mFRR from October 2018 to July 2019 resulted in lower energy prices and higher capacity prices for aFRR and mFRR compared with the previous award procedure. The return to the old award procedure led to lower average capacity prices again for aFRR and mFRR and – as a result – to lower costs for contracting aFRR and mFRR.

TenneT, TransnetBW and Amprion tasked third parties to reserve and operate special grid facilities with a capacity of 1,200 MW in accordance with section 11(3) EnWG (in the version of 17 July 2017 and repealed in the version of 16 July 2021) in order to be able to restore the security and reliability of the electricity supply system in the event of an actual local outage of one or more facilities in the transmission system. The TSOs awarded 300 MW of capacity in each of the four regions in southern Germany; the facilities will be set up for

[75] The "capacity reserve costs" were a new addition in 2020. They are newly included in the costs for system services.

ten years and will start operation in autumn 2022 or in 2023. The costs for the whole ten-year period of operation amount to around €2.6bn. These costs are supplemented by generation costs.[76]

Since 1 October 2020, a capacity reserve has been in place in accordance with section 13e EnWG. The power plants in the capacity reserve do not operate in the electricity market but start up at the TSOs' request when it is not possible to balance supply and demand despite free pricing on the electricity exchange and the use of balancing energy. The capacity reserve is made up of eight generation plants with a total capacity of 1,056 MW that are remunerated with an award price of €68,000/(MW*year). The provisional costs for keeping the plants in the capacity reserve between October and December 2020 amount to €18.0m.

[76] Generation costs are defined in the glossary.

Electricity: costs for system services recovered through the network charges (€m)

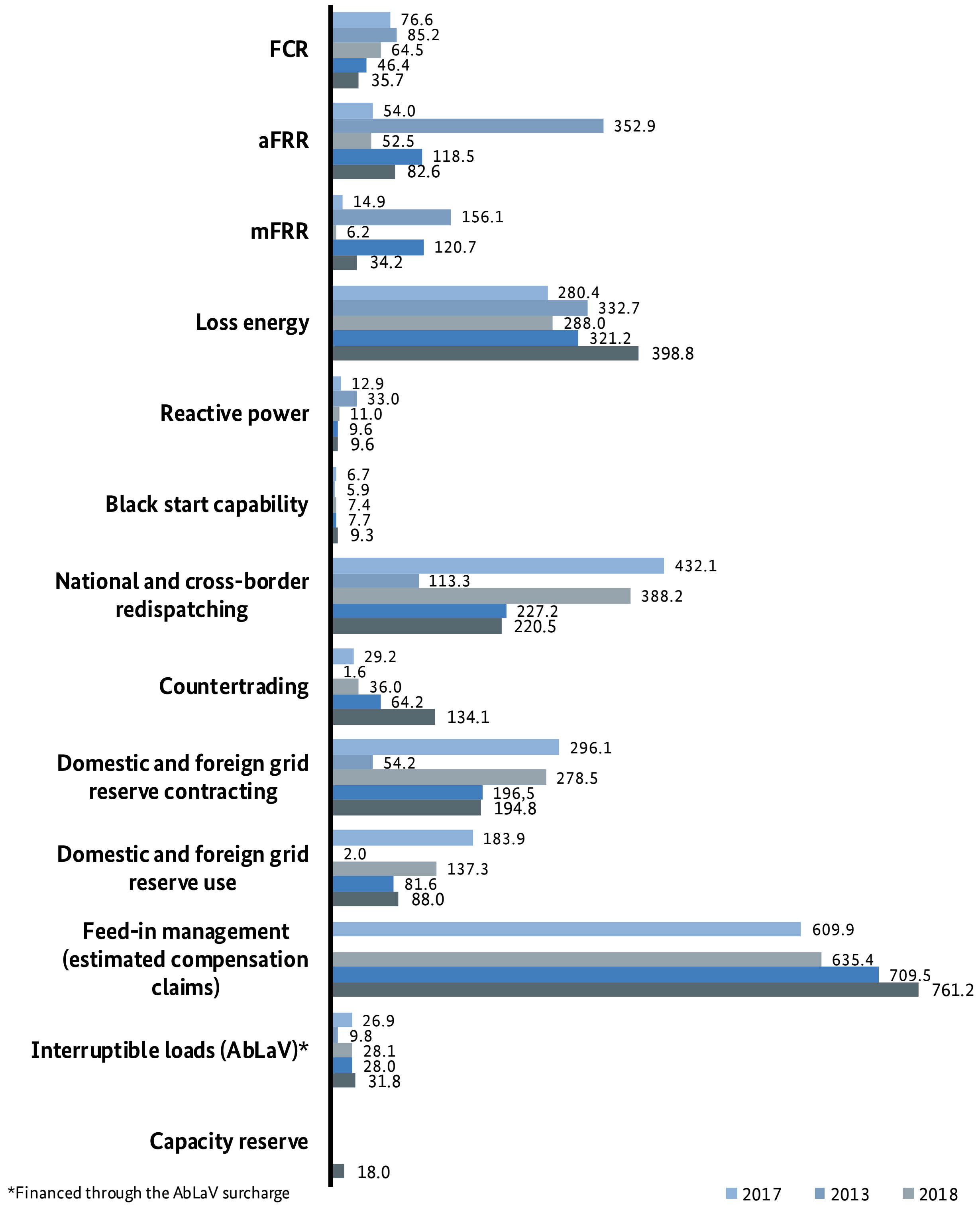


Figure 74: Costs for system services recovered through the network charges

The total costs for congestion management measures (redispatching using operational and grid reserve power plants, countertrading, feed-in management) were higher than in 2019 at €1,398.6m (see also I.C.5). Figure 74 shows the development in the costs for system services from 2017 to 2020. The chart below shows a breakdown of the costs for 2020.

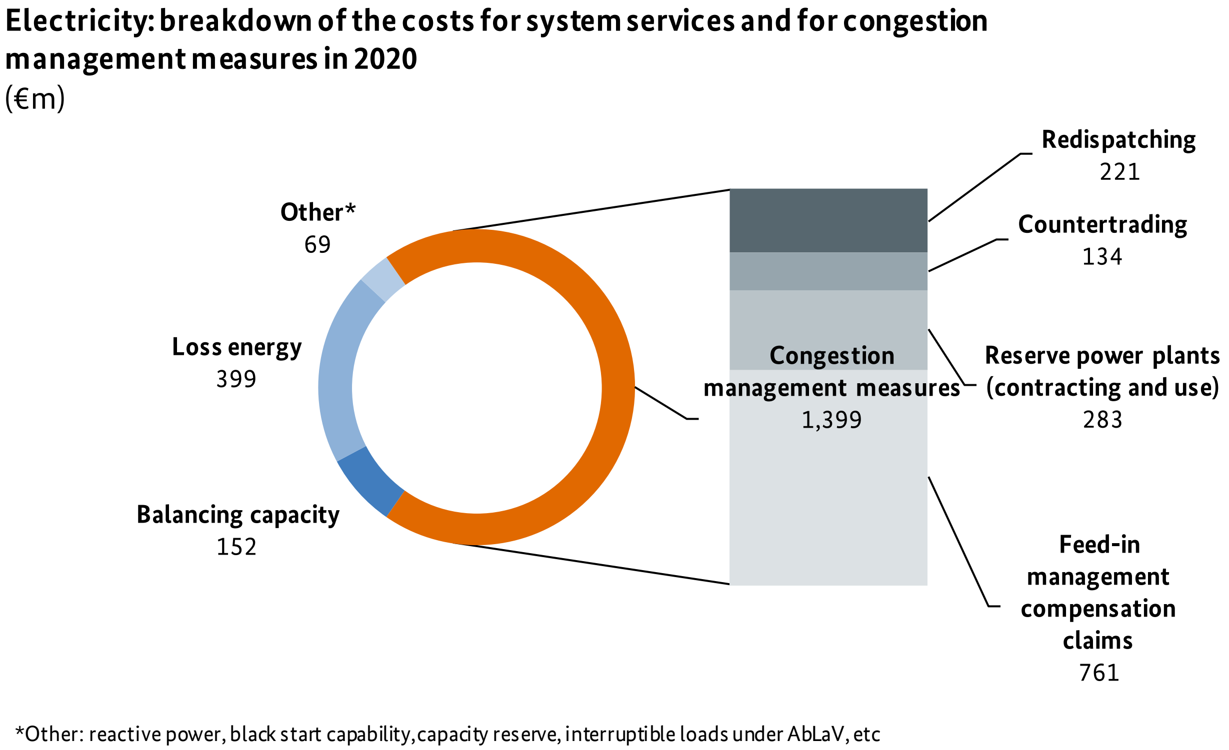


Figure 75: Breakdown of the costs for system services and for congestion management measures in 2020

2. Balancing services

Since the introduction of the balancing energy market on 2 November 2020 (first delivery day: 3 November 2020) there are separate, successive markets for balancing capacity and balancing energy for aFRR and mFRR. Previously, balancing energy could only be delivered by providers successfully bidding in the capacity market; now, balancing energy may be delivered by all pre-qualified providers and – in contrast to the previous design of the tendering process – is independent of participation in the capacity market.

The balancing capacity market has had a different function since 2 November 2020. The bids accepted on the balancing capacity market serve as an "insurance product". They ensure that sufficient balancing energy is available if there is an outage in the balancing energy market, for instance because of technical problems. The energy from the "surplus" bids that are not needed to meet demand is released by the TSOs and can be marketed elsewhere. The aim of this is to increase the liquidity of the intraday market.

For the time being, the product validity periods in the balancing energy market will be the same as in the balancing capacity market (six products with a validity period of four hours each). The balancing energy market opens when the bids in the capacity market are awarded and closes one hour before the start of the product validity period. The product validity periods and gate closure times will be adjusted when the European platforms for the exchange of balancing energy – PICASSO (aFRR) and MARI (mFRR) – go live.

The TSOs contract balancing capacity and use it in the form of balancing energy as required to continuously balance demand and generation in the electricity supply system and thus maintain the stability and frequency of the system. The provision of balancing capacity and/or balancing energy is referred to as balancing services.[77] The TSOs can contract and use three types of balancing service that are used in a certain order:

- Frequency containment reserves (FCR) – FCR are used to maintain the system frequency. They regulate positive and negative frequency deviations in the electricity system automatically and continuously within 30 seconds. The period of time covered for each disturbance is from zero to 15 minutes. After 15 minutes, the capacity must be released so that it is available again to regulate new, unforeseeable frequency deviations. The energy delivered is not metered or charged for.[78]

- Frequency restoration reserves with automatic activation (aFRR) – aFRR are a type of frequency restoration reserve used to restore the system frequency to the nominal frequency of 50 Hz after a disturbance. They must be fully available within five minutes of activation by the connecting TSO. The period of time covered for each disturbance is from 30 seconds to 15 minutes.

- Frequency restoration reserves with manual activation (mFRR) – mFRR are also a type of frequency restoration reserve. They are used to support or replace aFRR and must be fully available within 15 minutes. mFRR are usually provided as scheduled deliveries at 15-minute intervals.

The following figure shows the order and time frame for the use of the different types of balancing service.

Electricity: order and time frame for the use of balancing services

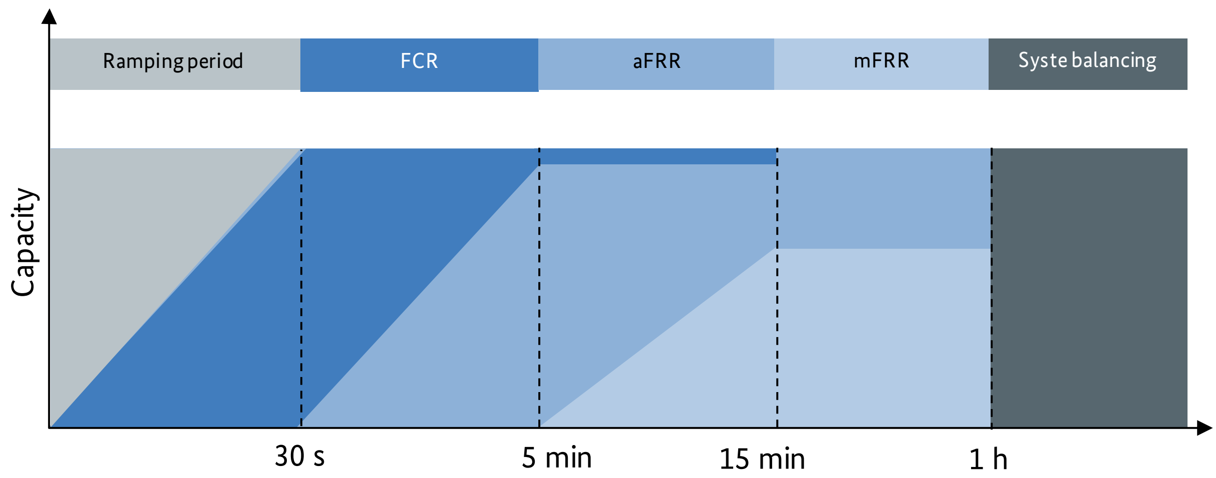


Figure 76: Order and time frame for the use of balancing services

[77] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, Article 2 point (3)

[78] Only balancing capacity prices are paid for FCR. Balancing energy prices are not paid because the positive and negative capacity delivered averages out to zero. On average, in the course of a contract period, the same amount of electrical energy is fed into the grid as is withdrawn. In addition, charging balancing energy prices would entail considerable transaction costs as a result of continuous frequency balancing.

A distinction is made between positive and negative balancing services. If, at any one time, less energy is fed into the system than is required, the system frequency will be below the nominal frequency of 50 Hz. Positive balancing services are required to restore the system frequency to the nominal frequency. In this case, the TSO will – on a short-term basis – need more energy to be fed into the system and/or less energy to be consumed. The TSO procures both types of balancing service from balancing service providers. If, at any one time, more energy is fed into the system than is required, there will be too much power in the system and the system frequency will be above the nominal frequency of 50 Hz. In this case, the TSO will – on a short-term basis – need negative balancing services in the form of electricity consumers withdrawing more electricity from the system and/or electricity generators feeding less electricity into the system. The TSO also procures these services from balancing service providers.

A grid control cooperation comprising the control areas of the four responsible TSOs (50Hertz, Amprion, TenneT and TransnetBW) has been in place in Germany since 2010. The cooperation creates a nationally uniform, integrated market mechanism for aFRR and mFRR and thus optimises the costs of using balancing capacity for the whole of Germany. Under the cooperation, the imbalances in the individual control areas are netted so that only what remains has to be compensated for by using balancing services. Inefficient use in the different control areas is almost completely eliminated and the volume of balancing capacity required is reduced.

Module 1 of the national cooperation, which aims to prevent the inefficient use of aFRR, has been expanded over the past few years into an international cooperation. Under the International Grid Control Cooperation (IGCC), Germany cooperates with Denmark, the Netherlands, Switzerland, Czechia, Belgium, Austria, France, Croatia and Slovenia to avoid the inefficient use of balancing services. Since no fixed transmission capacity at the borders is reserved for the cross-border exchange of energy (only the free capacity available can be used to exchange the balancing energy), the TSOs in each country still need to contract sufficient balancing capacity nationally to cover their own requirements. The cooperation under IGCC is, however, reflected by the decrease in the activated volumes of aFRR and, indirectly, mFRR (see also 3.3).

2.1 Tendering for balancing capacity

The TSOs responsible for the control areas in Germany procure the balancing capacity that they require for system balancing in national tendering processes in accordance with the provisions of the Bundesnetzagentur's determinations and approvals on FCR[79], aFRR[80] and mFRR.

The tendering for the procurement of aFRR and mFRR was, however, redesigned following the entry into force of new European provisions.[81] The new provisions require the TSOs to introduce a balancing energy market for aFRR and mFRR. The Bundesnetzagentur approved the TSOs' application for the introduction of a balancing energy market in Germany on 2 October 2019 (BK6-18-004-RAM). As of 2 November 2020 there are separate tendering processes for balancing capacity and balancing energy. In the past, balancing energy could

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[79] Tendering in accordance with the decision of 13 December 2018 (BK6-18-006). See 3.1.

[80] Joint tendering by Germany and Austria since the beginning of 2020 in accordance with the decisions of 18 December 2018 (BK6-18-064) and 12 December 2019 (BK6-19-160). See 3.3.

[81] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing and Regulation (EU) 2019/943 of the European Parliament and of the Council 5 June 2019 on the internal market for electricity

only be delivered by providers successfully bidding in the capacity market; now, balancing energy may be delivered by all pre-qualified providers and – in contrast to the previous design of the tendering process – is independent of participation in the capacity market.

FCR are procured as a symmetric product. No distinction is made between positive and negative balancing services. Nor is a distinction made between "holding" and "delivering" FCR capacity and consequently there are no separate tendering processes for FCR capacity and energy and therefore no balancing energy market.

In the past, balancing capacity was mainly provided by conventional power plants. It is now also increasingly being offered by battery storage systems. Renewable generators providing balancing capacity today include hydro power and, in particular, biogas plants. 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 the electricity supply in the future. To make it easier for flexible generators such as wind turbines to participate in the balancing markets, in June 2017 the Bundesnetzagentur issued new tendering conditions and publication requirements for aFRR and mFRR (BK6-15-158/159). As a result, in July 2018 the tendering frequency for aFRR was changed from one week to one calendar day. In addition, the product validity period was shortened considerably to four hours. These changes are essential in particular for wind and photovoltaic generators to be able to forecast capacity and decide on deployment. The changes to the conditions for mFRR included changing the tendering frequency from one working day to one calendar day. In addition, new rules were introduced on the minimum bid volumes and safeguards for both aFRR and mFRR. These framework conditions also apply in the balancing energy market. The balancing energy market is designed to make it easier for flexible generators to participate in the balancing markets because balancing energy bids can be submitted and changed up to one hour before the product is delivered.

As from the delivery day 10 December 2019, the requirements for positive and negative aFRR and mFRR are determined not on a quarterly basis but in a dynamic process in which the individual requirements are determined for each four-hour product.

The national grid control cooperation and the determinations issued by the Bundesnetzagentur contribute to increasing competition among balancing service providers by creating a national market for aFRR and mFRR and aligning the tendering conditions. By 1 April 2021, the number of pre-qualified balancing service providers stood at 29 for FCR (2020: 29; 2019: 30), 35 for aFRR (2020: 35; 2019: 37) and 38 for mFRR (2020: 40; 2019: 45). The numbers of pre-qualified providers for FCR and aFRR have therefore remained stable, while there has been another slight decrease in the number of pre-qualified providers for mFRR.

Procurement of FCR

FCR procurement needs are determined jointly by ENTSO-E and are based on the simultaneous failure of the two largest power plant blocks within the network area. The total amount – currently 3,000 MW – is divided proportionally between the participating TSOs; the proportions are recalculated each year based on both the previous year's electricity feed-in and the load.

Figure 77 shows a continued slight increase in the amount of FCR to be contracted by the German TSOs up to 2018. In 2019, the first deviation from this trend was recorded. There was also a slight decrease in 2020, with the volume of FCR tendered amounting to 573 MW. As there has been an overall decrease in generation in

Germany in the past few years compared with other countries, Germany's share in FCR has also decreased, as has its share in feed-in and load in continental Europe.

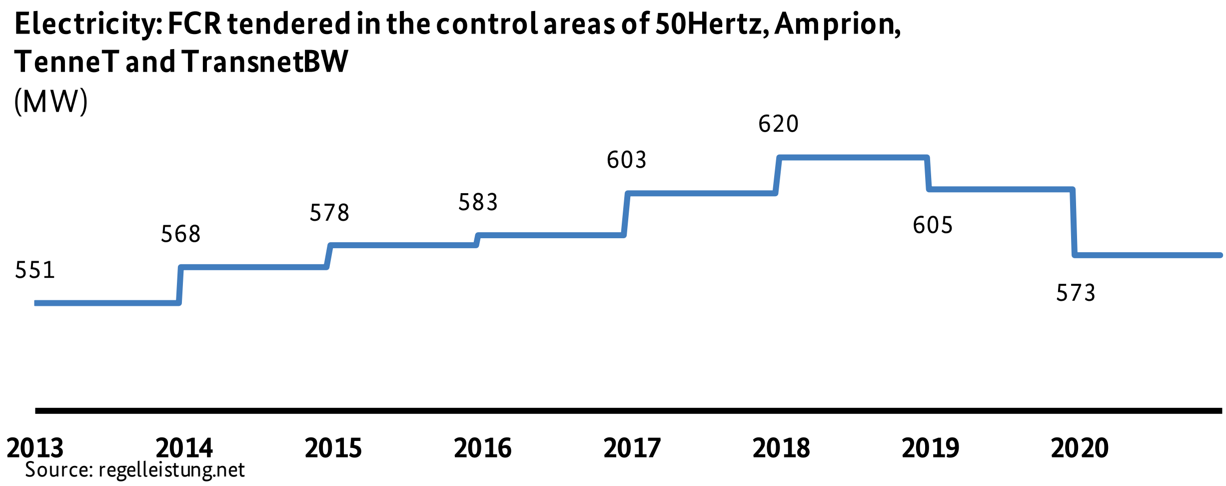


Figure 77: FCR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

Procurement of aFRR

Figure 78 shows that in 2020 there was another increase in the average volume of both positive and negative aFRR tendered. The average volume of positive aFRR tendered was 2,101 MW (2019: 1,903 MW) and the average volume of negative aFRR tendered was 2,022 MW (2019: 1,798 MW).

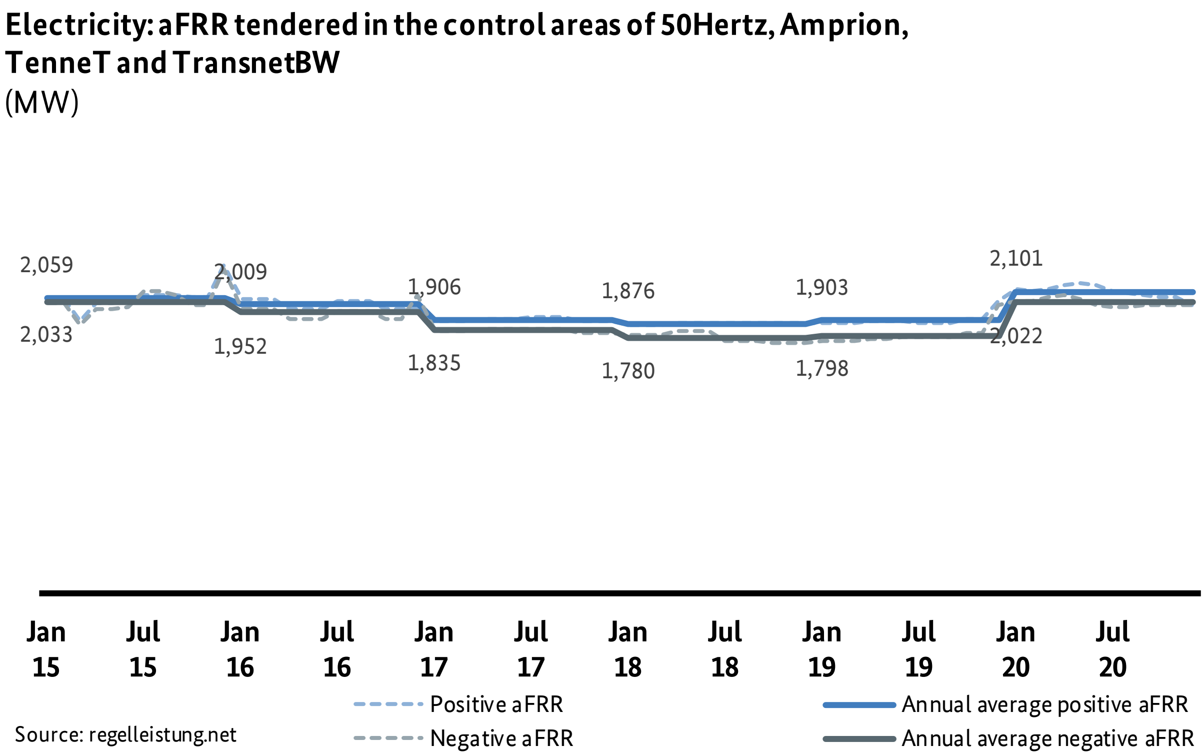


Figure 78: aFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

Table 78 shows that the ranges for both positive and negative aFRR were larger than in previous years. This is due to the introduction at the end of 2019 of a dynamic process in which the balancing capacity requirements are determined on a four-hourly basis; this leads to a wider range in the volumes tendered because, for instance, PV forecast errors do not need to be taken into account at night, but have a stronger impact during the day.

Electricity: range of aFRR tendered by the TSOs

	Year	Capacity tendered (MW)	
		Min	Max
aFRR (positive)	2015	1,868	2,234
	2016	1,973	2,054
	2017	1,890	1,920
	2018	1,869	1,907
	2019	1,882	2,131
	2020	1,618	2,218
aFRR (negative)	2015	1,845	2,201
	2016	1,904	1,993
	2017	1,818	1,846
	2018	1,745	1,820
	2019	1,760	2,216
	2020	1,682	2,251

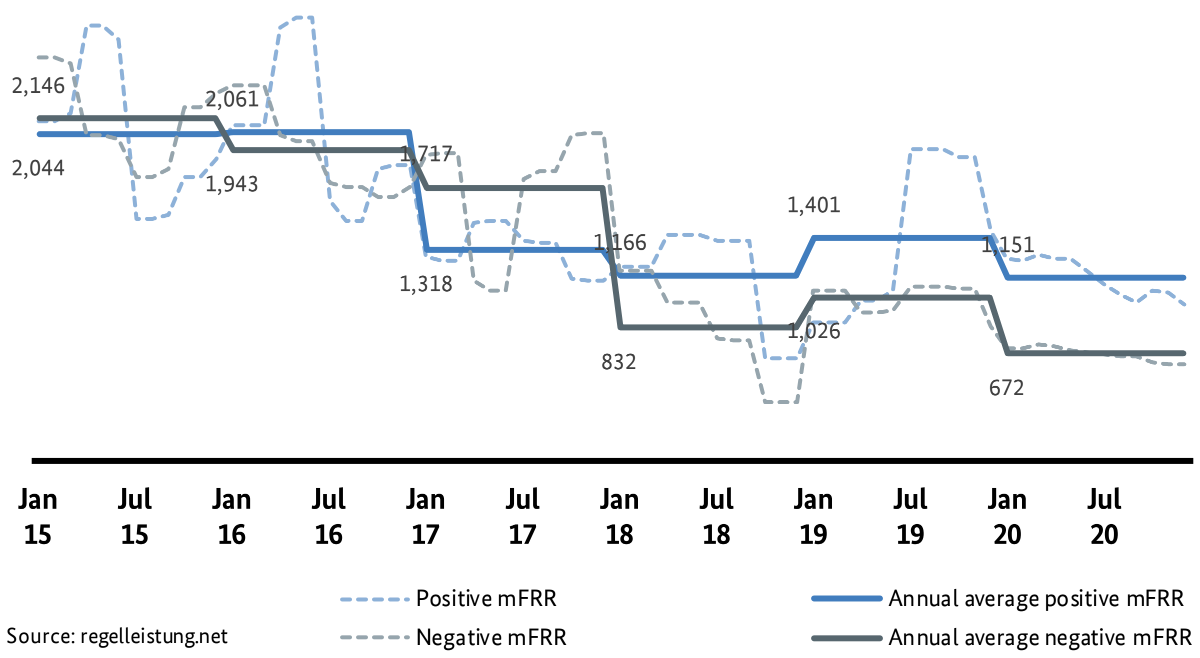
Source: regelleistung.net

Table 74: Range of aFRR tendered by the TSOs

Procurement of mFRR

Following an increase in the average volume of both positive and negative mFRR tendered in 2019, after a series of decreases in the previous years, there was a decrease in both volumes in 2020, with an average volume of positive mFRR of 1,151 MW and of negative mFRR of 672 MW. This trend is underscored by the ranges shown in Table 79, with the highest and lowest volumes tendered each lower than in the previous year.

Electricity: mFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW
(MW)



Source: regelleistung.net

Figure 79: mFRR tendered in the control areas of 50Hertz, Amprion, TenneT and TransnetBW

Electricity: range of mFRR tendered by the TSOs

	Year	Capacity tendered (MW)	
		Min	Max
mFRR (positive)	2015	1,513	2,726
	2016	1,504	2,779
	2017	1,131	1,850
	2018	641	1,419
	2019	874	1,952
	2020	337	1,406
mFRR (negative)	2015	1,782	2,522
	2016	1,654	2,353
	2017	1,072	2,048
	2018	375	1,199
	2019	644	1,094
	2020	276	809

Source: regelleistung.net

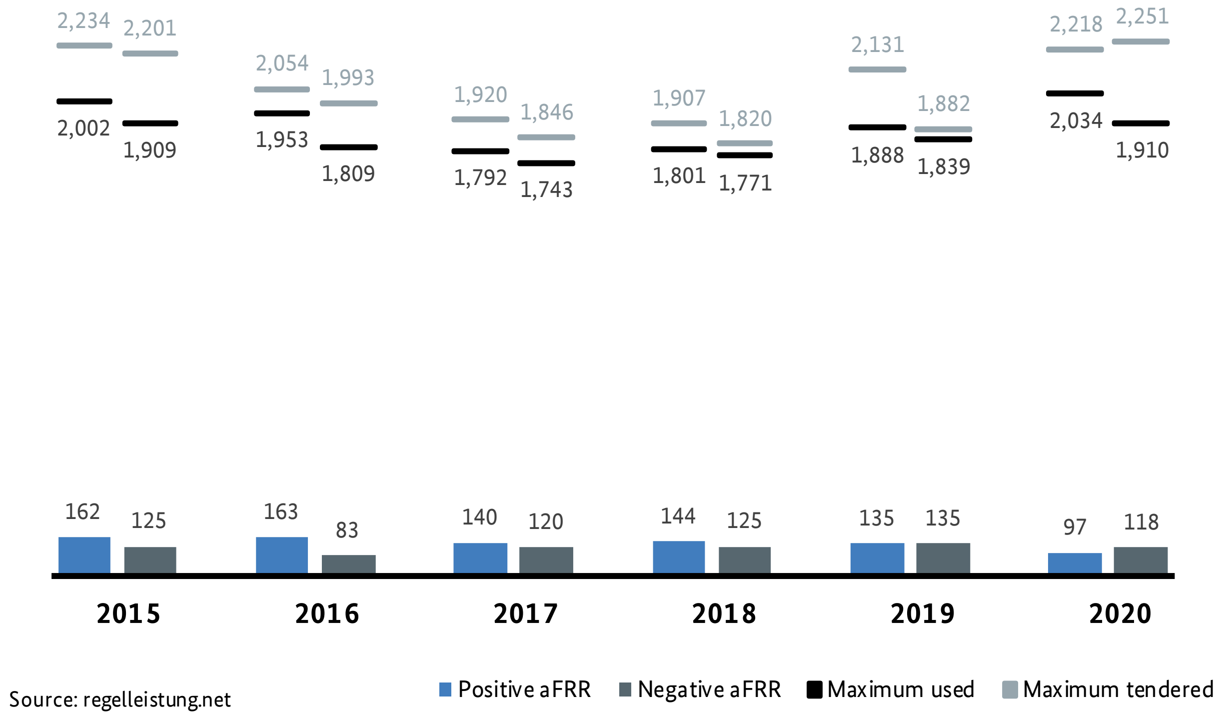
Table 75: Range of mFRR tendered by the TSOs

2.2 Use of balancing capacity

Electrical energy can be stored only to a certain extent. To ensure that the amount of electrical energy generated is always the same as the amount of energy consumed, each generator and each consumer is allocated to a balancing group. Balance responsible parties (regional suppliers, electricity traders, suppliers, etc) are obliged to maintain the balance in their balancing group every quarter of an hour. In other words, the energy delivered to and drawn from the balancing group must balance each other out. Differences between the forecast and actual consumption of different balancing groups within the four control areas in Germany partly balance each other out (netting). Only the remaining difference – the sum of all the balancing group imbalances within the national grid control cooperation (known as the control area balance) – is compensated by using positive or negative balancing capacity through activating positive or negative balancing energy.

Figure 80, which illustrates the total volume of aFRR tendered, shows a decrease in the average volume of aFRR used. By contrast, the highest volume of both positive and negative aFRR activated was higher than in the previous year.

Electricity: average volume of aFRR used, including aFRR drawn and delivered under online netting in the national grid control cooperation
(MW)



Source: regelleistung.net

Figure 80: Average volume of aFRR used, including aFRR drawn and delivered under online netting in the national grid control cooperation

In 2020, the total amount of positive aFRR activated was around 0.8 TWh (2019: 1.2 TWh), and the total amount of negative aFRR activated was 1.0 TWh (2019: 1.2 TWh). There was therefore a decrease in both amounts compared with the previous year.

On average in 2020, just under 4% of the average volume of positive aFRR tendered and just under 5% of the average volume of negative aFRR tendered was used. At least 80% of the average balancing capacity held was required in only six quarter hours of the year. The highest volumes of positive and negative aFRR requested correspond to around 75% and 45% of those tendered respectively.

The Bundesnetzagentur publishes market data on balancing capacity 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 capacity.[82]

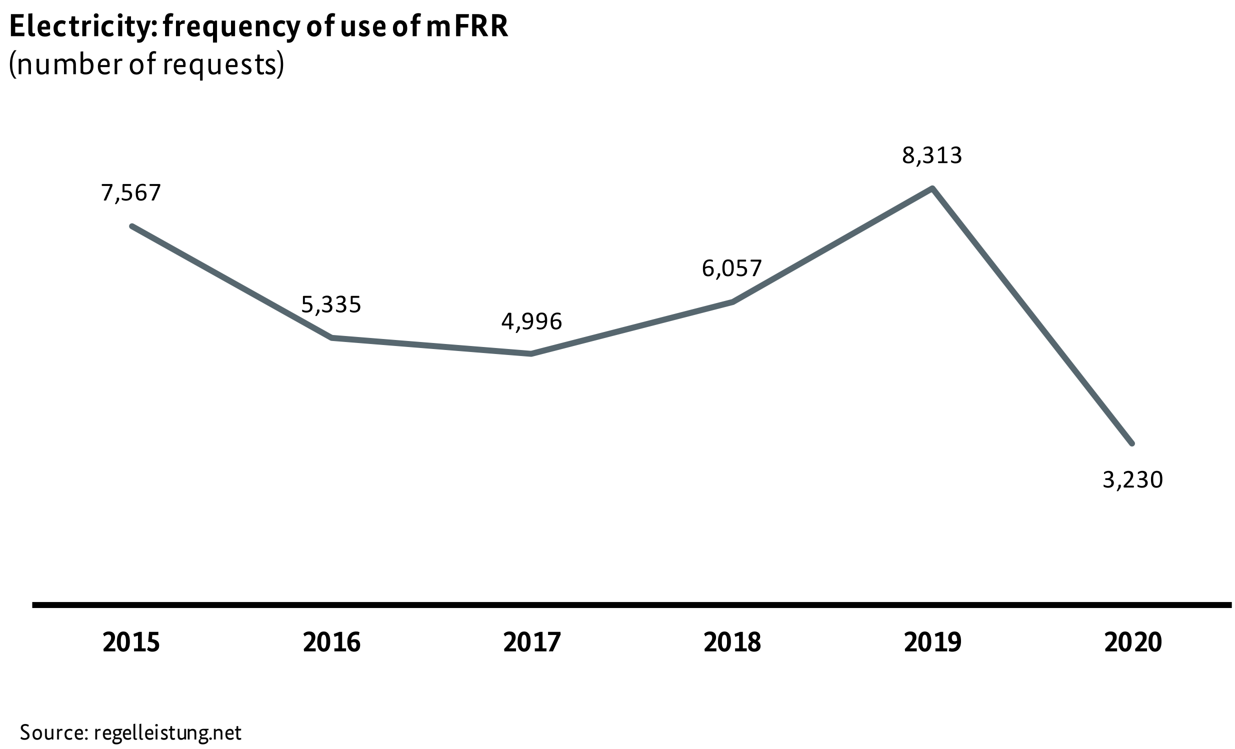


Figure 81: Frequency of use of mFRR

At 3,230, the total number of requests for mFRR was considerably lower than in the previous year. Overall, there were 974 requests for negative mFRR in 2020 (2019: 3,042) and 2,256 requests for positive mFRR (2019: 5,271).[83]

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[82] https://smard.de/home/marktdaten/78?marketDataAttributes={"resolution":"hour","from":1535148000000,"to":1536097532454, "moduleIds":[18000426,18000427,18000428,18000429],"selectedCategory":null,"activeChart":true,"region":"DE","style":"color"}

[83] The number of requests for aFRR is not illustrated separately because it is requested in nearly every quarter hour.

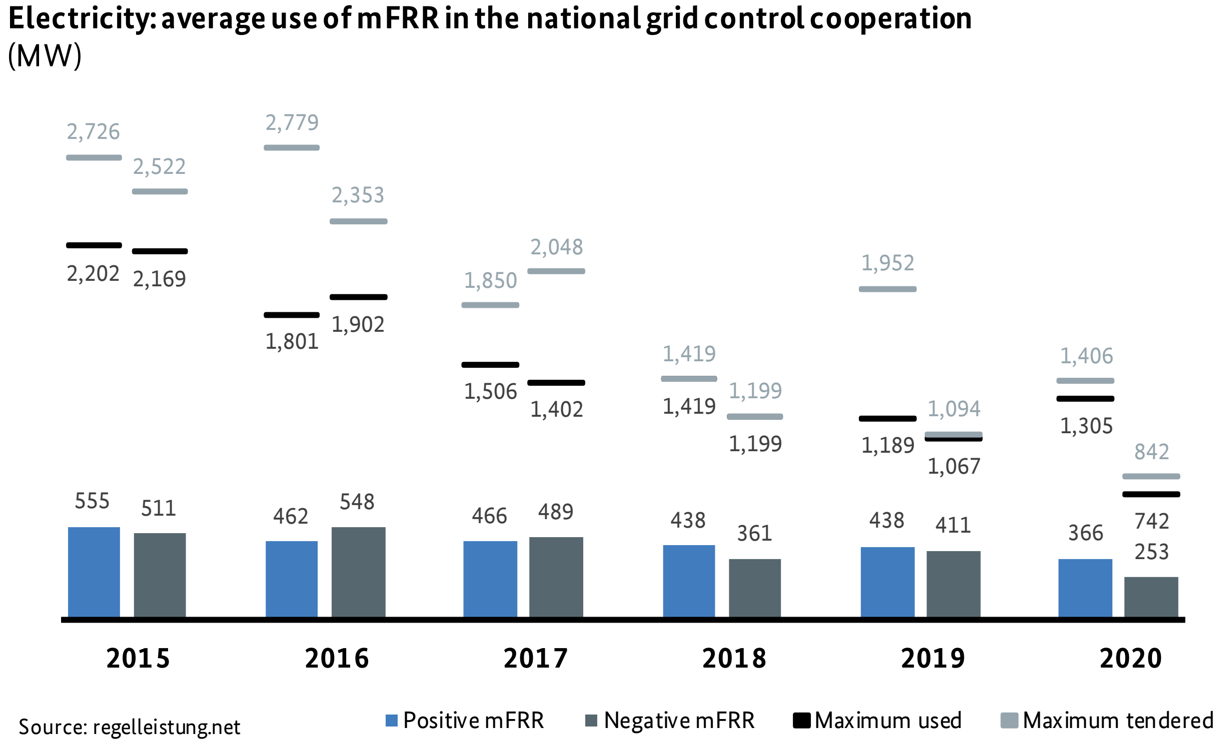


Figure 82: Average use of mFRR in the national grid control cooperation

In the quarter hours in which mFRR were requested, on average 30% of the positive mFRR tendered and 36% of the negative mFRR tendered were used. There was a decrease in the average volume of positive mFRR requested from 438 MW in 2019 to 366 MW in 2020. At 253 MW, the average volume of negative mFRR requested in 2020 was considerably lower than in the previous year (2019: 411 MW).

As with aFRR, however, it must be noted that in several quarter hours all or almost all of the mFRR balancing capacity held was required. In 35 cases, at least 80% of the average balancing capacity held was required. The total volume of positive mFRR held was requested in eight quarter hours.

While aFRR are used in nearly all of the 35,040 quarter hours of a normal year, mFRR are only rarely used. Thus the actual frequency of use for aFRR is more or less the same as the possible frequency of use. By contrast, the volumes of positive and negative mFRR used in 2020 each amounted to less than 1% of the average volumes tendered.

In 2020, a total of about 55 GWh of positive mFRR (2019: 186 GWh) and a total of 18 GWh of negative mFRR (2019: 102 GWh) were activated.

Figure 83 illustrates the average use of aFRR and mFRR in each calendar week from 2015 to 2020. Following a relatively high level of use of aFRR and mFRR (from 2018 until mid-2019), the original downward trend from the years before 2018 can be seen again. This is probably mainly due to the following reasons.

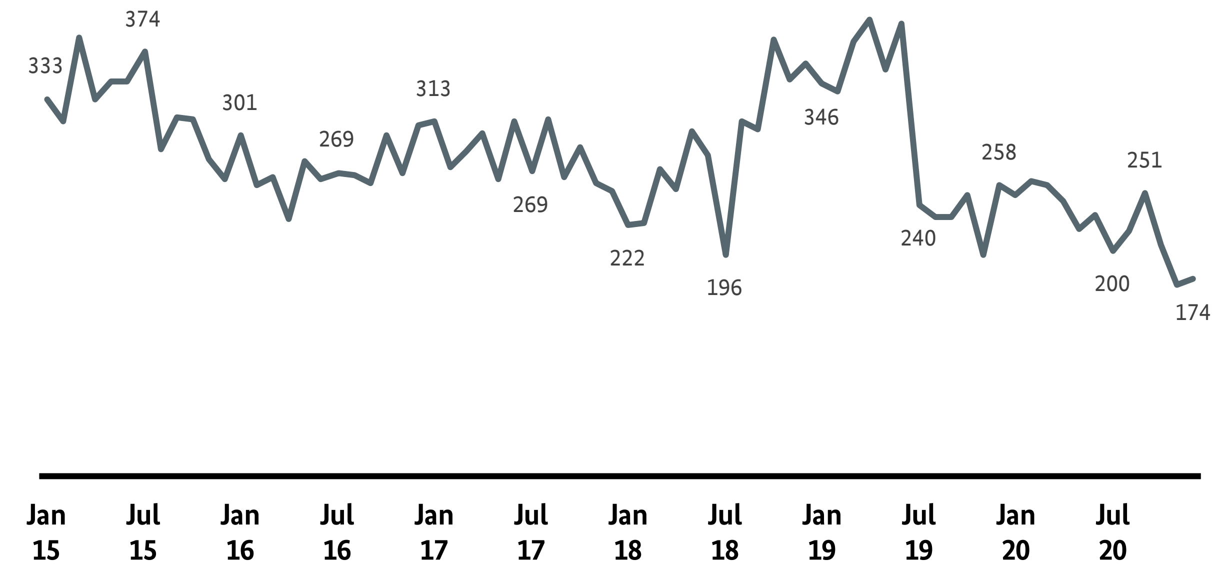
In response to the major imbalances in the German transmission system that occurred on three days in June 2019, the Bundesnetzagentur drew up a package of measures that was designed to improve the upholding of balancing group commitments and that took effect in the first quarter of 2020. The measures reinforced the provisions on balancing energy volumes in balancing groups every 15 minutes, introduced early reporting of certain measurements to permit system imbalances to be cleared up and explained more quickly in future, and adjusted the penalty in the calculation of the imbalance price with the aim of creating a greater economic incentive to balance energy volumes in balancing groups.[84]

As well as bringing in these structural measures, the Bundesnetzagentur opened six supervisory proceedings to investigate whether certain balance responsible parties had contributed to the major imbalances through individual irregular behaviour. In five cases, the ruling chamber identified a breach of the balancing responsibilities by the parties that had caused significant imbalances. The other case was discontinued as the suspicion that was the subject of the proceedings could not be substantiated.

In addition, the abolition of the mixed price procedure that had applied in the tendering for aFRR and mFRR from October 2018 to July 2019 and the return to the old award procedure based on capacity prices led to lower average capacity prices again and considerably higher energy prices for aFRR and mFRR and – as a result – to higher imbalance prices in 2020.

Overall, there were greater incentives for balance responsible parties to fulfil their balancing responsibilities with utmost care, which was reflected in fewer imbalances in the system and consequently less use of aFRR and mFRR.

Electricity: average volume of balancing capacity used (aFRR and mFRR)
(MW)



Source: regelleistung.net

Figure 83: Average volume of balancing capacity used (aFRR and mFRR)

[84] See decisions of 11 December 2019 (BK6-19-212, BK6-19-217 and BK6-10-218).

2.3 Imbalance prices

While the costs for contracting balancing capacity are included in the network charges through the network capacity charge and are thus borne by consumers, the costs for the actual use of balancing capacity – by activating balancing energy – are settled under what is known as the imbalance settlement directly with the balance responsible parties causing the imbalance.

Balancing energy is the electrical energy that is required to compensate for an imbalance in the system balance. While – as described above – only the control area balance is actually compensated by the use of balancing capacity, each individual imbalance in a balancing group has to be balanced out by the TSO responsible with positive or negative balancing energy and billed to the balancing group responsible for the imbalance (even if the imbalance caused can be compensated by an imbalance in another balancing group). The amount of balancing energy used is therefore usually several times higher than the amount of balancing energy actually activated. The imbalance price is determined for each quarter hour as a uniform single imbalance price applicable to all the control areas, which is basically calculated by dividing the total costs of the balancing energy used in the four control areas (based on the balancing energy price) with the corresponding total amount of balancing energy used in each quarter hour. The imbalance price thus has the effect of a surcharge that shares the costs for the balancing energy actually activated between the balance responsible parties that have caused an imbalance.

The exact imbalance price calculation methodology is based on the Bundesnetzagentur's determination that came into effect in December 2012 (BK6-12-024). The aim of the determination is to provide better incentives for the proper management of balancing groups with a view to preventing system-relevant imbalances. The methodology in place since December 2012 for calculating the imbalance price is made up of three modules. Module 1 involves calculating the basic imbalance price based on the costs and revenues from using aFRR and mFRR; module 2 is the market-price coupling of the imbalance price as an "incentive component"; and module 3 is the "scarcity component" of the imbalance price in the form of the 80% criterion.

The major imbalances in the German transmission system that occurred in June 2019 made it clear that the method for calculating the imbalance price needed to be changed. In 2020, the market-price coupling for the imbalance price was therefore amended.[85] The new market-price coupling creates a stronger economic incentive for balance responsible parties to compensate for imbalances through electricity trading instead of using balancing energy and thus impedes arbitrage against the imbalance price. In 2021, the scarcity component of the imbalance price was then also amended.[86] The new scarcity component in use since August 2021 aims to ensure that there is an economic incentive to compensate for imbalances through electricity trading even when there are large imbalances in the system and to prevent arbitrage against the imbalance price: it sets a minimum/maximum price for when there are large imbalances in the system – when the balance within the national grid control cooperation is at least 80% of the aFRR and mFRR – that increases/decreases disproportionately as the national grid control cooperation balance increases (parabola).

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[85] See decision of 11 May 2020 (BK6-19-552) https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK6-GZ/2019/BK6-19-552/BK6-19-552_Beschluss_DB.html.

[86] See decision of 11 May 2021 (BK6-20-345) https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK6-GZ/2020/BK6-20-345/BK6-20-345_beschluss.html?nn=411978.

Electricity: maximum imbalance prices

Year	National grid control cooperation (€/MWh)
2015	6,343.59
2016	1,212.80
2017	24,455.05
2018	2,013.51
2019	2,865.11
2020	15,859.10

Source: regelleistung.net

Table 76: Maximum imbalance prices

In 2020, the highest imbalance price was around €15,859/MWh. This imbalance price was possible on 2 December 2020 because the technical price limit of €9,999.99/MWh for balancing energy prices ceased to apply when the balancing energy market was introduced at the beginning of November 2020. The introduction of the balancing energy market and the abolition of the technical price limit meant that balancing energy bids of up to €99,999.99/MWh were permissible. Following the introduction of the balancing energy market, bids up to this new technical price limit were submitted, accepted and – for instance on 2 December 2020 – activated and therefore formed the basis for the imbalance price. On 16 December 2020, the Bundesnetzagentur ordered the TSOs to re-introduce a technical price limit of €9,999.99/MWh because the average accepted energy price per validity period had been €10,000/MWh or more on a number of occasions since the beginning of November 2020.[87] The reason behind this was the risk of high imbalance prices re-occurring, which would have meant enormous financial risks for the balance responsible parties even with small and unavoidable imbalances. The price exceeded €500/MWh in a total of 94 quarter hours in 2020.

In 2020, the average volume-weighted imbalance price (per quarter hour) within the national grid control cooperation in the case of a positive control area imbalance (short portfolio: balancing service providers reduce consumption or increase feed-in) was considerably higher than in the previous year at €101.98/MWh (up €25.22/MWh). The average volume-weighted imbalance price in the case of a positive control area imbalance was thus more than three times as high as the average (peak) intraday trading price in 2020.[88] The average volume-weighted imbalance price in the case of a negative control area imbalance (long portfolio: balancing service providers increase consumption or reduce feed-in) was negative €25.67/MWh and thus similar to the level in 2017 and considerably lower than in previous years.

[87] See decision of 16 December 2020 (BK6-20-370) https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK6-GZ/2020/BK6-20-370/BK6-20-370_Beschluss.html?nn=411978.

[88] Based on the EPEX SPOT average (peak) intraday trading price of €32.74/MWh for 2020.

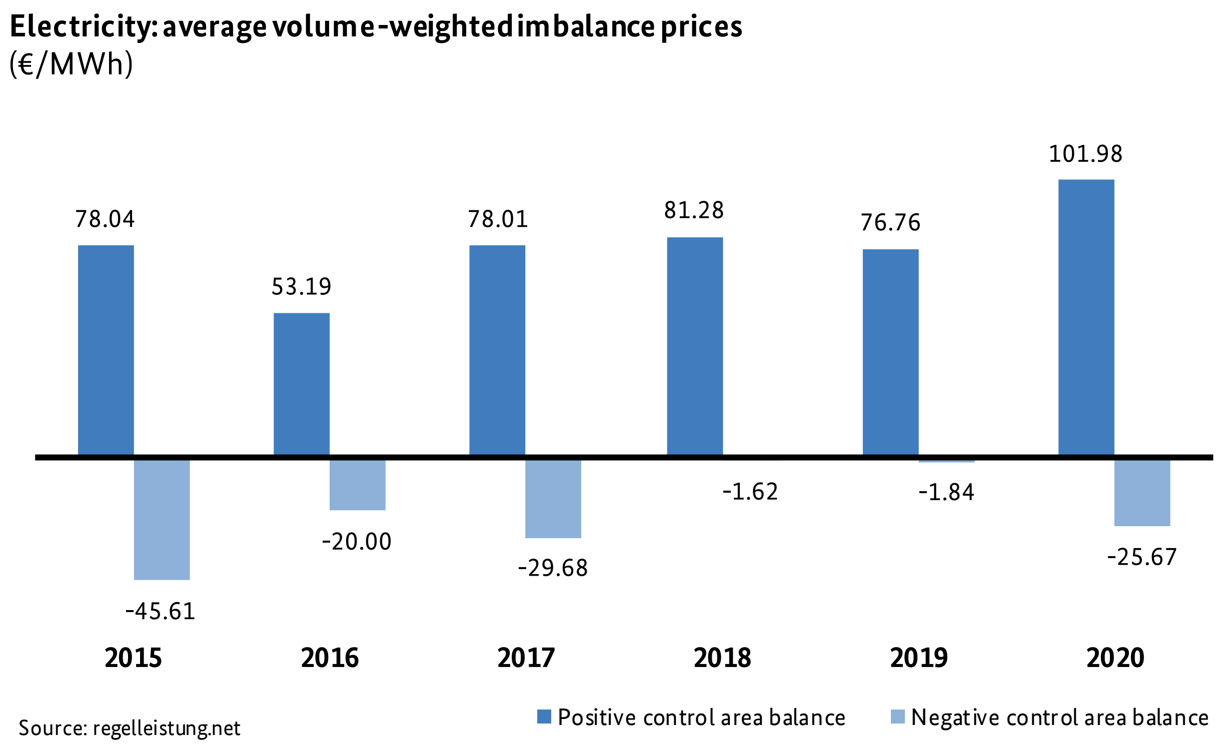

Figure 84: Average volume-weighted imbalance prices

3. European developments in the field of electricity balancing

3.1 International frequency containment reserves cooperation

To reduce the costs for balancing services further, the German TSOs are seeking to achieve further cross-border harmonisation of the markets for FCR in cooperation with the Bundesnetzagentur and other European TSOs and regulators.

The coupling of the national markets has created the largest FCR market in Europe, comprising a total volume of just over 1,400 MW as illustrated below.

Graph illustrating the total volume of frequency containment reserves tendered from 2009 to 2020. The volumes tendered in particular by France and Germany are large.

Electricity: total volume of FCR tendered in the control areas of the German TSOs, Swissgrid (CH), TenneT (NL), APG (AT), ELIA (BE) and RTE (F) (MW)

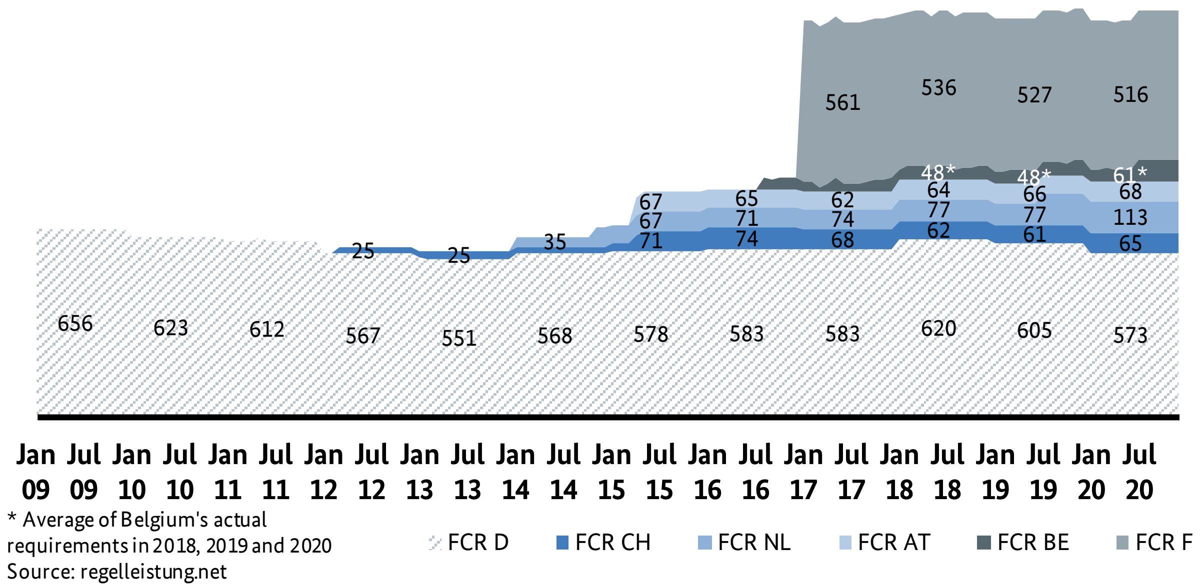

Figure 85: Total volume of FCR tendered in the control areas of the German TSOs, Swissgrid (CH), TenneT (NL), APG (AT), ELIA (BE) and RTE (F)

The proportion of the volume of around 1,400 MW that is procured jointly by the TSOs participating in the FCR cooperation to the volume of 3,000 MW contracted for the whole of the synchronous area is based on the net electricity generation of all the participating countries. The volume of around 1,400 MW is in turn divided up among the participating TSOs based on their shares in net electricity generation.

The joint FCR tendering by the TSOs participating in the cooperation is open to all pre-qualified providers in the participating countries and follows the joint harmonised provisions approved by the competent regulatory authorities pursuant to Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing (see BK6-18-006).

In 2020, the FCR cooperation's product design underwent further development. The following changes were made with effect from 1 July 2020:

- the tendering frequency was changed from one week to one calendar day; and
- the product validity period was shortened from one week to four hours (six products per day).[89]
- In addition, since 2020 Belgium has been procuring all of its required FCR through the cooperation scheme and no longer procures part of it nationally.

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[89] See decision of 13 December 2018 (BK6-18-006).

– In 2021, the TSOs in Denmark (energinet.dk) and Slovenia (ELES) joined the scheme, and the TSO in Czechia (CEPS) officially expressed interest in joining in the future.

3.2 Approved methods for the future European balancing energy exchange platforms

The implementation of Commission Regulation (EU) 2017/2195, which aims to integrate European balancing energy markets, involves cooperation between the European TSOs for the cross-border exchange of balancing energy. Joint platforms have been established to promote the exchange of balancing energy from FRR. Alongside this, a harmonised imbalance settlement mechanism, involving changes to the imbalance price, creates pan-European incentives for market players to maintain the balance within their balancing groups and maintain system stability.

In January 2020, ACER approved the implementation frameworks for the two European cross-border balancing energy platforms. The PICASSO platform (pursuant to Article 21 of Regulation (EU) 2017/2195) will serve the exchange of balancing energy from aFRR and the MARI platform (pursuant to Article 20 of Regulation (EU) 2017/2195) the exchange of balancing energy from mFRR. The aim of the two platforms is to enable the pan-European exchange of balancing energy from aFRR and mFRR, enhance the efficiency of system balancing and increase the liquidity of the balancing markets. Both platforms are due to go live in summer 2022, but the German TSOs plan to use the joint platforms slightly earlier as part of the pilot phase.

Approval was also given for a method for pricing balancing energy (pursuant to Article 30(1) of Regulation (EU) 2017/2195). The method lays down common marginal pricing for the settlement of balancing energy between TSOs and balancing service providers. The aim behind the common methodology is to improve consistency in balancing energy pricing in the EU and create a uniform framework for the integration of the balancing energy markets. In 2021, all the European TSOs proposed an amendment of the methodology with the introduction of a technical price limit of €15,000/MWh on the European balancing energy platforms, with the aim of limiting price spikes on the two balancing energy platforms at the start when there will only be a small number of participating TSOs.

3.3 Automatic frequency restoration reserves cooperation between Germany and Austria

Since 2016, the German TSOs responsible for the control areas have cooperated with the Austrian TSO APG with regard to the use of aFRR. The use of aFRR is based on a common merit order list. This ensures that – provided that sufficient cross-border transmission capacity between Germany and Austria is available and there are no network restrictions – only the most economically efficient aFRR bid in the two countries is used. This enables the costs for balancing energy to be reduced. If cooperation is not possible, for instance because of a lack of cross-border transmission capacity or network restrictions, the German and Austrian TSOs use aFRR at a national level as before.

Since December 2019, Germany and Austria have also requested mFRR in a cross-border process. This means that the two countries already activate all FRR jointly on the basis of common merit order lists.

Since February 2020, part of the national aFRR capacity has now also been procured in a cross-border process. Transmission capacity between Germany and Austria is reserved/allocated for the associated cross-border exchange of aFRR. Joint procurement is currently limited to 80 MW. Relevant harmonised provisions for joint aFRR procurement in Germany and Austria were approved pursuant to Regulation (EU) 2017/2195 by the Bundesnetzagentur and the Austrian regulatory authority E-Control at the end of 2018 (see BK6-18-064).

ACER's decision (Decision No 11/2021 of 13 August 2021) on the market-based allocation process of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves (pursuant to Article 41(1) of Regulation (EU) 2017/2195) lays down new European rules for the allocation of transmission capacity within the framework of cross-zonal balancing capacity cooperation. These rules will also apply to the aFRR cooperation between Germany and Austria.

4. Interruptible loads

4.1 Transmission system operators' tendering for interruptible loads

The legal basis for tendering for interruptible loads is the Interruptible Loads Ordinance (AbLaV), which first entered into force in January 2013 and was replaced by a revised version with effect from 1 October 2016. 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 for immediate and fast interruption.

The chart below shows the capacity tendered and contracted for immediate and fast interruption in 2020. The chart shows that the capacity contracted for immediate interruption remained relatively constant over the whole period and was still well below the total interruptible load capacity tendered of 1,500 MW. By contrast, the capacity for fast interruption increased in the reporting period to up to 875 MW. The reason for contracting more than 750 MW of interruptible capacity is that section 11 AbLaV allows more capacity to be contracted if the volume tendered (750 MW) is not covered without accepting one further bid that results in the capacity contracted exceeding 750 MW. The ratio of immediately to quickly interruptible loads is due to fluctuations in the quickly interruptible loads offered. However, the highest total amount of capacity contracted for immediate interruption in 2020 was only 519 MW. This represents an increase compared with the previous year (2019: 462 MW), but it is still well below the maximum possible of 750 MW.

Electricity: capacity tendered and contracted for immediate and fast interruption from January 2020 to December 2020 (MW per calendar week)

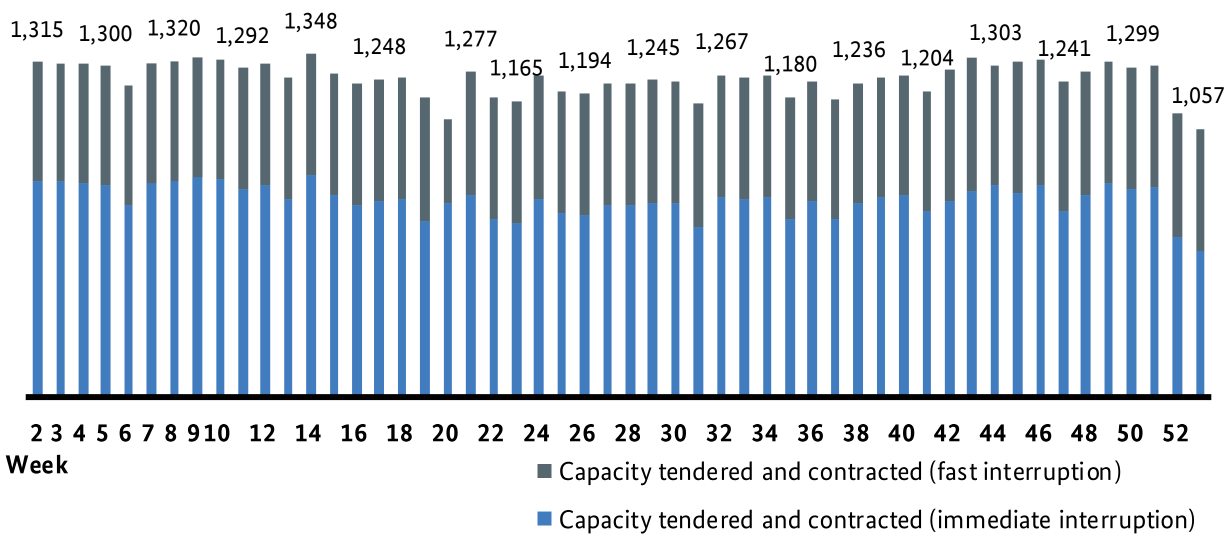

Figure 86: Capacity tendered and contracted for immediate and fast interruption from January 2020 to December 2020

4.2 Pre-qualified capacity

By the end of 2020, an additional five interruptible loads with a total interruptible capacity of 50 MW had taken part in the initial pre-qualification procedure pursuant to section 9 AbLaV, and all had successfully pre-qualified.

Nine loads with a total interruptible capacity of 802 MW had therefore pre-qualified as immediately interruptible loads, and at the same time as quickly interruptible loads, by the end of the year under review. In 2020, 41 loads pursuant to section 2 para 11 AbLaV with a total interruptible capacity of 1,559 MW (including the 802 MW above) had therefore pre-qualified as quickly interruptible loads. No consortia pursuant to section 2 para 12 AbLaV pre-qualified as interruptible loads. The pre-qualified capacity of immediately interruptible loads in 2020 was 9 MW higher than in the previous year. The capacity of the pre-qualified quickly interruptible loads in 2020 was 59 MW higher than in 2019. The majority of the loads are connected to Amprion's control area, while others are in the control areas of 50Hertz, TenneT and TransnetBW.

4.3 Use of interruptible loads

In 2020, interruptible loads were used comparably with the use of balancing capacity to balance the system on nine days. The highest interruptible load capacity of 480 MW was requested on 4 June 2020. The interruptible loads were used to balance the system at the same time as positive mFRR. As with interruptible loads, however, not all of the positive mFRR had to be used in 2020. Interruptible loads were not used in 2020 for redispatching purposes. Interruptible loads were used for test purposes on one occasion.

The contracted immediately interruptible loads were registered on time as not available for 805 hours, thus 73,862 MWh of interruptible energy was not available from the immediately interruptible loads. By contrast, the quickly interruptible loads were registered as not available in 2020 for 34,005 hours, thus 561,320 MWh of interruptible energy was not available from the quickly interruptible loads. Significant use was therefore made of the opportunity to register the unavailability of contracted interruptible loads one day in advance. The loads are then not available to TSOs for system balancing or redispatching. Nevertheless, during the whole period no contracted loads were registered as not available because of alternative marketing on the balancing or the spot market.

4.4 Costs for interruptible loads

The energy-based costs for the actual reductions in consumption in 2020 were lower at €1,200,460 (2019: €2,933,093; 2018: €952,774; 2017: €293,935), reflecting the decrease in the use of interruptible loads compared with the previous year. By contrast, the capacity-based costs for contracting the interruptible loads increased again to €30,124,235 (2019: €28,013,447; 2018: €26,770,491; 2017: 26,940,103). The TSOs' transaction costs for implementing the AbLaV rose in 2020 to €454,000 (2019: €306,112; 2018: €355,023; 2017: €886,532). The total costs for interruptible loads therefore amounted to €31,778,695 in 2020 (2019: €31,252,653; 2018: €28,078,289; 2017: €28,120,570). The increase in the total costs is due to an increase both in the costs for contracting capacity and in the transaction costs.

4.5 Increasable loads ("use, don't curtail")

In January 2018, the Bundesnetzagentur agreed on a voluntary commitment known as "use, don't curtail" with the three relevant TSOs: TenneT, Amprion and 50Hertz. This enables the TSOs to contract with CHP installation operators in the "network expansion area" for the reduction of active power feed-in while continuing to supply electrical energy to maintain heat supplies. The aim is to avoid feed-in management measures in the network expansion area and, at the same time, to make new redispatch potential available. The new rules in the 2021 version of the EnWG extend the applicability of the arrangement to plants outside the "southern region" (see Annex 1 KVBG).

Under the voluntary commitments, a power plant is suitable for the economic and efficient elimination of congestion if the savings obtained from the avoided feed-in management measures are projected to cover at least the required investment costs forecast over the five-year period following commissioning (terms of the contracts). This means that an across-the-board efficiency approach – one not related to grid costs – is adopted.

The above-mentioned TSOs started to offer relevant contracts to plant operators in 2018. Since then, five contracts have been concluded in the 50Hertz control area. The potential redispatch load of the plants under contract amounts to around 126 MW.

E Cross-border trading and European integration

1. Power exchanges and market coupling

The countries of the European Union are part of a European interconnected system for the exchange of electricity in which Germany acts as a central hub. The aim of the ongoing development of the European internal market for electricity is to integrate electricity markets more closely, to facilitate cross-border trade and to ensure the secure, cost-efficient and sustainable supply of electricity.

The Bundesnetzagentur cooperates with other regulatory authorities in Europe (National Regulatory Authorities – NRAs) and the Agency for the Cooperation of Energy Regulators (ACER) on implementing European Union rules.

The internal market for electricity is divided into separate bidding zones in which electricity prices are determined according to supply and demand. Electricity is traded within the bidding zone free of congestion (ie without capacity restrictions) from the generator to the consumer. This only works if physical congestion is rectified within a bidding zone by means of redispatch measures and network expansion or if internal overloading of power lines is taken into account in the calculated cross-border capacity. Due to congestion between bidding zones, cross-border trading may be limited by the transmission capacity available. Germany and Luxembourg constitute a common bidding zone with uniform prices.

With the addition of Belgium and Norway, Germany acquired two new electricity external borders at the end of 2020. These are the interconnections ALEGrO (Aachen Lüttich Electricity Grid Overlay) and the NordLink subsea power cable.

The electricity for delivery in Europe is traded mainly in two time frames:

- In the day-ahead market electricity is auctioned for the following day. The auction applies a marginal pricing procedure in which the last accepted bid sets the price for all transactions.

- Intraday trading mainly involves the continuous buying and selling of electricity (with one-hour, half-hour or quarter-hour settlement periods). This means that the price of each accepted bid is different (pay as bid).

Most day-ahead and intraday markets in Europe are coupled. This means that available capacity between bidding zones is directly linked to the volume of electricity auctioned, so that neither the seller nor the buyer need to worry about the transmission of the electricity, ie the cross-border capacity. This procedure, in which two market participants in different bidding zones are able to trade with each other without any additional steps, is referred to as implicit capacity allocation. In contrast, explicit capacity allocation, in which transmission rights between bidding zones have to be acquired in addition to the actual transaction of electricity, is becoming less important.

Almost all the countries of the European Union are now nearly completely coupled in the MRC (Multi-Regional Coupling).

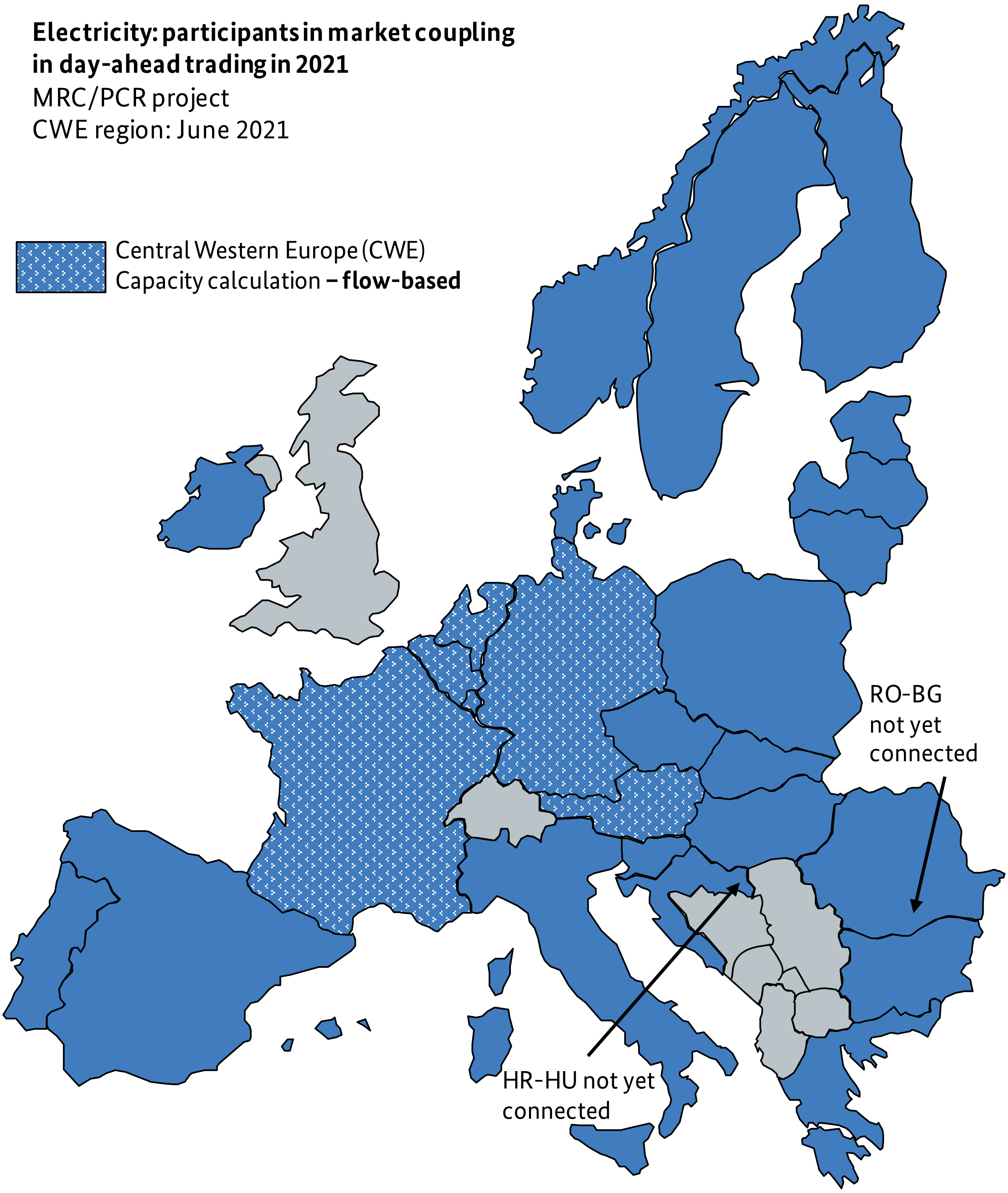

Figure 87: Participants in market coupling in day-ahead trading in 2021

The aim of market coupling is the efficient use of available day-ahead and intraday transmission capacity between the participating countries. The MRC results in an alignment of prices on the day-ahead market while capacity is allocated at the individual borders also according to potential welfare benefits. Indeed, price convergence (which serves as an indicator for the efficient use of interconnector capacity) is significantly higher in coupled regions than in uncoupled regions.

2. Calculation of capacities for cross-border trade

Transmission capacity between bidding zones is a scarce resource. Limited interconnector capacity and also internal network elements that are highly sensitive to cross-border trading may act as a natural physical limit on cross-border trading.

In Europe the capacities made available to day-ahead electricity markets are determined either by the Net Transfer Capacity (NTC) calculation or by the flow-based market coupling (FBMC) algorithm.

Net Transfer Capacity (NTC)

In the NTC process, TSOs bilaterally agree on the available – also for long-term – cross-border capacity for trading. The overall trading capacity at the border is determined by the lower NTC value of both sides of the border based on the historical load capacity of the part of the respective domestic grid leading to the border.

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 calculation methodology not only takes account of particular bidding zone borders but also of all the flows of electricity in the area including the internal transmission lines relevant for trading.

Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (Commission Regulation (EU) 2015/1222) defines flow-based market coupling as the target model for central Europe. For this reason, justified grounds must be given if any region decides not to use a flow-based approach as its capacity calculation methodology. This cross-border, regional capacity calculation methodology for the geographically larger Core Region (consisting of CWE and CEE, whereby CEE is made up of the borders between Austria, Croatia, Czech Republic, Germany, Hungary, Poland, Romania, Slovenia and Slovakia) is expected to be introduced in 2022.

3. Average available cross-zonal capacity

The mean available cross-zonal capacity is the capacity that can be transmitted between two bidding zones on an hourly basis averaged over the year. Both import and export capacities have been analysed. Different methodologies were applied for the two procedures presented in I.E.2.

Net Transfer Capacity (NTC)

For this report, the average available cross-zonal capacity was determined using the annual average of the German TSOs' hourly NTC values. The average values determined represent the capacity basically made available to the market without being fully used in both trading directions.

Flow-Based Market Coupling (FBMC)

The trading capacities used as a result of the FBMC are always geared to optimising welfare and these values do not therefore reflect the average cross-zonal capacity actually made available. As the cross-zonal trading capacities in FBMC are dependent on each other, it is not possible to provide an independent value per border, as is the case with the NTC process. A trading capacity is evaluated as the estimated value for each border that can only be achieved if no electricity is traded at any other FBMC borders. These hourly values are then used to calculate the average transmission capacity.

Electricity: import capacity

Border	2018	2019		2020	
			Change compared to previous year		Change compared to previous year
NTC					
CH → DE	3,888.25 MW	3,491.04 MW	-10 %	3,707.67 MW	6 %
CZ → DE	1,442.00 MW	1,416.35 MW	-2 %	1,420.55 MW	0 %
DK → DE	1,465.57 MW	1,782.23 MW	22 %	1,900.75 MW	7 %
NO → DE **				380.09 MW	
PL → DE	1,358.29 MW	1,249.22 MW	-8 %	1,414.65 MW	13 %
SE → DE	450.39 MW	533.56 MW	18 %	516.24 MW	-3 %
Flow-based					
AT → DE *	4,999.43 MW	5,080.67 MW	2 %	5,028.24 MW	-1 %
BE → DE **				571.59 MW	
FR → DE	4,323.96 MW	3,748.00 MW	-13 %	4,810.14 MW	28 %
NL → DE	2,504.17 MW	3,246.32 MW	30 %	3,560.67 MW	10 %

Source: TSOs; *bidding zone split DE/AT in October 2018; **commissioning end 2020

Table 81: Overview of the development of import capacities

Electricity: export capacity

Border	2018	2019		2020	
			Change compared to previous year		Change compared to previous year
NTC					
DE → CH	1,394.25 MW	1,342.98 MW	-4 %	1,263.67 MW	-6 %
DE → CZ	1,235.23 MW	1,348.30 MW	8 %	1,050.24 MW	-22 %
DE → DK	1,850.68 MW	1,965.43 MW	6 %	2,180.85 MW	11 %
DE → NO **				571.00 MW	
DE → PL	1,002.97 MW	904.03 MW	-11 %	1,042.28 MW	15 %
DE → SE	232.39 MW	248.55 MW	7 %	321.61 MW	29 %
Flow-based					
DE → AT *	5,051.92 MW	4,984.73 MW	-1 %	4,864.04 MW	-2 %
DE → BE **				571.59 MW	
DE → FR	4,995.58 MW	5,488.41 MW	9 %	5,820.48 MW	6 %
DE → NL	3,212.04 MW	3,301.61 MW	3 %	3,016.47 MW	-9 %

Source: TSOs; *bidding zone split DE/AT in October 2018; **commissioning end 2020

Table 877: Overview of the development of export capacities

The fundamentally different approach taken makes it impossible to 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 81 and Table 877.

Reasons for the long-term changes in capacity include construction of new lines and other grid elements (such as phase-shifters or transformers). In addition, on 26 April 2018 a mandatory minimum capacity share of 20% of the interconnector capacity was introduced in the CWE region for flow-based market coupling. As of 1 January 2020, a minimum trading capacity for all borders was also determined as part of the Clean Energy for all Europeans Package (CEP) (see I.E.7.1), which will also increase available capacity in the region. Negative year on year changes in capacity may also be due to outages and maintenance work. Electricity trading capacity at the border between Western Denmark and Germany is largely subject to special rules (see I.C.5.2.5 "Countertrading").

Figure shows aggregated exports and imports of electricity across all Germany's borders throughout the year and as a duration curve (exports and imports sorted in descending order by the largest absolute value). It should be noted that the exports and imports shown in the duration curve are not obtained simultaneously at high absolute values.

Electricity: export and import capacity
(GW)

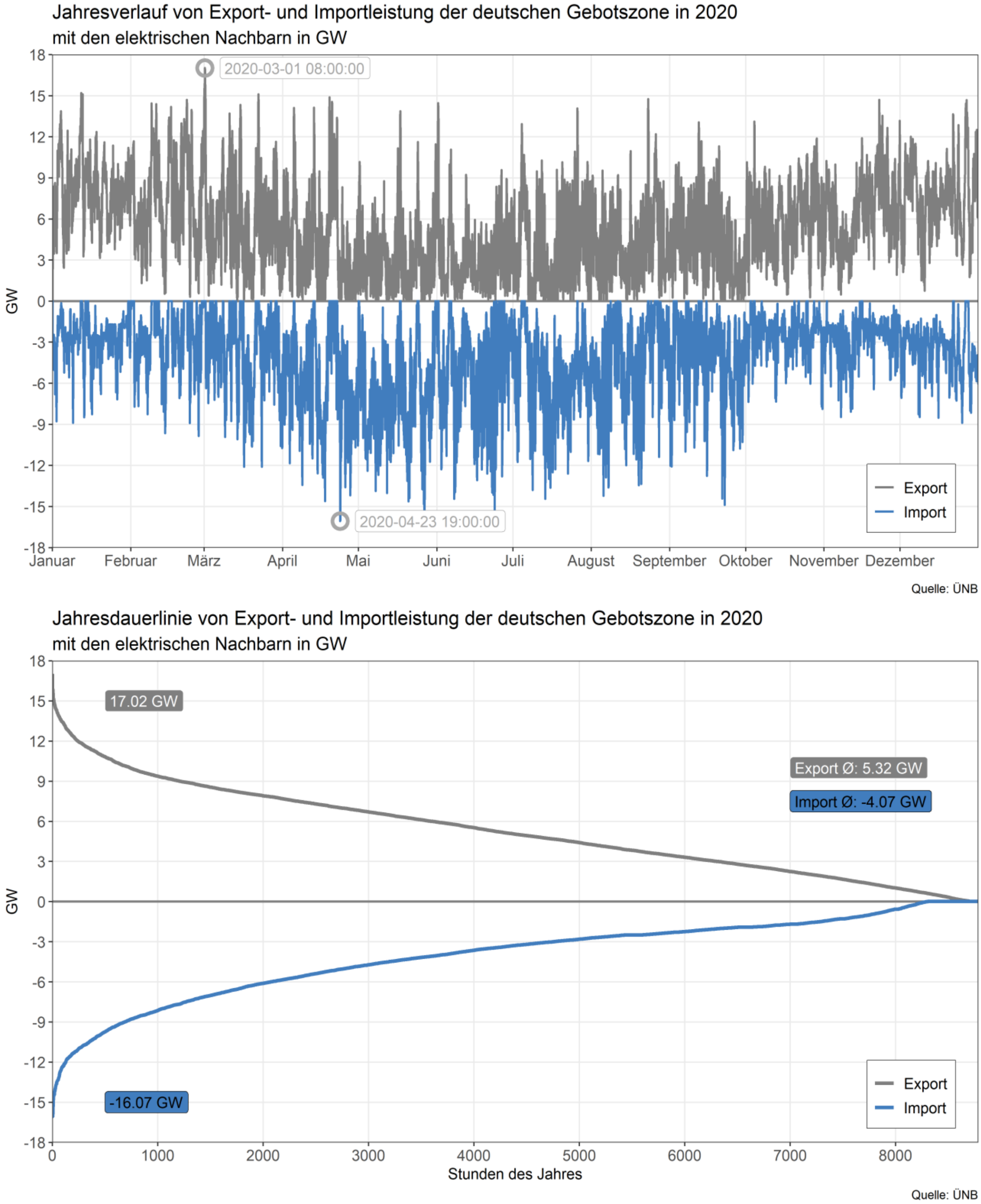

Figure 88: Export and import capacity

4. Cross-border load flows and realised trade flows

The physical load flows measured at bidding zone borders are related to the realised exchange schedules, or trade flows. Theoretically, the balance of physical flows and trade flows should, in an overall view, be nearly identical. However, this is often not the case owing to unscheduled flows (loop and transit flows, see I.E.5 on page 228 onwards), transmission losses, cross-border redispatch and measurement tolerances. As physical electricity flows always follow the path of least resistance, physical flows and actual trade flows at each border may differ considerably from each other (see Figure). This is unavoidable in a highly meshed network with large bidding zones.

Electricity: exchange schedules (cross-border electricity trade) and physical flows (TWh)

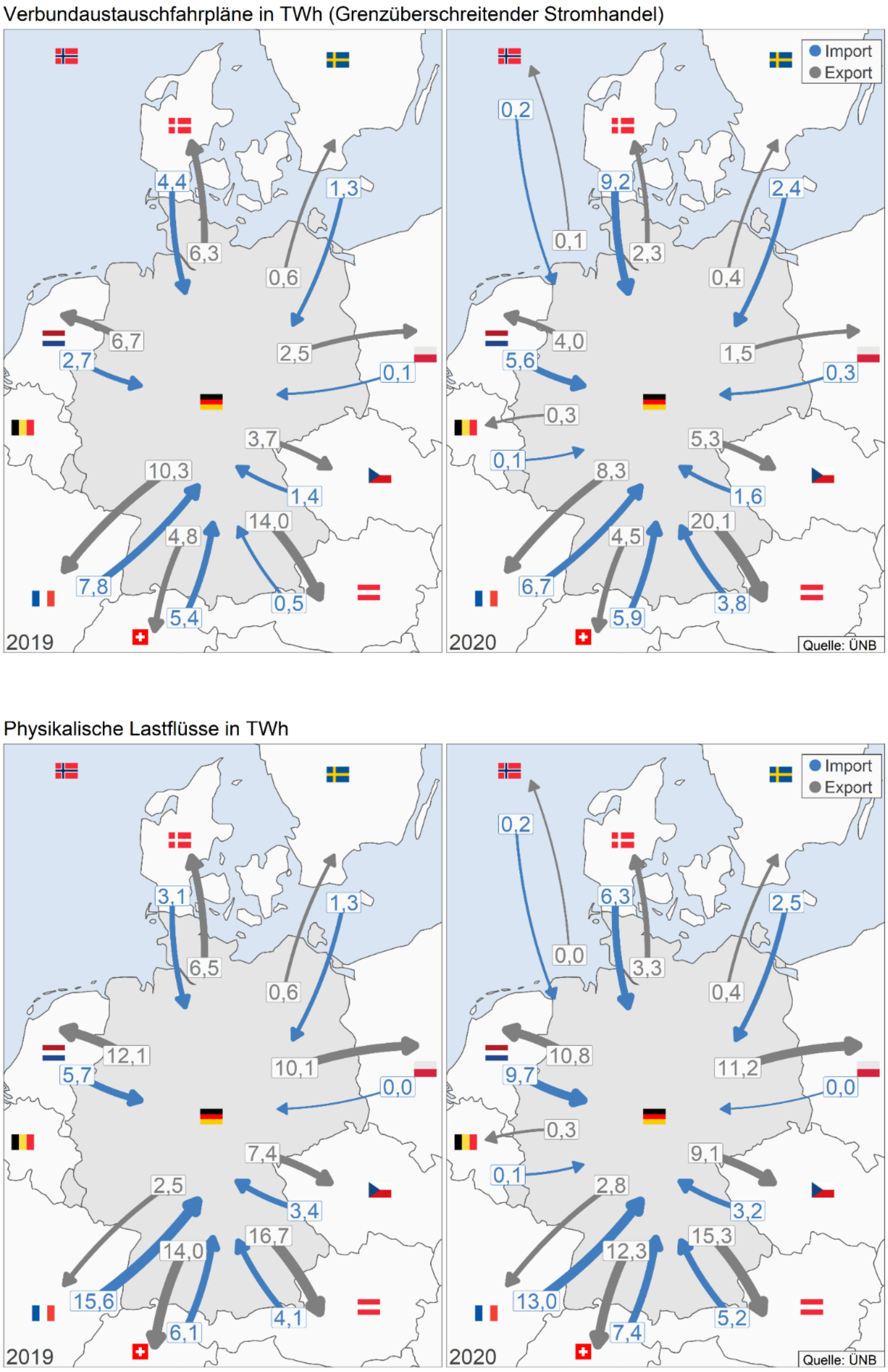

Figure 89: Exchange schedules and physical flows

The realised exchange schedules are decisive in assessing the net balance of electricity imports and exports at each external border and at all of Germany's borders as a whole. Figure shows the realised exchange schedules and the physical flows at Germany's borders in 2019 and 2020. Tables 8878 to 85 show the summarised values.

Electricity: comparison of the balance of cross-border electricity flows
(TWh)

	Actual physical flows in 2019	Binding exchange schedules 2019	Actual physical flows in 2020	Binding exchange schedules 2020
Imports	39.4	23.6	47.6	35.8
Exports	69.8	48.8	65.4	46.7
Balance	30.4	25.2	17.8	11.0

Source: TSOs

Table 878: Comparison of the balance of cross-border electricity flows

Electricity: comparison of imports from cross-border flows
(TWh)

	Actual physical flows in 2019	Exchange schedules 2019	Actual physical flows in 2020	Exchange schedules 2020
AT → DE	4.1	0.5	5.2	3.8
BE → DE **			0.1	0.1
CH → DE	6.1	5.4	7.4	5.9
CZ → DE	3.4	1.4	3.2	1.6
DK→ DE	3.1	4.4	6.3	9.2
FR → DE	15.6	7.8	13.0	6.7
NL → DE	5.7	2.7	9.7	5.6
NO → DE **			0.2	0.2
PL→ DE	0.0	0.1	0.0	0.3
SE → DE	1.3	1.3	2.5	2.4

Source: TSOs; **commissioning end of 2020

Table 879: Comparison of imports from cross-border flows

Electricity: comparison of exports from cross-border flows
(TWh)

	Actual physical flows in 2019	Exchange schedules 2019	Actual physical flows in 2020	Exchange schedules 2020
DE → AT	16.7	14.0	15.3	20.1
DE → BE **			0.3	0.3
DE → CH	14.0	4.8	12.3	4.5
DE → CZ	7.4	3.7	9.1	5.3
DE→ DK	6.5	6.3	3.3	2.3
DE → FR	2.5	10.3	2.8	8.3
DE → NL	12.1	6.7	10.8	4.0
DE → NO **			0.0	0.1
DE→ PL	10.1	2.5	11.2	1.5
DE → SE	0.6	0.6	0.4	0.4

Source: TSO; **commissioning end of 2020

Table 880: Comparison of exports from cross-border flows

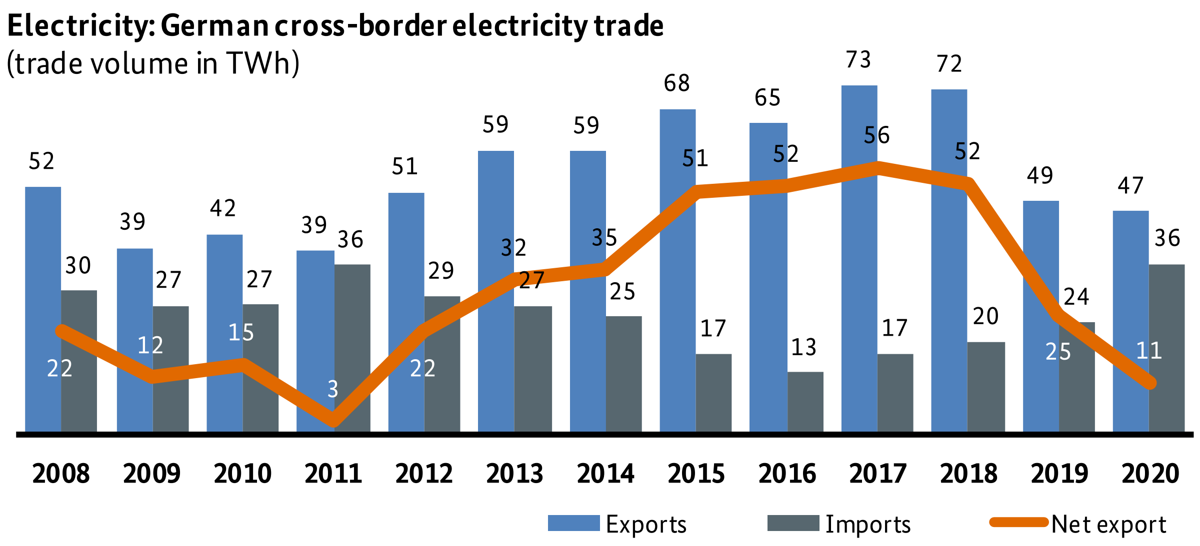

Figure 90: German cross-border electricity trade

Imports and exports are evaluated by multiplying the trading volumes of realised exchange schedules with the day-ahead EPEX Spot price for the Germany/Luxembourg bidding zone. Rational market behaviour is assumed insofar as longer-term contracts will only be fulfilled if the price incentives are right. If they are not, electricity is purchased in the cheaper local market. The monetary value of electricity imported to or exported from Germany is calculated by regarding imports as costs and exports as revenues.

Electricity: monetary development of cross-border electricity trade

	2019		2020	
	TWh	Trade in €m	TWh	Trade in €m
Exports	48.79	1,705.00	46.73	1,249.96
Imports	23.60	968.90	35.75	1202.00
Balance	25.19	736.10	10.98	47.96
Export revenues (€/MWh)		34.94		26.75
Import costs (€/MWh)		41.05		33.62

Source: TSOs; ENTSO-E

Table 881: Monetary development of cross-border electricity trade (trade flows)

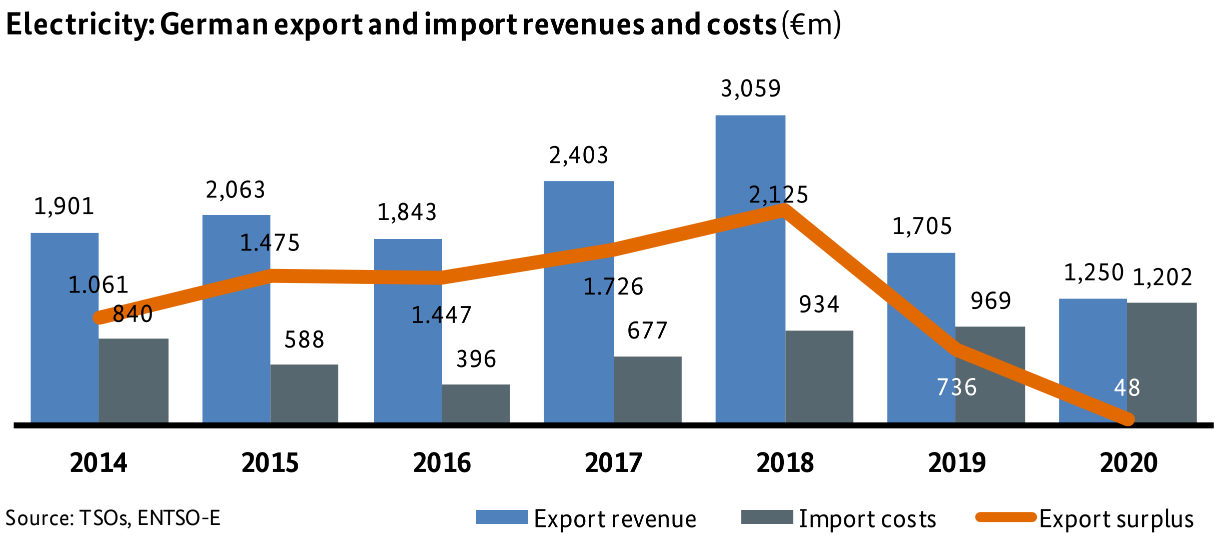

Figure 91: German export and import revenues and costs

Changes in cross-zonal 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.

5. Unscheduled flows

Electricity always flows from a source to a sink. In doing so, it takes the path of least resistance in an alternating current network without selective control. For this reason, unscheduled flows cannot be avoided, or only with disproportionate effort, in an electricity trading system that is organised in zones. Unscheduled flows occur if physical electricity 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 bidding zone that is not involved in the commercial transaction. In contrast, loop flows of electricity occur whenever electricity from one bidding zone passes through a bidding zone that is not involved in the commercial transaction before returning to the zone from which it originated. At present, there are no clear dividing lines between the effects of both types of flow. As a 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 transit and loop flows in and from neighbouring countries. Article 16(8) Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity stipulates that 70% of transmission capacities must be made available for cross-border trade in electricity while 30% may be used for internal and loop flows and a reliability margin.

The unscheduled flows are determined as annual aggregate figures for each border 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 2020, Germany imported (trade) 5.6 TWh from and exported 4.0 TWh to the Netherlands. This is equal to an export surplus (trade) of 1.6 TWh. At the same time, 9.7 TWh flowed physically from the Netherlands to Germany. In contrast, 10.8 TWh flowed from Germany to the Netherlands. This is equal to an export surplus (physical) of 1.1 TWh. This means that on balance (physical minus trade) 2.7 TWh of electricity flowed from Germany to the Netherlands which had not been traded between the two countries.

The following diagrams show the unscheduled flows arising from the difference between net physical and trade flows from the Germany/Austria/Luxembourg market area (or the Germany/Luxembourg market area since October 2018) to its neighbouring countries and vice versa.

Electricity: unscheduled flows
(TWh)

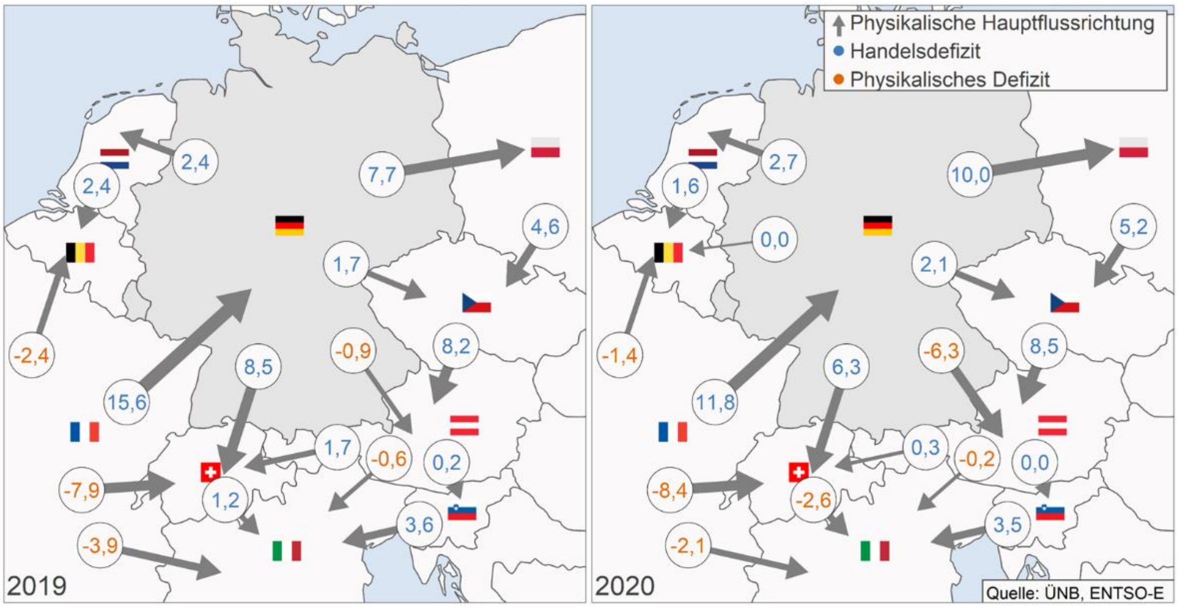

Figure 92: Unscheduled flows

The arrows show the main direction of physical flow and the figures show the trade deficit: orange figures reflect a physical deficit (trade > physics) while the blue figures illustrate a trade deficit (physics > trade). In

2020, for example, the net physical flow from France to Switzerland was 8.4 TWh less than the volume of 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 that 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 overflows 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 due to electricity trading within Germany and Europe.

6. Revenue from compensation payments for cross-border load flows

Pursuant to Article 1 of Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, 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 cost 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 (Transite).

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. According to provisional ACER[90] calculations, the ITC fund for 2020 comprises a record volume of approximately €352.8m (€252.8m for the costs of lost energy, €100m for provision of transport infrastructure). For the ITC year 2020, the four German TSOs with responsibility for control areas received compensation for lost energy and the provision of infrastructure totalling €11.73m and in return were required to pay contributions of €4.94m. On balance, therefore, the German TSOs received a net sum of €6.79m from the ITC mechanism. This makes Germany a net recipient from the ITC fund for the first time since 2014. The changes in the amount of compensation paid from the ITC fund are shown in Figure .

[90] The final figures for 2020 will be published in the ACER ITC Monitoring Report towards the end of 2021. https://www.acer.europa.eu/electricity/infrastructure/inter-tso-compensation-monitoring

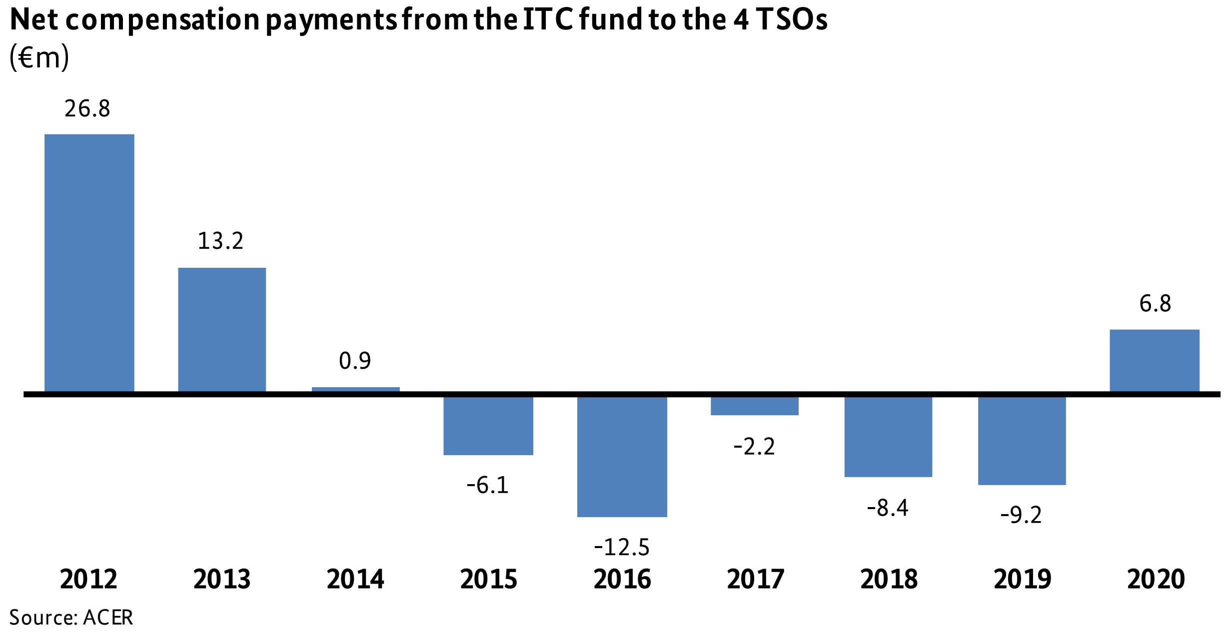

Figure 93: Net compensation payments from the ITC fund to the four TSOs

Although the reasons for the reversal in previous trends is due to the interplay of numerous influencing factors in Germany and abroad, it is nonetheless the case that a further decline in net exports in 2020, a sharp rise in German transmission losses accompanied by rising procurement costs for lost energy and an increase in transmission volumes were conducive to the current development and the resulting compensation payments to the German contracting party. In detail, payments by the German contracting party into the ITC fund in the reporting year fell by €10.8m, while at the same time compensation payments from the fund rose by €5.1m, leading to a precipitous overall change compared to the previous year.

7. Current developments in the European electricity sector

7.1 Implementation of the Clean Energy for all Europeans Package (CEP)

A comprehensive legislative package for the further integration of the European internal market for electricity, the Clean Energy for all Europeans Package (CEP), was adopted in 2019. This package included the new Regulation (EU) 2019/943 on the internal market for electricity, which came into effect on 1 January 2020.

Minimum capacity available for trade and the national action plan

One aspect of this Regulation is that it requires EU Member States to make a minimum of 70% of transmission capacities available for cross-zonal trade. Just in time for the new Regulation to come into force, the federal government submitted its "Bidding zone action plan"[91], which enables this minimum trading capacity to be reached in stages by 31 December 2025. The Bundesnetzagentur's task was to work with the TSOs on the development of principles for the calculation and reporting of the starting point of the linear trajectory of minimum trading capacities and to publish them on its homepage by the end of 2019. The TSOs then calculated and published the starting points so that the corresponding capacities could be made available for

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[91] https://www.bmwi.de/Redaktion/DE/Downloads/A/aktionsplan-gebotszone.html

cross-border trading from 1 January 2020. Since then the Bundesnetzagentur has been monitoring compliance with the minimum values.

In the first half of 2020, the Bundesnetzagentur concentrated in particular on implementing the minimum capacities on the DE-SE4 (Baltic Cable) border at which the “Bidding zone action plan" and the start value calculation applied a minimum capacity of 248MW for the year 2020. In the import direction (SE4 >> DE), countertrading enabled the minimum capacity to be met when the German electricity grid was congested. As not enough liquidity is available in the small SE4 bidding zone to provide sufficient countertrade potential, it was not possible initially to achieve this value for the opposite direction DE >>SE4 without endangering system security in Sweden or risking load shedding in SE4. It was therefore necessary to apply new technical processes with the transmission system operators Baltic Cable and TenneT and the distribution system operator Schleswig-Holstein Netze AG to avoid network congestion. Implementation was accompanied by the Bundesnetzagentur and completed by the end of August 2020. As a result, shortfalls in minimum capacity and risks to system security in SE4 can now be avoided.

On 1 June 2021, the Bundesnetzagentur approved the report of the five TSOs (50 Hz Transmission GmbH, Amprion GmbH, Baltic Cable AB, Tennet TSO GmbH, TransnetBW GmbH) on the available cross-border capacity for 2020 under Article 15(4) of Regulation (EU) 2019/943[92]. In this report, the five TSOs state that the minimum capacity regulations had not been infringed. As the TSOs are required to submit such a report for the previous year to the Bundesnetzagentur every year, the next approval procedure is expected in the second quarter of 2022.

Regional coordination centres

The regional coordination centres (RCCs) for Central Europe – emerging from the existing regional security coordinators TSCNET and Coreso – are due to go into operation on 1 July 2022. The Bundesnetzagentur and the other regulatory authorities affected in the Central Europe system operation region approved the provisions on the establishment of the RCCs in January 2021 and are now monitoring the implementation of the new RCC tasks, which include risk-preparedness, emergency and restoration, training and certification, calculating required capacity and sizing of reserve capacity, and procurement of balancing capacity. Furthermore, joint efforts were made – in accordance with the CEP – to place the historical participation of Swissgrid in TSCNET on a new contractual footing to secure operative cooperation between EU TSOs and Swissgrid on the new RCC.

Congestion income

As with regulations before it, the CEP subjects congestion income earned by the transmission system operators from the award of cross-border interconnection capacities to an earmarking regime. Under Art 19(2) and (3) Regulation (EU) 2019/943, this income must continue to be used primarily to guarantee, maintain or increase cross-border capacities. Once these aims are met, any remaining income can be used to reduce network charges or for later investments in cross-border capacities. The CEP also proposes stipulating these requirements in a methodology. Against this background, ACER adopted a Decision on 23 December 2020,

[92] https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/HandelundVertrieb/EuropMarktkopplung/start.html

ACER approving the ENTSO-E proposal for a methodology for the use of congestion income (Decision No. 38/2020[93]). The methodology includes detailed lists of cost categories subject to the uses of congestion income referred to in the Regulation and specifies the procedure for assessing compliance with the requirements for the use of congestion income by transmission system operators.

In the first half of 2020, the Bundesnetzagentur held intensive discussions with the German transmission system operators to consolidate their common understanding of the underlying rules and to ensure they are taken into account in the ENTSO-E proposal. Through its participation in committee work at ACER, the Bundesnetzagentur has also contributed to the development of appropriate solutions at the European level. The methodology that has now been stipulated, and on which the German transmission system operators have worked intensively, provides a good basis for a uniform European approach to the use of congestion income

Resource adequacy assessment methodology (ERAA)

ENTSO-E, the European Network of Transmission System Operators for Electricity, has developed methodologies in the fields of security of supply that correspond with those in the Regulation on the internal market for electricity referred to above. One of these methodologies establishes rules for a European resource adequacy assessment (ERAA Methodology). This methodology was confirmed in ACER Decision 24/2020[94].

Pursuant to section 51 Energy Industry Act (EnWG), the Bundesnetzagentur has been responsible for monitoring security of supply since 2021. The European rules are applied analogously to national monitoring. This enables modelling results to be compared in a European context.

Supply security calculation methodologies

Other methodologies developed by ENTSO-E and confirmed by ACER in Decision 23/2020[95] are designed to provide uniformly calculated figures and values:

- on willingness to pay to avoid an interruption of electricity supply (Value of Lost Load, VoLL);
- on determining the costs for creating new capacity resources or loads in the electricity market (Cost of New Entry, CoNE); and
- on a reliability standard that may be regarded as a threshold value in the measurement of security of supply (Reliability Standard, RS).

The responsible authorities in EU Member States – in Germany, the Bundesnetzagentur – must take account of the stipulated methodologies.

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[93] https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2038-2020%20on%20use%20of%20Congestion%20Income%20methodology.pdf

[94] https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2024-2020%20on%20ERAA.pdf

[95] https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2023-2020%20on%20VOLL%20CONE%20RS.pdf

The Bundesnetzagentur will finalise its report on the monitoring of security of supply for 2021 at the end of October 2021. Pursuant to section 63(2) sentence 7 EnWG, the report will be published by the German federal government.

Establishment of the European entity for distribution system operators (EU DSO Entity)

Article 52 et seq. of Commission Regulation (EU) 2019/943 stipulates the establishment of the EU DSO Entity, in which DSOs are required to cooperate at the Union level, including participating in the development of network codes.

The EU DSO Entity was officially founded on 8 June 2021. The EU DSO Entity is conceived as a counterpart to the European Network of Transmission System Operators (ENTSO-E).

Up-to-date information and registered distribution system operators as well as, for example, the governance structure of the Entity can be found on the EU DSO Entity website[96].

Risk-Preparedness Regulation

Regional and national crisis scenarios

As the authority appointed pursuant to section 54b(2) EnWG, the Bundesnetzagentur participated through ENTSO-E in the development of regional[97] electricity crisis scenarios within the meaning of Article 6 of Regulation (EU) 2019/941 of 5 June 2019 on risk-preparedness in the electricity sector (Regulation (EU) 2019/941). The Bundesnetzagentur had defined national electricity crisis scenarios pursuant to Article 7 of the Regulation by 7 January 2021. This concerns scenarios that are could potentially cause electricity crises on a national scale. The crisis scenarios fall within the categories of disasters, outage of grid elements and malicious attacks on the electricity supply system. The Federal Ministry for Economic Affairs and Energy (BMWi) develops the risk-preparedness plan on the basis of regional and national crisis scenarios. The Bundesnetzagentur will monitor the development of this plan. The risk-preparedness plan refers to the scenarios identified as regional and national crises.

Short term adequacy assessment

Seasonal adequacy assessments are undertaken by ENTSO-E separately for the summer and winter months (ENTSO-E Summer and Winter Outlook). These are performed using the methodology in Article 8 Regulation (EU) 2019/941 confirmed by ACER. This stipulates that – as is the case with the European Resource Adequacy Assessment (ERAA) – the concerned period must be subject to a probabilistic assessment with a resolution no greater than hourly. The main result is the "weekly LOLP" (weekly Loss of Load Probability) as a measure of the level of security of supply and the EENS (Expected Energy Not Served), ie the energy which is expected not to be supplied.

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[96] https://www.eudsoentity.eu

[97] "Regional" within the meaning of the system operation region pursuant to Article 36 Regulation (EU) 2019/943 and ACER's related Decision (ACER Decision 08-2021 on the Definition of System Operation Regions (SOR), https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Pages/Individual-decision.aspx

The current Summer Outlook 2021 has identified practically no risks to security of supply, except for Ireland due to maintenance work on power plants and the interconnector to the UK. The Winter Outlook 2020/2021 shows retrospectively that on the whole weather conditions were favourable for supply security. The cold spell in Western Europe in early January 2021 shrank the generation margin but did not result in shortfalls.

Owing to the provisions of Article 9(2) of Regulation (EU) 2019/941, the ENTSO-E Winter Outlook 2021/2022 is only expected on 1 December 2021.

7.2 Implementation of European network codes and guidelines

Further progress was made in 2020 on the implementation of EU network codes and guidelines in relation to the further development of the single European electricity market in the areas of grid connection, market and system operation.

Inclusion of further states in the day-ahead multi-regional market coupling (MRC)

In an interim project, the so-called 4M market coupling (4 MMC) countries, CZ, HU, SK and RO, were successfully included along with PL in the existing MRC in June 2021. The project was agreed by the regulatory authorities of these countries, the Austrian regulatory authority E-Control and the Bundesnetzagentur in December 2018. This should strengthen the integration of the region's day-ahead market until the Core flow-based project takes effect in 2022.

Capacity management

TSOs and nominated electricity market operators are working with NRAs and ACER on the implementation of Commission Regulation (EU) 2015/1222 for cross-border congestion management, capacity calculation and capacity allocation for day-ahead and intraday trading. The regulatory authorities and ACER issued approval decisions under this Regulation. In this context approval was given for the guidelines on the coupling algorithms[98], the relevant products[99] and the necessary back-up measures[100], the times at which intraday trading opens and closes[101] and the fallback procedures for capacity allocation[102]. This rulebook is the bedrock on which the single European electricity market stands. After commissioning of the cross-border intraday solution (XBID) in 2018 and a second implementation wave in 2019, Italy and Greece will join the system in

98 https://extranet.acer.europa.eu//Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2004-2020%20on%20Algorithm%20methodology.pdf

99 https://extranet.acer.europa.eu//Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2037-2020%20on%20the%20DA%20Products.pdf

100 https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK6-GZ/2017/BK6-17-022/BK6-17-022_Beschluss_vom_01_02_2018.pdf?__blob=publicationFile&v=2

101 https://extranet.acer.europa.eu/en/Electricity/MARKET-CODES/CAPACITY-ALLOCATION-AND-CONGESTION-MANAGEMENT/6%20IDCZGT/Action%205c%20-%20IDCZGT%20ACER%20decision%20Annex%20I.pdf

102 For the Region Core:
https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2010-2018%20on%20the%20Core%20CCR%20TSOs%20proposal%20for%20fallback%20procedures.pdf
For the Region Hansa: https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK6-GZ/2016/BK6-16-289/BK6-16-289_beschluss_vom_14122017.pdf?__blob=publicationFile&v=2

early 2022, by which time most of the European Union will be coupled in intraday trading. The aim of coupling is to increase the efficiency of intraday trading and thereby enhance welfare.

In the German market, the capacity calculation method for the capacity calculation region Core is also particularly relevant. This is a further development of the CWE region's flow-based capacity calculation method.

ACER reached a decision on the TSOs' submitted proposal in February 2019 and thereby determined the capacity calculation method for day ahead and intraday trading of electricity. The Bundesnetzagentur has appealed and the decision by ACER is therefore not yet legally valid. The action for a declaration of nullity being brought by the Bundesnetzagentur is currently pending before the European Court of Justice (ECJ). The court has not yet ruled.

The Regulation on forward capacity allocation (Regulation (EU) 2016/1719) is also being implemented. The methodology for calculating long-term capacities, for allocating them to different time periods and for designing them for the CORE and HANSA capacity calculation regions were developed in 2020/21. Apart from the capacity calculation methodology for CORE (which was transferred to ACER for decision in 2021), all the methodologies previously referred to have been approved by the responsible national regulatory authorities in the region. For 2021, a change is envisaged to the calculation methodology for long-term capacities for HANSA, which was approved in 2019, to take account of the decision of the EU-KOM on the priority feed-in of wind energy (and secondary market-based interconnector use) of the CGS Kriegers Flak project.[103]

System operation

Regulation (EU) 2017/1485 deals inter alia with European harmonisation in the area of system operation and the definition of security limits. Implementation will require TSOs to develop various terms and conditions as well as methodologies, which will also involve participation/approval by the relevant regulatory authorities. In 2020, these included, at the European and regional level, methodologies for the coordination of operational analyses and changes. At the synchronous area level, a proposal for additional properties of frequency containment reserves was developed further and, in early 2021, the initial results of a cost-benefit study for the definition of a minimum delivery period for frequency containment reserves with limited energy storage were discussed; these will require approval in the course of 2021.

Regulation (EU) 2017/2196 on electricity emergency and restoration also concerns system operation. Certain modalities (eg for system services for restoration, for a test plan, for the suspension and resumption of market activities and the associated settlement of balancing energy) were revised in 2020 and approved by the Bundesnetzagentur.

[103] https://ec.europa.eu/energy/sites/ener/files/documents/2020_kriegers_flak_decision_de.pdf (11. November 2020)

F Wholesale market

Liquid 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 enable the hedging of price risks and speculation in the medium and long term, play an 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 off-exchange wholesale trading (referred to as over-the-counter trading or OTC, and partly brokered), electricity exchanges also create reliable trading places and provide important price signals for market players in other areas of the electricity industry.

The trading volume and liquidity on the electricity wholesale markets remained at a high level in 2020. The trading volume on the day-ahead 12 noon auction amounted to approx. 231.2 TWh. However, this figure can only be compared to a limited extent with that of the previous year because the presentation of trading volumes for 2020 was adjusted to reflect the participation of several electricity exchanges in the coupled day-ahead auction according to the MNA (Multiple NEMO Arrangement). The trading volume on the intraday market rose again to 68.52 TWh, representing an increase of around 11.62 TWh or approx. 20.4 % over 2019.

On-exchange futures trading volumes increased. The on-exchange trading volume of Phelix DE futures increased by approx. 5% in 2020 to 1,416 TWh. The off-exchange volumes traded via broker platforms also increased. In 2020 the OTC clearing volume of Phelix DE futures on EEX also increased by around 28% to 1,668 TWh and now clearly exceeds the volume of exchange trading.

There was a decline in electricity wholesale prices in 2020. The average spot market price for Phelix Day Base for 2020 was around 30.46 Euro/MWh compared with an average of 37.67 Euro/MWh in the previous year. The average prices for futures contracts for the subsequent year also fell. With an annual average of 40.17 Euro/MWh the Phelix Base Year Future for the year 2021 fell by approx. 16% over the previous year when it was traded at 47.82 Euro/MWh for the year 2020. The price of the Phelix Peak Year Futures averaged 49.04 Euro/MWh over the year in 2020. This represents a fall in price over the previous year (57.67 Euro/MWh) of 8.63 Euro/MWh or around 15%.

However, futures prices rose in the course of 2020. At the beginning of 2020 the Phelix-DE Peak Year Future was quoted at a price of 53.02 Euro/MWh and at the end of December 2020 at 57.54 Euro/MWh, i.e. approx. 9% higher although prices mid-year were clearly lower.

1. On-exchange wholesale trading

The review of on-exchange electricity trading relates to the Germany/Luxembourg market area and to the exchanges in Leipzig (European Energy Exchange AG– EEX), Paris (EPEX SPOT SE), Vienna (EXAA Abwicklungsstelle für Energieprodukte AG) and Berlin/Oslo (Nord Pool AS). EEX offers electricity products in futures trading; EPEX SPOT, EXAA and Nord Pool offer electricity products on the spot markets. These exchanges took part in collecting energy monitoring data again this year. On 1 October 2018 the market areas Germany/Luxembourg and Austria were split into separate market areas. The main focus of this monitoring report has since been on the German-Luxembourg market area.

The total number of participants admitted to the respective electricity exchanges in the Germany/Luxembourg market area has differed over the last few years. The number of participants active in futures trading on EEX has constantly increased in recent years. On 31 December 2020 a new all-time high was reached on EEX with 336 participants (2019: 261 participants). However, there was little change in the number of participants on the spot market. There was a slight increase in the number of participants on the EPEX SPOT market to 197 (2019: 193 participants); the number of participants admitted to the EXAA remained the same as in the previous year at 71. The number of participants on the Nord Pool exchange was 50 (compared with 43 participants in the previous year).

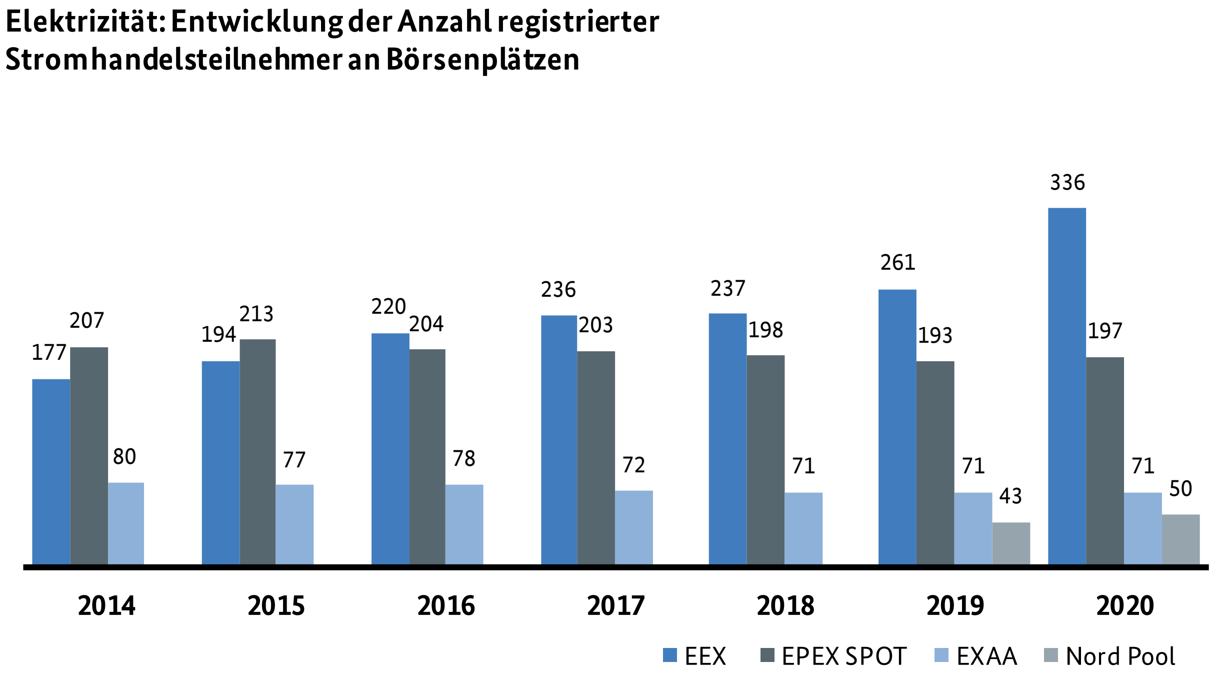

Figure 87: Development of number of registered trading participants on the exchanges

Not every company requires its own access to the exchanges. 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.

Futures trading and spot trading perform different but largely complementary functions. While the spot market, like over-the-counter trading, 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 and the futures markets are dealt with separately below.

1.1 Spot markets

Electricity is auctioned on the on-exchange spot markets a day ahead and for the following and current day (intraday). The spot markets examined here, EPEX SPOT, EXAA and Nord Pool, offer day-ahead trading. EPEX SPOT and Nord Pool also offer continuous intraday trading (for details on the different time periods, see below). Contracts can be physically fulfilled (supply of electricity) on the two on-exchange spot markets for Luxembourg (Creos) and for the four German control areas (50Hertz, Amprion, TenneT, TransnetBW).

Since 2nd July 2019 the “Multiple NEMO Arrangement” (MNA) based on Commission Regulation 2015/1222 of 24 July 2015 applies to all bidding zones of the central west European (CWE) region (and likewise also to the German bidding zone) for the day ahead auction. This enables every exchange (NEMO - Nominated Electricity Market Operator) admitted to allow their market participants access to the noon market coupling auction for the respective bidding zones. The auction prices are calculated using a key auction algorithm, by which every NEMO within a bidding zone receives the same auction prices within the framework of the European market coupling.

EXAA currently offers two day-ahead auctions for the respective Austria and Germany/Luxembourg market areas: an auction at 10:15 a.m. and a coupled day ahead auction at noon. The earlier auction time on the EXAA at 10:15 a.m. provides an initial price signal for traders for the remainder of the trading day.

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. Bids for the complete or partial physical fulfilment of futures traded on EEX (futures positions) may also be submitted.

EPEX SPOT also offers the intraday auction for quarter hourly offers for the Germany/Luxembourg market area up to 3 p.m. on the previous day. Continuous intraday trading on EPEX SPOT and Nord Pool involves single hours, 15-minute periods and standardised or user-defined blocks. On EPEX SPOT continuous Intraday trading begins at 3 p.m. for next-day single-hour supplies and blocks and at 4 p.m. for the 15-minute periods on Nord Pool at 8.00 a.m. on the day before commencement of supply.[104] Electricity contracts for the German control areas can be traded on EPEX SPOT up to 30 minutes before commencement of supply, on Nord Pool up to 20 minutes before commencement of supply and on EPEX SPOT up to 5 minutes before commencement of supply within the control areas and up to immediately before commencement of supply on Nord Pool.

Since 13. June 2018 a “Multiple NEMO Arrangement” (MNA), also based on the EU Regulation, has been applied for continuous intraday trading via the XBID (Cross-Border Intraday Coupling) project (now renamed SIDC (Single Intraday Coupling) in many European states (and hence also in the German bidding zone). This allows market participants access to the same liquidity, irrespective of which NEMO is used for trading. In the German bidding zone this is offered by Nord Pool and EPEX SPOT.[105]

The so-called shared order books, SOB, are essential for SIDC. In the Commission’s Regulation (EU) 2015/1222 all NEMOs active in single intraday market coupling are obliged to submit orders received from their market participants to the SOB immediately on their receipt. If transmission capacity is available, orders to trade will be automatically collated across the bidding zones to enable full use of the transmission capacities. This

[104] See https://www.nordpoolgroup.com/49ba3b/globalassets/download-center/xbid/nord-pool-sidc-gate-opening-times-gate-closing-times.pdf(retrieved on 16 September 2021).

[105] Nord Pool has already been active in Germany since 2006 with intraday trading from and to Sweden or Denmark, i.e. before the XBID project.

obligation ends on closure of the cross-zonal intraday market at exactly 60 minutes before commencement of supply.

However, irrespective of the closure of the cross-zonal intraday market, intraday trading within the Germany/Luxembourg bidding zone continues until the actual commencement of supply. This means that access to intraday orders is also just as necessary for all NEMOS in the Germany/Luxembourg bidding zone in the last 60 minutes. Against this background the EU Commission initiated a formal investigation proceeding (KOM AT.40700) as it was concerned that EPEX SPOT could have restricted competition on the intraday markets. It was alleged that EPEX SPOT could have resorted to measures to foreclose its competitors from the market by restricting the ability of their customers to access the entire liquidity of the intraday market.[106]

1.1.1 Trading volumes

The trading volume on the day-ahead 12 noon auction amounted to approx. 231.2 TWh in 2020. 198 TWh was traded on EPEX Spot, 18.3 TWh on Nord Pool and 15.37 TWh on EXAA.[107] The volume of the independent 10:15 a.m. day-ahead auction on EXAA for the German bidding zone declined by approx. 11% and amounted to around 3.31 TWh (2019: 3.73 TWh).

The volume of intraday trading on EPEX SPOT increased again, to 63.63 TWh (approx. 7.58 TWh in the intraday auction and 56.05 TWh in continuous intraday trading). This represents an increase of approx. 9.9 TWh or 18.6 over 2019. The volume of continuous intraday trading on Nord Pool in the DE-LU bidding zone amounted to around 4.89 TWh in 2020, an increase of approx. 51% over the previous year (3.24 TWh).

[106] See press release of the EU Commission of 30 March 2021 https://ec.europa.eu/commission/presscorner/detail/en/ip_21_1523.

[107] The presentation of trading volumes for 2020 was adjusted to reflect the participation of several electricity exchanges in the day-ahead auction within the framework of the MNA. The volumes shown for 2020 represent the average of purchase and sales orders fulfilled on each electricity exchange. In this and past reports trade volumes on EPEX Spot for the day-ahead auction in the years before 2020 are quoted as the total of the maximum purchase and sales volumes per hour of supply. In the event of several electricity exchanges participating in an auction, this method, when applied to all participants, would overstate the total volume of electricity traded. Due to the adjustment of the calculation method, the 2020 figures for the joint day-ahead auction can only be compared to a limited extent with the figures of the previous year. Using the previous calculation method, the total of the maximum purchase and sales volumes traded per hour of supply on EPEX Spot in 2020 was approx. 216 TWh.
The volumes of continuous intraday trading in 2020 and previous years already represent the average of purchase and sales orders fulfilled throughout the year on each electricity exchange.

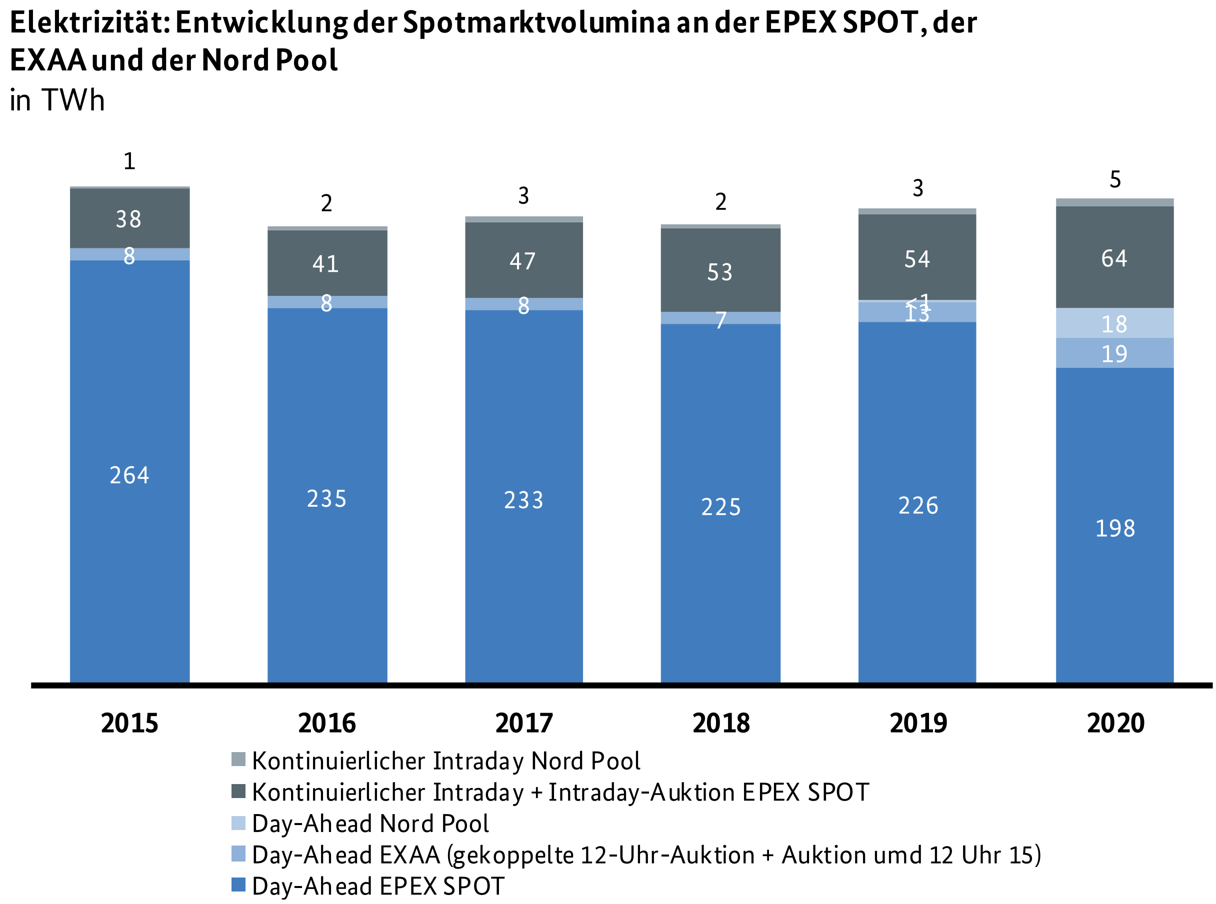

Figure 88: Development of spot market volumes on EPEX SPOT, EXAA and Nord Pool

1.1.2 Price dependence of bids

Bids in the day-ahead auctions on can be submitted on a price-dependent or price-independent basis. If a price-dependent bid (limit order) is submitted, the order is not fulfilled at the next possible opportunity but only realised at the fixed price or a better price. If a price-independent bid (market order) is placed, the order is not linked to a price but is to be fulfilled in every case and as soon as possible.

For example, approx. 167.8 TWh of the purchase bids submitted on EPEX SPOT in 2020 were price-independent. In the previous year, it was also only 149.3 TWh. Approx. 126.5 TWh of the sales bids submitted were price-independent. The volume of price-independent sales bids thus remained almost the same as in the previous year (125.3 TWh).

Elektrizität: Preisabhängigkeit der ausgeführten Gebote in den Stundenauktionen der EPEX SPOT im Jahr 2020

	Ausgeführte Verkaufsgebote		Ausgeführte Kaufgebote	
	Volumen in TWh	Anteil	Volumen in TWh	Anteil
Preisunabhängige Gebote	126,5	69,1%	167,8	79,2%
davon durch ÜNB	39,4		0,3	
davon physisch erfüllte Phelix Futures	17,4		56,3	
davon sonstige	69,7		111,2	
Preisabhängige Gebote i. w. S.	56,7	30,9%	44,1	20,8%
davon Blöcke	12,3		5,6	
davon preisabhängige Gebote i.e.S.	44,4		38,5	
Gesamt	183,2	100%	211,9	100%

Table 82: Price dependence of bids submitted in hour auctions on EPEX SPOT in 2020

The marketing of renewable energy (EEG) volumes by the transmission system operators (TSOs) plays a major role on the seller side. In accordance with statutory provisions this was almost completely price-independent at 99.2%.[108] However, according to the power exchanges, the volume marketed by the transmission system operators only marginally fell to around 39.4 TWh (39.7 TWh in 2019 and 35.1 TWh in 2018).

1.1.3 Price level

The most common price index used for the spot market for the 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 of the coupled day-ahead auction, 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 for the separate auction at 10:15 a.m., which relate to the corresponding single hours for the same market area. The following figure shows the annual average price of Phelix DE/AT for the Germany/Austria/Luxembourg market area up to 30 September 2018. Since the bidding zone splitting on 1 October, 2018, the Phelix DE average is represented as being applicable to the Germany/Luxembourg market area.

Average spot market prices fell in 2020. The average spot market price for Phelix day base for 2020 was around 30.46 Euro/MWh compared with an average of 37.67 Euro/MWh in the previous year.

[108] Section 1(1) of the Equalisation Scheme Execution Ordinance (Verordnung zur Ausführung der Verordnung zur Weiterentwicklung des bundesweiten Ausgleichsmechanismus – AusglMechAV) requires TSOs 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) no. 2 EEG) on a spot market exchange and offer them on a price-independent basis.

The Phelix day peak DE average for 2020 was approx. 32.74Euro/MWh (2019: 40.43 Euro/MWh.)

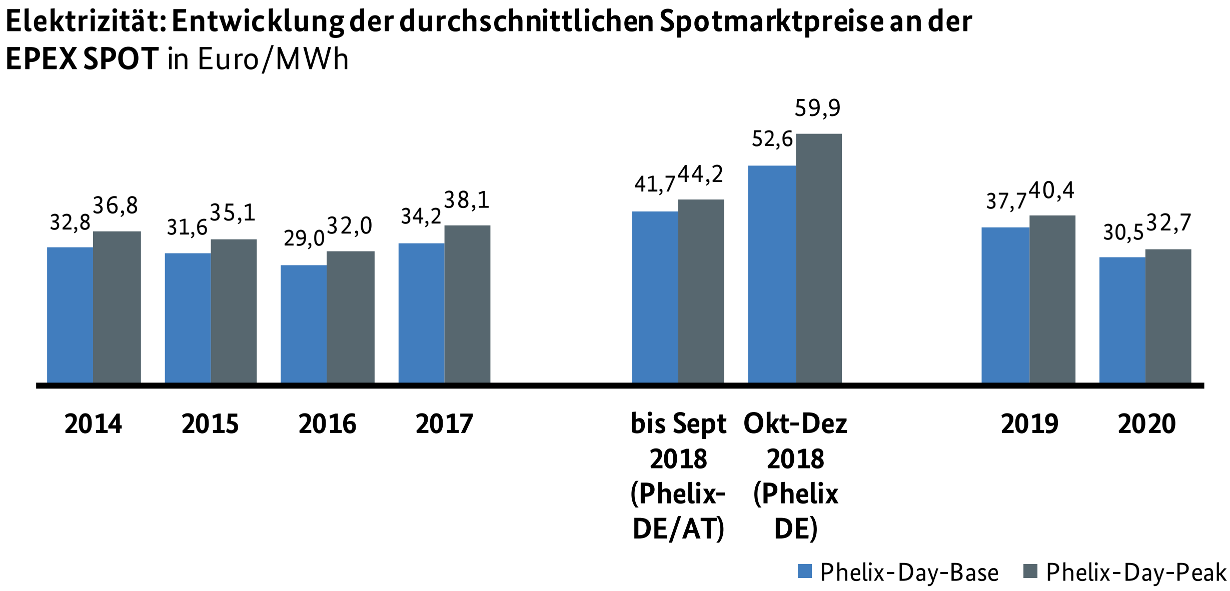

Figure 89: Development of average spot market prices of joint auction

The bEXA and Phelix indices for 2020 are very close to each other. If one considers the products for the German bidding zone, electricity prices were higher in 2020 in the day ahead auctions than in the 10:15 a.m. auction on EXAA. This applies to both the base as well as the peak price. The difference between Phelix day base and bEXAbase was around 0.10 Euro/MWh. The difference between Phelix day peak and bEXApeak was around 0.10 Euro/MWh.

1.1.4 Price dispersion

As in previous years the prices on the joint day-ahead auction exhibit considerable dispersion. The following figure shows the development of spot market prices over the year, using the Phelix DE day base as an example. Daily average prices typically have a weekly profile with lower prices at the weekend.

Elektrizität: Entwicklung des Phelix-Day-Base im Jahr 2020
in Euro/MWh

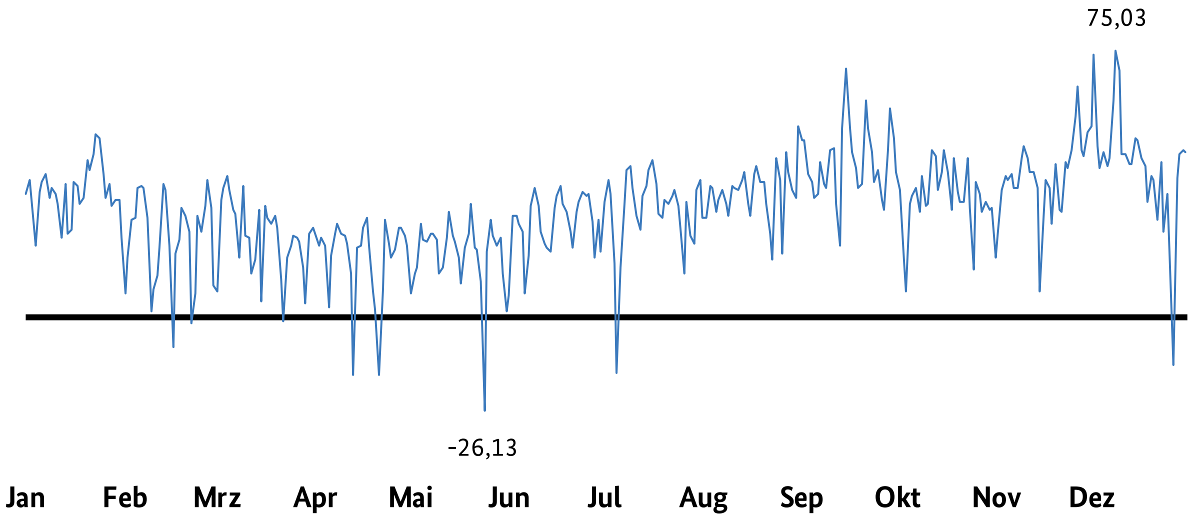

Figure 90: Development of Phelix Day Base in 2020

There were significant positive and negative extreme values in the Phelix base and peak prices in the joint auction in 2020. The range of the middle 80% of the graded Phelix day base values rose in 2020 to 32.54 Euro/MWh. In 2019 the difference amounted to 23.08 Euro/MWh. The corresponding peak range of the middle 80% also rose significantly from 23.75 Euro/MWh in 2018 and 25.69/Euro MWh in 2019 to 40.81 Euro/MWh in 2020.

Negative values were reached in the Phelix day base prices on eight days in 2020, and even on 16 days in the case of the Phelix day peak.[109] The Phelix day base reached its lowest value on 24 May 2020 at -26.13/MWh. The Phelix day peak registered its lowest value on the same day at -45.64. In 2019 the minimum day base value was -42.24 Euro/MWh and the minimum day peak was -65.94 Euro/MWh. In spite of falling demand, peak prices were distinctly less negative.

The maximum values of both indices also decreased compared to the previous year. In 2020 the highest Phelix day base value was 75.03 Euro/MWh, or around 13% below the previous year's value of 85.80 Euro/MWh. The maximum day base price was reached on 9 December 2020. The Phelix day peak value was 103.79 Euro/MWh in 2020, slightly higher than in the previous year (102.74 Euro/MWh.)

[109] Negative prices are price signals on the electricity market that occur when high and e.g. inflexible power generation meets weak demand. Inflexible power sources cannot be quickly shut down and started up again without major expense or they have to continue operating due to other supply obligations (heat, industrial processes, reserve procurement).

Ongoing subsidies for negative prices can also play a significant role in generating negative prices.

Elektrizität: Preisspannen des Phelix-Day-Base und des Phelix-Day-Peak
in Euro/MWh

	Mittlere 80 Prozent	Spanne der mittleren 80 Prozent	Extremwerte	Spanne der Extremwerte
	10 bis 90 Prozent der größensortierten Werte		Min – Max	
Base 2018	33,55 – 56,12	22,57	-25,30 – 80,33	105,63
Base 2019	24,76 – 47,84	23,08	-42,24 – 85,80	128,04
Base 2020	13,72 – 46,26	32,54	-26,13 – 75,03	101,16
Peak 2018	37,16 – 60,91	23,75	-21,46 – 97,48	118,94
Peak 2019	27,79 – 53,47	25,69	-65,94 – 102,74	168,68
Peak 2020	11,58 – 52,39	40,81	-45,64 – 103,79	149,43

Table 83: Price ranges of Phelix day base and Phelix day peak between 2018 and 2020

1.2 Futures markets

Futures with standardised maturities can only be traded on EEX for the German/Luxembourg market area where the Phelix DE (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.

The following section deals solely with on-exchange transaction volumes, excluding OTC clearing (cf. section **Fehler! Verweisquelle konnte nicht gefunden werden.** "**Fehler! Verweisquelle konnte nicht gefunden werden.**").

1.2.1 Trading volumes

The on-exchange trading volume of Phelix DE futures increased by approx. 5% year-on-year in 2020 to 1,417 TWh. From 2018, with the splitting of the bidding zones of Germany/Luxembourg and Austria on 1 October, the focus lay primarily with the assessment of trading volumes for Phelix DE. These amounted to 1,346 TWh in 2019.

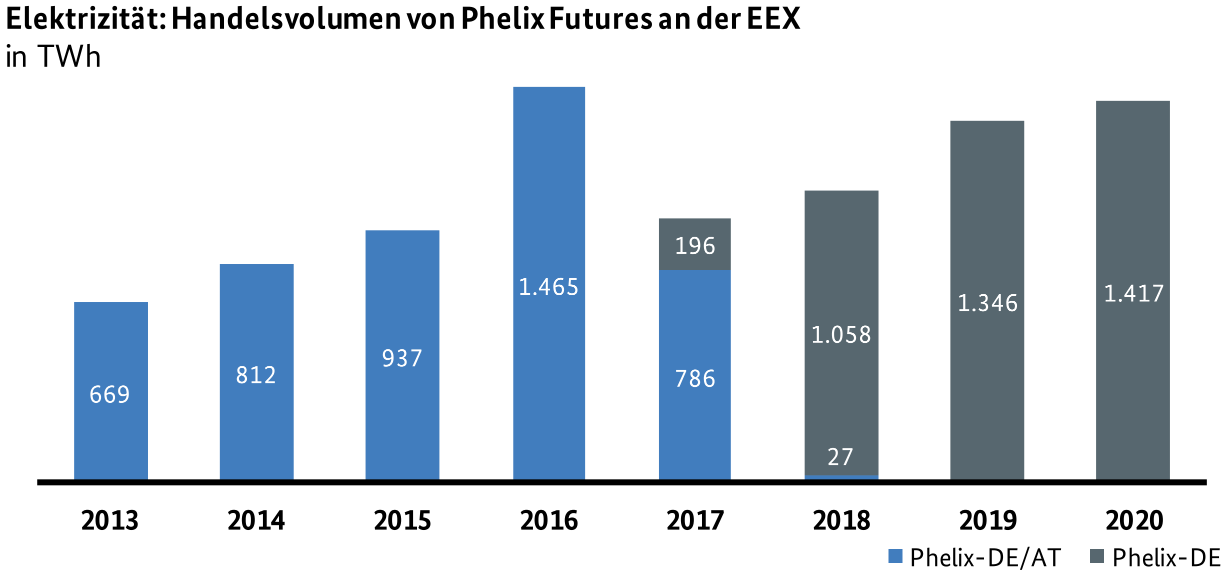

Figure 91: Trading volumes of Phelix DE/AT and Phelix DE futures on EEX

Exchange trading in Phelix DE futures in 2020 predominantly focused on contracts for the year ahead (2022 as the fulfilment year) with approx. 61% of the total trading volume, i.e. 858 TWh. Trading for 2021 made up the second largest share with approx. 24%, i.e. a total of 346 TWh. Trading for 2023 and subsequent years declined in comparison with the previous year. After an increase in the previous year, trading for the third subsequent year (i.e. 2023 in 2020) declined again to approx. 161 TWh. Volumes for the fourth subsequent year also declined to 45 TWh and to approx. 6 TWh for the fifth subsequent year.

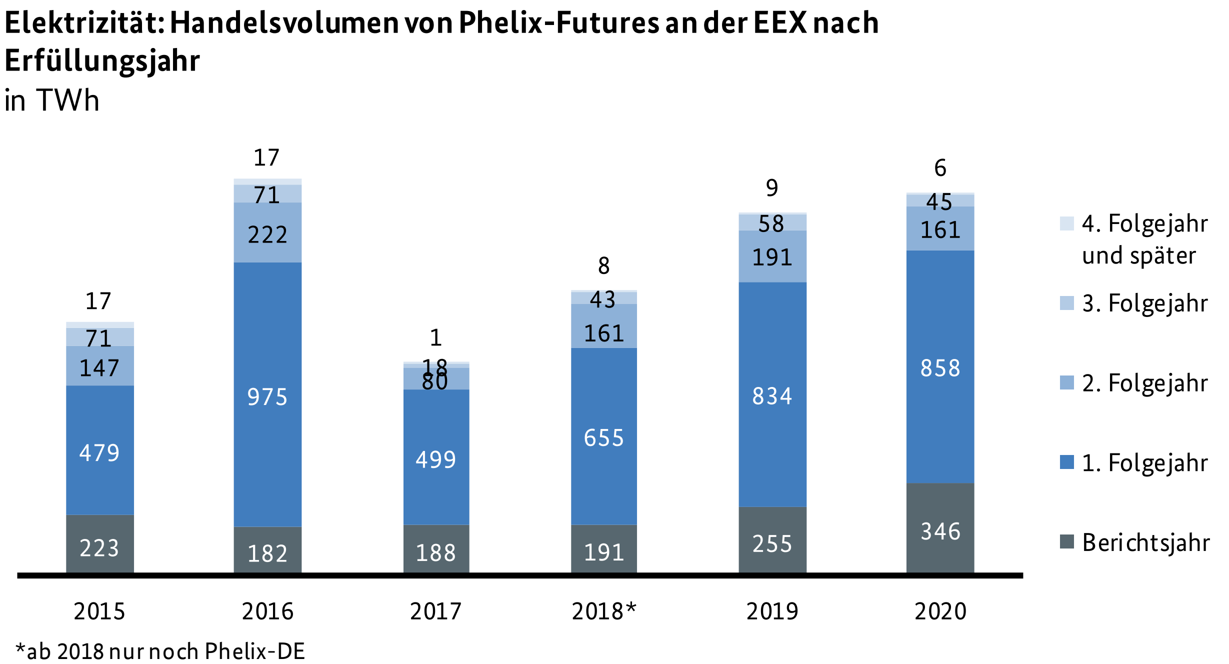

Figure 92: Trading volumes of Phelix DE/AT futures and from 2018 Phelix DE on EEX by fulfilment year

1.2.2 Price level

Futures prices rose in the course of 2020. At the beginning of 2020, the Phelix-DE peak year ahead future was quoted at a price of 53.02 Euro/MWh and at the end of December 2020 at 57.54 Euro, i.e. representing an approx. 9% increase over the year. The Phelix DE base year future also increased over the year from 43.85 Euro/MWh to 48.15 Euro/MWh. This represented an increase of around 10% since the beginning of the year, even though the prices were lower over the course of the year.

Elektrizität: Preisentwicklung der Phelix-Frontjahres -Futures im Jahresverlauf 2020
in Euro/MWh

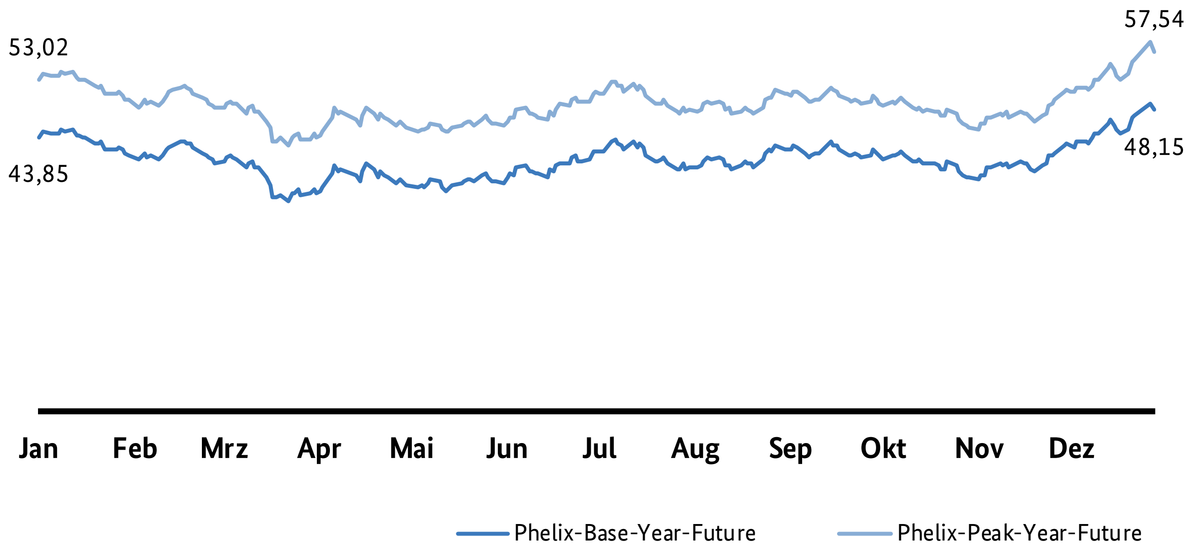

Figure 93: Price development of Phelix DE front year futures in 2020

An annual average can be calculated on the basis of the Phelix DE front year futures prices recorded on the 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 futures prices fell sharply year-on-year. With an annual average of 40.17 Euro/MWh, the Phelix base year future fell by 7.64 Euro/MWh from 47.82 Euro/MWh in 2019, a decrease of approximately 16%. The price of the Phelix peak front year futures averaged 49.04 Euro/MWh over the year. This represents a fall in price over the previous year (57.67 Euro/MWh) of 8.63 Euro/MWh or around 15%.

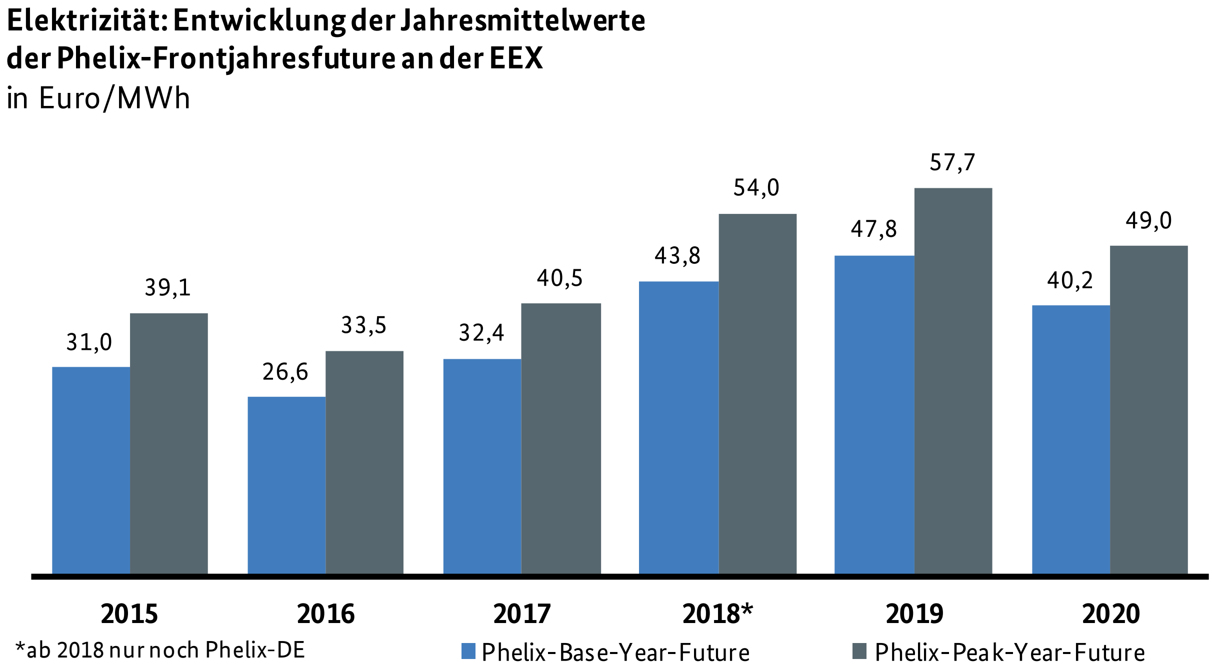

Figure 94: Development of annual averages of Phelix DE front year futures prices on EEX

The annual average price difference between base and peak products was 8.87 Euro/MWh. In 2019 the difference still amounted to 9.90 Euro/MWh. The peak price was therefore around 22% higher than the base price.

1.3 Share of trading volume of exchange participants

1.3.1 Share of market makers

An exchange participant which 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.

Five companies were active as market makers on the EEX futures market for Phelix futures for the German market area in the reporting period: Uniper Global Commodities SE, RWE Supply & Trading GmbH, EDF Trading Limited, Vattenfall Energy Trading GmbH and ENGIE Global Markets SAS. The market makers' share of the purchase volume was thus approx. 18.9% and more or less remains the same as the share in the previous year, i.e. 18.2%. On the sales side the volume fell to 19.3% from 21.9% in the previous year.[110]

[110] However, it is be noted that some market makers were not active during the entire reporting period, but only during several months. EEX trading data does not differentiate between trade conducted by market makers and non-market makers. The data on the share of the market makers can thus be overstated as well as understated.

In addition to agreements with market makers, EEX maintains contracts with trading participants who are committed to strengthening liquidity to an individually agreed extent. In terms of trading volume, these companies accounted in total for about 3.2% and 3% respectively of purchases and sales in 2020. In the previous year their share of purchases was around 4.9% and their share of sales also 4.5%.

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.

The share of TSOs of the day-ahead sales volume on EPEX SPOT was approx. 19% in 2020; in the previous year it was 18%. By comparison: Their share was still 28% in 2012. The volumes marketed by the TSOs also declined in absolute terms over the years. The on-exchange day-ahead sales volume marketed by the TSOs was approximately 40.4 TWh in 2020; in 2019 this value was still around 41.3 TWh. In the years previous to this the sales volume marketed by the TSOs was higher; in 2012 it was still approx. 69.6 TWh and in 2014 approx. 50.6 TWh. The TSOs generated a very small spot market volume of about 1% on the buyer side.

1.3.3 Share of participants with the highest turnover

An analysis of the trading volume generated by the five 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.[111]

The share of the five purchasers with the highest turnover of the trading volume on the day-ahead auction rose from 37% in 2019 to 39% in 2020. The corresponding share on the seller side remained constant compared to the previous year. The cumulative share of the five sellers with the highest turnover was approximately 30% in 2020. This was 31% in the previous year.

[111] Generally speaking, company groups only have one participant registration.

Elektrizität: Anteil der je fünf umsatzstärksten Verkäufer bzw. Käufer am Day-Ahead-Volumen der EPEX SPOT in Prozent

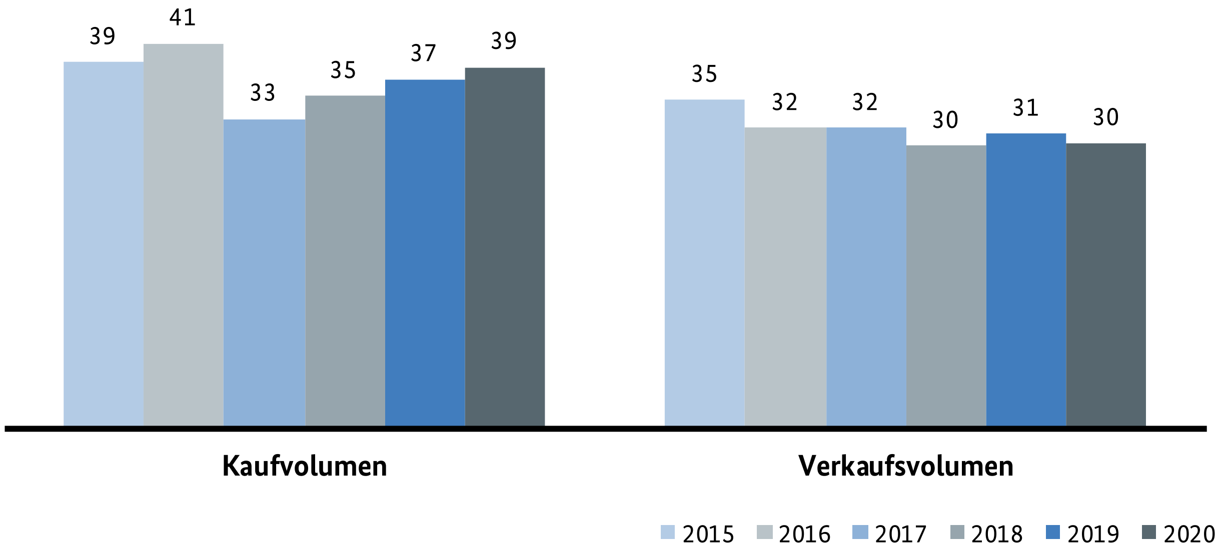

Figure 95: Share of the five sellers and buyers with the highest turnover of the day-ahead volume on EPEX SPOT

The share of the five buyers of Phelix DE futures with the highest turnover on EEX (excluding OTC clearing) fell from around 31.3% in 2019 to 28.3% in 2020. The share of the five sellers with the highest turnover fell from around 35.2% in 2019 to 29.1% in 2020.

2. Off-exchange wholesale trading

Bilateral wholesale trading ("OTC" or "over the counter trading") 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 wholesale trading since off-exchange there are no clearly definable market places nor is there a standard set of contract types. Moreover, the trading places have developed from bilateral to multilateral trading places where not only buyers and sellers but also intermediaries, brokers etc. are active.

Brokers play a major role in bilateral and multilateral wholesale trading. They act as intermediaries between buyers and sellers and pool information on the demand and offer 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 which correspond to on-exchange standard products can be registered on the exchange to hedge the parties' trading risk. EEX no longer refers to this service as "OTC clearing", but as "trade registration". The original designation has been retained in this Monitoring Report. OTC clearing provides an interface between on-exchange and off-exchange electricity wholesale trading.

In 2020 different broker platforms were once again surveyed with regard to off-exchange wholesale trading (see sections below). Data on OTC clearing on EEX was also collected. The surveys again revealed an increased level of liquidity in off-exchange electricity wholesale trading in 2020.

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 the brokers was around 5,702 TWh in 2020 compared to 5,770 TWh in 2019. Contracts for the year ahead (2021, i.e. year following the publication of the report) continue to make up the main focus of electricity transactions brokered on broker platforms with 45% (48% in the previous year), followed by the activities for the current year 2020 with 32%. Short-term transactions with a fulfilment period of less than one week generated only small volumes. Compared to the previous year, the distribution of the fulfilment periods has only minimally shifted.

A further observation of the trading volume can be based on data from the London Energy Brokers' Association (LEBA), which, however, does not include all broker platforms surveyed. There was an increase in volume of trading transactions brokered by LEBA members. The trading volume for German power brokered by LEBA members rose from 4.757 TWh in 2019 to 5,368 TWh in 2020, or by around 13% year-on-year.[112]

Elektrizität: Volumen des Stromhandels über Brokerplattformen im Jahr 2020 nach Erfüllungszeitraum

Erfüllungszeitraum	Handelsmengen in TWh	Anteil
Intraday	0	-
Day-Ahead	85	1%
unter 1 Woche	54	1%
über 1 Woche	1.812	32%
1. Folgejahr	2.546	45%
2. Folgejahr	933	16%
3. Folgejahr	237	4%
4. Folgejahr	34	1%
Summe	**5.702**	**100%**

Table 84: Volume of electricity traded via broker platforms in 2020 by fulfilment period

[112] See London Energy Brokers' Association, Monthly Volume Report: https://www.lebaltd.com/monthly-volume-reports/ (retrieved on 7 July 2021).

2.2 OTC-Clearing

Alongside on-exchange trading, on-exchange OTC clearing played a special role in off-exchange wholesale trading. In OTC clearing, the exchange, or its clearing house, is the contracting party of the trading participants 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, see above) for all futures market products that are also approved for exchange trading on EEX and for EPEX SPOT.

The volume of OTC clearing of Phelix futures on EEX was 1,668 TWh in 2020. The volume was still 1,302 TWh in 2019. Since OTC clearing is used to "retrospectively" offset futures concluded on the exchange, the development of the OTC clearing volume should also be considered in the context of the on-exchange futures market volume. The volume has increased slightly since 2013. Compared to 2019 the volume increased, both in OTC and on-exchange trading. It is worthy of note that the volume of OTC clearing in 2020 increased more than the volume of normal exchange trading. The OTC clearing volume increased by approx. 28%, whilst on-exchange trading only increased by approx.5% compared to the previous year.

Elektrizität: Volumen OTC-Clearing und Börsenhandel von Phelix-Terminkontrakten an der EEX
in TWh

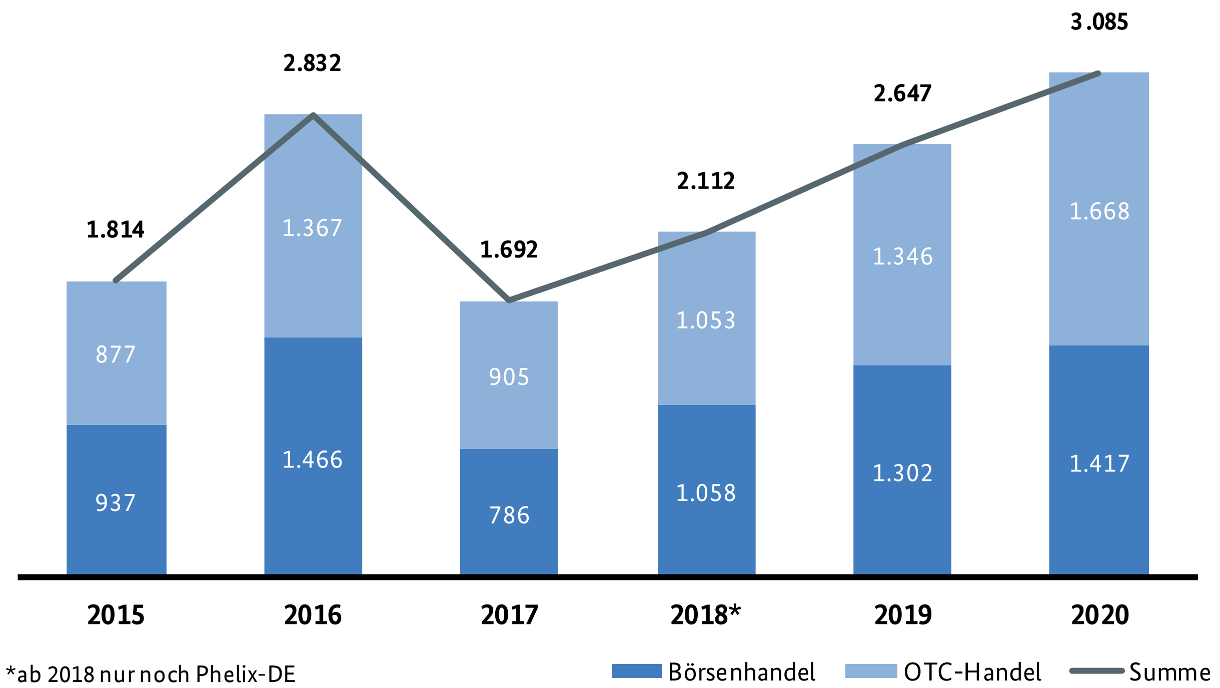

Figure 96: Volume of OTC clearing and exchange trading of Phelix DE futures

If the additional data provided by LEBA is included in the assessment, the volume for "German power" registered by LEBA members for clearing was approx. 1,580 TWh in 2020, which is equivalent to a share of about 29% of the total OTC contracts brokered by LEBA members. Here the registered volume for clearing also increased, accounting for approx. 1,240 TWh in 2019 or 26% of the total volume.[113]

Up to now Phelix options have played no role in exchange trading on EEX. As in the previous year there were no such transactions in 2020. However, there are Phelix options which are agreed off-exchange and cleared on EEX. In 2020 Phelix options agreed off-exchange and cleared OTC accounted for 79 TWh on EEX. This corresponds to a share of 5%. The OTC clearing volume for options in 2020 rose significantly by approx. 60% compared with the previous year.

The distribution of the volumes registered on EEX for OTC clearing across the various fulfilment periods in 2020 only marginally changed compared to the previous year. While in 2019 approx. 55% consisted of contracts for the year ahead (2021), this figure fell to 54% in 2020 (719 TWh). Around 35% (586 TWh) related to 2020 itself. In 2019 this was still around 35% or 428 TWh. Around 8% related to the year after next (trading for 2022). Later fulfilment periods made up only a small share.

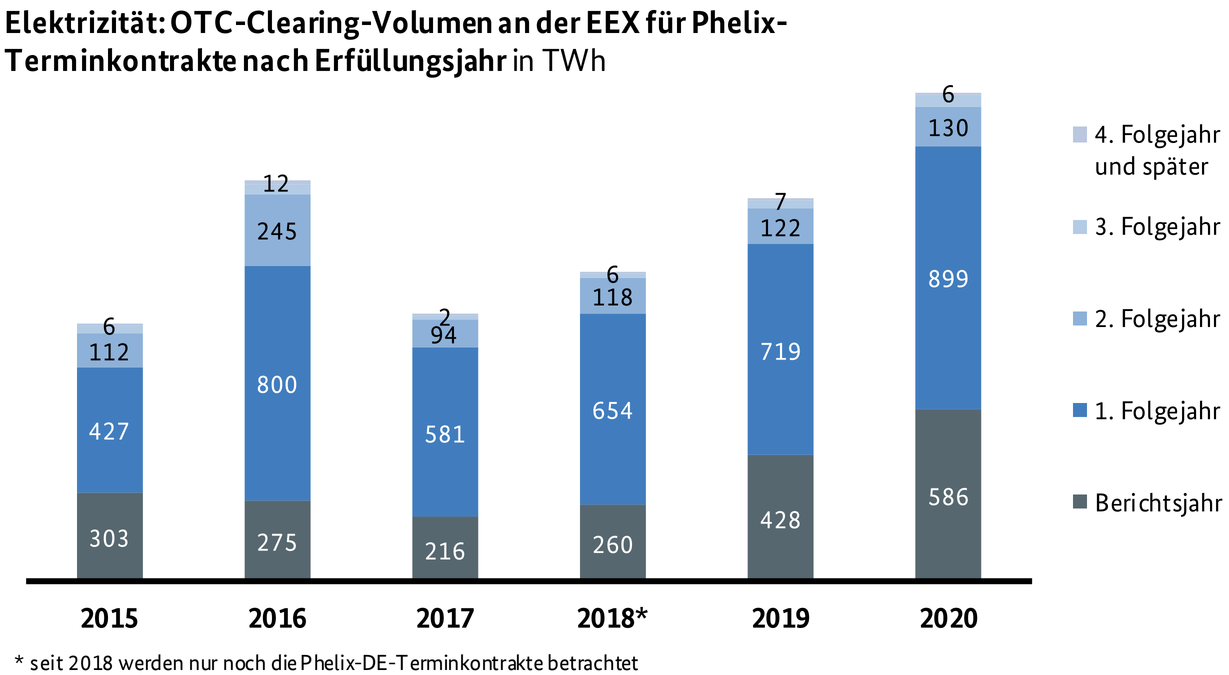

Figure 97: OTC clearing volume of Phelix futures on EEX by fulfilment year

[113] Cf. https://www.lebaltd.com/monthly-volume-reports/ (retrieved on 31 July 2020). The total volume of "German power" brokered by LEBA members was 4,757 TWh in 2019.

G Retail

1. Supplier structure and number of providers

In total, at least 1,440 companies were operating as electricity suppliers in Germany in the year 2020. Suppliers are considered to be individual legal entities without taking company affiliations or links into account.

Around 51.4m market locations of final consumers were recorded in the monitoring survey. As Abbildung 105 shows, of 1,364 suppliers, approximately 84% serve fewer than 30,000 market locations. This amounts to just under 8.1m market locations in this category (around 16% of all market locations). Some 6% of all suppliers serve over 100,000 market locations. In absolute terms, these 6% serve around 36.5m market locations, or 71% of all customers, the same figure as in the previous year. The 86 large suppliers serve the largest number of market locations in Germany. Hence the majority of companies operating as suppliers continue to have a customer base made up of a relatively small number of market locations. A large number of suppliers therefore does not automatically translate into a high level of competition.

Electricity: number and share of suppliers serving the given number of market locations in 2020
not taking company affiliations into account

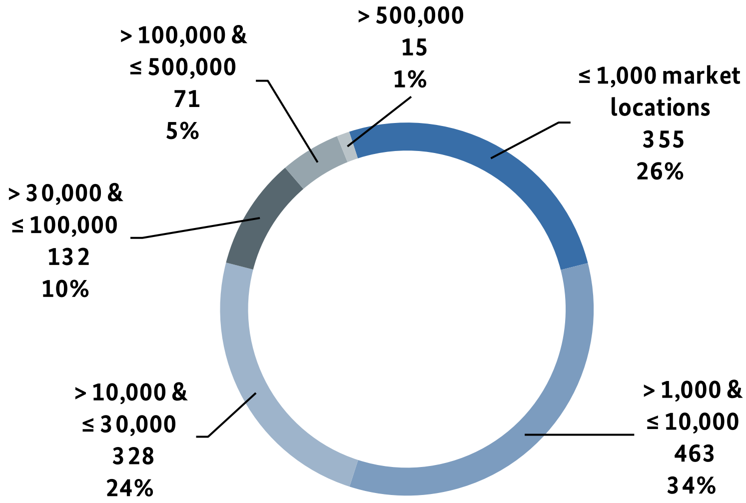

Figure 98: Number of suppliers by number of market locations supplied

A more comprehensive picture of the supplier structure emerges from an evaluation of the regional activity of the suppliers. The analysis of the data submitted by 1,227 suppliers shows that nearly half of them only operate regionally. 103 suppliers, or around 8%, supply customers in more than 500 network areas (see Abbildung 106). 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: 212 suppliers have concluded contracts in all 16 federal states. On a national average, a supplier has customers in 99 network areas (2019: 97 network areas).

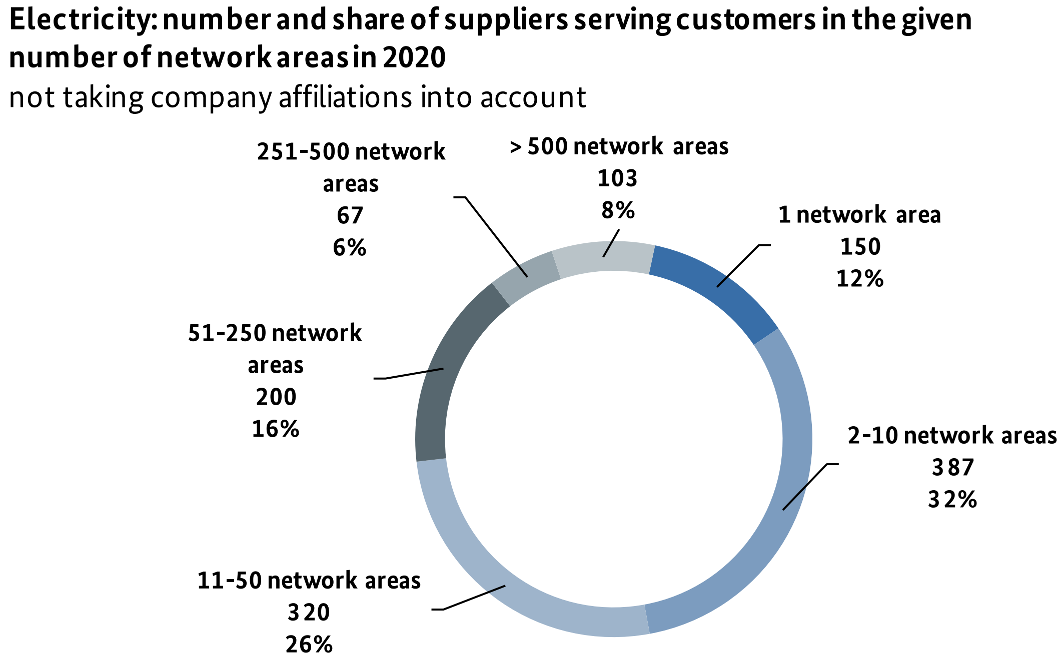

Figure 99: Number of suppliers by number of network areas supplied

Although the majority of suppliers continue to operate regionally, the number of suppliers that electricity customers could choose from has increased over the past eight years. An evaluation of the data supplied by 823 distribution system operators on the number of suppliers that supply the consumers in each network area produced the following results (see Abbildung 107): in 2020, more than 50 suppliers operated in 89% of all network areas (734 network areas). In 2008 this figure was 50% of the network areas (362 network areas). Today more than 100 suppliers operate in around 74% of the network areas, whereas five years ago it was only 55% (439 network areas). On average, final consumers in Germany were able to choose between 162 suppliers in 2020 (2019: 156), while household customers were able to choose between 142 suppliers (2019: 138).

Electricity: breakdown of network areas by number of suppliers operating
in %, not taking company affiliations into account

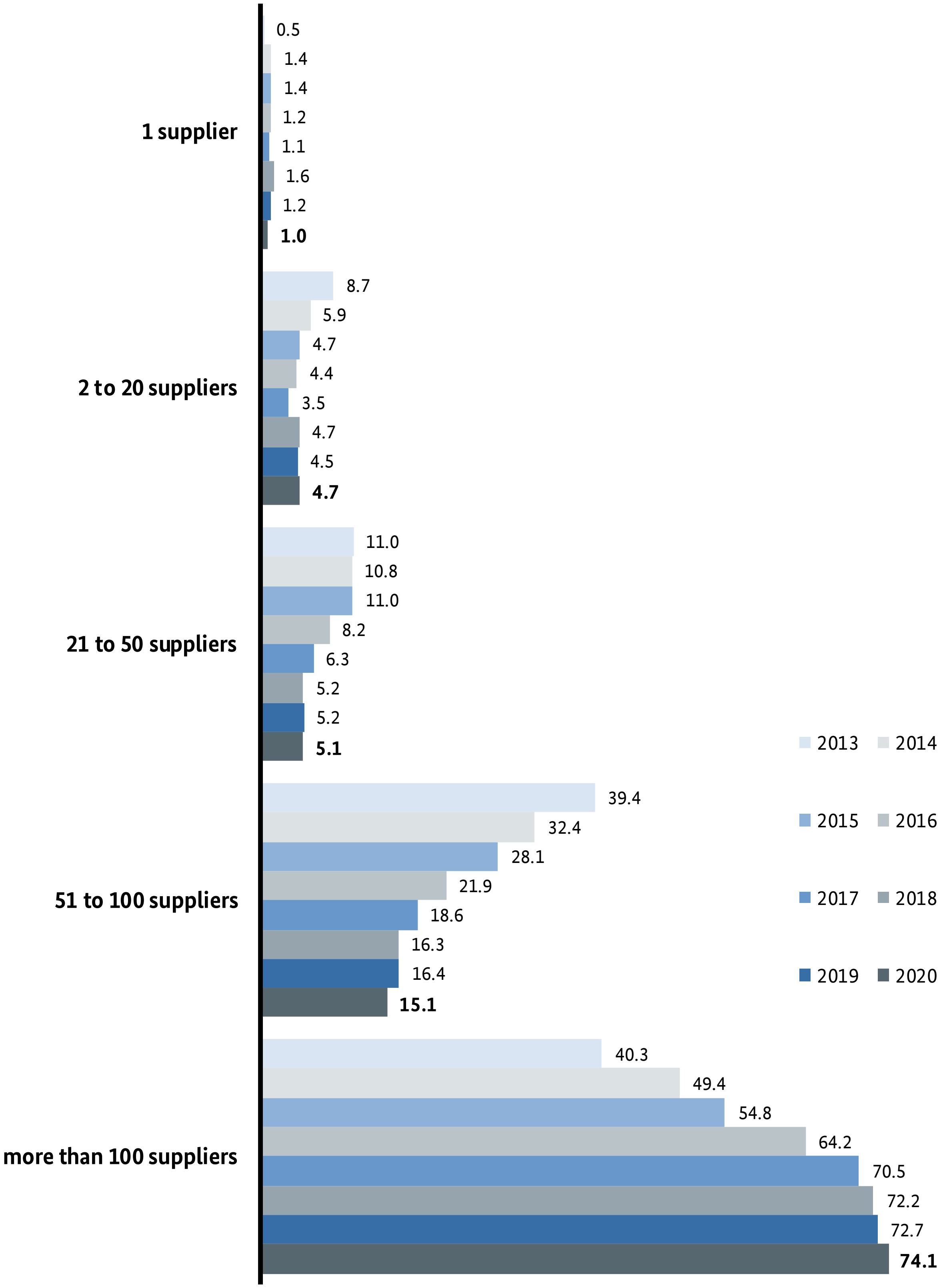

Figure 100: Breakdown of network areas by number of suppliers operating

2. Contract structure and supplier switching

37% of household customers are supplied with electricity under a non-default contract with the local default supplier. Around 25% of household customers are supplied under a standard default tariff. 38% of household customers have a contract with a supplier other than the local default supplier.

A total of 62% of all households are still served by the default supplier. Thus the position of the default suppliers in their respective service areas remains strong.

In 2020, around 5.4m household customers switched electricity suppliers. Household customers are more and more likely to turn directly to a supplier that is not the local default supplier and thus to access a cheaper electricity contract.

Consumers are recommended to find out what kind of contract they have (default or otherwise) and to compare the prices of their current supplier with those of competitors. Switching contracts with the existing supplier or changing supplier can usually save customers money.

Switching rates and processes are important indicators of growing competition. The collection of key figures for supplier switches is based on relevant indicators that best reflect the actual switching behaviour. For monitoring purposes, the term “supplier switch” refers to the process by which a final consumer’s market location is assigned to a new supplier. As a rule, moving into or out of premises is not considered a supplier switch. In this context it must be noted that the change of supplier refers to a change in the supplying legal entity. According to this definition, a supplier switch can thus be brought about by an internal reallocation of supply to another group company, the insolvency of the former supplier or by the supplier terminating the contract. The actual scope of supplier switches can therefore deviate from the figures registered. In addition to supplier switches, the monitoring report also analyses household customers’ choice of supplier upon moving house if they choose a supplier other than the default supplier. The term switch of contract refers to a switch that takes place within the same company.

In order to calculate the indicators, 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 Act (EnWG) primarily according to qualitative characteristics.[114] 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[115] 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 supplier data, the volume of electricity sold to all final consumers in 2020 was approximately 347.3 TWh. In the previous year, this figure was 414.1 TWh. In 2020, around 213.3 TWh of this amount was supplied to interval-metered customers and 133.8 TWh to SLP customers (including 11.2 TWh of electricity for thermal night storage heating and heat pumps). The majority of SLP customers are household customers.

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,
- non-default contract with a default supplier and
- contract with a supplier other than the local default supplier.

For the purpose of this analysis, the default supply contract category also includes auxiliary energy supply (section 38 EnWG) and doubtful cases.[116] Delivery outside the default supply contract is referred to either as a non-default contract or is defined specifically ("non-default contract with the local supplier" or "contract with a supplier other than the local default supplier"). An analysis on the basis of these three categories makes it possible to draw conclusions as to the extent of the decline in the importance of default supply 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". 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).

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[114] 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.

[115] 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.

[116] 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.

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[117], the majority are industrial or other high-consumption non-household customers.

In the reporting year 2020, approximately 1,413 electricity suppliers (individual legal entities) provided data on the meter points supplied and on the consumption of interval-metered customers (1,318 in the previous year). The 1,413 electricity suppliers include many affiliated companies, so that the number of suppliers does not equal the number of competitors.

The companies supplied just under 213.3 TWh of electricity to the approximately 368,586 meter points of interval-metered customers in 2020 (approx. 260.6 TWH was supplied to 368,377 meter points in the previous year). 99.9% of this was supplied under contracts outside of default supply[118]. It is unusual but not impossible for interval-metered customers to be supplied under default or fallback supply contracts. A total of 0.21 TWh of electricity was supplied to interval-metered customers with a default or fallback supply, which is 0.1% of the total electricity supplied to interval-metered customers.

24.4% of the total electricity for interval-metered customers was supplied under a special contract with the default supplier (divided between around 36.1% of all interval meter points). Approximately 75.5% of the total electricity was supplied under a contract with a legal entity other than the local default supplier (divided between approximately 62.9% of all meter points). In the previous year, 27.1% of the volume was sold under special contracts with the default supplier and 72.7% under special contracts with other suppliers. Developments over the last few years show that with regard to the volume sold, default supply and special contracts with the default supplier outside the default supply are still losing in importance for the acquisition of interval-metered electricity customers.

[117] In accordance with Section 12 of the Electricity Network Access Ordinance (StromNZV), interval metering is generally required if annual consumption exceeds 100 MWh.

[118] In accordance with Section 36 EnWG, default supply relates only to household customers. Any mention in the following of the default supply of non-household customers refers to fallback supply.

Elektrizität: Vertragsstruktur bei RLM-Kunden im Jahr 2020
Menge und Verteilung

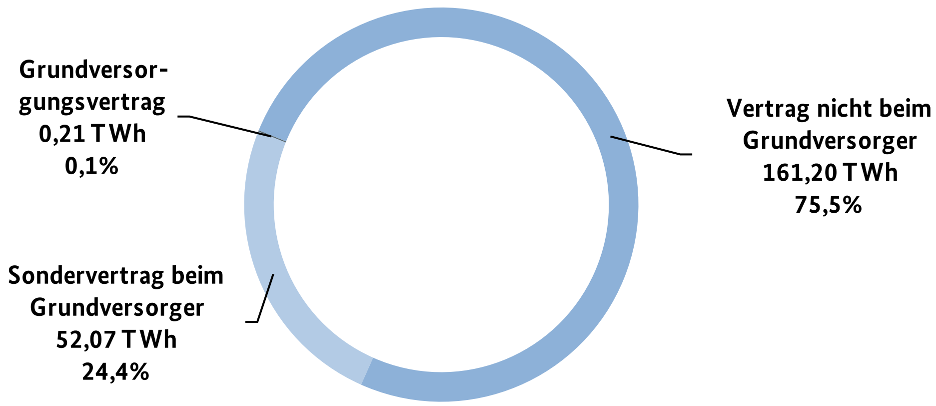


Figure 101: Contract structure for interval-metered customers in 2020

2.1.2 Supplier switching

Data on the supplier switching rates among different customer groups in 2020 and the consumption volumes attributed to these customers was collected in the TSO (transmission system operators) and DSO (distribution system operators) 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, or hospitals fall into the 10 MWh/year to 2 GWh/year category. The survey produced the following results:

Elektrizität: Lieferantenwechsel nach Verbrauchskategorien im Jahr 2020

Letztverbraucher-kategorie	Anzahl der Marktlokationen mit Lieferanten-wechseln	Anteil an allen Marktlokationen der Verbrauchs-kategorie	Entnahmemenge an Marktlokationen mit Lieferanten-wechseln in TWh	Anteil an Entnahmemenge der Verbrauchs-kategorie
>10 MWh/Jahr – 2 GWh/Jahr	293.119	14,8%	16,2	14,1%
> 2 GWh/Jahr	2.461	15,6%	22,4	10,3%
Gesamt Nicht-Haushaltskunden	**295.580**	**14,8%**	**38,6**	**11,6%**

Table 85: Supplier switching by consumption category in 2020

The volume-based switching rate for the categories with a consumption exceeding 10 MWh/year was 11.6% in 2020. The switching rate in the previous year was 11.7%. 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.

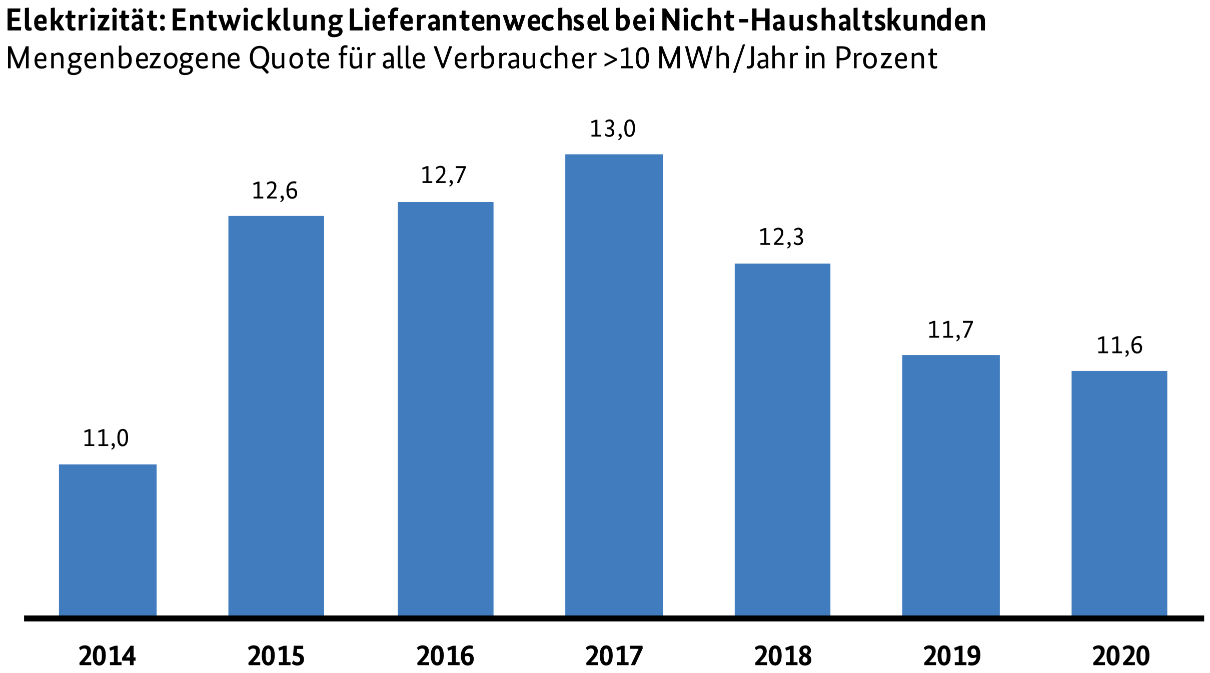


Figure 102: Supplier switching among non-household customers

2.2 Household customers

2.2.1 Contract structure

The data from the monitoring report shows that in 2020 the category "non-default contract with the default supplier" accounted for around 37% of electricity consumption by household customers (2019: 40%). The percentage of household customers with a standard default supply contract is 25% of electricity consumption (2019: 26%). The percentage of customers served by a contract with a company other than their local default supplier was 38% (2019: 34%). Overall, 62% of all households are still served by the default supplier (2019: 66%). Despite a steady decline in recent years, the position of the default suppliers in their respective service areas remains strong.

Electricity: contract structure of household customers in 2020
TWh and percentage

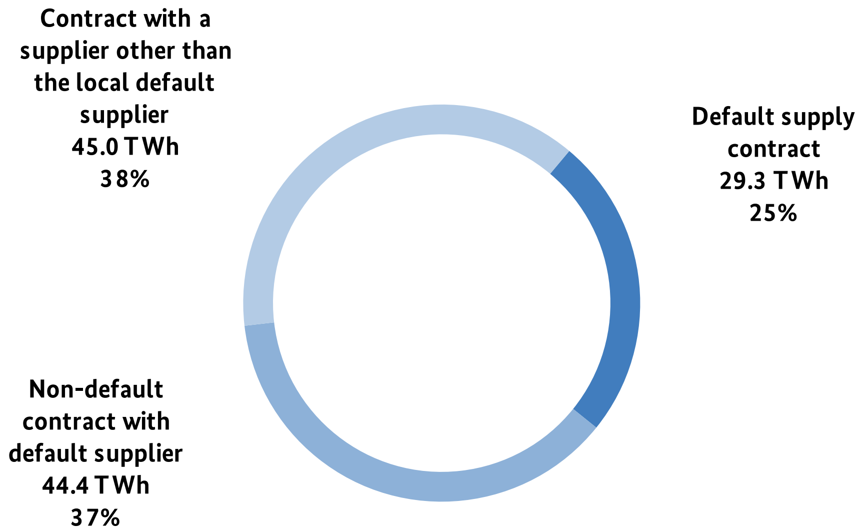


Figure 103: Contract structure of household customers in 2020

2.2.2 Switch of contract

Fehler! Verweisquelle konnte nicht gefunden werden. depicts contract switches within a company carried out at the customer's request. The total number of contract switches was around 1.83m, which is the same as the previous year's figure (2019: 1.83m contract switches). The corresponding volume of electricity involved in the contract switches amounted to approximately 5.3 TWh (2019: 5.6 TWh). This results in a number and volume-based contract switching rate of 3.8% and 4.5% respectively. Compared to the previous year's figures, the number of switches within a company thus remained constant, while the volume of electricity involved in contract switches declined, by approximately 0.3 TWh.

Electricity: contract switches by household customers in 2020

Category	Contract switches in TWh	Percentage of total consumption	Number of contract switches	Percentage of total number of household customers
Household customers who switched their existing energy supply contract with their supplier	5.3 TWh	4.5%	1.83 Mio.	3.8%

Table 86: Contract switches by household customers (based on survey of electricity suppliers)

2.2.3 Supplier switch

The supplier switching rate of household customers is comprised of the number of switches to another supplier and the number of switches when customers choose a supplier other than the default supplier when moving home. Electric heating customers are not taken into account here. In 2020 the total number of household customers switching supplier was around 896,000, which is significantly higher than the previous year's level of 4.5 million. It should be noted that in the analysis of monitoring data for 2019, the special effect caused by insolvencies was deducted from the total number of active (voluntary) supplier changes. Because of the resulting degree of uncertainty in the previous year's figures, the values are thus not directly comparable.

In 2020 the overall supplier switching rate was approximately 10.9% for household customers and has thus increased by 1% (2019: 9.9%; 2018: 10.2%). These switches entail an electricity volume of about 16.2 TWh, which is slightly higher than the previous year's figure (2019: 14.6 TWh). This corresponds to a switching rate based on volume of 12.9%, which is higher than the number-based switching rate. This may suggest that customers with a high level of electricity consumption are more prone to switching suppliers. **Fehler! Verweisquelle konnte nicht gefunden werden.** shows the increasing trend in the rate of supplier switches since 2009.

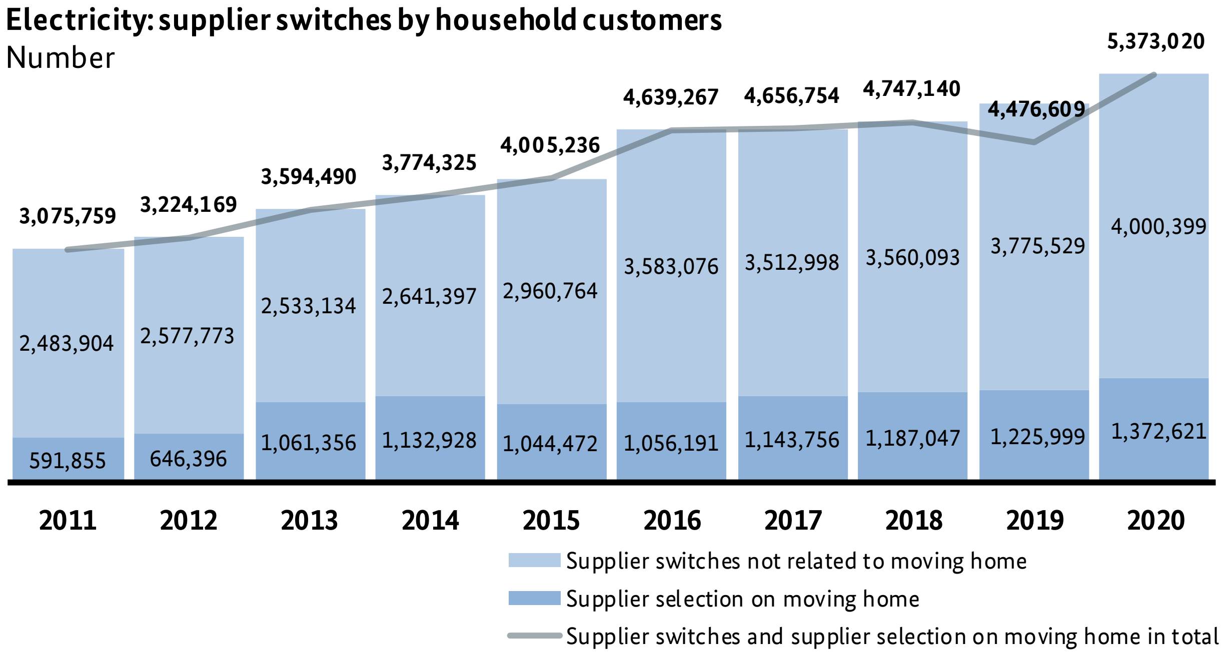


Figure 104: Supplier switches by household electricity customers[119]

[119] Due to insolvencies, the number of switches for the years 2011 and 2013 have been adjusted by approximately 500,000 insolvency-related switches per year.

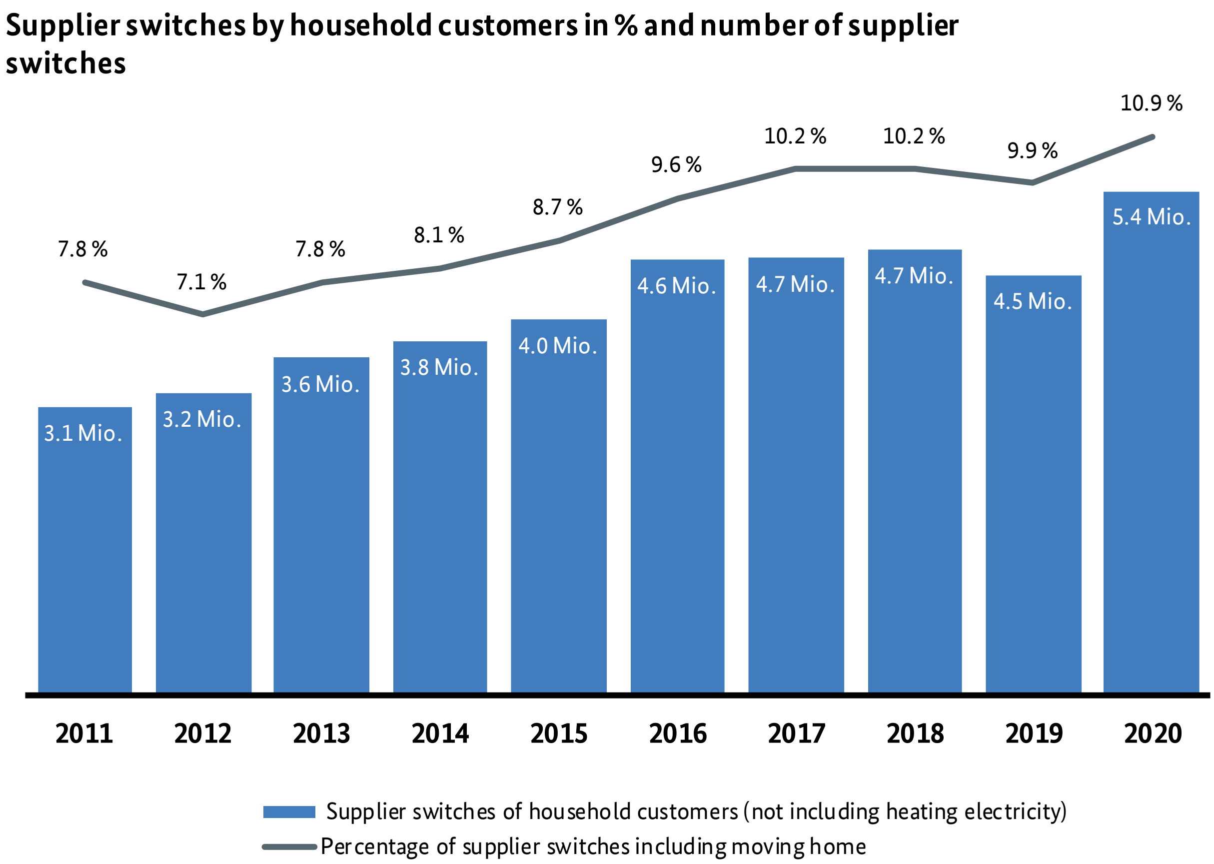


Figure 105: Supplier switches by household electricity customers

A joint view of the contract and supplier switches in 2020 makes it possible to determine the number of household customers who undertook a change in their energy supply contract. Around 7.2m switches were made.

3. Disconnections, cash/smart readers, tariffs and contract 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.

Disconnection (interruption) of supply is carried out at the earliest four weeks after the disconnection notice. The date of actual disconnection must be announced to the customer three working days in advance.

Under a default supply contract, the interruption of power supply may only be carried out if the customer is €100 or more in arrears. The default supplier is also required to verify the proportionality of the decision to disconnect supply.

The supplier may charge the customer a price for issuing notices, disconnecting supply, as well as for reinstating service. These charges can vary considerably, depending on supplier and network operator. Under a default supply contract, customers can demand verifiable documentation of the basis for calculation.

If changes in consumption are foreseeable, consumers can adjust their advance payments, thereby avoiding high one-off back payments. By changing tariff or supplier, consumers can lower their energy costs. They can also receive energy cost counselling from consumer advice centres, for example.

In 2020 – as a result of the coronavirus pandemic – a right to refuse performance was introduced, effective between April 1 and June 30 (Art. 240 section 1 EGBGB), which also applied to energy supply contracts. In addition, some suppliers announced that they would forgo carrying out disconnections. However, the significant decline in disconnections carried out in 2020 as a result of this exceptional case is not indicative of future developments.

3.1 Disconnections of supply

In 2020, the Bundesnetzagentur questioned network operators and electricity suppliers about disconnection notices and disconnection requests, as well as about the number of actual disconnections carried out, along with the associated costs. The number of disconnections carried out by network operators was at 230,015, which is 20% lower than the previous year's figure (2019: 289,012). Based on the total number of market locations of final consumers, the disconnection rate thus is 0.4%. This decline is likely attributable in part to the right to refuse performance in accordance with Art. 240 section 1 EGBGB, which was introduced as a result of the coronavirus pandemic to provide temporary relief to consumers and was in effect between April 1 and June 30 2020. In addition, 72% of the electricity suppliers surveyed announced that they chose to forgo – at least temporarily – carrying out disconnections of supply. Electricity suppliers also agreed to special or individual payment terms with customers in order to reach customer-friendly solutions. Furthermore, some electricity suppliers have adjusted their individual criteria for disconnections to the customer's benefit.

To request a disconnection under section 24(3) of the Low Voltage Network Connection Ordinance (NAV), the supplier must be contractually entitled to do so vis-à-vis the connection user, and must convince the network operator that the contractual prerequisites for disconnection between supplier and connection user are met. The rights and obligations that are in effect between network operator and network user are regulated in the network usage contract/supplier framework agreement for electricity, which is specified by the Bundesnetzagentur and regulates the possibility to discontinue supply at the request of any 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 the appropriate notice has been given. Non-default suppliers stipulate the regulations governing failure to fulfil payment obligations in their contracts.

Abbildung 113 sho ws how often during 2020 suppliers issued notices threatening disconnection of supply due to failure to fulfil payment obligations, how often they issued disconnection requests, and how often those disconnections were carried out.

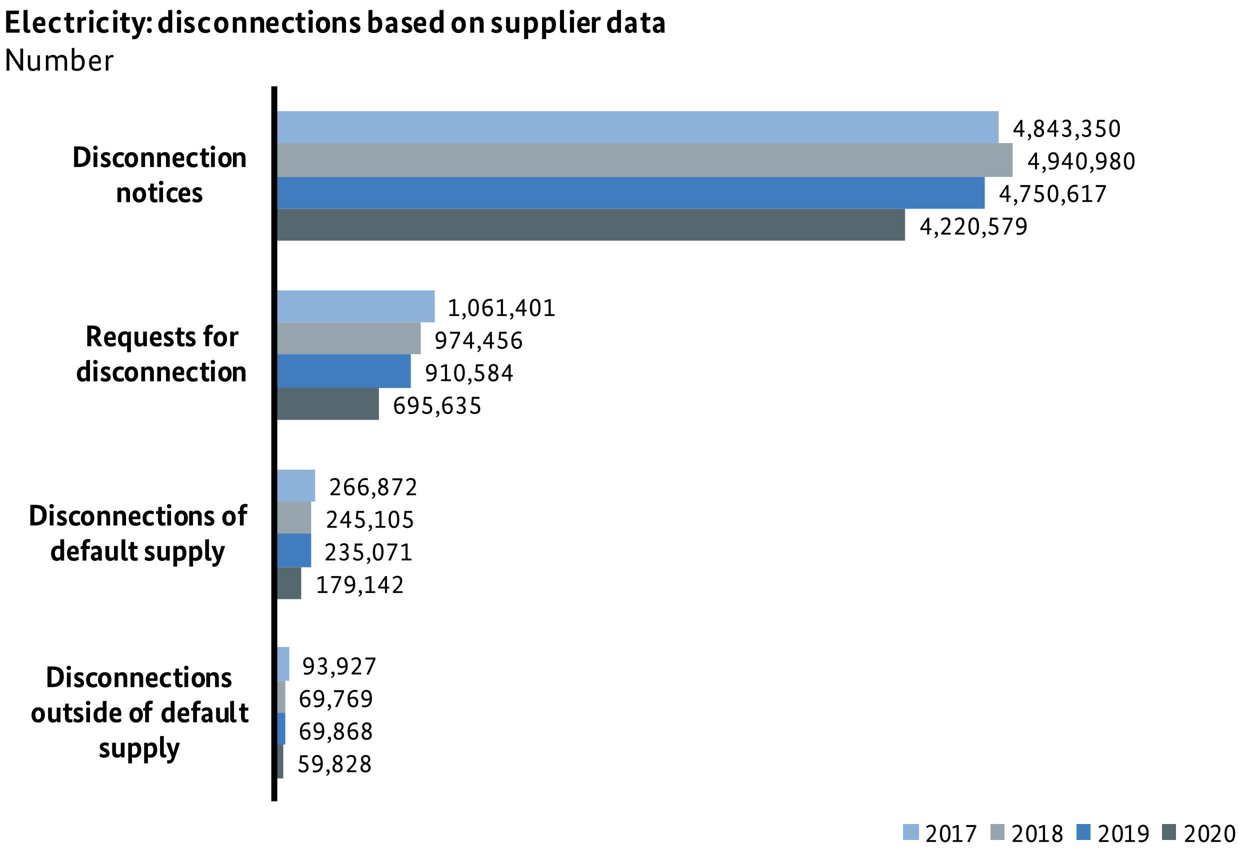


Figure 106: Disconnection notices, requests for disconnection and disconnections within and outside of default supply, based on survey of suppliers

According to the data provided by suppliers, disconnection notices were sent out when, on average, a customer was €121 in arrears. Suppliers reported that around 5% of disconnections involved repeat disconnections of the same customer.

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. The electricity suppliers were asked whether they charge the flat rate according to section 19(4) StromGVV. Using this flat rate calculation, suppliers charged their customers an additional average price of around €43 (including VAT),[120] with the actual fee ranging between €1 and €199. Suppliers who did not carry out a flat rate calculation charged their customers an average of €47 (including VAT), with the actual cost ranging between €4 and €140. For reconnection, electricity suppliers using the flat rate model charged their customers an average of approximately €49 (including VAT), with the actual cost ranging between €2 and €145, while suppliers who did not use the flat rate model charged an average of €51 (including VAT), with the actual charges ranging between €5 and €135. Suppliers charged household customers an average of €2.90 for issuing a reminder because of arrears in payment.

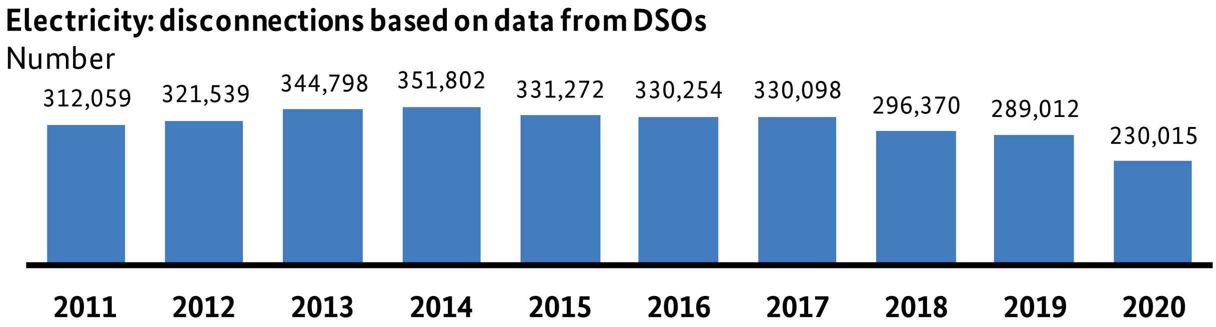


Figure 107: Disconnections based on data from DSOs[121]

A total of 230,015 disconnections and 212,707 reconnections were carried out in 2020. The following table shows the distribution of disconnections broken down by federal state:

[120] Suppliers' own costs, not including costs incurred with the commissioned network operator.

[121] The figures from 2011 to 2014 entail those disconnections requested by the local default supplier. As of 2015 the figure entails the disconnections from all suppliers.

Electricity: number of disconnections by federal state in 2020 (DSO data)

	Number of disconnections (within and outside of default supply)	Percentage of market locations of final consumers in the federal state
Saxony-Anhalt	10,688	0.70
Northe Rhine-Westfalia	75,200	0.67
Berlin	7,389	0.63
Hamburg	12,548	0.52
Saxony	14,598	0.51
Bremen	5,570	0.49
Schleswig-Holstein	8,822	0.48
Mecklenburg-Western Pomerania	2,917	0.44
Hesse	16,241	0.42
Saarland	5,767	0.41
Rhineland-Palatinate	17,004	0.36
Thuringia	8,948	0.36
Lower Saxony	1,558	0.35
Brandenburg	5,590	0.33
Bavaria	21,828	0.28
Baden-Württemberg	15,347	0.23

Table 87: Number of disconnections by federal state in 2020

The network operators charged the electricity suppliers an average fee of €55 (excluding VAT) for disconnecting a supply, with the actual costs charged ranging between around €12 and €350. The average amount charged for reinstating supply to household customers was €58 (excluding VAT), with the actual charges varying from €15 to €350.

The average length of time between an actual disconnection and a reconnection was 14 days (for reasons of clarity, this figure only includes cases in which both disconnection and reconnection were carried out in 2020). Some 13,404 disconnections lasted longer than 90 days. DSOs were not asked to provide a reason for these longer disconnection periods, which may have been due to customers' long-term inability to pay, vacant properties or faulty customer facilities that could not be reconnected for safety reasons.

3.2 Terminations

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 and where there is no obligation to provide basic services. For the default supplier, continued supply must be deemed to be economically reasonable. In 2020, suppliers (default and non-default suppliers) terminated overall nearly 173,627 contracts with their customers (2019: approximately 221,209). The average customer arrears upon a termination of the energy supply contract was €168.

3.3 Cash meters and smart card readers

In the 2020 monitoring survey, meter operators and suppliers were again surveyed on prepayment systems in accordance with section 14 StromGVV, such as cash meters or smart card readers. Over the course of 2020, such prepayment systems were installed on behalf of the local default supplier at about 18,850 household customers' points of consumption. This corresponds to 0.04% of all market locations of household customers in Germany. In just under 3,100 cases, a cash meter or smart card reader was newly installed in the 2020 calendar year, with about 2,700 such meters being removed again.

3.4 Tariffs

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 2020, around 10% of suppliers offered load-based tariffs, while some 62% of suppliers offered time-of-use tariffs.

Overall, 30% of all suppliers offer an online-only tariff that can be concluded online (eg on the company's website or through a price comparison portal) 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.

Separate tariffs that include energy saving incentives are currently offered by around 7% of companies.

Some 0,2% of suppliers offer tariffs with dynamic pricing that reflect the price on the day-ahead market in intervals; this requires the installation of a corresponding meter. Both the rollout of smart metering systems and the continued support for dynamic contracts, including through European regulations (see section 41a(2) ENWG) can encourage the interest of additional consumers in such systems in the future and lead to an increase in the number of contracts concluded. However, a qualitative evaluation of this development can only take place as the rollout of smart metering systems progresses. Since only 27,599 metering locations of customers with standard load profiles (SLP), or less than 0.1%, were equipped with smart metering systems certified by the Federal Office for Information Security (BSI) in the reporting year 2020, no accurate conclusions can be made regarding the development of dynamic tariffs.

In 2020, 142 companies (or 14% of all companies) offered so-called bundled tariffs, under which suppliers link the electricity contract with other products and services. Among large companies with more than 500,000 market locations, the share was around 40%. Among companies with 10,000 to 200,000 market locations, primarily municipal utility companies offer bundled tariffs.

Electricity tariffs were often tied to other energy sector services such as natural gas or PV systems, but were also linked with hardware, telecommunications services or water supply. Other linked products include heating oil, pellets, district heating, heat pumps, electromobility services, insurance policies, vouchers and event tickets.

Electricity: products offered on bundled tariffs in 2020		Electricity: size of companies offering bundled tariffs in 2020	
Product category	**Frequency**	**Number of market locations**	**Percentage**
Natural gas	74	< 1.000	1%
Hardware	19	≥ 1000 & < 10.000	7%
Telecommunications, Internet	24	≥ 10.000 & < 30.000	15%
Water	9	≥ 30.000 & < 100.000	20%
Solar PV systems/tenants' electricity	37	≥ 100.000 & < 500.000	31%
Other	32	≥ 500.000	40%
Total	**195**	**Total**	**10%**

Table 88: Products offered on bundled tariffs and size of the companies offering them

3.5 Billing cycles of less than one year

Section 40(3) EnWG, in the version effective in 2020, also required suppliers to offer final consumers monthly, quarterly or semi-annual billing. In 2020, 170 suppliers stated that they carry out monthly, quarterly or semi-annual billing for some 59,000 household customers (2019: 33,500). The average charge (including VAT) for each additional billing was approximately €8 with customer reading and approximately €10 without customer reading.

4. Price level

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.

Electricity prices are not subject to price regulation in Germany.

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 2021 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 to 5,000 kWh consumption range.

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, including the non-variable price components such as the capacity price, standing charge and service charge, in cents per kilowatt hour (ct/kWh). 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 meter operation charges. Furthermore, the state-controlled surcharges and taxes are taken into account in the total price, ie value added and electricity taxes, surcharges under the EEG, KWKG and section 19(2) StromNEV, and surcharges for offshore liability and interruptible loads under section 17f EnWG. 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.

Since the analysis of the price level is based on the reference date of 1 April 2021, the temporary VAT reduction from 19% to 16% that was effective from 1 July 2020 to 31 December 2020 was not taken into account.

Both with regard to the overall price and the individual price components, the suppliers provided their "average" overall price for the four consumption levels of household consumers for each of the three different contract types (see below).[122]

For household customers, companies were asked to provide data on the individual price components for the six consumption bands for the following three different contract types:

- default supply contract,
- non-default contract with a default supplier (after change of contract) and
- contract with a supplier other than the local default supplier (after switch of supplier).

The findings of the supplier survey are presented in the following by contract type or 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 2021 and 1 April 2020, 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.

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

[122] If a company cannot calculate an average price due to the many different tariffs they offer, one representative tariff is chosen.

arrangements is very important to this customer group. Suppliers generally do not use specific tariff groups for customers that 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 directly with the network operator. In extreme cases, these types of contracts may in terms of their economic effect even result in suppliers merely providing balancing group management services for their customers. For high-consumption customers, the distinction between retail and wholesale trading is therefore 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 annual reduction available to companies in the 24 GWh/year consumption category. However, the questions on prices were 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 19(2) AbLaV, Section 17f. EnWG). In the following consumption category the VAT is not indicated because of the input tax deduction

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 applies to only a limited number of suppliers. The following price analysis of the consumption category was based on data from altogether 197 suppliers (191 in the previous year).

This data was used to calculate the arithmetic mean of the overall price and of the individual price components. Furthermore, the data spread for each price component was 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:

Elektrizität: Preisniveau am 1. April 2021 für den Abnahmefall 24 GWh/Jahr ohne Vergünstigungen

	Streuung zwischen 10 und 90 Prozent der größensortierten Lieferantenangaben in ct/kWh	**Mittelwert** (arithmetischer) in ct/kWh
Nicht vom Lieferanten beeinflussbare Preisbestandteile		
Nettonetzentgelt	1,67 - 4,12	2,66
Messung, Messstellenbetrieb	0,00 - 0,01	0,01
Konzessionsabgabe	0,03 - 0,11	0,11
EEG-Umlage		6,5
weitere Umlagen[1]		0,72
Stromsteuer		2,05
Vom Lieferanten beeinflussbarer Preisbestandteil (Restbetrag)	3,38 - 6,19	4,88
Gesamtpreis (ohne Umsatzsteuer)	**14,81 - 18,65**	**16,94**

[1] Umlage nach KWKG (0,254 ct/kWh), Umlage nach § 19 StromNEV (0,066 ct/kWh), Umlage nach § 18 AbLaV (0,009 ct/kWh), Offshore-Netzumlage (0,395 ct/kWh)

Table 89: Price level for the 24 GWh/year consumption category without reductions on 1 April 2021

The arithmetic mean of the price component that can be controlled by the supplier rose from 4.20 ct/kWh in the previous year to 4.88 ct/kWh in 2021, representing an increase of around 16%. The surcharges totalled 7.22 ct/kWh (the EEG surcharge amounted to 6.50 ct/kWh and the other surcharges in this consumption category to 0.72 ct/kWh). The average net network charge remained unchanged at 2.66 ct/kWh (2.66 ct/kWh in the previous year). As the spread of net network charges is very high, the average charge does not necessarily represent the actual development.[123] The average overall price (excluding VAT and excluding possible reductions) of 16.94 ct/kWh was 0.40 ct/kWh higher than the arithmetic mean of the figures collected in the previous year (16.54 ct/kWh), i.e. around 2.4% higher.

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

[123] 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.

category defined in this way, cost items outside the supplier's control accounted for a total of 12.05 ct/kWh, or about 71% of the overall price. However, electricity customers that 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 StromNEV, Section 18 AbLaV and Section 17f. EnWG. 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. If all of these possible reductions are applied, the price component outside the supplier's control could be reduced from over 12 ct/kWh to below 1 ct/kWh.

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 EEG. Under Section 19(2) sentence 1 StromNEV, the net network charge may also be reduced.[124] Electricity tax may be waived, refunded or reimbursed in full in accordance with Section 9a StromStG. The concession fees under Section 2(4) sentence 1 KAV and the surcharges under Section 27 KWKG, Section 19(2) AbLaV and Section 17f 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.

Elektrizität: Mögliche Vergünstigungen für den Abnahmefall 24 GWh/Jahr

Preisabfrage zum 1. April 2021	Angenommener Wert	Mögliche Reduktion	verbleibender Betrag
EEG-Umlage	6,5	-6,181	0,319
Stromsteuer	2,05	-2,05	0,00
Nettonetzentgelt	2,66	-2,13	0,53
weitere Umlagen	0,72	-0,59	0,13
Konzessionsabgabe	0,12	-0,12	0,00
Summe	**12,05**	**-11,07**	**0,98**

Table 90: Possible reductions for the 24 GWh/year consumption category on 1 April 2021

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/year consumption category ("household customers") and is also around two thousandths of the 24 GWh/year consumption category ("industrial customers"). Given the moderate level of consumption,

[124] The even greater reductions possible under Section 19(2) sentence 2 StromNEV are not relevant to the 24 GWh/year consumption category since this has been defined as comprising 6,000 hours of use.

individual contract arrangements play a significantly smaller role than in the 24 GWh/year consumption category. Suppliers were asked to provide 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 2021. 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 generally required to use interval metering, it is safe to assume that in this category consumption is often measured using a standard load profile.

The following price analysis of the consumption category was based on data from altogether 940 suppliers (938 in the previous year). This data was used to calculate the arithmetic mean 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 middle 80% of the figures provided by the suppliers. The analysis produced the following results:

Elektrizität: Preisniveau am 1. April 2021 für den Abnahmefall 50 MWh/Jahr

	Streuung zwischen 10 und 90 % der größensortierten Angaben in ct/kWh	**Mittelwert (arithemetischer) in ct/kWh**	**Anteil am Gesamtpreis**
Nicht vom Lieferanten beeinflussbare Preisbestandteile			
Nettonetzentgelt	4,32 - 8,61	6,35	27%
Messstellenbetrieb	0,02 - 0,94	0,29	1%
Konzessionsabgabe	0,11 - 1,59	0,79	3%
EEG-Umlage		6,5	28%
weitere Umlagen[1]		1,09	5%
Stromsteuer		2,05	9%
Vom Lieferanten beeinflussbarer Preisbestandteil (Restbetrag)	4,32 - 8,29	6,16	27%
Netto-Gesamtpreis	**20,58 - 25,90**	**23,23**	**100%**

[1] Umlage nach KWKG (0,254 ct/kWh), Umlage nach § 19 StromNEV (0,066 ct/kWh), Umlage nach § 18 AbLaV (0,009 ct/kWh), Offshore-Netzumlage (0,395 ct/kWh)

Table 91: Price level for the 50 MWh/year consumption category on 1 April 2021

The remaining balance that can be controlled by the supplier increased again as at the 2021 reference date. While this value was at 5.96 ct/kWh on 1 April 2020, it rose to 6.16 ct/kWh on 1 April 2021 – an increase of 0.20 ct/kWh or 3%.

The EEG surcharge fell from 6.76 ct/kWh in the previous year to 6.50 ct/kWh. The other surcharges rose from 1.01 ct/kWh in the previous year to 1.09 ct/kWh in April 2021. The average net network charge also rose from 6.17 ct/kWh in the previous year to 6.34 ct/kWh. As the spread of net network charges is very high, the average charge does not necessarily represent the actual development.[125]

The average overall price (excluding VAT) rose by 0.20 ct/kWh from 23.03 ct/kWh in the previous year to 23.23 ct/kWh as at 1st April 2021, which is an increase of around 0.9%. This increase is mainly accounted for by a rise in the price component which can be controlled by the supplier. This price component altogether accounts for around 26.5% of the overall price, whereby an average of about 73.5% of the overall price relates to cost items outside the supplier's control, in particular the EEG surcharge and the network charge.

4.2 Household customers

In this section, retail prices and individual 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[126, 127]): annual electricity consumption below 1,000 kWh
- band II (DB): annual electricity consumption from 1,000 kWh to 2,500 kWh
- band III (DC): annual electricity consumption from 2,500 kWh to 5,000 kWh
- band IV: annual electricity consumption from 5,000 kWh to 10,000 kWh
- band V: annual electricity consumption from 10,000 kWh to 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 from 2,500 kWh to 5,000 kWh per year (band III). In section **Fehler! Verweisquelle konnte nicht gefunden werden.**, individual consumption bands are subsequently analysed, with the focus on the consumption band of a typical household customer in band III. It is important to note

[125] 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.

[126] "DA", "DB", "DC" and "DE" refer to the consumption bands defined by EUROSTAT.

[127] 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) sentence one of the StromNEV specifies that as from 1 January 2017 the charge for meter operations must also include the charge for metering.

that the average network charge listed for each type of tariff is calculated using the figures provided by the suppliers, who in turn provide the charges averaged over all the networks they supply. This results in a different network charge for each of the three tariffs.

4.2.1 Volume-weighted price across all contract categories for household customers

In the following tables and figures, the volume-weighted overall price across all contract categories in the middle consumption category[128] is examined. The average price for all household customers in the middle consumption category is taken as a key figure. It is calculated by weighting the individual prices for the three contract categories (default supply; non-default supply; contract with a supplier other than the local default supplier) by the respective amount of electricity consumed. The average price calculated as at 1 April 2021 was 32.63 ct/kWh, which is an increase from the previous year (2020: 32.05 ct/kWh). The increase of the retail price as at 1 April 2021 is mainly due to the increase of the price component "energy procurement, supply and the margin". Energy procurement costs are significantly influenced by the wholesale electricity price. With regard to short-term electricity purchases made in April 2021, the overall increase in wholesale electricity prices was influenced by a higher electricity demand that came about despite the COVID-19 pandemic, accompanied by higher conventional and lower renewable generation. In addition, the increased prices for CO2 certificates, which is one of the price components making up the overall electricity price that cannot be influenced by the supplier, also had an impact on the wholesale electricity price.[129]

[128] Eurostat customer category: Band III (DC): annual electricity consumption from 2,500 kWh to 5.000 kWh

[129] CO_2 price: 2020 – €24.8/t; 2021 – €46/t: source: Spectron
Network load: April 2020 – 36.4 TWh; April 2021 – 41.4 TWh: source: SMARD.de

Electricity: average volume-weighted price per type of contract for household customers with an annual consumption between 2,500 kWh and 5,000 kWh (band III; Eurostat: DC) as at 1 April 2021 (ct/kWh)

Price component	Volume-weighted average across all types of contract (ct/kWh)	Percentage of total price
Energy procurement, supply and margin	8.59	26.3
Net network charge	7.17	22.0
Meter operation charge	0.34	1.1
Concession fee	1.67	5.1
EEG surcharge	6.50	19.9
KWKG surcharge	0.25	0.8
Section 19 StromNEV surcharge	0.43	1.3
Section 18 AbLaV surcharge	0.01	0.03
Offshore grid surcharge	0.40	1.2
Electricity tax	2.05	6.3
VAT	5.21	16.0
Total	**32.63**	**100.0**

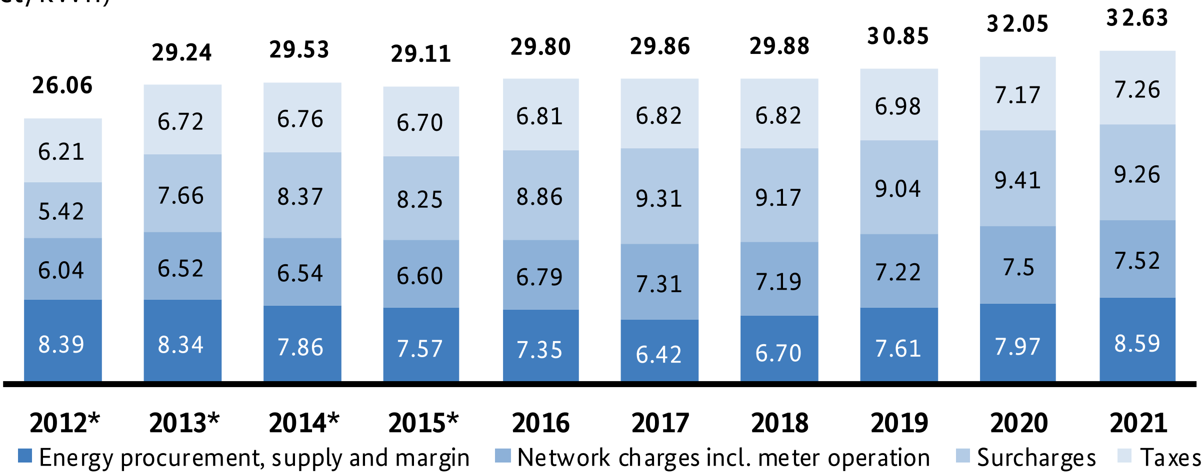
Table 92: Average volume-weighted price for household customers in consumption band III across all types of contract as at 1 April 2021

Electricity: change in volume-weighted price level for household customers across all types of contract from 1 April 2020 to 1 April 2021 for an annual consumption between 2,500 and 5,000 kWh (band III; Eurostat:DC)

Price component	Volume-weighted average across all types of contract (ct/kWh)	Change in level of price component	
		in ct/kWh	%
Energy procurement, supply and margin	8.59	0.62	7.2
Net network charge	7.17	0.04	0.5
Meter operation charge	0.34	-0.02	-5.3
Concession fee	1.67	0.03	1.6
EEG surcharge	6.50	-0.26	-3.9
KWKG surcharge	0.25	0.03	11.0
Section 19 StromNEV surcharge	0.43	0.07	17.1
Section 18 AbLaV surcharge	0.01	0.00	22.2
Offshore grid surcharge	0.40	-0.02	-5.3
Electricity tax	2.05	0.00	0.0
VAT	5.21	0.09	1.8
Total	**32.63**	0.58	1.8

Table 93: Change in the volume-weighted price level for household customers across all types of contract from 1 April 2020 to 1 April 2021 (consumption band between 2,500 kWh and 5,000 kWh per year)

Electricity: volume-weighted price across all contract types for household customers with an annual consumption from 2,500 to 5,000 kWh as at 1 April
(ct/kWh)



* Based on an annual consumption of 3,500 kWh

Figure 108: Development of the electricity price for household customers, volume-weighted across all types of contract

Electricity: breakdown of retail price for household customers with an annual consumption from 2,500 to 5,000 kWh as at 1 April 2021 (volume-weighted across all types of contract, band III, Eurostat: DC) (%)

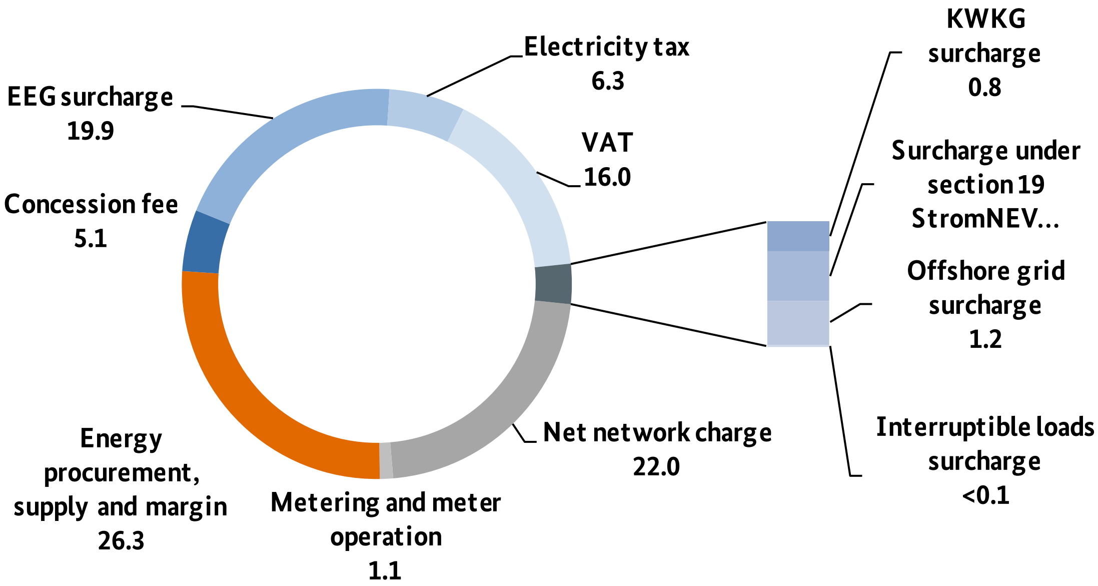


Figure 109: Breakdown of the retail price level for household customers in consumption band III as at 1 April 2021 (volume-weighted average across all types of contracts)[130]

First, a look at the network charges[131] shows a relatively sharp increase until 2017, following successive decreases in the period up to 2011. In 2021, a stabilisation of the average network charge is noticeable. The network charge thus continues to be high.

[130] 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.

[131] Net network charge includes charges for meter operations.

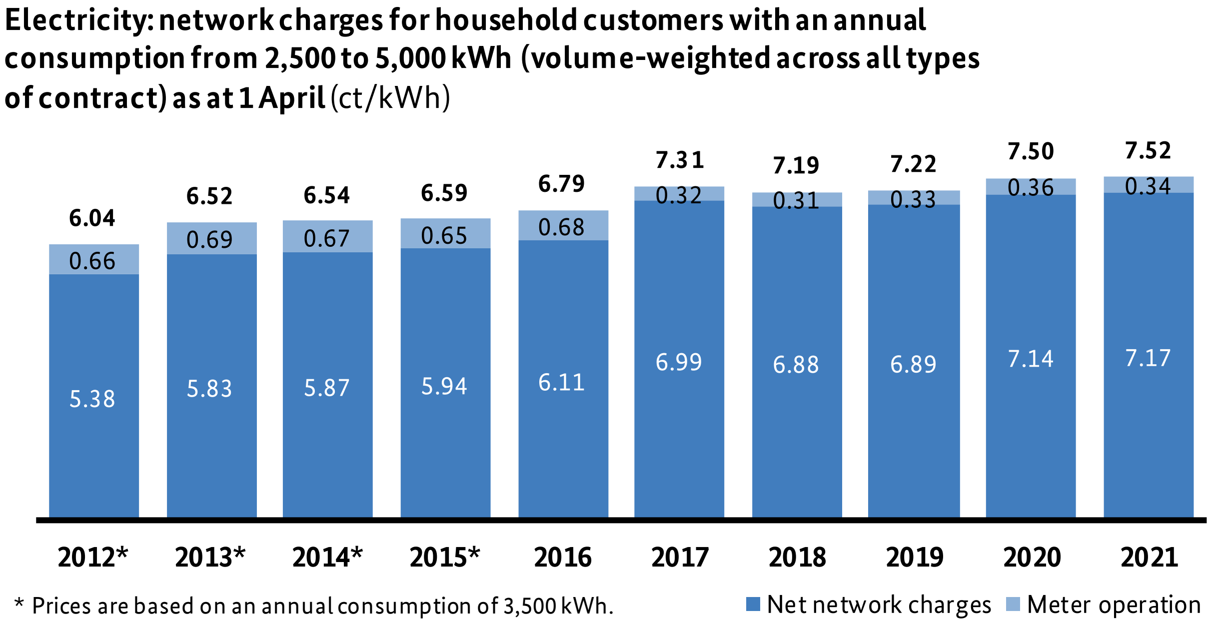


Figure 110: Development of network charges for household customers, including charges for meter operation

In 2021 there have been noticeable increases in other taxes and levies. These include in particular the renewable energy surcharge (EEG surcharge) and the surcharge under section 19 StromNEV (see section **Fehler! Verweisquelle konnte nicht gefunden werden.** "Surcharges" below). 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 of each year for the following calendar year. The Bundesnetzagentur ensures that the surcharge has been determined properly. The renewable energy surcharge for 2021 is at 6.5 ct/kWh and is thus below the previous year's level. The reason for this is the coronavirus economic stimulus package of June 2020, in which the surcharge for 2021 was determined. The surcharge has also already been determined for 2022, and is expected to drop to 6.0 ct/kWh. Figure Abbildung 118 shows the changes in the renewable energy surcharge in more detail.

The price component of "energy and supply costs and the margin" (see figure Abbildung 119) remained largely stable in the period from 2009 to 2013. While this supplier-controlled price component has fallen steadily since 2014, in 2021 it increased by nearly 8% (+0.62 ct/kWh) to 8.59 ct/kWh (2020: 7.97 ct/kWh).

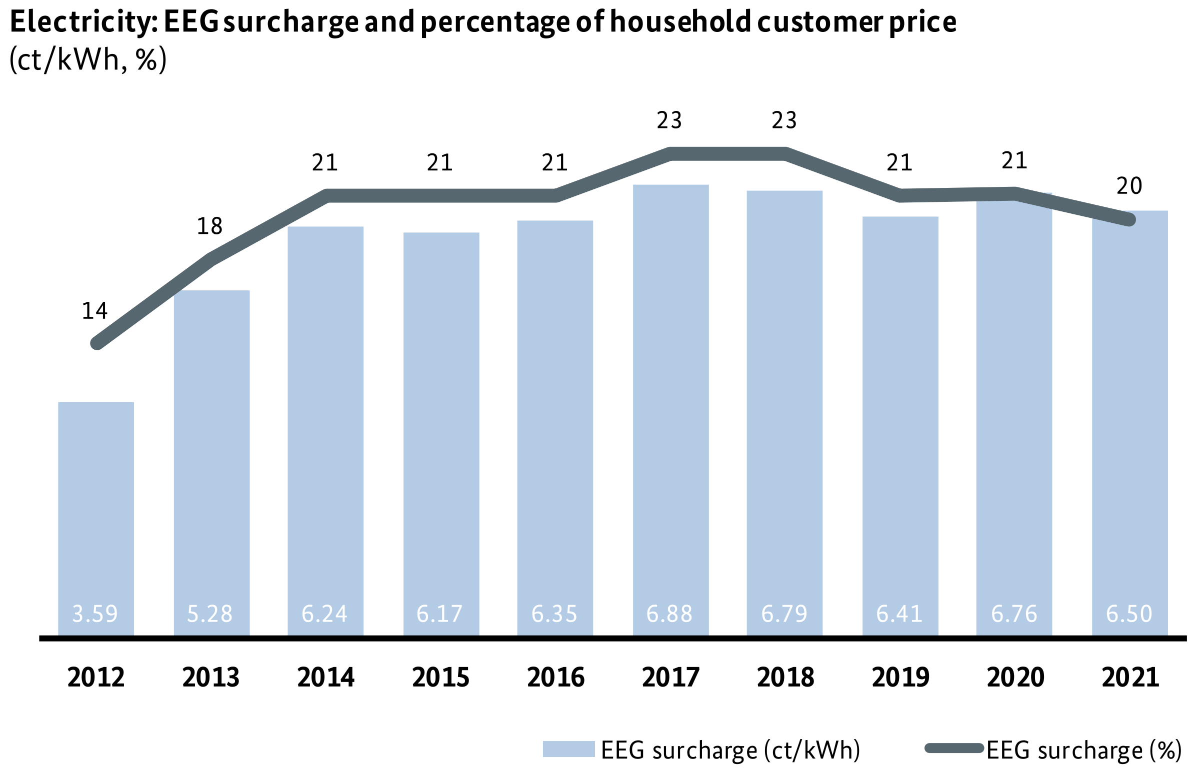


Figure 111: Renewable energy surcharge and percentage of household customer price

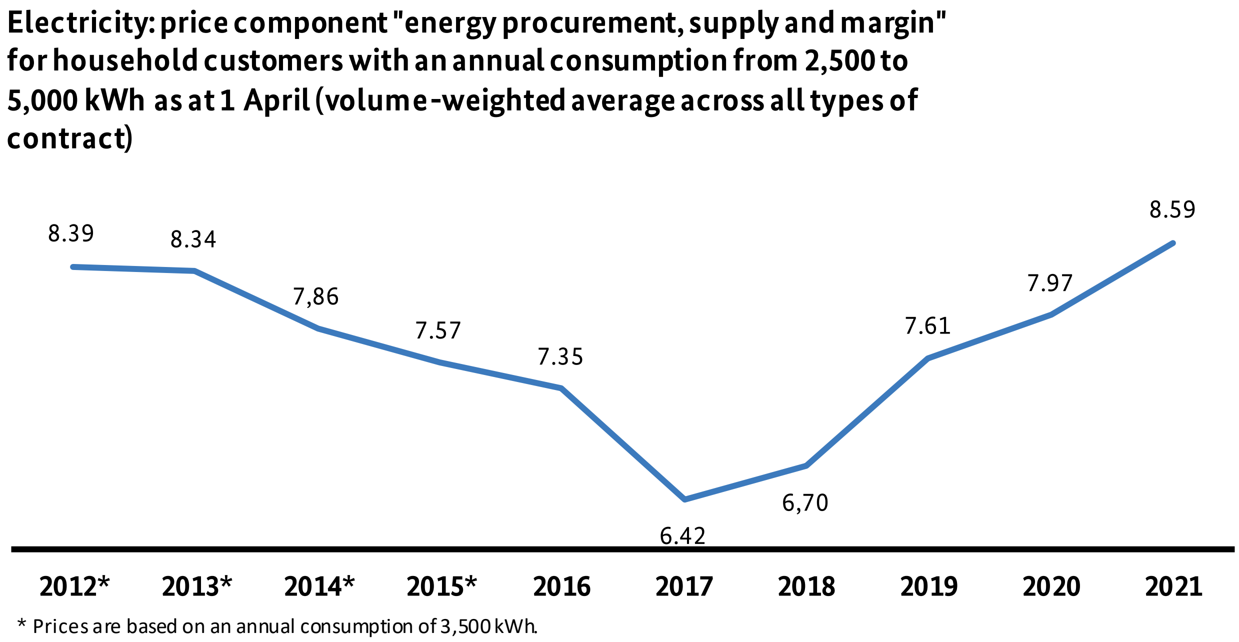


Figure 112: Change over time in the price component "energy and supply costs and margin" for household customers

4.2.2 Household customer prices by consumption categories

From the figures provided by suppliers, average prices can be derived 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 charge given for each type of tariff is calculated using the figures provided by the suppliers, who in turn provide the charges averaged over all the networks they supply. This results in a different network charge for each of the three tariffs. 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. Due to 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 a single 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 prices as at 1 April 2021 and the consumption volumes for 2020. The use of new consumption bands since 2016 is due to a change in the methodology used by the European statistical authority Eurostat to collect price data. This monitoring report shows the results for six consumption bands.

Band I: Annual electricity consumption up to 1,000 kWh

Electricity: average volume-weighted price per type of contract for household customers with an annual consumption up to 1,000 kWh (band I; Eurostat: DA) as at 1 April 2021
(ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy procurement, supply and margin	15.36	12.82	11.80
Net network charge	14.07	14.63	13.29
Meter operation charge	2.33	2.07	1.49
Concession fee	1.76	1.68	1.77
EEG surcharge	6.50	6.50	6.50
KWKG surcharge	0.25	0.25	0.25
Section 19 StromNEV surcharge	0.43	0.43	0.43
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore grid surcharge	0.40	0.40	0.40
Electricity tax	2.05	2.05	2.05
VAT	8.20	7.76	7.22
Total	**51.36**	**48.61**	**45.20**

Table 94: Average volume-weighted prices per type of contract for household customers in consumption band I as at 1 April 2021

Please note that in the low consumption bands, prices include non-variable price components (capacity price, standing charge, service charge etc.). The combination of lower consumption levels with the non-variable price components such as the standing charge thus results in a higher kilowatt-hour rate in this table.

Band II: Annual electricity consumption from 1,000 kWh to 2,500 kWh:

Electricity: average volume-weighted price per type of contract for household customers with an annual consumption from 1,000 kWh to 2,500 kWh (band II; Eurostat: DB) as at 1 April 2021 (ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy procurement, supply and margin	10.76	8.84	9.07
Net network charge	8.42	8.31	8.58
Meter operation charge	0.65	0.62	0.54
Concession fee	1.67	1.63	1.67
EEG surcharge	6.50	6.50	6.50
KWKG surcharge	0.25	0.25	0.25
Section 19 StromNEV surcharge	0.43	0.43	0.43
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore grid surcharge	0.40	0.40	0.40
Electricity tax	2.05	2.05	2.05
VAT	5.92	5.52	5.61
Total	**37.05**	**34.55**	**35.11**

Table 95: Average volume-weighted prices per type of contract for household customers in consumption band II as at 1 April 2021

Band III: Annual electricity consumption from 2,500 kWh to 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.

Electricity: average volume-weighted price per type of contract for household customers with an annual consumption from 2,500 kWh to 5,000 kWh (band lII; Eurostat: DC) as at 1 April 2021 (ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy procurement, supply and margin	9.81	8.12	8.40
Net network charge	6.83	6.99	7.51
Meter operation charge	0.36	0.35	0.33
Concession fee	1.77	1.69	1.60
EEG surcharge	6.50	6.50	6.50
KWKG surcharge	0.25	0.25	0.25
Section 19 StromNEV surcharge	0.43	0.43	0.43
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore grid surcharge	0.40	0.40	0.40
Electricity tax	2.05	2.05	2.05
VAT	5.40	5.09	5.22
Total	**33.80**	**31.89**	**32.70**

Table 96: Average volume-weighted prices per type of contract for household customers in consumption band III as at 1 April 2021

In previous years there has been a noticeable convergence of the prices of non-default with the default supplier and with suppliers other than the local default supplier. For the first time in ten years, the price across the different contract types for electricity supply with the default supplier outside of default supply is lower than the price for electricity supply with a supplier who is not the local default supplier.

A comparison of the three types of contract – default contract, non-default contract with the default supplier (usually after changing contract) and contract with a supplier other than local default 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 direct comparison is only possible to a limited extent. While the average consumption in 2020 for customers on default tariffs was around 1,984 kWh, the average for customers on non-default tariffs with the default supplier and customers who had switched from their default supplier was around 36% higher, at around 2,692 kWh.

Electricity: household customer prices for the different types of contract (volume-weighted average, band III, Eurostat: DC) as at 1 April
(ct/kWh)

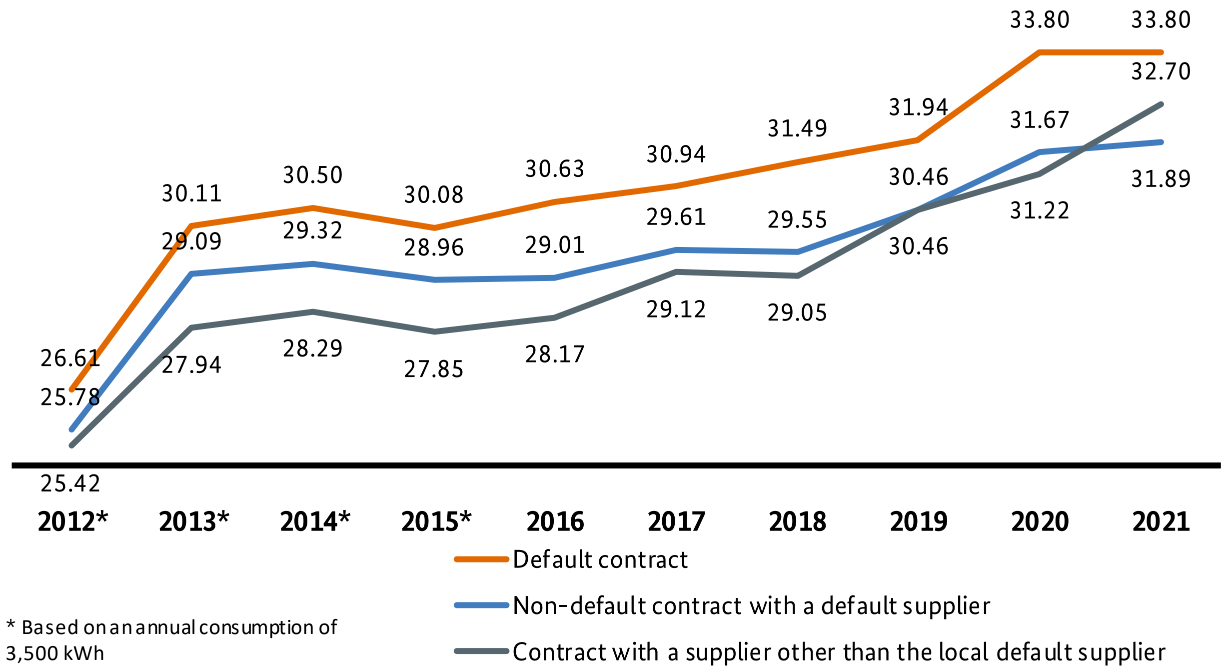


Figure 113: Household customer prices for the different types of contract (volume-weighted average, band III, Eurostat: DC)

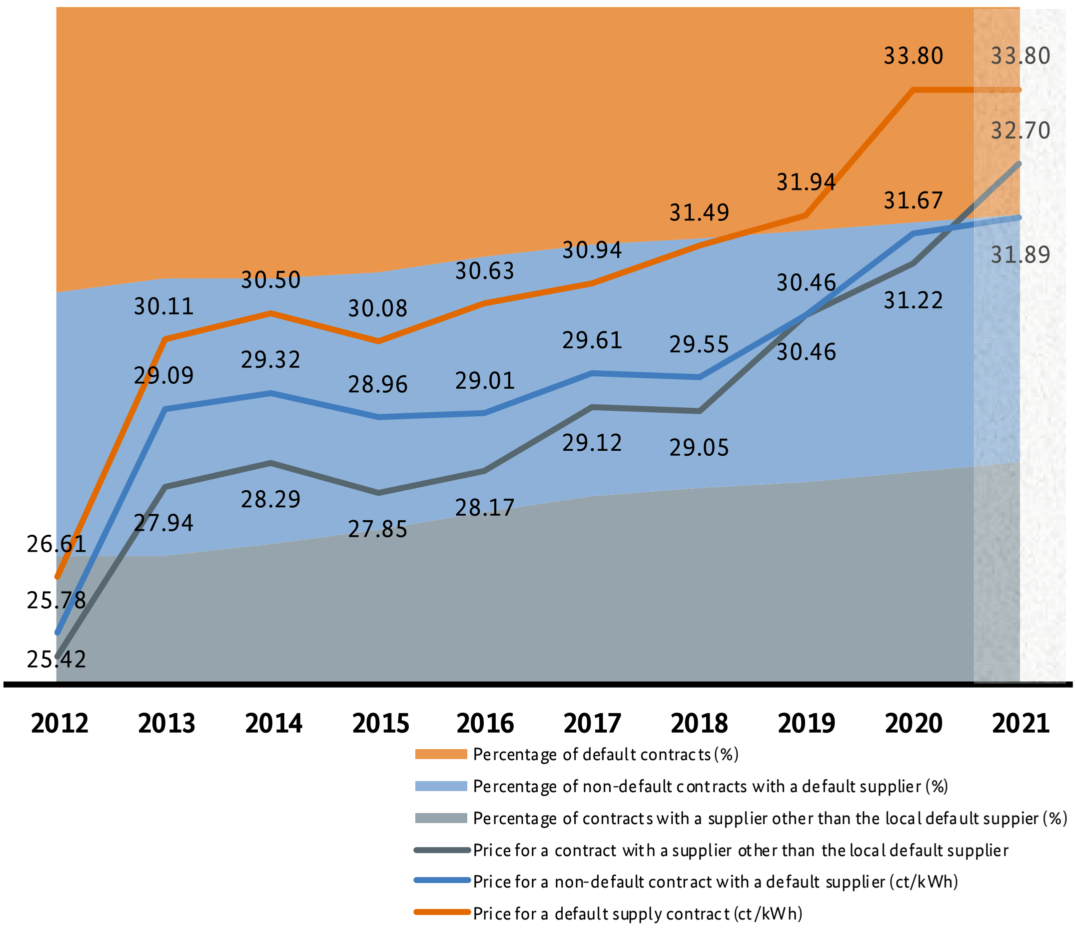
A comparison of the average prices for the three types of tariffs shows that throughout the period since 2008, default tariffs were the most expensive option for household customers. Prices for customers on non-default contracts with the default supplier were consistently cheaper over the same period than for those on default tariffs. Since 2013 the prices for non-default contracts with the default supplier and contracts with a supplier who is not the local default supplier have been converging more and more. In 2020 for the first time, the lowest average prices can be found in non-default contracts with the default supplier. This shows that default suppliers want to keep their regional customers and for this reason offer attractive prices.

Household customers can achieve additional savings compared to a default supply contract by changing contract with the default supplier (-1.89 ct/kWh) or by switching supplier (-1.10 ct/kWh).[132] For a household customer with an annual consumption of 3,500 kWh, this amounts to savings in energy costs of around €66 per year.

The following figure shows the changes in the electricity price against the background of the development trend in the three types of supply, that is, default contract, non-default contract with the default supplier and contract with a supplier other than the local default supplier.

[132] The cost savings apply to the consumption band between 2,500 kWh and 5,000 kWh/year.

Electricity: household customer prices (band III, Eurostat DC) as at 1 April in ct/kWh and percentage of household customers for the different types of contract



The percentages for the different types of contract for 2021 are not yet available and are shown here based on the trend from previous years.

Figure 114: Household customer prices for electricity and percentage for the different types of contract

At 9.81 ct/kWh, the price component that can be controlled by the supplier, including energy and supply costs, was nearly 17% higher for customers on default tariffs than for customers who had switched from their default supplier; the average price for the latter group was 8.40 ct/kWh. Customers on non-default contracts with their local default supplier paid an average of 8.12 ct/kWh (2020: 7.83 ct/kWh) for energy and supply costs and the margin, and thus around 17% less than customers on default tariffs. Any direct comparison of these figures must take into account further differences between the three customer groups other than their different consumption levels. For instance, default contracts have shorter notice periods and on average a higher risk of non-payment. These risk costs are also included in the price component that can be controlled by the supplier. The following figure provides a detailed overview of the trend.

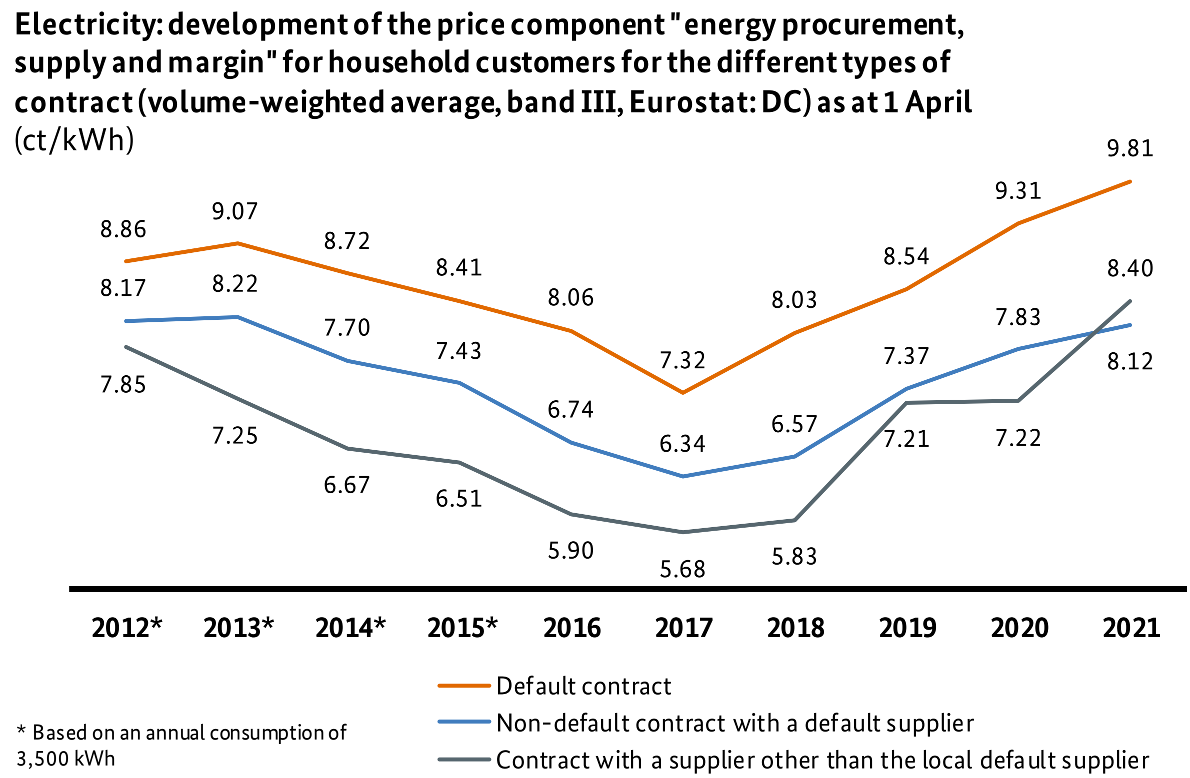


Figure 115: Development of the price component "energy and supply costs and margin" for household customers

The higher price of default supply is due to the differences in customer structure between default supply and other segments of the household customer market, which results in additional administrative costs for the supplier as well as a higher risk of non-payment.

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 (eg price stability) or to the supplier (eg pre-payment, minimum contract period), which is then compensated for between the parties elsewhere (overall price).

The suppliers were questioned specifically about such features. In 2020 a distinction was also made for the first time between different contract periods when looking at special bonuses and schemes offered by suppliers other than the default supplier. The results show that higher bonus payments and longer price stability can be achieved with a longer contract period and thus greater customer retention.

Electricity: special bonuses and schemes for household customers

	Non-default contract with a default supplier		Contract with supplier other than the default supplier					
			Contract period 1 month		Contract period 12 months		Contract period 24 months	
	No. of tariffs	Average scope	No. of tariffs	Average scope	No. of tariffs	Average scope	No. of tariffs	Average scope
Minimum contract period	298	11 months	208	8 months	360	11 months	238	17 months
Price stability	293	14 months	113	12 months	353	13 months	247	19 months
Advance payment	67	10 months	25	11 months	42	10 months	26	10 months
One-off bonus payment	115	€ 56	56	€ 63	157	€ 69	99	€ 77
Free kilowatt hours	6	192 kWh	2	300 kWh	6	217 kWh	3	100 kWh
Deposit	4	-	0	-	2	-	2	-
Other bonuses and special arrangements	97	-	76	-	101	-	70	-

Table 97: Special bonuses and schemes for household customers

Band IV: Annual electricity consumption from 5,000 kWh to 10.000 kWh

Band IV as used in the monitoring survey represents household customers with an above-average annual consumption from 5,000 kWh to 10,000 kWh per year. The following table shows the results of the survey.

Electricity: average volume-weighted price per type of contract for household customers with an annual consumption from 5,000 kWh to 10,000 kWh (band lV) as at 1 April 2021
(ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy procurement, supply and margin	9.28	7.77	7.75
Net network charge	6.26	6.40	6.63
Meter operation charge	0.21	0.20	0.17
Concession fee	1.67	1.57	1.60
EEG surcharge	6.50	6.50	6.50
KWKG surcharge	0.25	0.25	0.25
Section 19 StromNEV surcharge	0.43	0.43	0.43
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore grid surcharge	0.40	0.40	0.40
Electricity tax	2.05	2.05	2.05
VAT	5.14	4.86	4.90
Total	**32.20**	**30.44**	**30.68**

Table 98: Average volume-weighted prices per type of contract for household customers in consumption band IV as at 1 April 2021

Band V and band VI: Annual electricity consumption from 10,000 kWh to 15,000 kWh and annual electricity consumption above 15,000 kWh

Data provided by suppliers on bands V and VI was included for the first time in the 2018 monitoring report. Bands V and VI consist of household customers with a very high annual consumption from 10,000 kWh to 15,000 kWh and from15,000 kWh upwards, respectively.

Electricity: average volume-weighted price per type of contract for household customers with an annual consumption from 10,000 kWh to 15,000 kWh (band V) as at 1 April 2021
(ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy procurement, supply and margin	9.02	7.25	7.32
Net network charge	5.70	5.92	6.18
Meter operation charge	0.16	0.11	0.11
Concession fee	1.70	1.56	1.56
EEG surcharge	6.50	6.50	6.50
KWKG surcharge	0.25	0.25	0.25
Section 19 StromNEV surcharge	0.43	0.43	0.43
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore grid surcharge	0.40	0.40	0.40
Electricity tax	2.05	2.05	2.05
VAT	4.98	4.65	4.71
Total	**31.20**	**29.14**	**29.52**

Table 99: Average volume-weighted prices per type of contract for household customers in consumption band V as at 1 April 2021

Electricity: average volume-weighted price per type of contract for household customers with an annual consumption above 15,000 kWh (band VI) as at 1 April 2021 (ct/kWh)

Price component	Default contract	Non-default contract with a default supplier	Contract with a supplier other than the local default supplier
Energy procurement, supply and margin	9.05	6.97	7.03
Net network charge	5.58	5.76	5.93
Meter operation charge	0.09	0.08	0.11
Concession fee	1.71	1.56	1.55
EEG surcharge	6.50	6.50	6.50
KWKG surcharge	0.25	0.25	0.25
Section 19 StromNEV surcharge	0.43	0.43	0.43
Section 18 AbLaV surcharge	0.01	0.01	0.01
Offshore grid surcharge	0.40	0.40	0.40
Electricity tax	2.05	2.05	2.05
VAT	4.95	4.56	4.61
Total	**31.03**	**28.56**	**28.87**

Table 100: Average volume-weighted prices per type of contract for household customers in consumption band VI as at 1 April 2021

4.3 Surcharges

In the electricity sector, surcharges still account for a significant share of the electricity price.

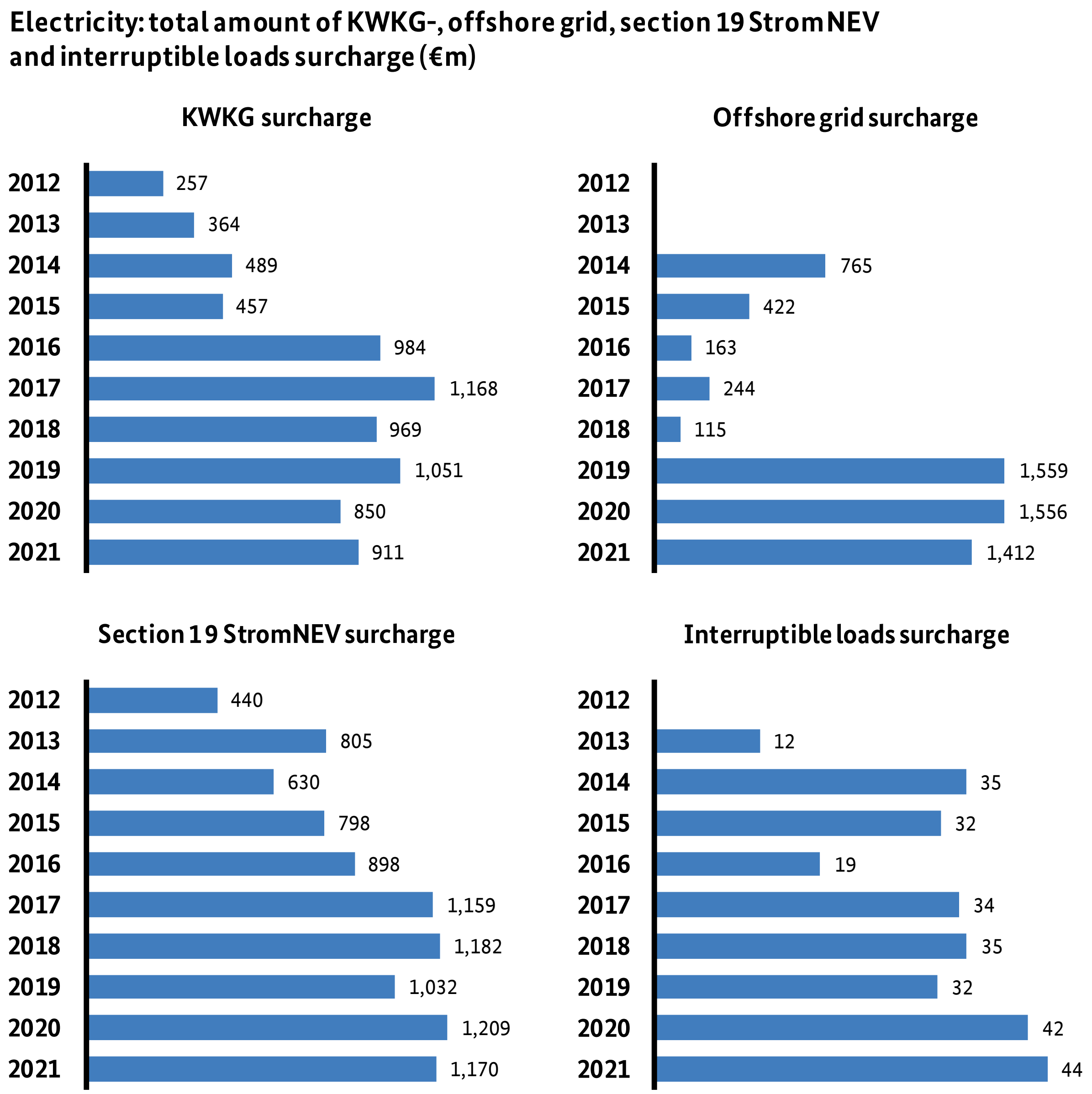


Figure 116: Total amount of KWKG, offshore grid, section 19 StromNEV and interruptible loads surcharges

EEG surcharge

Under section 60(1) EEG, transmission system operators are entitled and obliged to demand from electricity suppliers that supply of electricity to final consumers the costs for the necessary expenses following deduction of revenue attained, proportionate to the electricity supplied and in accordance with 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) and also 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.

In 2021 a federal grant totalling nearly 10.8bn euros is to be introduced to cap the renewable energy surcharge.

KWKG surcharge

Under sections 26a and 26b of the Combined Heat and Power Act (KWKG), the 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, as well as of heating and cooling networks and storage systems.

The KWKG surcharge is determined and announced by 25 October of each year for the following calendar year by the TSOs.

Offshore network surcharge

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. In addition, as of 2019, the offshore grid surcharge also includes the costs of installing and operating the offshore transmission links.

The offshore grid surcharge is determined and announced by 15 October of each year for the following calendar year by the transmission system operators. The surcharge is calculated based on a forecast of the expected recoverable costs for the subsequent year, taking into account any possible actual deviations from the forecasts for the previous years.

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 revenues lost as a result of individual network charges. TSOs must balance these payments as well as their own lost revenue among themselves.

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.

Interruptible loads surcharge

Each year the German TSOs calculate the interruptible loads surcharge based on section 18 of the Interruptible Loads Ordinance (AbLaV). For 2016, final consumers were not subject to this charge as the amendment of the AbLaV Ordinance had not yet been completed 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 TSOs.

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 (DSOs).

In 2020 the market structure significantly changed. Due to obligations imposed by the European Commission in the M.8870 E.ON/innogy proceeding, all heating electricity customers of what was previously E.ON Heizstrom Nord and E.ON Heizstrom Süd GmbH were transferred to Lichtblick GmbH. This transaction became effective on 1 August 2020 which is why it must be reflected in this year's data.

Overall heating electricity consumption decreased compared to the previous year. According to the volumes reported by around 1,000 heating electricity suppliers, about 11.2 TWh of heating electricity was supplied to customers at just under 1.79 million meter points. This corresponds to an average supply of just under 6,256 kWh per meter point. The previous year's figure was just under 6,336 kWh per meter point, with a total volume of 13.47 TWh supplied to 2.12 million meter points.

According to the data provided by the suppliers, just under 8.0 TWh was supplied for night storage heating at 1.23 million night storage meter points, resulting in an average of about 6,500 KWh per meter point in 2020. The volume of electricity supplied to the approximately 559,486 meter points for heat pumps amounted to just over 3.19 TWh, or an average of about 5,518 kWh/year. Night storage heating accounts for the largest share of consumption (around 71.5% in terms of volume and 68.8% in terms of meter points). The share of heat pumps compared to night storage heating has constantly increased over the years. In 2020 the share of heat pumps accounted for as much as 31.2% of meter points and 28.5% in terms of volume. In the previous year it accounted for 24.1% of meter points and 22.6% in terms of volume. 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 on the one hand and heat pumps on the other and therefore estimated the breakdown or entered the total in only one of the two categories.

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 839 DSOs, a total of 12.53 TWh of heating electricity was supplied to just under 2.09 million meter points (night storage heating and heat pumps) in 2020. 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 the electricity, which excludes company affiliations. In contrast to the electricity 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.[133]

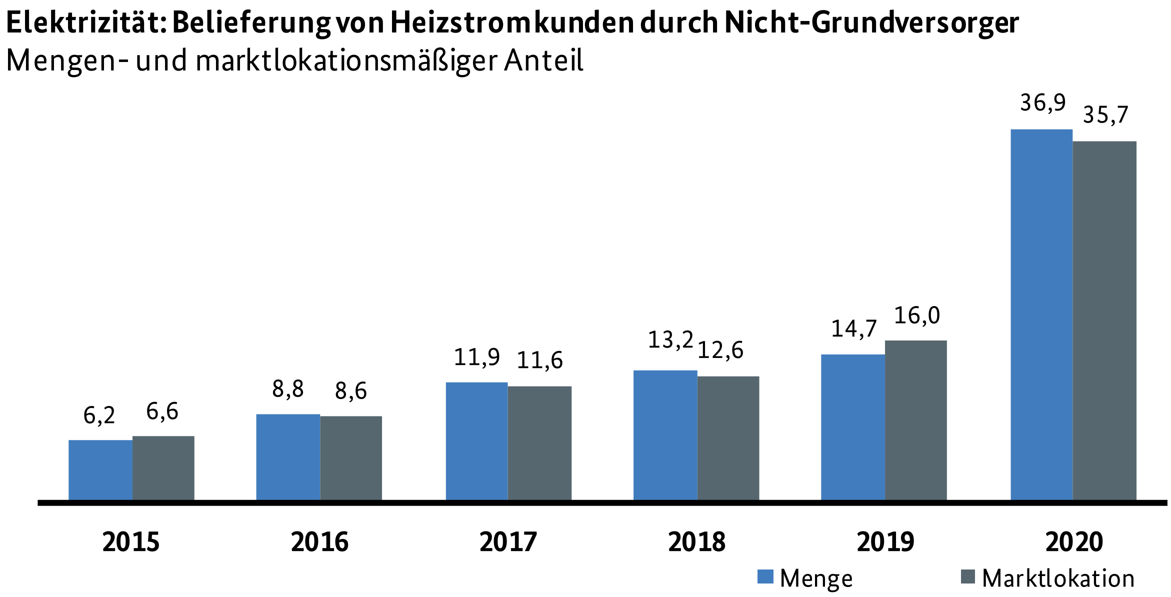


Figure 117: Percentage of heating electricity volume and meter points supplied by a supplier other than the regional default supplier

The share of heating electricity supplied in 2020 by a legal entity other than the regional default supplier rose from 2.15 TWh in the previous year to 4.29 TWh. Around 37.7% of the total heating electricity volume came from suppliers other than the default supplier (2019: 16%). The number of heating electricity meter points not served by the default supplier also increased from 14.7% to 39.4%. The increased switching rate must be assessed in the context of the transfer of the meter points and heating electricity volume from E.ON Heizstrom to Lichtblick GmbH as this automatically caused a change of supplier in a market where E.ON Heizstrom was a major player.

The decisive factor in this increase is the fact that the number of heat pumps not supplied by the regional default supplier rose from around 98,567 meter points in 2019 to 193,594 meter points in 2020. A total of 34.6% (2019: 19.2%) of all the heat pump meter points as well as 33.7% of the total number of heat pumps supplied (2019: 20.9%) were served by a legal entity other than the default supplier.

According to the data provided by the DSOs, there was an increase in supplier switching rates based on the number of meter points supplied in the heating electricity sector compared to the previous year. The data shows that there was a change of supplier at about 310,526 heating electricity meter points. These meter points accounted for about 1,502 GWh of heating electricity in 2020. This represents a switching rate of 12% in terms of volume and 14.8% in terms of meter points.

133 Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren (Electric Heating - overview and proceedings), September 2010, pp. 9 – 10.

In the previous year, there was a change of supplier at just under 142,064 meter points, accounting for a volume of around 967 GWh. This corresponds to a switching rate of 7.2% in terms of consumption volume and of 6.9% in terms of meter points. The trend over several years shows that switching rates for heating electricity have continuously risen.

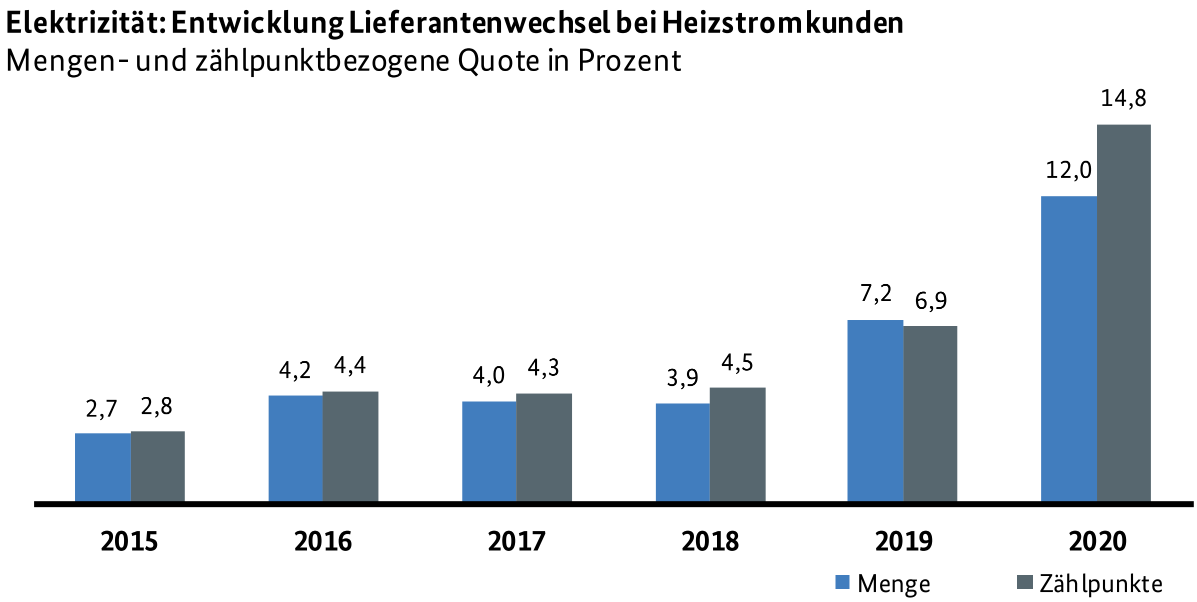


Figure 118: Supplier switching rate for heating electricity customers

570 of the 798 DSOs that provided data on heating electricity volumes also reported figures on supplier switching. These 570 DSOs represent around 98% of the heating electricity volume and meter points of all 798 DSOs that provided data on heating electricity. This means that the survey was able to cover a large share of the market and only a few, mainly small DSOs could not report figures on supplier switching.[134] 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 1.2% and 17.7%.

The percentage of heating electricity and meter points supplied by a legal entity other than the regional default supplier is, however, 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 expanded over the last two years. Consumers are now able to find local suppliers more easily, e.g. through online portals, consumer magazines or information from consumer advice centres.

5.2 Price level

Price data was collected on night storage tariffs and heat pump tariffs as at 1 April 2021. Suppliers were asked to base their figures on a consumption of 7,500 kWh/year. The following analysis is based on the price data for

[134]Several DSOs also pointed out that they had no data, or only individual data, in the heating electricity sector for analysis. The reasons why around 242 suppliers provided no data were insufficient evaluation possibilities or limited resources for survey purposes.

night storage heating provided by 866 suppliers (2019: 883 suppliers) and the price data for heat pumps provided by 901 suppliers (2019: 846 suppliers).

According to the data provided by the suppliers, the arithmetic mean of the total gross price for night storage heating was 23.39 ct/kWh (including VAT) on 1 April 2021, which is above the previous year's level of 23.14 ct/kWh. The arithmetic mean of the total gross price for heat pump electricity was 23.80 ct/kWh, which was also up on the previous year's level of 23.58 ct/kWh.

Elektrizität: Preisniveau am 1. April 2021 Nachtspeicherheizung mit 7.500 kWh/Jahr

	Streuung zwischen 10 und 90 Prozent der Lieferanten in ct/kWh	**Mittelwert** (arithmetischer) in ct/kWh	**Anteil am Gesamtpreis**
Nicht vom Lieferanten beeinflussbare Preisbestandteile			
Nettonetzentgelt	1,52 - 4,43	2,95	13%
Messstellenbetrieb	0,12 - 0,47	0,32	1%
Konzessionsabgabe	0,11 - 0,97	0,40	2%
EEG-Umlage		6,50	28%
weitere Umlagen[1]		1,09	5%
Stromsteuer		2,05	9%
Umsatzsteuer	3,31 - 4,27	3,74	16%
vom Lieferanten beeinflussbarer Preisbestandteil (Restbetrag)	4,36 - 8,61	6,35	27%
Gesamtpreis (inkl. Umsatzsteuer)	**20,71 - 26,76**	**23,39**	**100%**

[1] KWKG (0,254 ct/kWh), § 19 Abs. 2 StromNEV (0,432 ct/kWh), Umlage nach §18 AbLaV (0,009 ct/kWh), Offshore-Netzumlage (0,395 ct/kWh)

Table 101: Price level on 1 April 2021 for night storage heating with a consumption of 7,500 kWh/year

The remaining balance that can be controlled by the supplier, which includes energy and supply costs and the margin, was 6.35 ct/kWh for night storage heating and thus rose again by around 5% above the 2020 level of 6.04 ct/kWh. The trend over the last two years shows that the price component that can be controlled by the supplier has risen steadily in the heating electricity sector.

The remaining balance that can be controlled by the supplier also increased in the heat pump sector to 6.58 ct/kWh as at 1 April 2021, compared to 6.28 ct/kWh in the previous year, i.e. by around 5%. The price component which can be controlled by the supplier makes up about 27% of the total price for night storage heating and about 28% of the total price for heat pumps. About 73% of the price for night storage heating and 72% of the price for heat pumps consists of taxes, surcharges and concession fees. Compared to the previous year, the total of all fixed surcharges rose slightly from 1.01 ct/kWh to 1.09 ct/kWh. The Bundeskartellamt has set the concession fee at 0.11 ct/kWh because heating electricity is supplied under special contracts.[135] Nevertheless, some suppliers again 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.

[135] Cf. Bundeskartellamt, Heizstrom – Überblick und Verfahren (Electric Heating - overview and proceedings), September 2010, pp. 9 – 10.

Elektrizität: Preisniveau am 1. April 2021 Wärmepumpe mit 7.500 kWh/Jahr

	Streuung zwischen 10 und 90 Prozent der Lieferanten in ct/kWh	**Mittelwert** (arithmetischer) in ct/kWh	**Anteil am Gesamtpreis**
Nicht vom Lieferanten beeinflussbare Preisbestandteile			
Nettonetzentgelt	1,51 - 4,80	3,04	13%
Messstellenbetrieb	0,12 - 0,48	0,32	1%
Konzessionsabgabe	0,11 - 1,32	0,41	2%
EEG-Umlage		6,50	27%
weitere Umlagen[1]		1,09	5%
Stromsteuer		2,05	9%
Umsatzsteuer	3,36 - 4,27	3,79	16%
vom Lieferanten beeinflussbarer Preisbestandteil (Restbetrag)	4,58 - 8,77	6,58	28%
Gesamtpreis (inkl. Umsatzsteuer)	**21,10 - 26,77**	**23,80**	**100%**

[1] KWKG (0,254 ct/kWh), § 19 Abs. 2 StromNEV (0,432 ct/kWh), Umlage nach §18 AbLaV (0,009 ct/kWh), Offshore-Netzumlage (0,395 ct/kWh)

Table 102: Price level at 1 April 2021 for heat pumps with a consumption of 7,500 kWh/year

6. Green electricity segment

In the 2021 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 marketing, is shown to have been produced with a high share/high promotion of efficient or regenerative production technologies and that is offered/traded at a separate tariff. The amount of green electricity supplied to household customers and other final consumers in 2020 and the share of green electricity in the total amount of electricity supplied in 2020 are presented below.

Electricity: green electricity supplied to household customers and other final consumers in 2020

	Category	Total electricity supplied	Total green electricity supplied	Share of green electricity in total volume and market locations
Household customers	TWh	118.8	37.2	31.3%
	Market locations (thousand)	48,012	14,252	29.7%
Other final consumers	TWh	262.2	36.3	13.8%
	Market locations (thousand)	3,614	861	23.8%
Total	TWh	380.9	73.4	19.3%
	Market locations (thousand)	51,626	15,112	29.3%

Table 103: Green electricity supplied to household customers and other final consumers in 2020

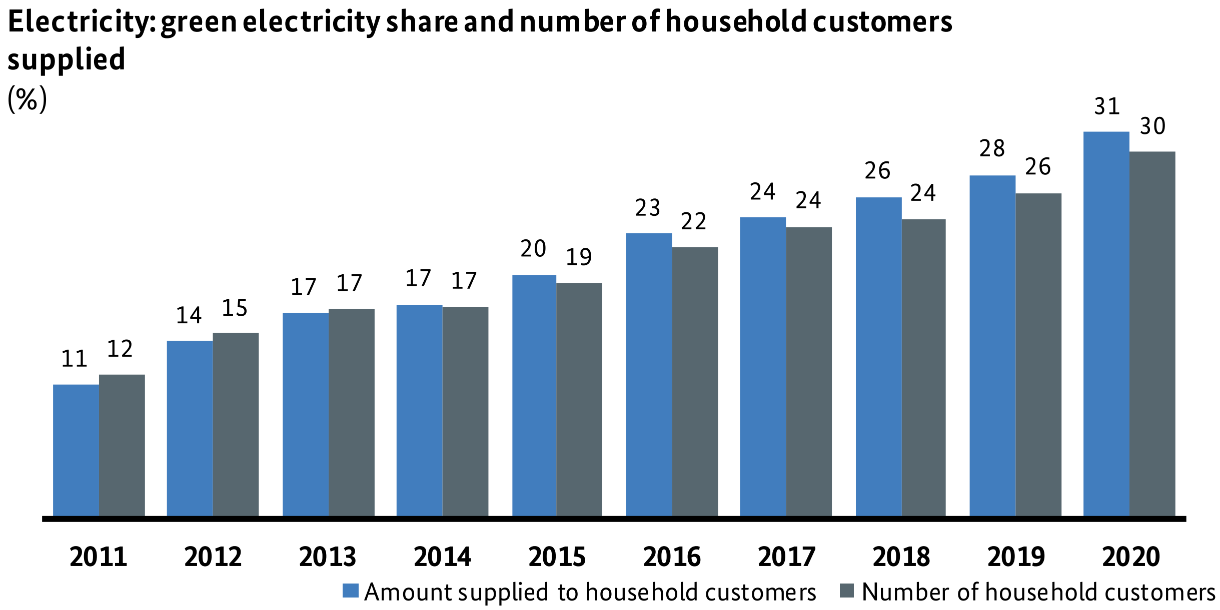


Figure 119: Green electricity share and number of household customers supplied

There was a further increase in the share of green electricity supplied to household customers in 2020. The number of household customers supplied with green electricity increased by a total of more than 1.6m market locations. The share of green electricity in total consumption rose by 3.4%. The number of household customers supplied with green electricity is now at around 14.6m market locations.

The following table shows the average volume-weighted prices and the individual price components for green electricity supplied to household customers, as well as the change in these prices relative to 1 April 2020. The price for green electricity is 32.54 ct/kWh as at 1 April 2021 (2020: 31.66 ct/kWh) and has thus increased by nearly 3%.

Electricity: change in the volume-weighted price for green electricity supplied to household customers with an annual consumption between 2,500 kWh and 5,000 kWh from 1 April 2020 to 1 April 2021 (band III; Eurostat: DC)

Price component	Volume-weighted average across all types of contract (ct/kWh)	Change in level of price component	
		in ct/kWh	%
Energy procurement, supply and margin	8.31	0.72	8.7
Net network charge	7.28	0.10	1.4
Meter operation charge	0.49	0.07	13.9
Concession fee	1.64	0.03	1.7
EEG surcharge	6.50	-0.26	-3.9
KWKG surcharge	0.25	0.03	11.0
Section 19 StromNEV surcharge	0.43	0.07	17.1
Section 18 AbLaV surcharge	0.01	0.00	22.2
Offshore grid surcharge	0.40	-0.02	-5.3
Electricity tax	2.05	0.00	0.0
VAT	5.20	0.14	2.7
Total	**32.54**	**0.89**	**2.7**

Table 104: Average volume-weighted prices and change relative to 1 April 2020 for green electricity supplied to household customers in consumption band III as at 1 April 2021

The following diagram shows the percentage distribution of the individual price components for green electricity:

Electricity: breakdown of retail price for household customers with an annual consumption from 2,500 kWh to 5,000 kWh (DC) for green electricity, as at 1 April 2021 (%)

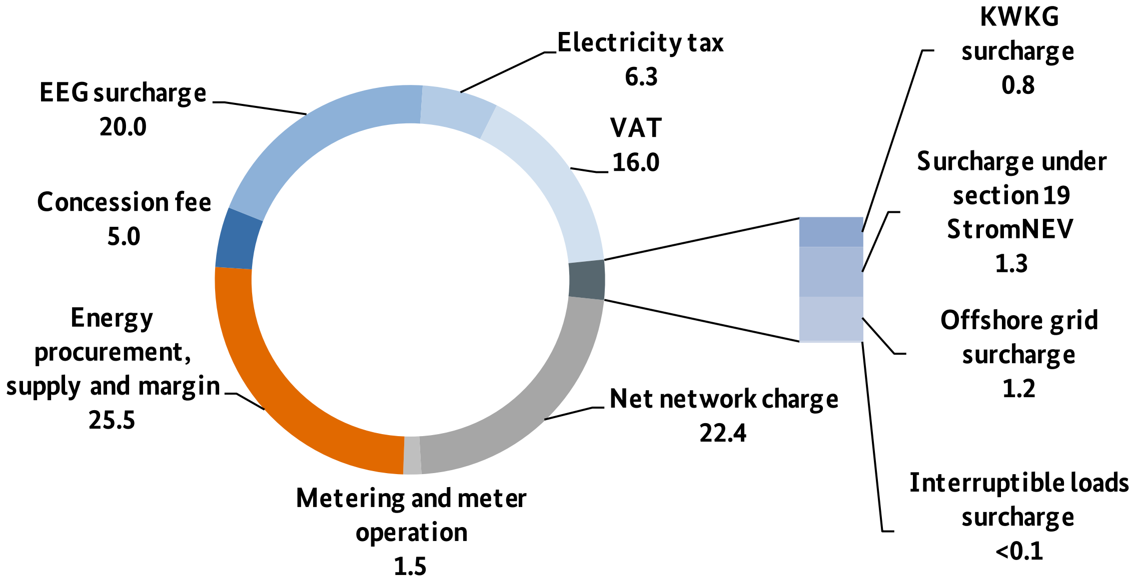


Figure 120: Breakdown of the retail price level for green electricity for household customers in consumption band III as at 1 April 2021[136]

As is the case 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 of price components (and various possible combinations of elements) makes it difficult to compare the wide range of competitive tariffs. 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.

[136] 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.

Electricity: special bonuses and schemes for household customers (green electricity)

As at 1 April 2021	Household customers (green electricity)	
	Number of tariffs	Average scope
Minimum contract period	381	11 months
Price stability	374	14 months
Prepayment	53	10 months
One-off bonus payment	173	€ 63
Free kilowatt hours	7	143 kWh
Deposit	6	-
Other bonuses and special arrangements	139	-

Table 105: 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 for the second six-month period 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, for Germany on data provided by the Federal Statistical Office.[137] However, the prices determined during monitoring cannot be directly compared with the data provided by Eurostat because of the different survey method used by the Federal Statistical Office. Rules on the classification, analysis and presentation of the price data aim to ensure European-wide comparability.[138] However, the relevant Regulation (EU) No 2016/1952, Article 3, allows the individual Member States a certain degree of freedom in the choice of survey method, which can lead to national differences.

[137] The average prices for electricity and natural gas in Germany for the second six-month period of 2019 were determined by the Federal Statistical Office. Before this the price data were collected by the German Association of Energy and Water Industries on behalf of the Federal Ministry for Economic Affairs and Energy. This change naturally also brought about changes in the survey methods, e.g. size and composition of the sample or the fact that administrative and tax data can now be used to determine the amount of tax, levies and surcharges actually paid.

[138] For further detail see: https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2008:298:0009:0019:EN:PDF (retrieved on19 June 2020).

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 during monitoring, falls into this consumption band.

The customer group with an annual consumption of 20 to 70 GWh consists of mainly industrial customers. These customers can usually deduct national VAT. For this reason, 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 – can also be 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 4.1 in "Price level").

According to the Eurostat data, there are significant differences in the price of electricity for industrial customers across Europe. Cyprus has the highest net price at 12.81 ct/kWh, while Luxembourg has the lowest, at 4.83 ct/kWh. The EU average is 8.89 ct/kWh. 2.52 ct/kWh of this average consists of non-recoverable taxes, levies and surcharges and 6.25 ct/kWh is made up of network charges and the remaining balance controlled by the supplier ("energy and supply"). At 5.66 ct/kWh, the adjusted net price in Germany is below the European average of 6.25 ct/kWh. The German net price is comprised of 2.44 ct/kWh network charges and 3.22 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 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.[139] 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 6.69 ct/kWh and therefore more than twice as much as the European average of 2.52 ct/kWh. The resulting net price for Germany is 12.71 ct/kWh, which is higher than the European average of 8.89 ct/kWh.

[139] 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 19 June 2020).

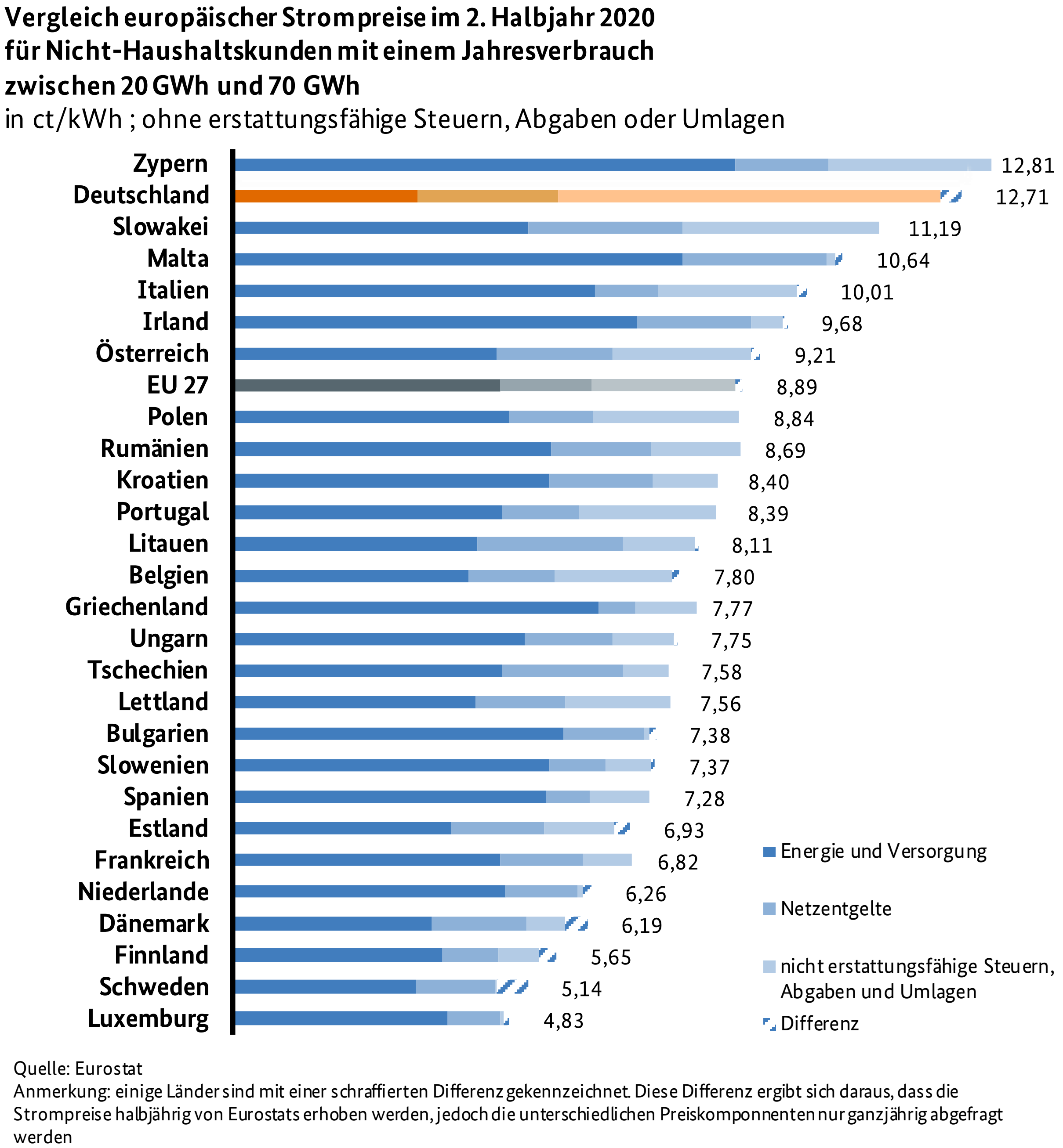


Figure 121: Comparison of European electricity prices in the second half of 2020 for non-household customers with an annual consumption between 20 GWh and 70 GWh

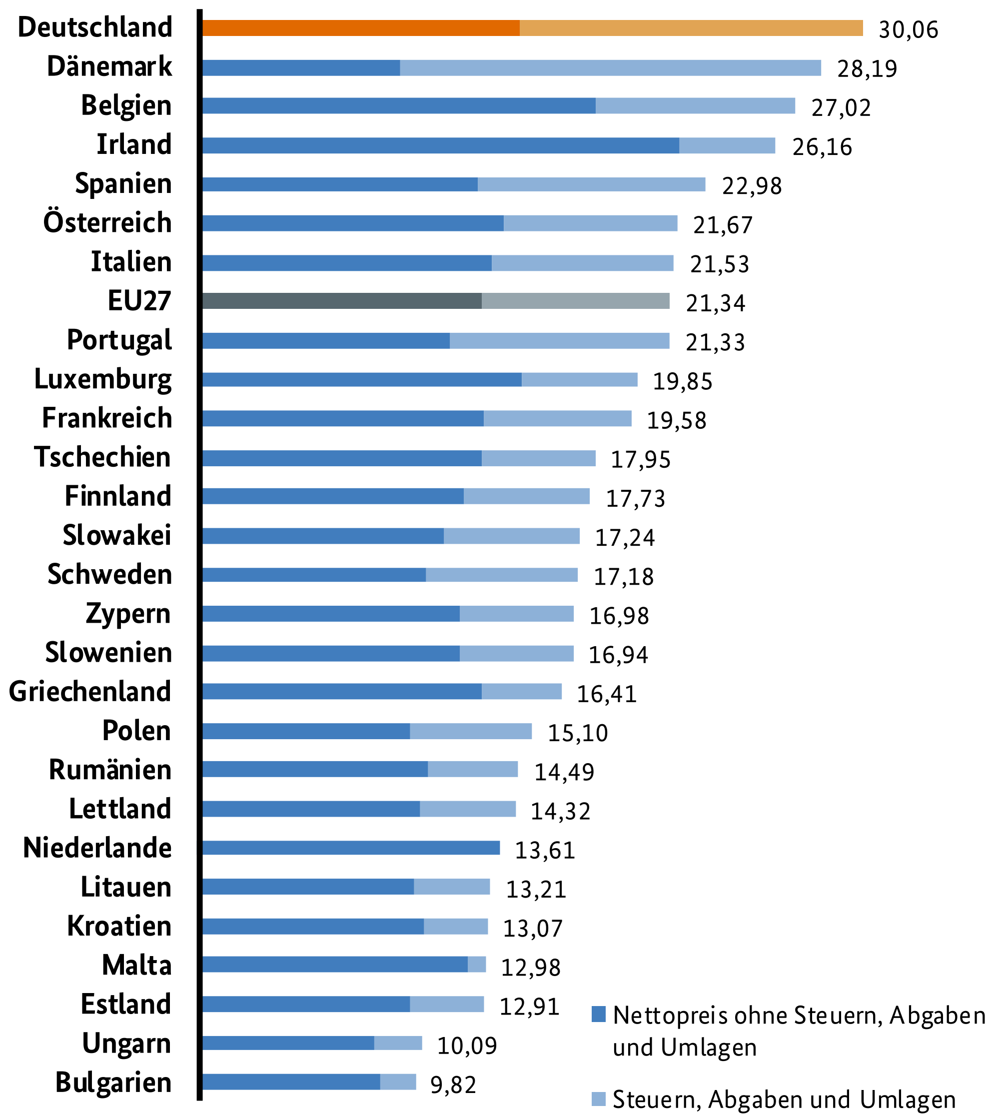
7.2 Household customers

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 medium category, with an annual consumption between 2,500 kWh and 5,000 kWh. The following shows an EU comparison of the medium consumption band. Household customers 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 customers vary greatly in Europe. Based on the calculation method used by the Federal Statistical Office, Germany has the highest price among the now 27 EU Member States, at 30.06 ct/kWh. Prices in Germany are about 41% higher than the EU average of 21.34 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, 8.52 ct/kWh on average consist of surcharges, taxes and levies, whereas in Germany these components account for more than 80% as much, at 15.55 ct/kWh. By contrast, at 14.51 ct/kWh, the net price adjusted for all taxes, surcharges and levies in Germany is on an equal par with the EU average of 12.82 ct/kWh.

Vergleich europäischer Strompreise im 2. Halbjahr 2020 für Haushaltskunden mit einem Jahresverbrauch zwischen 2.500 kWh und 5.000 kWh
in ct/kWh ; inkl. Umsatzsteuer



Quelle: Eurostat

Figure 122: Comparison of European electricity prices in the second half of 2020 for household customers with an annual consumption between 2,500 kWh and 5,000 kWh.

H Metering

1. Digitisation of metering

The Energy Transition Digitisation Act and the Metering Act (MsbG) contained therein made the rollout of modern metering equipment and smart metering systems legally mandatory in Germany. The implementation of the rollout and the legal deadlines concomitant with it are dependent on many different factors. One important factor in the implementation is the technical availability of modern metering equipment and smart metering systems.

The first modern metering systems have been available on the market since the beginning of 2017 and have already been installed by the default meter operators.

The default meter operators were required to notify the Bundesnetzagentur by 30 June 2017 of their metering operations and thereby their intention to continue as default meter operators. These notifications also served to trigger a deadline set by the Metering Act: three years after the notification of responsibility for default metering operations, ie by 30 June 2020, the default meter operators had to have installed modern metering equipment in at least 10% of the meter locations that have to be fitted with them by law. If they have not fulfilled this requirement, they are required to initiate a process to transfer their default metering responsibility.

Installation of smart metering systems could theoretically have started when the first smart meter gateway was certified by the Federal Office for Information Security (BSI) on 12 December 2018. The second and third gateways were certified in October and December 2019 respectively. The BSI then published its formal market statement on 31 January 2020, determining that smart metering systems can be installed. On 24 February 2020 the BSI announced a general administrative order for immediate enforcement. For the default meter operators this marked the beginning of the mandatory rollout of smart metering systems.

By February 2020, an Aachen-based company and some default meter operators, mainly municipal utilities, had started legal action against the BSI's general administrative order determining the technical feasibility of the installation of smart metering systems. At the time of writing, these legal disputes are still ongoing. However, in an application for an interim injunction, the Higher Administrative Court (OVG) in Münster ruled in favour of the complainant. Adjustments have been made to the MsbG to remove the resulting legal uncertainties. The law introducing these amendments (Act transposing provisions of Union law and regulating pure hydrogen networks in energy industry law) was promulgated in the Federal Law Gazette I No 47 on 26 July 2021 and entered into force on 27 July 2021. A central amendment to the MsbG was carried out in section 19(6) MsbG, creating a provision protecting vested rights for smart metering systems that have already been installed and those still to be installed, with the objective of restoring legal certainty for the industry and the rollout of smart meters. This puts the legal basis in place for continuing the installation of smart metering systems.

A further important step towards creating greater legal certainty in the smart meter rollout was the setting up and consultation of the Gateway Standardisation committee, with the Federal Ministry for Economic Affairs and Energy (BMWi) subsequently agreeing to the expanded Technical Directive TR-03109-1 v1.1 of

23 September 2021. The technical directive focuses on the interoperability certification of smart meter gateways.

2. The network operator as the default meter operator and independent meter operators

There were 868 companies operating a total of 52,815,528 meters[140] who responded to the questions about electricity metering for the monitoring survey in 2020.

Meter operation is carried out mostly by the network operator as the default meter operator. The default meter operator may also outsource to another company, either in a transfer or an in-house process. Companies wishing to take over the default metering operations and not already approved 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.

The 812 meter operators for conventional meter operation and 788 meter operators for meter operation of modern metering equipment and smart metering systems had the following roles in 2020 (some of them were active in more than one market role):

Electricity: meter operator roles within the meaning of the Metering Act in 2020

	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	812	788
Network operator as non-default meter operator offering meter services on the market	26	26
Supplier acting as meter operator	56	53
Third-party, independent meter operator	50	29

Table 1061: Meter operator roles within the meaning of the Metering Act according to data provided by electricity meter operators

This overview shows that the network operator usually performs the role of meter operator and that only in a few cases does the supplier or independent meter operator take on this role. With only 26 companies (around

[140] The term "meter location" corresponds to the term "meter" within the meaning of section 2 para 11 of the Metering Act. A meter location is a location at which energy is measured and that has all the 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.

3% of all meter operators) as independent meter operators, the meter operation of modern metering equipment and smart metering systems is clearly dominated by the joint roles of network operator and meter operator.

A connection user can choose which company is to be responsible for the installation, operation, maintenance of metering equipment and systems, and metering under section 5 of the Metering Act. A competing third party can be responsible instead of the default meter operator. Independent operators take on the activity of metering operations in the DSOs' network areas, 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 48 networks, between 31 and 50 independent meter operators are active, but in 86 networks there is only a choice between the default meter operator and two to four others. The highest number is 154 independent meter operators in one network area.

The following graph shows the number of independent meter operators regardless of the size of the network.

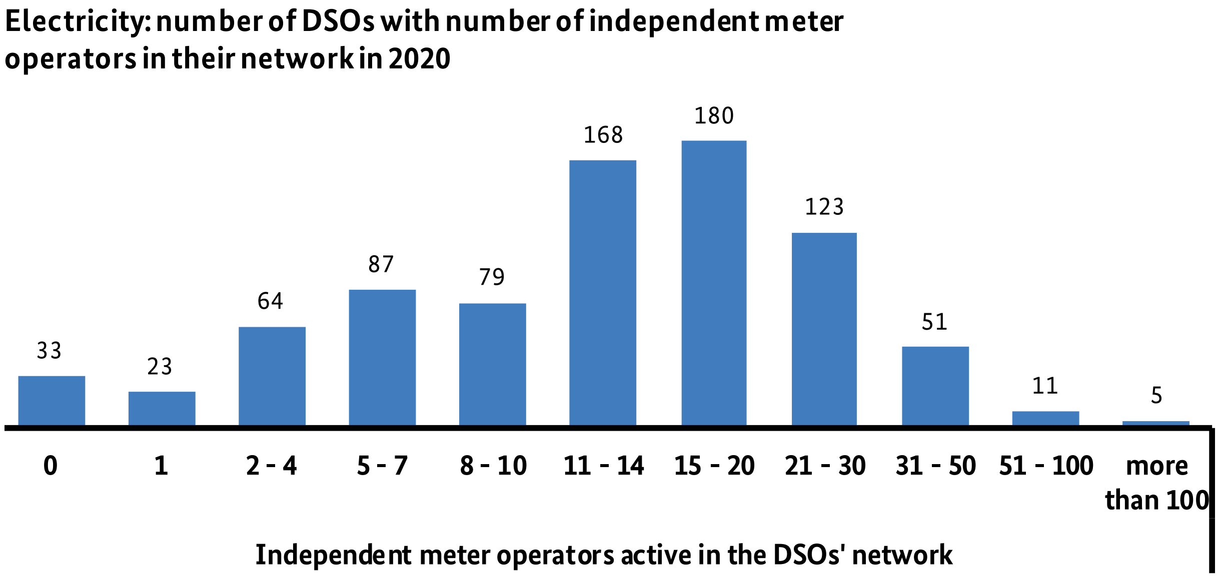


Figure 123: Number of DSOs with number of independent meter operators in their network (grouped)

Independent meter operators cover about 515,745 meter locations in the distribution networks, which equates to a share of around 1% of the total number of meter locations in these networks. This low proportion can be seen in Figure 124. The meter locations where independent meter operators are active are shown in proportion to the total meter locations of a network area. There are very few networks, only about 10% of all networks, where more than 1% of meter locations are covered by independent meter operators.

Electricity: number of meter locations per DSO operated in 2020 by independent meter operators

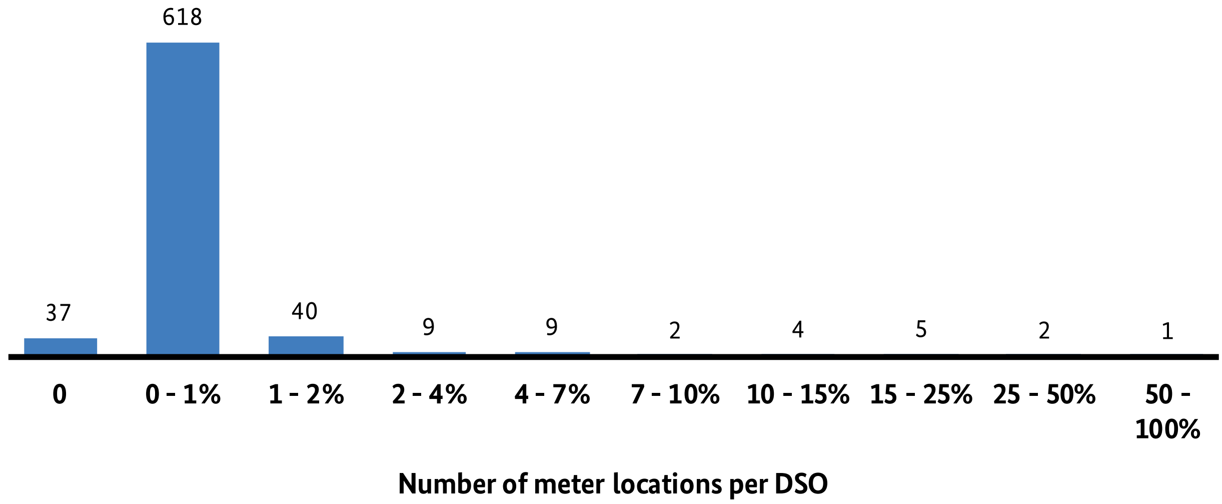


Figure 124: Number of meter locations per DSO operated by independent meter operators

Electricity: number of meter locations by federal state in 2020

	Meter locations - consumption	Meter locations - feed-in
Baden-Württemberg	6,540,408	300,510
Bavaria	7,758,283	689,472
Berlin	2,410,488	11,862
Brandenburg	1,699,488	63,209
Bremen	448,115	3,860
Hamburg	1,173,056	5,907
Hesse	3,818,241	140,549
Mecklenburg-Western Pomerania	1,129,663	30,270
Lower Saxony	4,555,922	199,907
North Rhine-Westphalia	11,121,373	247,420
Rhineland-Palatinate	2,522,747	85,483
Saarland	593,363	29,083
Saxony	2,837,918	61,568
Saxony-Anhalt	1,560,836	39,859
Schleswig-Holstein	1,547,145	60,308
Thuringia	1,362,032	38,134

Table 1072: Number of meter locations by federal state

The total number of meter locations is broken down by federal state as shown in Table 112. The table shows that the German state of North Rhine-Westphalia has the highest number of meter locations - more than 11m.

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. With nearly 2.1m meter locations, the majority of these are final consumers with an annual consumption of between 6,000 and 10,000 kWh. The following tables show the number of meter locations with mandatory installation of smart meters, broken down by the consumer groups used in the Metering Act. The grey columns in the tables refer to the future rollout of smart metering systems within the meaning of section 29 of the Metering Act.

Compared with last year there was a sharp increase of around 1,000 to the number of meter locations equipped with smart meters (around 25,500) in the >6,000 kWh and the >7 kW consumer groups.

As in previous years, there was also a sharp rise in installed modern metering equipment. Whereas there were only 5.8m meter locations with modern metering equipment in the 2019 reporting year, that figure had already reached 9.5m in the 2020 reporting year. Consequently, the number of installed Ferraris meters is falling as they are being replaced by modern metering equipment.

Electricity: meter locations requiring smart meters under section 29 in conjunction with secti

Information as at 31 December 2020	Number of meter locations			
	Total	equipped with metering systems in acc. With section 19(5) MsbG	equipped with modern metering devices as defined in the MsbG	equipped with smart metering systems as defined in the MsbG
Final consumers with annual power consumption				
> 6,000 kWh & ≤ 10,000 kWh	2,013,259	153,032	336,215	3,897
> 10,000 kWh & ≤ 20,000 kWh	1,036,329	82,251	174,085	9,582
> 20,000 kWh & ≤ 50,000 kWh	560,993	60,156	82,503	9,728
> 50,000 kWh & ≤ 100,000 kWh	166,605	37,739	17,713	2,058
> 100,000 kWh	256,614	116,685	6,824	9
Consumer devices in accordance with section 14a EnWG	1,181,093	99,501	169,490	86
of which meter locations at charging stations for electric vehicles	9,021	984	3,510	0
Installed capacity at plant operators in accordance with section 2(1) of the Metering Act				
> 7 kW & ≤ 15 kW	745,262	78,979	169,565	116
> 15 kW & ≤ 30 kW	360,571	39,108	61,930	25
> 30 kW & ≤ 100 kW	192,450	33,515	22,585	8
> 100 kW	496,915	81,848	1,659	0

Table 1083: Mandatory installations within the meaning of section 29 in conjunction with sections 31 and 32 of the Metering Act.

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 choose whether to install smart metering systems voluntarily (referred to as an optional installation) or just to install modern metering equipment. Meter operators reported approximately 43.0m final consumers for a possible optional installation. Of these, final consumers with an annual electricity consumption of less than 2,000 kWh form the largest group.

Electricity: optional installation within the meaning of section 29 in conjunction with section

Information as at 31 December 2020	Number of meter locations			
	Total	equipped with metering systems in accordance with section 19(5) MsbG	equipped with modern metering devices as defined in the MsbG	equipped with smart metering systems as defined in the MsbG
Final consumers with annual power consumption of:				
≤ 2,000 kWh	23,145,099	1,573,112	4,649,033	1,169
> 2,000 kWh & ≤ 3,000 kWh	9,330,094	629,214	1,714,465	217
> 3,000 kWh & ≤ 4,000 kWh	5,853,103	376,703	1,095,861	168
> 4,000 kWh & ≤ 6,000 kWh	4,713,266	329,203	854,562	646
Installed capacity at plant operators in accordance with section 2 para 1 MsbG				
> 1 kW & ≤ 7 kW	656,094	63,773	143,913	65

Table 1094: Voluntary installation within the meaning of section 29 in conjunction with section 31 of the Metering Act.

In response to the question in the monitoring survey as to whether the default meter operator is planning to equip meter locations of final consumers whose annual consumption is below 6,000 kWh with a smart metering system, 76 companies responded with "Yes" and 371 responded with "No". 349 companies remain undecided.

4. Organisation of metering operations

In addition to the installation of metering equipment, metering operations include the operation, maintenance and billing of metering operations, as well as gateway administration. Companies are free to choose between performing these tasks 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 performing gateway administration must be certified by the BSI. As of 5 August 2021, the BSI had certified 42 companies as gateway administrators. The stringent security requirements make gateway administration a business sector 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 at least a certain number of meter locations under their responsibility.

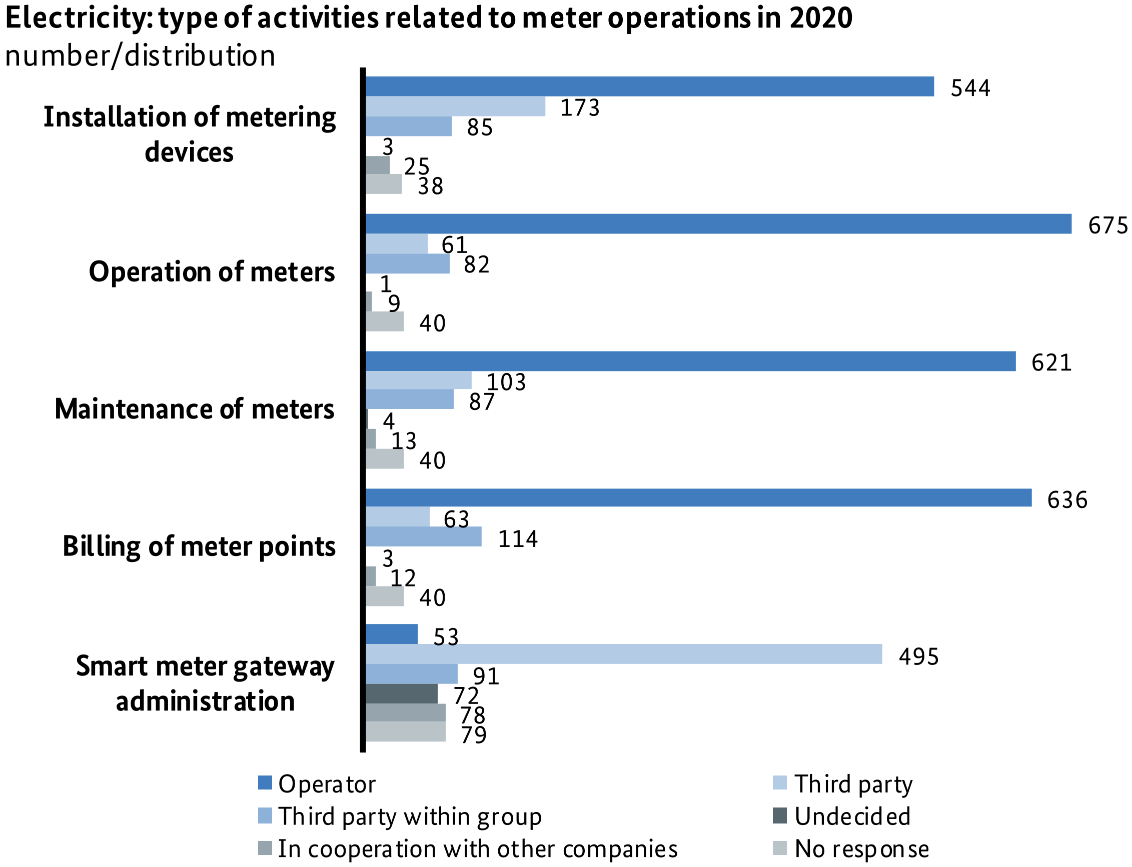


Figure 125: Performance of the activities related to metering operations

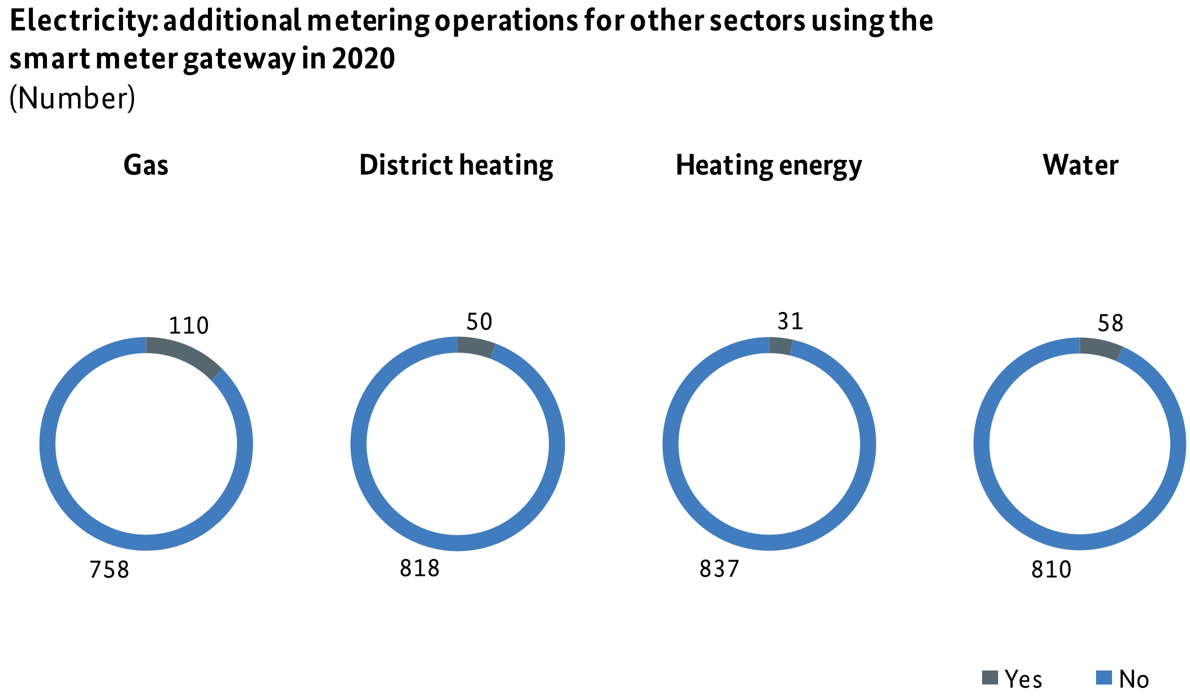


Figure 126: Additional metering operations for other sectors using the smart meter gateway

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.

So for sectors other than electricity - such as gas, heating and district heating, or water - most companies do not offer metering via the smart meter gateway. For the other sectors, the percentage of companies that provide additional metering operations is between 4% and 7% of the total number of the companies offering metering operations. Only for the gas sector is the number somewhat higher, with 110 providers (see Figure 126).

Both default meter operators and third party meter operators 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 also provide current and voltage transformers, up to now very few of them offer other services such as using smart metering systems for prepayment (see chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**), setting up or using smart metering systems for load control, or making smart meter gateways available and technically operating them for value-added services. At the same time, the number of meter operators that have not yet made a decision on additional services is high in all categories. This could be related to a lack of experience working with smart metering systems or possibly with lacking functionalities in the devices. Without the appropriate technology in place, many services cannot yet be offered. Figure 127 shows the evaluation of additional services.

Elektrizität: additional services for smart metering systems according to section 35(2) MsbG in 2020

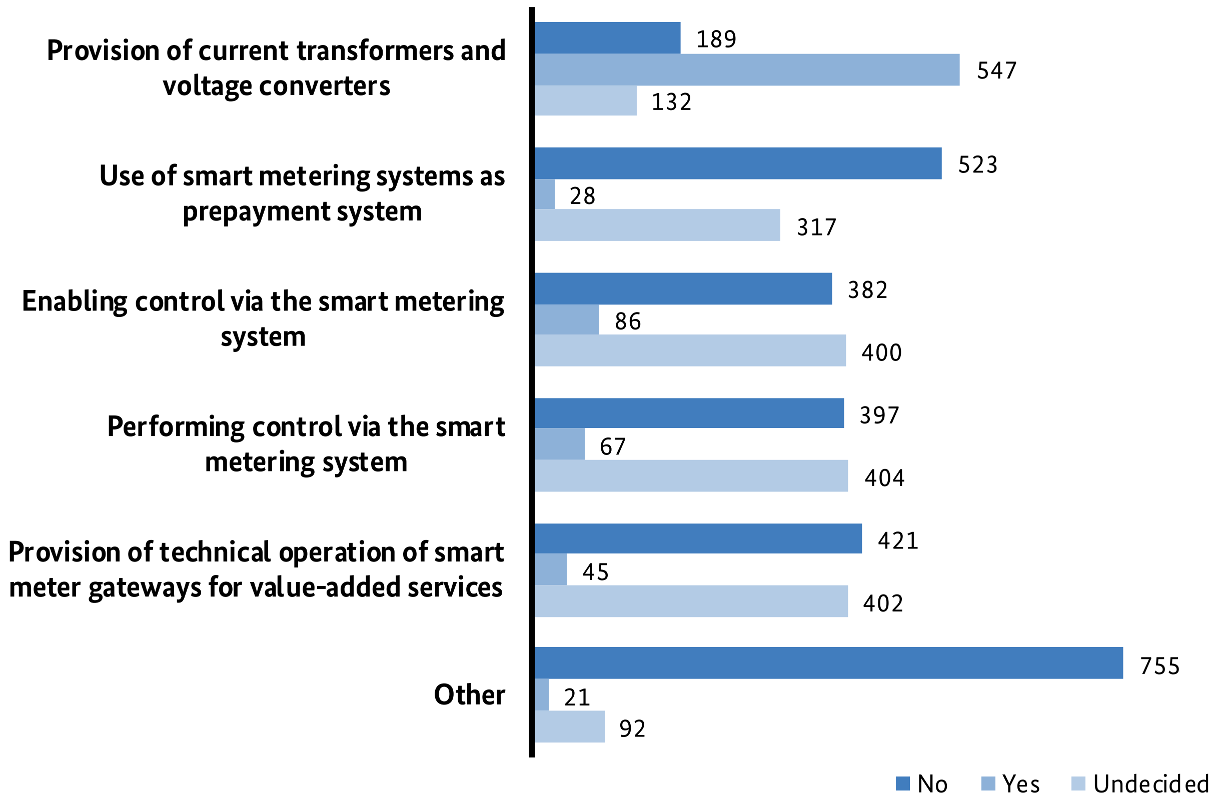


Figure 127: Additional services for smart metering systems

A large majority (81%) of meter operators do not sell products that combine electricity supply and meter operation (see Figure 128).

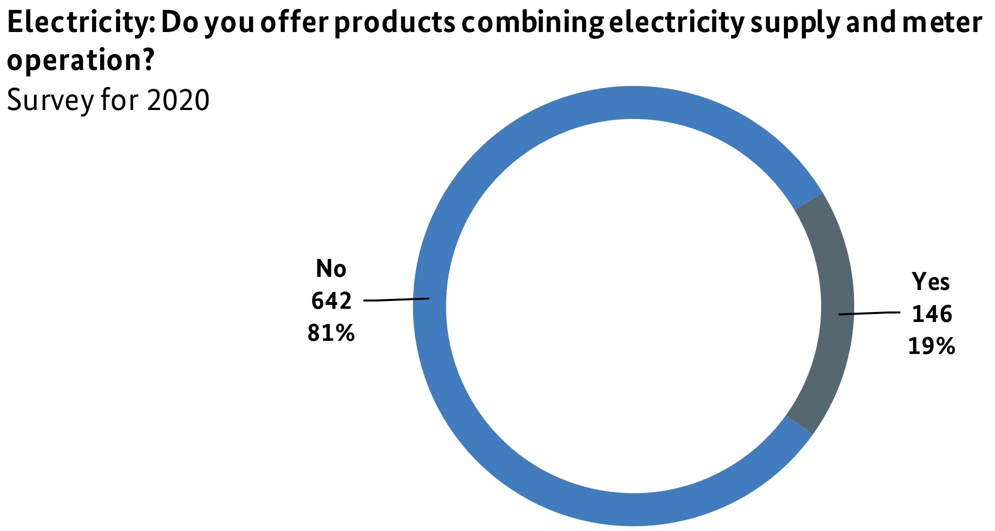


Figure 128: Combined products for electricity supply and meter operation

Although the billing of the connection user/owner for meter operation is no longer required to take place via the supplier, this is still often the case. Presumably suppliers and meter operators have made agreements to continue to bill meter operation jointly as part of the electricity bill. However, there has been a significant increase in mixed billing models where billing sometimes occurs separately and sometimes via the supplier. The number of companies that bill separately for meter operation services decreased slightly, from 70 meter operations in 2019 to 68 in 2020 (see graph below).

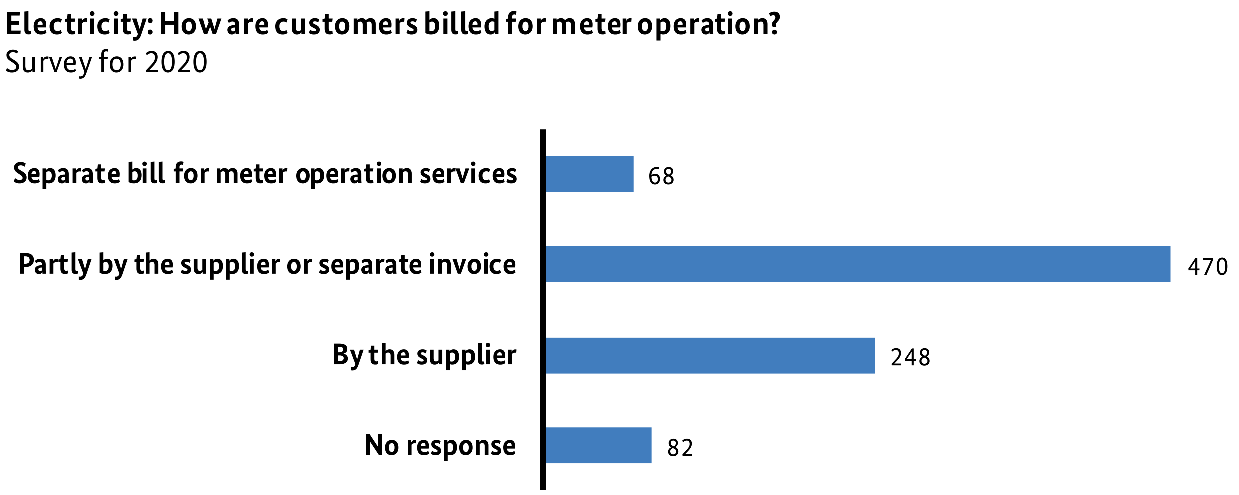


Figure 129: Billing the connection user/owner for meter operation

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:

Electricity: meter technology employed for standard load profile (SLP) customers

Requirement	Meter locations in 2019	Meter locations in 2020
Electromechanical metering systems (with current transformers and three-phrase meters based on the Ferraris principle)	36,696,299	33,709,940
of which are two-tariff and multiple-tariff meters (Ferraris principle)	2,219,431	2,045,361
Electronic meter device (basic meter not connected to a communication network) in accordance with section 2 para 15 MsbG	7,536,340	7,097,436
Modern measuring device (not connected to a communication network) in accordance with section 2 para 15 MsbG	6,115,873	9,637,122
Metering systems in accordance with section 2 para 13 MsbG that are not smart metering systems pursuant to section 2 para 7 MsbG (eg EDL40)	377,536	401,896
Smart metering systems in accordance with section 2 para 7 MsbG	968	27,599

Table 1105: Meter technology employed for standard load profile (SLP) customers

In 2020 there was again a move away from electromechanical meters for SLP customers, which also includes all household customers. The total number of electromechanical metering devices has dropped by about 3.0m meter locations. There has been another small drop in the use of two-tariff and multiple-tariff meters to just around 2.0m. The number of electronic meters has also declined over the previous year so that there are currently about 7.1m meter locations where these types of meters are used. These declines are due to the availability of modern metering equipment since the beginning of 2017 and the requirement under section 29(3) of the Metering Act to have modern metering equipment installed in at least 10% of meter locations by 30 June 2020. There was therefore again a sharp increase in 2020 in the number of modern metering devices that comply with section 2 para 15 of the Metering Act and are not connected to a communications network. Modern metering equipment is now in use at about 9.5m meter locations, which means that overall around 18% of meter locations required under the Metering Act to have modern metering equipment installed by the deadline mentioned above are now using modern metering equipment. However, the conclusion cannot be drawn that each individual default meter operator actually fulfilled the 10% quota. For the monitoring survey 102 companies reported that they did not meet the quota by 30 June 2020. When asked whether they had met the quota by 30 September 2020, 64 companies responded that they had not yet reached the quota at that time, and there was no response from 47 companies. The Bundesnetzagentur approached the companies concerned. Some of these companies indicated that the pandemic hindered them from meeting their 10% target. In nearly all cases the quota has since been fulfilled and the implementation target has been met. At the time this report went to press, clarification was not yet complete for just 10 of the companies concerned. The number of meter systems that are not smart metering systems as defined under section 2 para 13 of the Metering Act and are installed at around 400,000 SLP customer meter locations has also increased, as has the number of the nearly 27,600 meter locations with smart metering systems consisting of modern metering equipment and a smart meter gateway.

Electricity: transmission technologies for remotely read meters for SLP customers in 2020
Number and breakdown

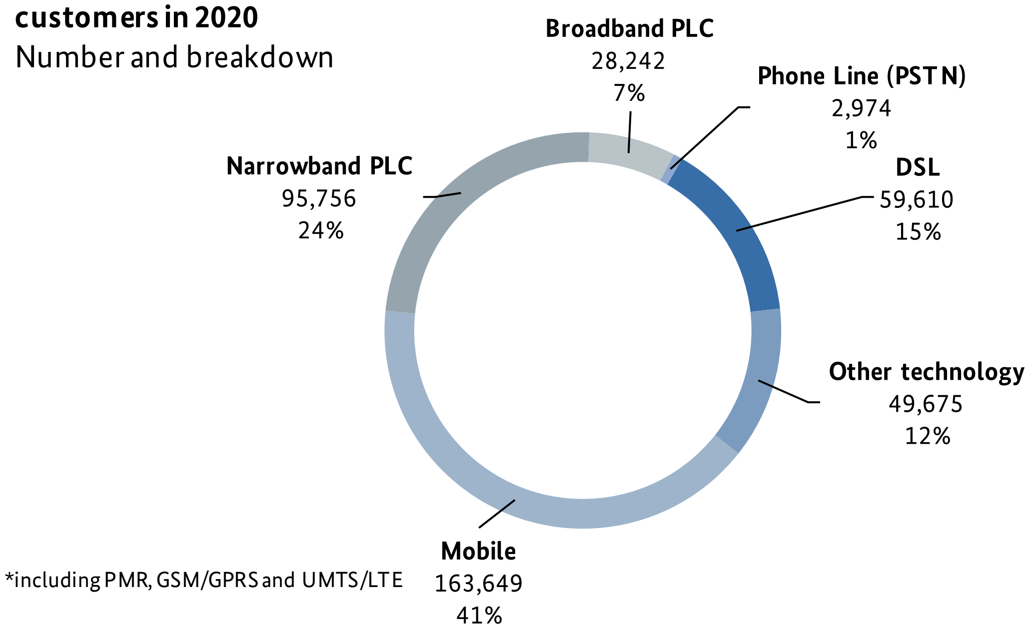


Figure 130: Transmission technologies for remotely read meters for SLP customers

Only about 400,000 of the nearly 53m meter locations for household customers are read remotely. As a rule, meters still have to be read manually once a year. The amount of data transmission via power line communication (PLC) declined by nearly 32,000 meter locations compared to the previous year. PLC transmission technology is now being used in just 31% of cases, while mobile transmissions are used in 41% of cases. Transmissions via broadband (DSL) have declined by 3%, thus reducing its overall share to 15%.

6. Metering technology used for interval-metered customers

According to information provided by the meter operators, the number of final consumers with interval metering totals around 400,000 meter locations. Interval-metered customers are solely non-residential customers from the industry and business sector.

Electricity: meter technology employed for interval-metered customers

Requirement	Meter locations 2020
Metering equipment in the interval-metered segment (> 100,000 kWh/year)	391,776
Meter systems under section 2 para 13 of the Metering Act that are not smart metering systems in accordance with section 2 para 7 of the Metering Act (eg EDL 40) (100,000 kWh/year)	220,761
Optional installations of BSI-certified smart metering systems	585
Other	5,362

Table 1116: Meter technology employed for interval-metered (RLM) customers

The following diagram shows the number and breakdown of transmission technologies used.

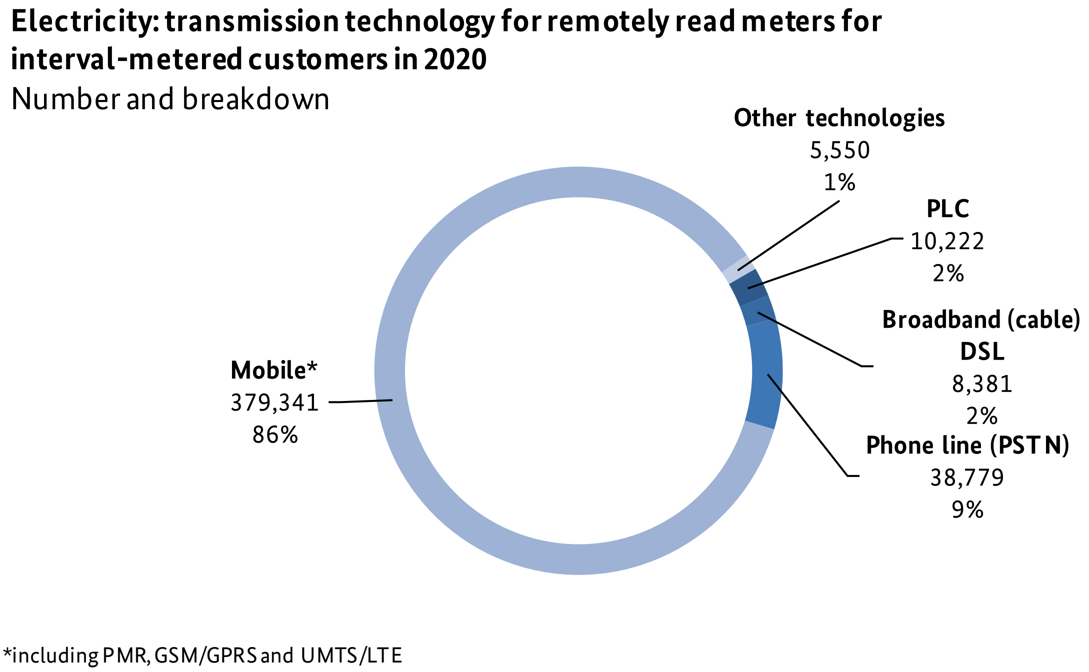
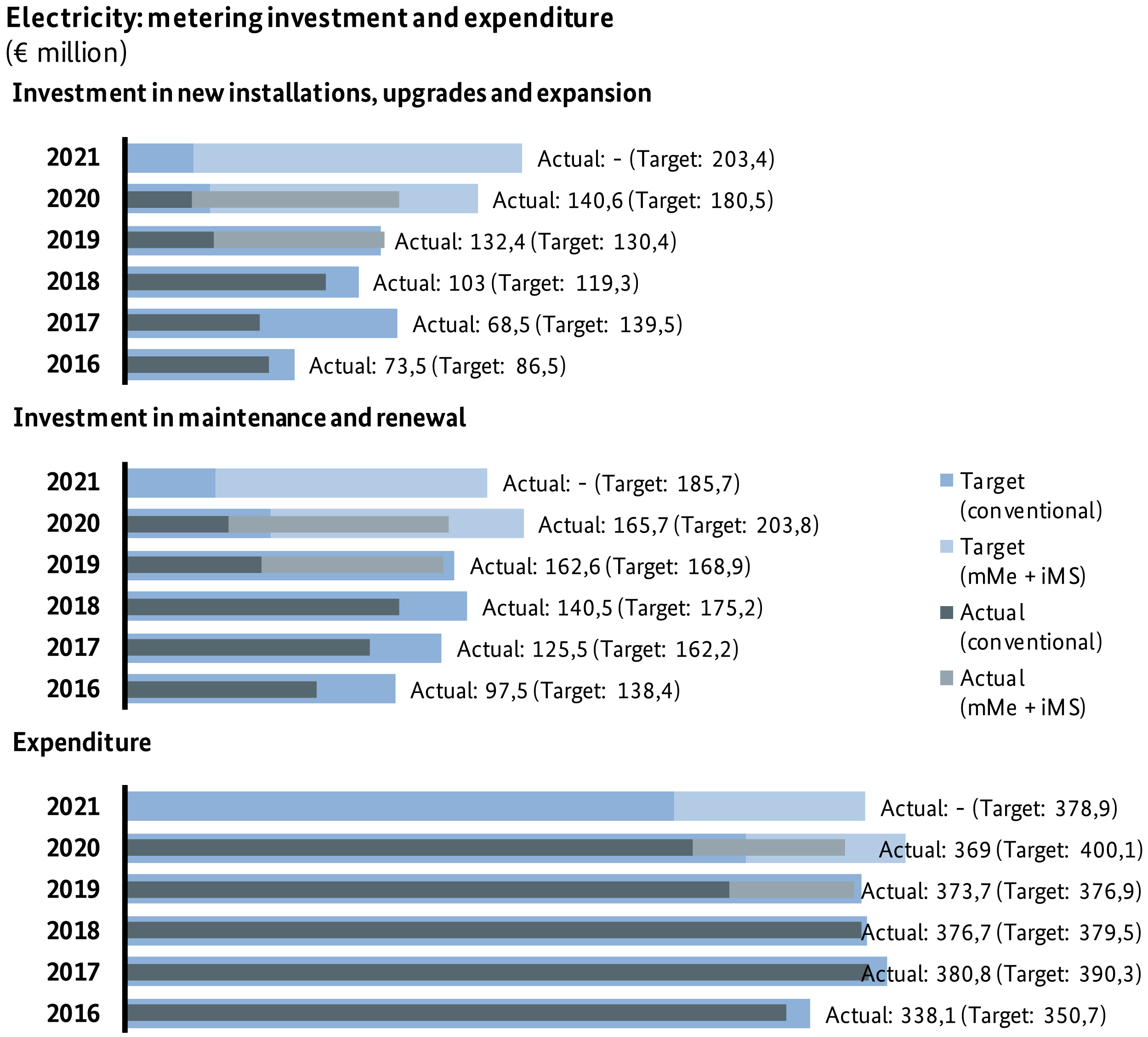


Figure 131: Transmission technologies for interval-metered customers

There were some changes in the transmission technology landscape for interval-metered customers compared with 2019. Remote meter readings transmitted via mobile communication increased slightly from 85% to 86%. Similar to last 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.

7. Metering investment and expenditure

Total investment and expenditure on metering was up about €6m to around €675m in 2020, leaving expenditures around €109.1m below the planned investment amounts. Investment in new installations, upgrades and expansion made in 2020 lagged around 22% behind projected figures for the year. Investments in maintenance and renewal were around 19% below what was planned. The volume of expenditure was around 7% less than the projected values. At a total of €768m, this year's forecast figures are lower than projections from the prior year but would lead to an increase in investments if fully implemented. Of the €675m invested in 2020, investment in smart metering systems and modern metering equipment was around €297m, which is around a €50m increase over the previous year. However, this share is projected to rise significantly to about €406m in 2021.



* With the change in the reporting procedure the actual vaules as from 2020 and the target values as from 2021 for investments and expenditure are surveyed proportionally for smart metering systems. That portion is shown in the chart in a lighter shade. The value that is used by smart metering systems and shown in the lighter shade is in brackets.

Figure 132: Metering investment and expenditure

8. Final consumer prices for metering equipment

For the fifth 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 117. The prices for standard services as defined in section 35(1) of the Metering Act range on average between €95.73 and €413.72 per year, depending on the final consumer group and installed capacity of installation operators. This means that price changes from the previous year were small. 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 11Table 1127. Depending on the final consumer group, they vary, on average, between €22.40 and €55.77 per year.

Table 119 shows that final consumers are charged on average €19.82 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.

Electricity: average prices for standard services* within the meaning of section 35(1) of the Metering Act for carrying out metering operations in 2020 (€ / year)

Final consumers with annual power consumption	Average price	Price cap
≤ 2.000 kWh**	22.40	23.00
> 2.000 kWh & ≤ 3.000**	28.62	30.00
> 3.000 kWh & ≤ 4.000**	37.76	40.00
> 4.000 kWh & ≤ 6.000**	55.77	60.00
> 6.000 kWh & ≤ 10.000	95.73	100.00
> 10.000 kWh & ≤ 20.000 kWh	125.64	130.00
> 20.000 kWh & ≤ 50.000 kWh	164.12	170.00
> 50.000 kWh & ≤ 100.000 kWh	193.92	200.00
> 100.000 kWh	413.72	
Consumption equipment in accordance with section 14a EnWG	95.18	100.00

* in accordance with section 35(1) MsbG

** optional installation in accordance with section 29 in conjunction with section 31 MsbG

Table 1127: Prices for standard services within the meaning of section 35(1) of the Metering Act for carrying out metering operations at final consumers.

Electricity: average prices for standard services* within the meaning of section 35(1) of the Metering Act for carrying out metering operations in 2020 (€ / year)

Installed capacity at plant operators in accordanc	Average price	Price cap
> 1 kW & ≤ 7 kW**	54.54	60.00
> 7 kW & ≤ 15 kW	96.02	100.00
> 15 kW & ≤ 30 kW	125.39	130.00
> 30 kW & ≤ 100 kW	192.11	200.00
> 100 kW	399.58	

* in accordance with section 35(1) of the Metering Act

** optional installation in accordance with section 29 in conjunction with section 31 of the Metering Act

Table 1138: Prices for standard services within the meaning of section 35(1) of the Metering Act for carrying out metering operations at installation operators

Electricity: prices for voluntary installation within the meaning of section 29 in conjunction with section 32 of the Metering Act in 2020 (€/year)

	Average price	Price cap
Modern metering device as defined in the Metering Act	19.82	20.00

Table 11419: Prices for voluntary installation within the meaning of the Metering Act

9. Regulatory costs for metering

Under section 7(2) of the Metering Act the costs for the operation of modern metering equipment and smart metering systems are not to be accounted for in the revenue cap and the network operator's network charges, instead they are to be allocated to the default meter operator for modern metering equipment and smart metering systems. The operator has its own contractual relationship with the connecting parties and levies its own non-regulated charges for meter operation and metering. The nationwide rollout of modern metering equipment began in 2018.

The difference between the actual costs of meter operation to end users for the calendar year (assuming efficient provision of services) and the revenue cap estimates for those costs is entered into the regulatory account. This difference is entered if it is caused by changes in the number of connection users and not by costs for meter operation of modern metering equipment and smart metering systems within the meaning of the Metering Act.

In the regulatory accounts of 2018 and 2019 the costs were determined for modern metering equipment and smart metering systems that replaced conventional metering equipment. These costs are removed from the network operator's revenue cap and are to be allocated to the default meter operator for modern metering equipment and smart metering systems. With this new separation of roles, however, there are also costs that remain, at least for the short term, with the network operator. Figure 140 shows the amount of costs removed from the network operators' revenue caps and the remaining costs for network operators after meters have been replaced. Final regulatory account figures for 2020 (application by 30 June 2021) will not be available until 2022.

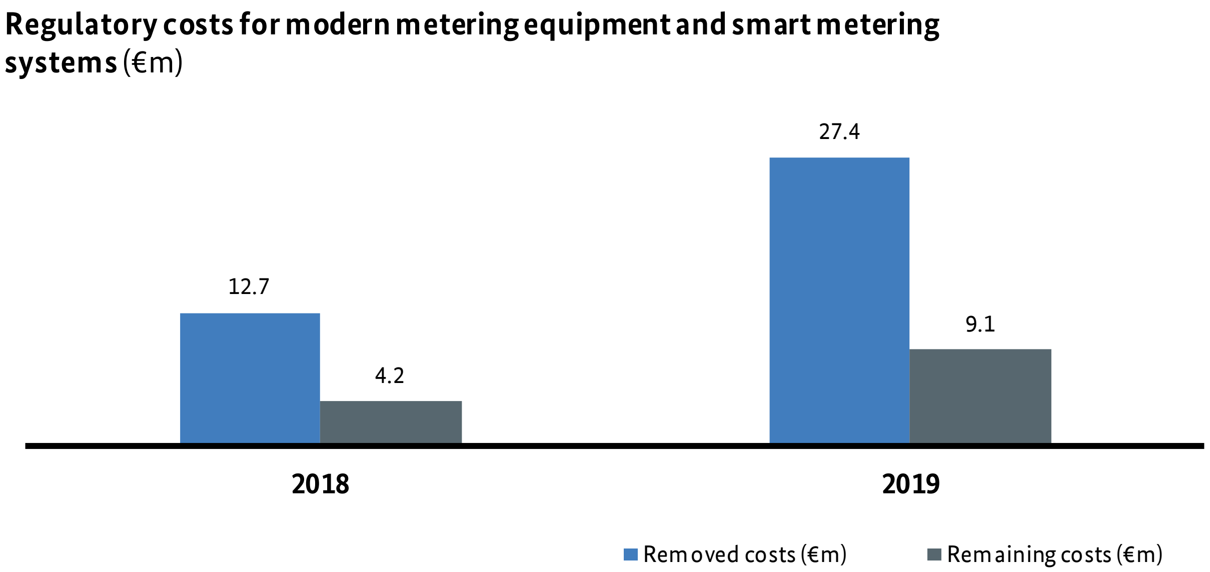


Figure 133: Regulatory costs for modern metering equipment and smart metering systems.

II Gas market

A Developments in the gas markets

1. Summary

1.1 Production, imports and exports, and storage

In 2020, natural gas production in Germany fell by 0.9 billion cubic metres (bn m^3) to 5.1bn m^3 of gas (with calorific adjustment).[141] This corresponds to a decrease of 15% compared to 2019. The decline in production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output.[142] Another factor is the lack of major new gas finds. 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 7.7 years as at 1 January 2021.

The total volume of natural gas imported into Germany in 2020 was 1,674 terawatt hours (TWh). Imports to Germany were thus down by 28 TWh from the previous year's figure of 1,703 TWh. The main sources of gas imports to Germany remain Russia and CIS as well as Norway, but the Netherlands is an important source for German importers too. It is an established and liquid European producer, trading hub and point of arrival for LNG shipments and it provides a connection to natural gas fields in Norway and the United Kingdom.

In 2020, the total volume of natural gas exported by Germany was about 814 TWh. As the previous year's figure was 701 TWh, exports from Germany were up 113 TWh.

The total maximum usable volume of working gas in underground storage facilities as at 31 December 2020 was 274.72 TWh (2019: 275.27 TWh).[143] Of this, 136.01 TWh (2019: 135.63 TWh) was accounted for by cavern storage, 117.01 TWh (2019: 117,54 TWh) by pore storage and 21.71 TWh (2019: 22,01 TWh) by other storage facilities.

The volume of short-term (up to 1 October 2020) freely bookable working gas rose again and there was a slight rise in the long-term bookable capacities as well.

Around 106 TWh have been injected into German natural gas storage facilities since the beginning of the injection season at the end of March 2021, taking the overall level of storage in the country to

[141] Calorific adjustment is used because natural gas is not sold according to its volume but according to its energy content (9.7692 kWh/m^3). 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/m^3).

[142] Source: Annual report "Erdöl- und Erdgasreserven in der Bundesrepublik Deutschland am 1. Januar 2020" [Crude Oil and Natural Gas Reserves in the Federal Republic of Germany as at 1 January 2021]; State Authority for Mining, Energy and Geology (LBEG), Lower Saxony.

[143] This figure includes the 7 Fields storage facility and part 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 network in the Netherlands are not taken into account since they have no direct impact on the German gas network.

about 164.2 TWh as at 31 October 2021. The storage level rose from just over 25% at the end of March to 71.3%, well below the average of previous years at the same time.

The market for the operation of underground natural gas storage facilities is still highly concentrated. The cumulative market share of the three largest storage facility operators stood at around 67.2% at the end of 2020, representing a slight increase compared to the previous year (66.6%).

1.2 Networks

1.2.1 Network expansion

The Gas Network Development Plan 2020-2030 (Gas NDP) comprises a total of 215 measures with an investment volume of about €8.5bn. A total of 60 new measures have been added compared to the Gas NDP 2018-2028. The additional proposed measures are largely related to the planned liquefied natural gas (LNG) terminals, the expansion measures necessary for green gases, the supply in Baden-Württemberg and security of supply in the Netherlands, Switzerland and Italy.

The Bundesnetzagentur is also enabling infrastructure for hydrogen to be set up. A total of 24 pipelines and gas pressure regulating and metering stations in the natural gas network have been identified that are not essential for the transport of gas and can be converted for hydrogen.

1.2.2 Investments

In 2020 the 16 German gas transmission system operators (TSOs) invested a total of €995m (2019: €1.33bn) in network infrastructure. Of this, €638m (2019: €1.08bn) was accounted for by investments in new builds, upgrades and expansion projects and €357m (2019: €249m) by investments in network infrastructure maintenance and renewal.

Across all TSOs, expenditure on maintenance and repair of network infrastructure amounted to €402m in 2020 (2019: €622m), with expenditure in 2020 and planned expenditure for 2021 shared almost equally between the two market areas.

The 600 gas distribution system operators (DSOs) reported total network infrastructure investments in 2020 of €1,674m (2019: €1,488m) in new builds, upgrades and expansion (€1,044m (2019: €940m)) and in maintenance and renewal (€631m (2019: €549m)). For 2021, the projected total investment is €1,689m.

Service and maintenance expenses, based on the data provided by the DSOs, totalled €1,365m in 2020 (2019: €1,152m). The projected expenditure on service and maintenance for 2021 is €1,183m.

1.2.3 Supply interruptions

In 2020, the average interruption in supply per connected final customer was 1.09 minutes (2019: 0.98 minutes in the year). This figure shows that the German gas network has a high quality of supply.

1.2.4 Network charges

As of 1 April 2021, the average volume-weighted network charge including the charges for metering and meter operation for household customers[144] (volume-weighted across all contract categories) was 1.59 cents per kilowatt hour (ct/kWh) (2020: 1.56 ct/kWh), an increase of slightly more than 2% compared to the previous year.

For business customers, as of 1 April 2021 the arithmetic mean of the network charge including the charges for metering and meter operation was 1.28 ct/kWh (2020: 1.27 ct/kWh). For industrial customers, as of 1 April 2021 the arithmetic mean of the network charge including the charges for metering and meter operation was 0.32 ct/kWh (2020: 0.37 ct/kWh), a decline of just over 13.5%.

1.2.5 Transport

The total quantity of gas supplied by general supply networks in Germany fell in 2020 by about 6.9 TWh to 941.1 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 of the Energy Industry Act (EnWG)) dropped to around 245 TWh (2019: 282.5 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 megawatts (MW) increased by about 10% to 108 TWh (2019: 98.5 TWh).

With regard to gas transmission networks, the quantity of gas procured directly on the market by large final customers (industrial customers and gas-fired power stations) – in other words not using the classic route via a supplier, and instead approaching the network operator as a shipper (paying the transport charges themselves) – amounted to 73.7 TWh (2019: 78.9 TWh), equivalent to about 37% of the total quantity of gas supplied by the TSOs to final consumers. As regards gas distribution networks, the amount of gas procured without a conventional supplier contract amounted to 41.1 TWh, compared with 42.4 TWh in 2019, corresponding to a share of approximately 6% of the DSOs' total gas supplies.

1.2.6 Market area conversion

The market area conversion, ie the conversion from low-calorific L-gas to high-calorific H-gas coordinated by the TSOs, is proceeding according to plan. A total of nearly five million appliances burning L-gas, such as gas cookers, gas-fired boilers and heating systems, have to be converted.

From a total of 35 network operators, 593,827 appliances were registered in 2020, of which 256,396 were condensing boilers (43.2%) and 63,605 self-adaptive appliances (10.7%). The proportion of condensing boilers had been 46.6% in 2019 and that of self-adaptive appliances 11.7%. During the reporting period, 347,599 appliances were adapted for standard load profile (SLP) customers and 723 for interval-metered customers. A total of 9,066 appliances that were to be adapted could not be, a proportion of 2.6% (2019: 2.2%).

1.3 Wholesale

The liquidity of the wholesale natural gas markets decreased again overall in 2020 owing to lower energy demand as a result of the coronavirus pandemic. There was a year-on-year drop of around 11% in the total volume traded on the exchange. For the volume of off-exchange wholesale trading via broker platforms,

[144] Customer category according to Eurostat: band II (D2): annual consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh).

which accounts for a much larger share, a very small rise of 2% was recorded for 2020, but this was probably caused by an additional broker being included in the evaluation for the year.

The volume traded on the spot market was about 429 TWh in 2020 (2019: about 472 TWh), which corresponds to a drop of 9%. As in previous years, the focus of spot trading for both market areas in 2020 was on day-ahead contracts (NCG: 148.7 TWh (2019: 179.5 TWh); GASPOOL: 117.6 TWh (2019: 121.5 TWh)). The futures trading volume fell from around 75 TWh in 2019 to about 58 TWh in 2020, corresponding to a decrease of 23%.

In 2020, broker platforms reported natural gas transactions for delivery to Germany had been traded for an amount totalling 2,898 TWh (2019: 2,844 TWh), representing growth of around 2%. Of this, 1,114 TWh was for contracts with delivery in 2020 and a delivery time of at least one week.

There were again lower wholesale gas prices in 2020 than in the preceding years. The respective price indices (EGIX and border prices as calculated by the Federal Office for Economic Affairs and Export Control (BAFA)) show a drop of some 24.5% (EGIX) and 39% (BAFA border price) from the arithmetic mean of the year before. The European Gas Spot Index (EGSI) fell year-on-year again, by about 32% in the NCG market area and about 29% in GASPOOL.

1.4 Retail

1.4.1 Contract structure and competition

An overall analysis of how household customers were supplied in 2020 in terms of volume shows that nearly half of them (48%) were supplied by the local default supplier under a non-default contract, receiving 117.4 TWh of gas.

Only 17% of household customers still had a default supply contract in 2020 and these were supplied with 41.2 TWh of gas. The percentage of household customers who had a contract with a supplier other than the local default supplier increased again to 35% for a total of 85.8 TWh of gas. 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 22.8% of the total volume delivered to these customers was supplied under a contract with the default supplier on non-default terms (2019: 24.1%) and about 77.2% was supplied under a contract with a legal entity other than the default supplier (2019: 75.9%). These figures show that default supply is of only minor significance in the acquisition of interval-metered customers in the gas sector.

The total number of customers changing contract in 2020 was 0.6m. The volume of gas these customers were delivered was approximately 11.9 TWh. The volume-based switching rate was therefore 4.9%. The total number of household customers changing supplier hit a new high in 2020, passing the 1.6m mark. Around 1.3m of these household customers changed directly by cancelling their previous contract. The remaining around 0.3m chose an alternative supplier rather than the default one right away when moving home.

The total consumption amount of non-household customers affected by supplier switches in 2020 was 80.6 TWh, corresponding to a year-on-year decrease of 8.3 TWh. The switching rate for non-household customers fell to 7.3% from 9% the year before.

The level of concentration in the two largest gas retail markets for standard load profile (SLP) and interval-metered customers is still well below the statutory thresholds for presuming market dominance. In 2020, the cumulative sales of the four largest companies to SLP customers was about 92.9 TWh and to interval-metered customers around 139.2 TWh. The aggregate market share of the four largest companies (CR4) in 2020 was thus 26% for SLP customers (2019: 24%) and 28% for interval-metered customers (2019: 29%).

Since market liberalisation and the creation of a legal basis for an efficient supplier switch, there has been a steady rise in the number of active gas suppliers for all final customers in the different network areas. This positive trend was maintained in 2020 as well.

On average, final customers in Germany can choose from 133 suppliers in their network area (2019: 129); household customers can, on average, choose between 113 suppliers (2019: 109 suppliers) (these figures do not take account of corporate groups).

1.4.2 Gas disconnections

There was a large drop in the number of gas disconnections in 2020. In 2020, about 24,000 customers were disconnected in total, representing a year-on-year decrease of around 22% (2019: 31,000). It may be assumed that this drop was partly due to the right to withhold performance set out in Article 240 section 1 of the Introductory Act to the Civil Code (EGBGB), which was put in place in the first half of the year because of the Covid-19 pandemic to provide temporary relief for consumers. Around 75% of the gas suppliers surveyed also said they had voluntarily decided not to disconnect their customers in 2020. Gas suppliers also accommodated customers by offering them special or individual payment arrangements. Some suppliers extended their criteria for disconnections to make them more customer-friendly.

According to the gas suppliers' data, a disconnection notice is issued when a customer is on average around €120 in arrears. Approximately 980,000 disconnection notices were issued to household customers in total, of which around 162,000, or 16.5%, were passed on to the relevant network operator with a request for disconnection. The suppliers' data show that around 3% of the relevant connections were actually disconnected.

The gas suppliers also stated that in some 18,000 cases they had disconnected customers with default contracts. Customers outside of default supply were disconnected around 7,600 times. The gas suppliers stated that around 10% of disconnections were the same customers being disconnected more than once.

1.4.3 Price level

The volume-weighted gas price for household customers across all contract categories rose about 6% year-on-year from 6.31 ct/kWh to 6.68 ct/kWh. The new carbon levy amounting to 0.4551 ct/kWh, which was introduced on 1 January 2021, was partly responsible for the rise as it was passed on to final customers almost completely and paid by them as part of the gas price. The carbon levy expanded the existing emissions trading system to the transport and heating sectors. Gas prices may be expected to continue rising in the next few years as the law provides for annual increases in carbon pricing until 2026. In the price across all contract categories, the largest price component "energy procurement, supply and margin", which makes up around 45%, fell by over 5% from 3.12 ct/kWh to 2.95 ct/kWh.

The volume-weighted gas price for customers on a default contract[145] as at 1 April 2021 was 7.45 ct/kWh (2020: 6.99 ct/kWh), corresponding to an increase of around 6.5% compared to the previous year.

On 1 April 2021, the volume-weighted price for customers under a non-default contract with the default supplier was 6.58 ct/kWh, an increase of about 4.6% compared to 2020 (6.29 ct/kWh).

On 1 April 2021, the volume-weighted price for a contract with a supplier other than the local default supplier was 6.41 ct/kWh, an increase of just over 7.6% compared to the previous year (2020: 5.96 ct/kWh).

The average household customer with gas consumption of 23,250 kWh could save an average of about €200 a year as at 1 April 2021 by changing contract. The average potential saving for the year from changing supplier was €240.

The falling wholesale prices on the procurement level are passed on to household customers in different ways. The price component "energy procurement, supply and margin"[146] for default supply customers was 3.41 ct/kWh as at 1 April 2021 (2020: 3.51 ct/kWh). That corresponds to a drop of just over 3% in gas procurement costs. The gas procurement costs in the price for customers supplied under a non-default contract with the default supplier fell by slightly more than 8.5% from 3.18 ct/kWh to 2.91 ct/kWh. The gas procurement costs for customers supplied under a contract with a supplier other than the local default supplier decreased by just over 3% to 2.72 ct/kWh (2020: 2.80 ct/kWh).

Special bonuses offered by suppliers, including one-off bonus payments, are an added incentive for customers to switch. These one-off payments amount to an average of €70 to €80.

The gas prices for non-household (industrial and commercial) customers as at 1 April 2021 showed year-on-year increases caused by the introduction of the carbon levy. The arithmetic mean of the overall price (excluding value-added tax (VAT)) for an annual consumption of 116 gigawatt hours (GWh) ("industrial customer") was 2.95 ct/kWh, and thus 0.42 ct/kWh or around 16.6% higher than the previous year's figure. The proportion of the total price (about 55%) controlled by the supplier was 1.63 ct/kWh. The arithmetic mean of the overall price (excluding VAT) for an annual consumption of 116 MWh ("commercial customer") was 4.74 ct/kWh on the reporting date, an increase of 0.22 ct/kWh or around 4.8% year-on-year. The proportion of the total price (about 51%) controlled by the supplier was 2.41 ct/kWh, down by 0.25 ct/kWh.

The prices paid by non-household customers in Germany in the annual consumption range of 27.8 GWh to 278 GWh was 2.34 ct/kWh in the second half of 2020, about 0.20 cents above the EU average of 2.14 ct/kWh. On an EU average, the net price is subject to about 11% (0.24 ct/kWh) of non-refundable taxes and levies. In this regard, Germany's figure of about 17.5% (0.41 ct/kWh) is higher than average. Compared with the gas prices for industrial customers, there are relatively large differences between the gas prices for household customers across the EU. The gas price for household customers in Germany was 6.20 ct/kWh and thus

[145] Customer category according to Eurostat: band II (D2): annual consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh).

[146] It is not possible to break down the individual elements of this price component owing to the survey method used.

around 12.5% below the EU average (6.98 ct/kWh). Taxes and levies amounted to an average of 1.49 ct/kWh in Germany. The EU average was 1.64 ct/kWh.

2. Network overview

All 16 TSOs took part in the 2021 Monitoring Report data survey. As at 31 December 2020, the length of pipelines in the transmission system was about 41,600 km[147] and included around 3,800 exit points for delivery to final customers, 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 registered final customer market locations in the transmission system was around 530 and approximately 199.5 TWh of gas was delivered to final customers from the TSO network, compared to 186.9 TWh in 2019. The volume of gas delivered from the TSO network was thus about 7% more than the level of the previous year.

As at 2 November 2021, a total of 703 gas DSOs were registered with the Bundesnetzagentur, 679 (about 97%) of whom took part in the 2021 monitoring survey. As at 31 December 2020, the total length of pipelines in the gas distribution system including house connections was around 554,400 km and included about 11m exit points for delivery to final customers, 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 at 31 December 2020, there were 14.6m registered final customer market locations in the gas distribution system. The number of market locations for household customers as defined in section 3 para 22 EnWG was 12.8m. Total gas supplies from the network of the DSOs amounted to 741.6 TWh in 2020, down by around 20 TWh compared to the previous year (2019: 761.1 TWh). The quantity of gas supplied to household customers as defined in section 3 para 22 EnWG was down nearly 2% at about 270.3 TWh (2019: 275 TWh).

A simplified comparison between the supply and use of natural gas in 2021 in Germany is shown below.

[147] For 2020, the survey asked for the total length of the network in km including pipes used by third parties, so the results are not directly comparable with data from previous monitoring reports.

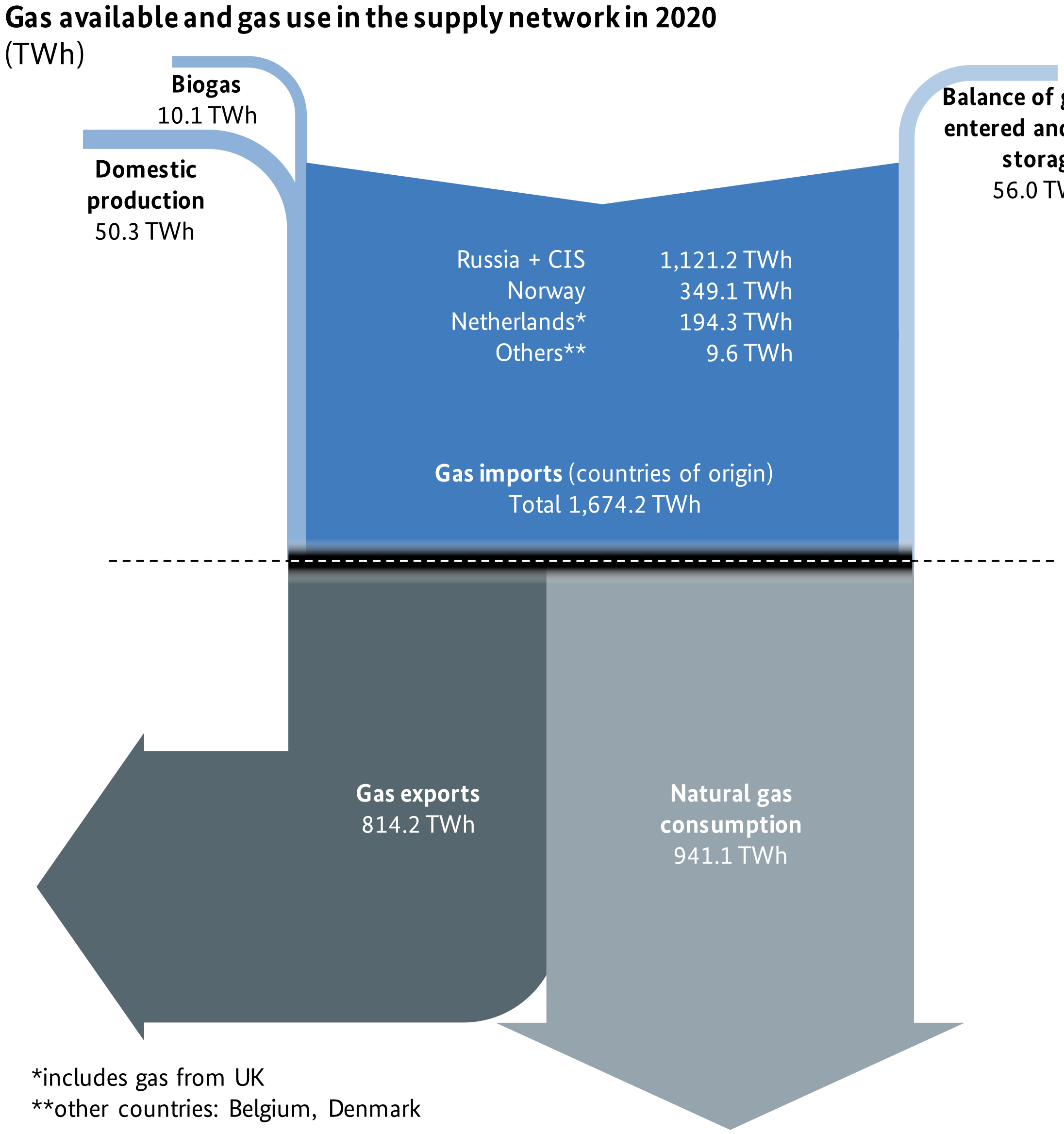


Figure 134: Gas available and gas use in Germany in 2020[148]

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 1,790 TWh in 2020. Of this, 50.3 TWh came from domestic sources, while 1,674 TWh was imported. The balance of gas that entered and exited storage in 2020 amounted to +56 TWh, so there was more gas being withdrawn from the storage facilities than injected into them. Moreover, 10.1 TWh of biogas upgraded to natural gas quality was fed into the German natural gas system during the year.

[148] Because of the infrastructure in place, recorded import volumes may also include transit flows or loop flows (eg volumes of gas that leave Germany at the Olbernhau cross-border interconnection point using the GAZELLE gas pipeline and then re-enter the German network at the Waidhaus cross-border interconnection point). These loop flows are not shown in the diagram.

Around 45% (814.2 TWh) of available gas volumes in Germany was transported to neighbouring countries in Europe in 2020. Final customers used 941.1 TWh of gas in Germany (2019: 948 TWh).

Gas: number of network operators in Germany registered with the Bundesnetzagentur

	2016	2017	2018	2019	2020	2021
TSOs	16	16	16	16	16	16
DSOs	715	717	718	708	703	703
DSOs with fewer than 100,000 connected customers	690	692	693	683	682	676
DSOs with fewer than 15,000 connected customers*	545	548	547	536	534	499

*Based on data from gas DSOs.

Table 115: Number of gas network operators in Germany registered with the Bundesnetzagentur as at 2 November 2021

The majority of gas DSOs (574 operators) have short to medium length systems of up to 1,000 km, but 91 DSOs have gas systems with a total length of more than 1,000 km. The following figure shows a percentage breakdown of DSOs by network length:

Gas: DSOs by pipeline network length in 2020
number and share

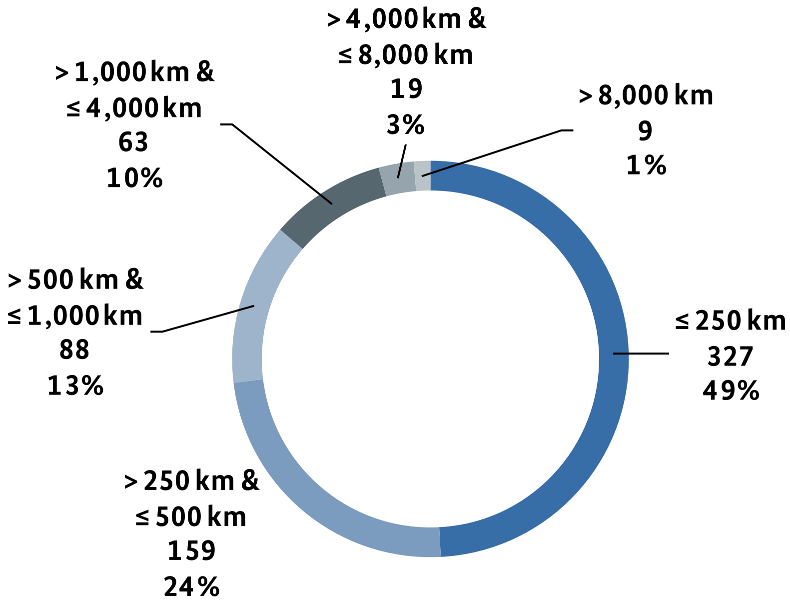


Figure 135: DSOs by gas pipeline network length as stated in the DSO survey – as at 31 December 2020

Gas network operators were asked about the total length of their networks, as well as the length subdivided into pressure ranges (nominal pressure in bar) including house connections. The findings from the operators surveyed are shown in the table below.

Since 2018 the market location has been the unit in the energy market in which connections are counted for supply and balancing. It is always used when referring not to the technical connection but to the contractual relationships behind the technical connection. The number of customers, for example, is counted via the market locations, whereas the number of installed meters is counted via the meter location. The meter location thus forms the technical equivalent to the market location, though a one-to-one relationship does not exist. Multiple meter locations can be assigned to one market location, and in another possible scenario multiple market locations can be assigned to one meter location.

Gas: 2020 network structure figures

	TSOs	DSOs	Total no of TSOs and DSOs
Network operators (number)	**16**	**665**	**681**
Network length (thousand km)	**41.6**	**554.5**	**596.2**
≤ 0.1 bar	0	204.3	204.3
> 0.1 – 1 bar	0	269.6	269.6
> 1 – 5 bar	0.1	29.2	29.3
> 5 – 16 bar	2.9	28.4	31.3
> 16 bar	38.6	23.1	61.7
Total exit points (thousand)	**3.6**	**11,039.9**	**11,043.6**
≤ 0.1 bar	0.002	6,085.5	6,085.5
> 0.1 – 1 bar	0.017	4,715.2	4,715.2
> 1 – 5 bar	0.066	226.2	226.3
> 5 – 16 bar	1.2	10.6	11.8
> 16 bar	2.3	2.5	4.8
Market locations of final customers (thousand)	0.5	14,609.6	14,610.1
Industrial and commercial customers and other non-household customers	0.5	1,809.9	1,810.4
Household customers	0.0	12,799.7	12,799.7

Table 116: 2020 network structure figures according to the TSO and DSO survey (data from 665 of the total 703 DSOs) – as at 31 December 2020

Gas: market locations by federal state at DSO level in 2020
number in millions

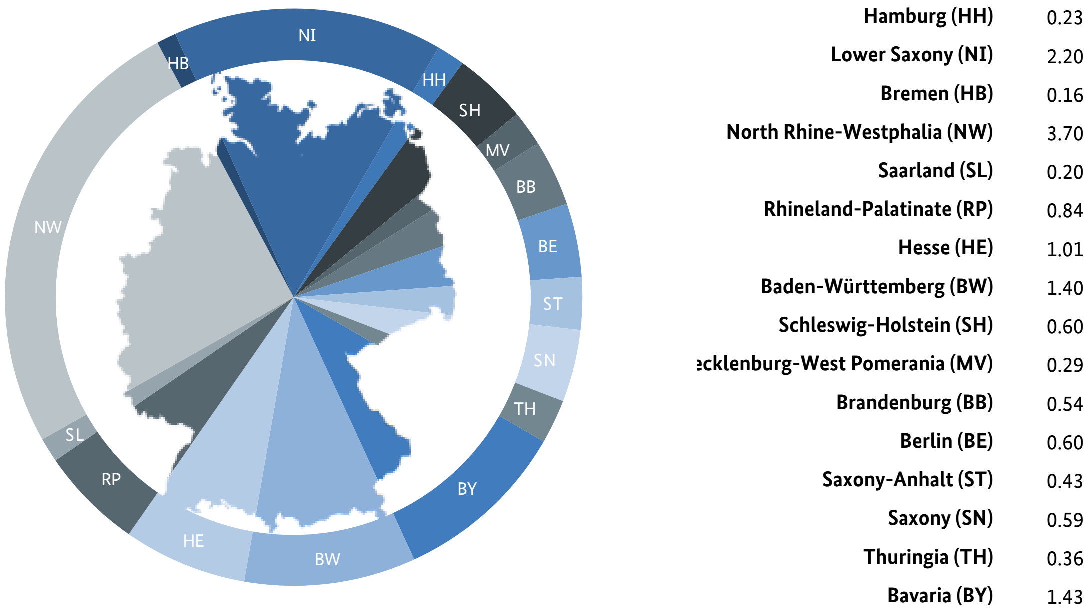


Figure 136: Market locations by federal state at DSO level as stated in the DSO survey – as at 31 December 2020

Gas: market locations by federal state at DSO level in 2020

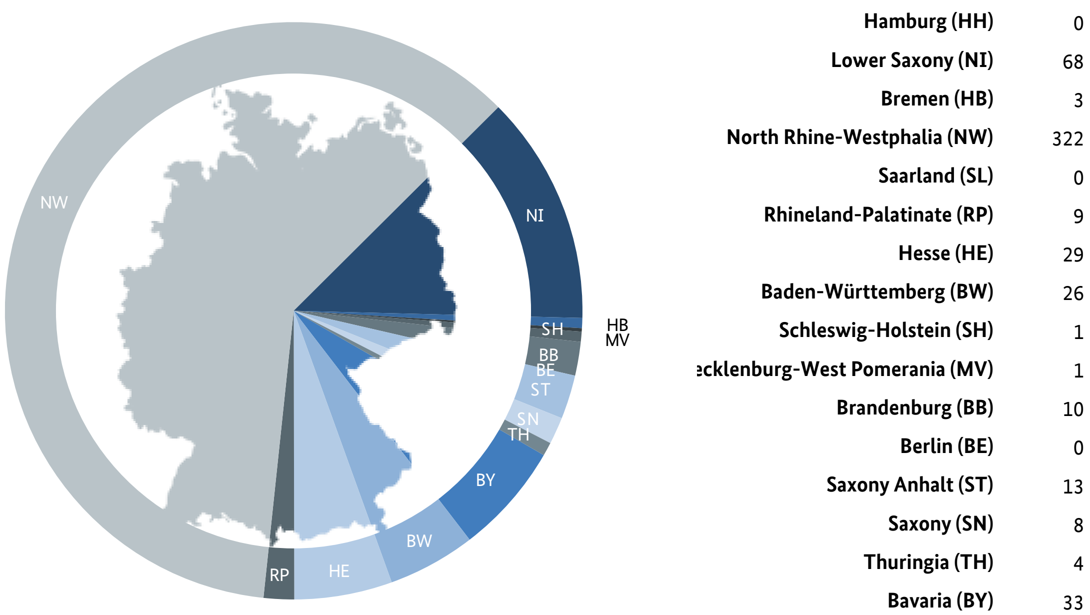


Figure 137: Market locations by federal state at TSO level as stated in the TSO survey – as at 31 December 2020

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 2020.

Gas: offtake volumes in 2020 broken down by final customer category, according to the survey of gas TSOs and DSOs

	TSO offtake volume (TWh)	Share of total	DSO offtake volume (TWh)	Share of total
≤ 300 MWh/year	<0.1	<0.1%	325.5	43.9%
> 300 MWh/year ≤ 10.000 MWh/year	0.5	0.3%	121.0	16.3%
> 10.000 MWh/year ≤ 100.000 MWh/year	5.5	2.8%	100.3	13.5%
> 100.000 MWh/year	146.0	73.2%	134.2	18.1%
Gas power plants ≥ 10 MW net nominal cap.	47.5	23.8%	60.6	8.2%
Total	199.5	100%	741.6	100%

Table 117: Gas offtake volumes in 2020 broken down by final customer category, according to the survey of gas TSOs and DSOs

The following consolidated overview includes the total gas offtake volumes of TSOs and DSOs and the quantity of gas provided to final customers by suppliers for 2020. Once again, gas TSOs and DSOs were asked in the 2021 monitoring survey to provide figures on the volumes that mostly large final customers (industrial customers and gas-fired power plants) procure directly on the market themselves, ie not using the traditional route via a supplier, and instead approaching the network operator as a shipper (paying the transport charges themselves). The quantity of gas procured directly on the market amounted here to 73.7 TWh (2019: 78.9 TWh), equivalent to about 37% of the total quantity of gas delivered by TSOs to final customers. As regards gas distribution systems, the amount of gas procured without a conventional supplier contract amounted to 41.1 TWh, compared with 42.4 TWh in 2019, corresponding to a share of approximately 6% of the DSOs' total gas supplies.

The difference between the 2020 offtake volumes of the system operators, 941.1 TWh (2019: 948 TWh), and the gas delivered by gas suppliers, 853 TWh (2019: 857.7 TWh) includes the amount of gas procured directly on the market without using a supplier (121.3 TWh).[149]

[149] Variations in data quality and response frequency mean that the difference calculated is slightly over the figure calculated for gas procured on the market.

Gas: total offtake volumes in 2020 according to survey of gas TSOs and DSOs and volume delivered according to supplier survey, broken down by final customer category

	TSO and DSO offtake volumes (TWh)	Share of total	Total volume delivered by suppliers (TWh)	Share of total
≤ 300 MWh/year	325.6	34.6%	311.7	36.5%
> 300 MWh/year ≤ 10.000 MWh/year	121.5	12.9%	109.7	12.9%
> 10.000 MWh/year ≤ 100.000 MWh/year	105.8	11.2%	92.4	10.8%
> 100.000 MWh/year	280.2	29.8%	253.6	29.7%
Gas power plants ≥ 10 MW net nominal cap.	108.1	11.5%	85.6	10.0%
Total	941.1	100.0%	853.0	100.0%

Table 118: Total gas offtake volumes in 2020, 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 2020 by 10 TWh or just over 1% year-on-year to 941.1 TWh. The quantity of gas supplied to household customers (as defined in section 3 para 22 EnWG) rose by about 4.3% to 270.3 TWh (2019: 282.5 TWh). Gas supplies to gas-fired power stations with a nominal capacity of at least 10 MW increased by about 10% to 108 TWh (2019: 98.5 TWh).

The structure of the gas retail market remained for the most part unchanged. There are a total of about 6,800 entry points to the gas distribution systems, of which 228 are for emergency entry only. A look at the number of market locations served by the DSOs shows that only 28 DSOs supply more than 100,000 each (2019: 26). Out of a total of 14.6m market locations supplied by the DSOs in Germany, some 47% (6.8m), accounting for just over 48% (353.6 TWh) of the total gas supplies, are served by DSOs that supply more than 100,000 customers. The majority (about 62%) of DSOs active in Germany supply between 1,000 and 10,000 gas customers.

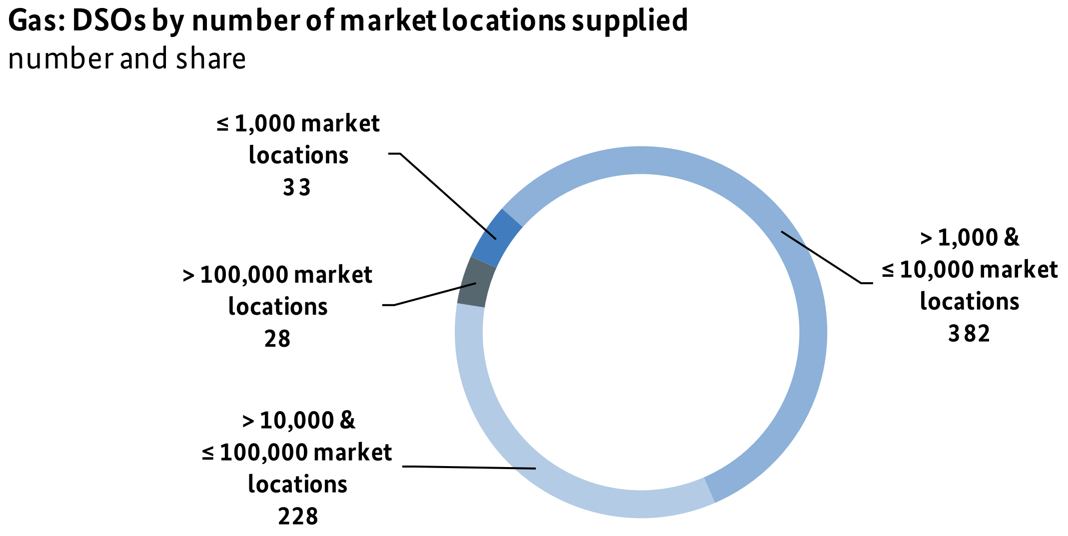


Figure 138: DSOs by number of market locations supplied (data from the gas DSO survey) – as at 31 December 2020

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 because they represent the extent to which demand in the relevant market was actually satisfied by one company during the reference period. 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 on the gas markets is the working gas volume in underground natural gas storage facilities, which represents the highest market level.

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 most recently defined this market as a national market and in the process also considered including the Haidach and 7Fields storage facilities in Austria.[150] 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 alternatives but ultimately left open the exact market definition.[151] 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. Data was therefore collected from

[150] Cf. Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, paras. 215 ff.; Bundeskartellamt, decision of 31 January 2012, B8-116/11 – Gazprom/VNG, paras. 208 ff.

[151] Cf. COMP/M.6910 – Gazprom/Wintershall of 3 December 2013, paras. 30 ff.

23 legal entities.[152] The Bundeskartellamt calculates the market shares in this market on the basis of storage capacities (maximum usable working gas volume).[153] Companies were attributed to a group according to the dominance method.

The market for the operation of underground natural gas storage facilities is highly concentrated; the degree of concentration has changed only slightly compared to the previous years. The maximum usable working gas volume of the underground natural gas storage facilities connected to the German gas network and analysed in the market concentration assessment was around 290.2 TWh on 31 December 2020 (291.6 TWh in the previous year). On 31 December 2020, the aggregate working gas volume of the three companies with the largest storage capacities amounted to approx. 195.2 TWh (194.2 TWh in the previous year). The CR3 value was around 67.2% and slightly higher than in the previous year (CR3 value: 66.6%).

Gas: Entwicklung des Arbeitsgasvolumens von Erdgasspeichern in TWh und des Anteils der drei größten Anbieter

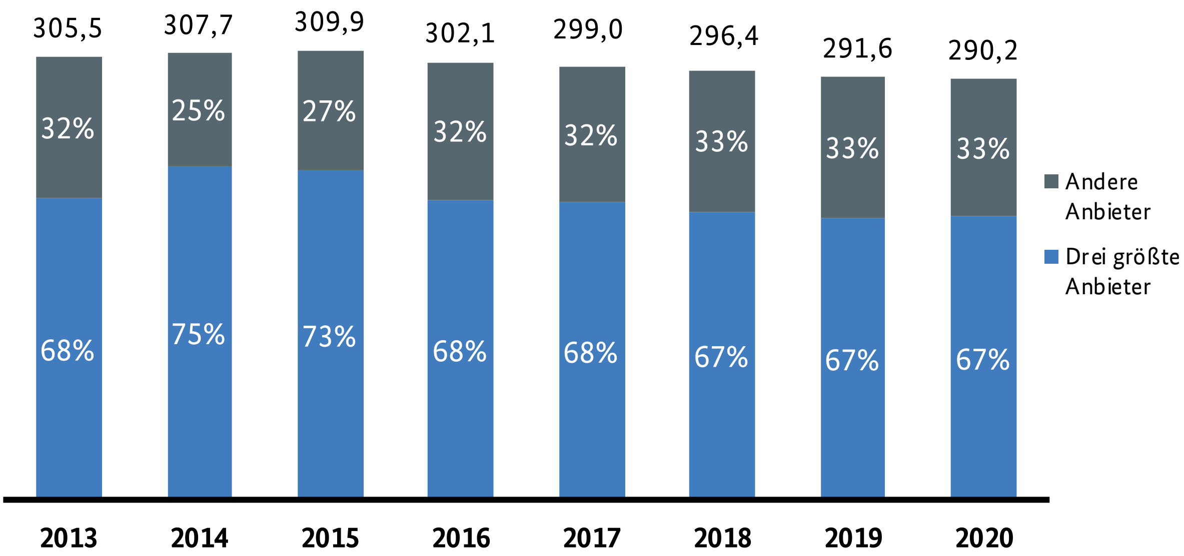


Figure 139: Development of the working gas volume of natural gas storage facilities and the share of volume of the three largest suppliers

3.2 Gas retail markets

On the gas retail markets the Bundeskartellamt differentiates between interval-metered customers and standard load profile customers. Interval-metered customers are those whose gas consumption is determined on the basis of a metered load profile. 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. They are usually 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

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[152] 25 storage facility operators in the previous year. Two storage facility operators stopped marketing their gas storage facilities in the reporting year.

[153] Cf. Bundeskartellamt, decision of 23 October 2014, B8-69/14 – EWE/VNG, paras. 236 ff.

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 (see comments in “Market concentration” chapter, Electricity retail markets, pp. 45 ff.). 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.[154]

In energy monitoring the sales volumes of the individual suppliers (legal entities) are collected as national total values[155]. In the survey a differentiation is made between default supply to standard load profile customers and supply on the basis of special contracts. The following analysis is based on the data provided by 952 gas suppliers (legal entities) (970 in the previous year). In 2020 these companies sold a total of 356 TWh of gas to standard load profile customers in Germany (2019: 361 TWh[156]) and 493.5 TWh of gas to metered load profile customers (2019: 500.5 TWh[156]). Of the total volume of sales to standard load profile customers, special contracts accounted for approx. 307.5 TWh (2019: 308.8 TWh) and default supply contracts for 48.5 TWh (2019: 51.3 TWh).

Sales volumes were attributed to company groups on the basis of the dominance method which provides sufficiently accurate results for the purposes of energy monitoring and in particular allows for year-on-year comparisons on a homogenous and ongoing calculation basis.

The monitoring report analyses the market concentration of the four strongest companies (CR4) on the gas retail market. Their cumulative sales to standard load profile customers amounted to around 92.9 TWh in 2020, of which approx. 81.5 TWh were accounted for by special contracts. Cumulative sales to metered load profile customers were around 139.2 TWh. The cumulative market share of the four strongest companies in 2020 was 26% for standard load profile customers (2019: CR4: 24%) and 28% for metered load profile customers (2019: CR4: 29%). Both market shares continue to be significantly below the statutory thresholds for the presumption of market dominance (Section 18(6) GWB). There was again only a slight change in the market concentration in relation to the four strongest companies supplying gas to standard load profile customers and metered load profile customers.[157]

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[154] Cf. Bundeskartellamt, decision of 23 December 2014, B8-69/14 – EWE/VNG, paras. 129-214.

[155] Sales here, as in the entire subsection “Gas retail markets”, consist of the volume of gas which the suppliers supply to their customers in energy/working units.

[156] Previous year’s figure corrected due to changes in the information provided by the suppliers.

[157] With regard to the percentage shares provided it should be noted that the monitoring survey among the gas suppliers covers a large proportion but not the whole of the market. The percentages consequently merely approximate the actual values.

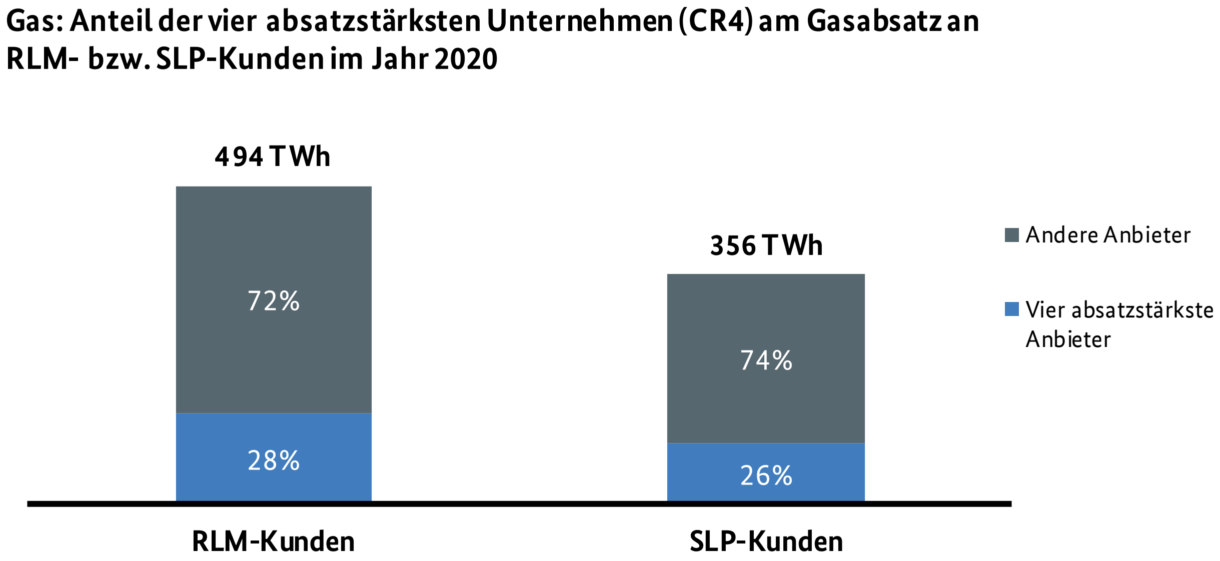


Figure 140: Share of the four strongest suppliers (CR4) in the sale of gas to metered load profile customers and standard load profile customers in 2020

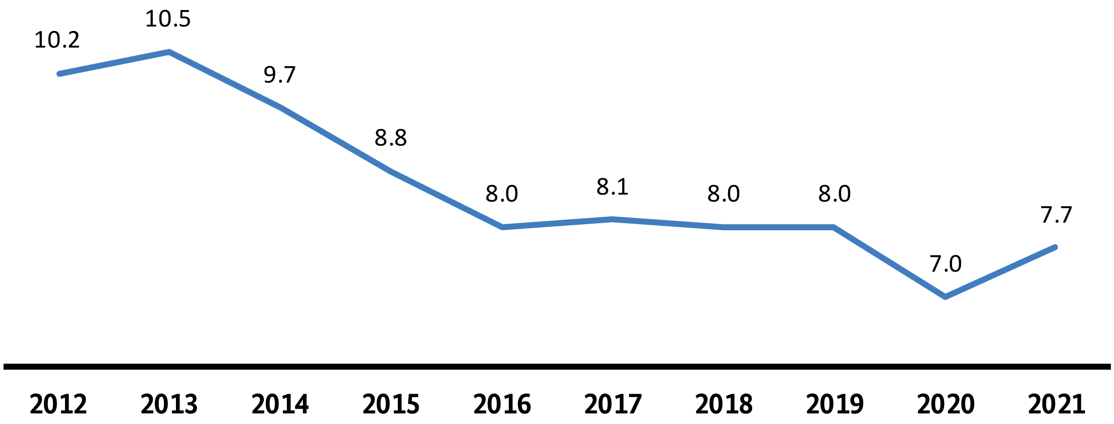
B Gas supplies[158]

1. Production of natural gas in Germany

In 2020, natural gas production in Germany fell by 0.9bn m³ to 5.1bn m³ of gas (with calorific adjustment).[159] This corresponds to a decrease of 15% compared to 2019. The decline in production is chiefly due to the increasing exhaustion of the large deposits and the resulting natural decline in output.[160] Another factor is the lack of major new gas finds.

The reserves-to-production ratio of proven and probable natural gas reserves was 7.7 years as at 1 January 2021. It was calculated on the basis of the previous year's proven and probable reserves and last year's production of gas without calorific adjustment. 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.[161]

Gas: reserves-to-production ratio of German natural gas reserves
(years)



Source: State Authority for Mining, Energy and Geology (LBEG), Lower Saxony

Figure 141: Reserves-to-production ratio of German natural gas reserves since 2001

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[158] This section is based on the Bundesnetzagentur's report on the status and development of security of the natural gas supply, which was published in December 2021.

[159] 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).

[160] Source: Annual report "Erdöl- und Erdgasreserven in der Bundesrepublik Deutschland am 1. Januar 2020" [Crude Oil and Natural Gas Reserves in the Federal Republic of Germany as at 1 January 2021]; State Authority for Mining, Energy and Geology (LBEG), Lower Saxony.

[161] Ibid.

2. Natural gas imports and exports

Just over 67% of gas imported into Germany comes from Russia and the Commonwealth of Independent States (CIS). This value also contains transit flows and loop flows

Germany's geographical position gives it the status of a gas hub, with gas imports arriving in the country largely being passed on, often to Austria and the Netherlands.

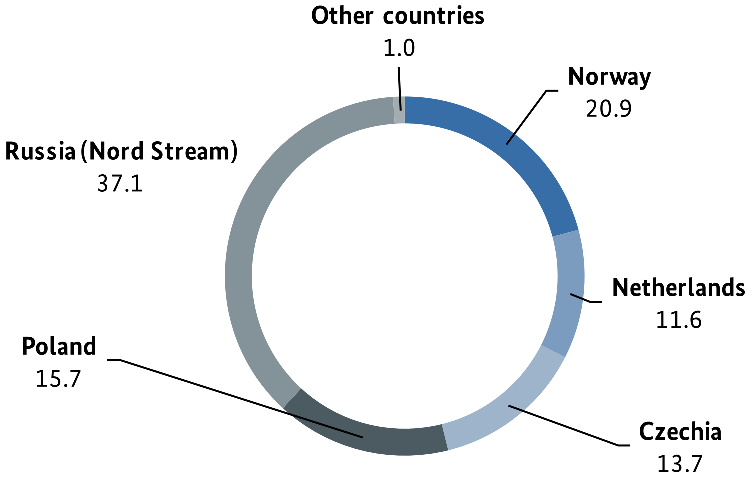
Domestic production is becoming less significant each year as deposits run out.

The monitoring report bases its assessment of imports and exports on the physical gas flows that enter and exit Germany at cross-border interconnection 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 interconnection point using the GAZELLE gas pipeline and then re-enter the German network at the Waidhaus cross-border interconnection point).

The total volume of natural gas imported into Germany in 2020 was 1,674 TWh. Imports to Germany were thus down by 28 TWh from the previous year's figure of 1,703 TWh. When looking at the countries of origin, the focus here is on the countries that Germany imports from at their given cross-border interconnection point.

The main sources of gas imports to Germany remain Russia and CIS as well as 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 have eased trading and provided further alternatives for gas traders.

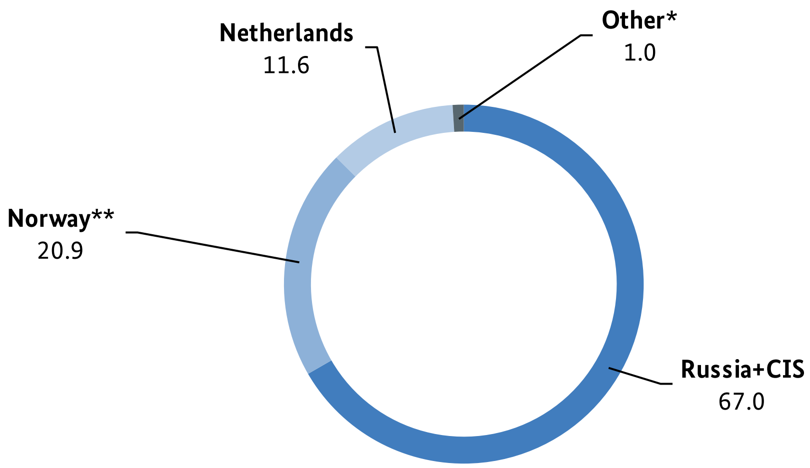
Gas: volumes imported to Germany (physical flows) in 2020 - broken down by transfer country
(%)



* Other countries: Belgium, Denmark, Austria

Figure 142: Gas volumes imported to Germany in 2020 by transfer country

Gas: volumes imported to Germany (physical flows) in 2020 - broken down by source country
(%)



* Other countries: Belgium, Denmark, Austria
** Includes gas from UK

Figure 143: Gas volumes imported to Germany in 2020 by source country

In 2020, the total volume of natural gas exported by Germany was 814 TWh. As the previous year's figure was 701 TWh, exports from Germany were up 113 TWh. When looking at the destination countries, the focus here is on the countries that Germany exports to at their given cross-border interconnection point.

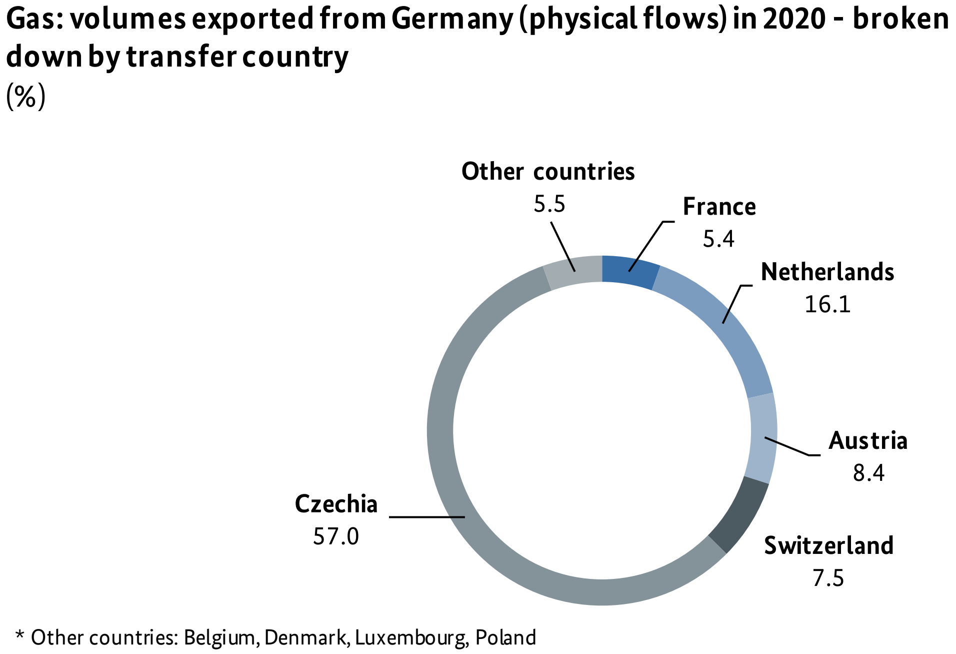


Figure 144: Gas volumes exported from Germany in 2020 by importing country

The tables below provide a consolidated overview of 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 2020 and 2019.

Gas: changes in imports (physical flows)

	Imports 2020 (TWh)	Imports 2019 (TWh)	Year-on-year change (TWh)	Year-on-year change (%)
Russia (Nord Stream)	621.4	613.9	7.5	1.2
Poland	263.4	287.5	-24.1	-8.4
Norway	349.1	300.2	48.9	16.3
Netherlands	194.3	241.7	-47.4	-19.6
Czechia	228.6	230.1	-1.5	-0.7
Austria	7.8	17.4	-9.6	-55.2
Belgium	9.6	9.3	0.3	3.2
Denmark	0.0	2.5	-2.5	-100.0
Total	1,674.2	1,702.6	-28.4	-1.7

Table 119: Changes in gas imports between 2020 and 2019

Gas: changes in exports (physical flows)

Importing country	Exports 2020 (TWh)	Exports 2019 (TWh)	Year-on-year change (TWh)	Year-on-year change (%)
Czechia	464.0	362.9	101.1	27.9
Netherlands	131.3	140.9	-9.6	-6.8
Switzerland	61.4	79.4	-18.1	-22.7
Austria	68.4	48.2	20.2	41.9
France	44.3	46.7	-2.4	-5.1
Belgium	7.1	17.6	-10.5	-59.4
Poland	8.2	4.1	4.1	100.5
Luxembourg	1.8	1.2	0.6	47.5
Denmark	27.6	0.1	27.5	27,540.0
Total	814.2	701.1	113.1	16.1

Table 120: Changes in gas exports between 2020 and 2019

3. Market area conversion

Over the next few years, gas supplies in north-western Germany will continue to be converted from L-gas to H-gas. A total of nearly five million appliances 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 charge. In 2020 this charge amounted to €0.5790 kWh/h/a. As a result of the increasing numbers of areas being converted, the charge for 2021 rose to €0.7291 kWh/h/a. In 2022, the charge will increase slightly to €0.7335 kWh/h/a as the number of appliances to be converted remains high. Apart from this, there is no impact on the gas bills of individual customers. Crucially, it is not allowed to charge consumers for hours worked or for materials needed for the technical adjustment of appliances. Rather, the network operators bear the costs and then get them reimbursed from the charge.

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 in the course of 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 significant amounts of gas will be exported from the Netherlands to Germany anymore 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 structure of natural gas supply will affect more than four million household, commercial and industrial gas customers that have 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. All larger network operators are now also in the process of converting their networks as well. Gastransport Nord, Gasunie Deutschland Transport Services, Nowega, Open Grid Europe and Thyssengas are the TSOs directly affected by the market area conversion. The planned conversions by individual network operators tend to take place in months when less gas is consumed, from April to October. Between 2021 and 2025, about 4,700 conversions will be carried out for interval-metered customers and about 2.1m for standard load profile (SLP) customers.

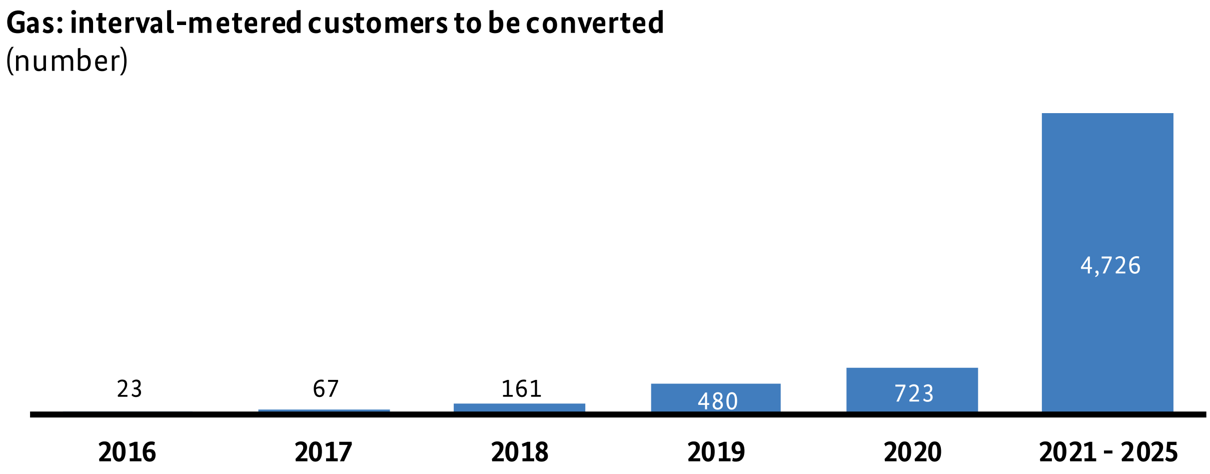


Figure 145: Interval-metered customers to be converted

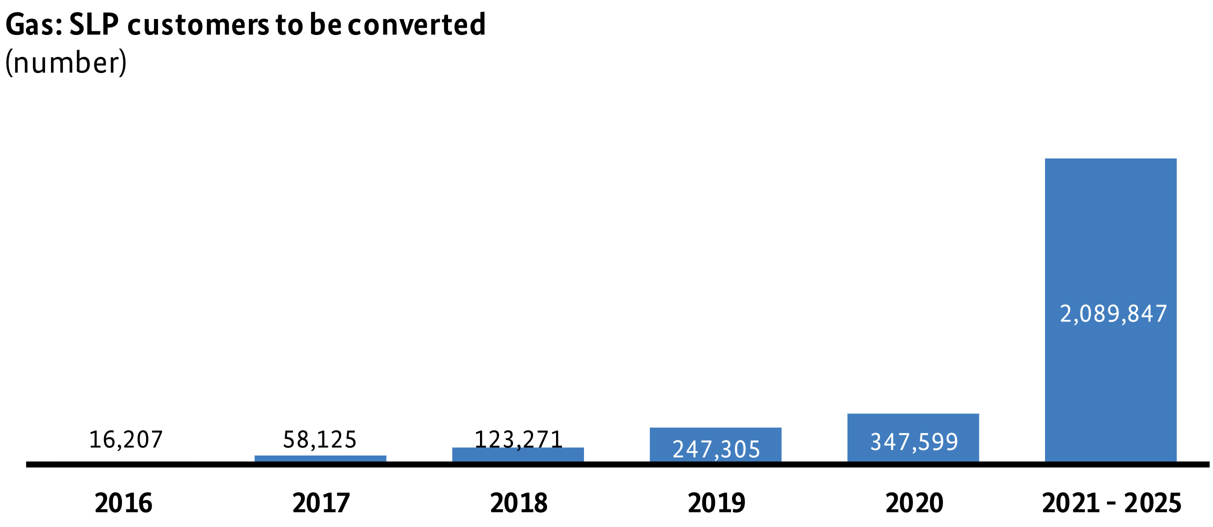


Figure 146: SLP customers to be converted

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 appliances are inspected again 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 40 active companies. A year ago it was 41. There continued to be a high response rate to the calls for bids from the network operators to carry out this work in 2020.

Gas: bids and awards for individual task packages for the market area conversion

Task packages	Bids				Awards			
	2017	2018	2019	2020	2017	2018	2019	2020
Appliance registration	7.1	7.3	7.3	9.4	3.8	2.6	3.3	3.6
Monitoring registration process	5.2	4.5	4.0	5.3	1.2	1.0	1.0	1.1
Conversion and appliance adjustments	7.0	7.4	7.3	9.2	3.7	2.6	3.3	3.5
Inspection of conversions and adjustments	5.2	4.6	4.5	5.6	1.5	1.0	1.0	1.1
Project management	4.2	4.4	3.8	4.3	1.1	1.0	1.0	1.0

Table 121: Bids and awards for task packages for the market area conversion

From a total of 35 network operators, 593,827 appliances were registered in 2020, of which 256,396 were condensing boilers (43.2%) and 63,605 self-adaptive appliances (10.7%). The proportion of condensing boilers had been 46.6% in 2019 and that of self-adaptive appliances 11.7%. During the reporting period, 347,599 appliances were adapted for SLP customers and 723 for interval-metered customers. A total of 9,066 appliances that were to be adapted could not be, a proportion of 2.6% (2019: 2.2%).

A total of 1,866 customers made use of the entitlement for a €100 rebate granted under section 19a(3) EnWG for the purchase of a new appliance that does not require adaptation in the course of market area conversion (2019: 1,523). There was a clear increase in the number of customers making use of the reimbursement granted under the Gas Appliance Reimbursement Ordinance (GasGKErstV), 287 compared to 193 the year before.

The market area conversion, too, was still affected by the coronavirus pandemic in early 2021, but in this area it actually turned out to be an advantage that many people were working from home and travelling less. Almost all network operators and companies carrying out adjustments reported that it was easier to make contact with customers for the conversions and many felt this outweighed the fact that individual steps are taking longer because of the hygiene and safety measures needed.

4. Biogas (including synthesis gas)

As at 31 December 2020, key biogas injection figures within the meaning of section 3 para 10c EnWG were as follows:

Gas: biogas injection 2020 key figures

	Injection, contractually agreed (million kWh/h)	Injection (kWh/a)	Number of plants
Biomethane	2.463	9,591.0	208
Hydrogen produced by water electrolysis provided that the electricity used to perform electrolysis is mainly and verifiably derived from renewable energy sources[1]	0.003	2.8	7
Synthetically produced methane provided that the electricity used to perform electrolysis and the carbon dioxide or carbon monoxide used for methanation are mainly derived from renewable energy sources[1]	0.041	0.3	2
Other (gas from biomass, landfill gas, sewage treatment plant gas and mine gas)	0.026	474.0	16
Total	2.533	10,068.1	233

[1] within the meaning of Directive 2009/28/EC (OJ L 140 of 5 June 2009, page 16)

Table 122: Biogas injection key figures for 2020

The costs for biogas passed on by gas network operators to all network users amounted to about €197m in 2020. That was the equivalent of about €0.0195 per kWh of biogas consumed, which is approximately the same as the average over several years as there is a close correlation between the network operators' costs and injected volumes.

5. Gas storage facilities

5.1 Access to underground storage facilities

Some 23 companies operating and marketing a total of 31 underground natural gas storage facilities took part in the 2021 monitoring survey. Two facilities are not currently being marketed. On 31 December 2020 the maximum usable working gas volume in the storage facilities was 274.72 TWh.[162] Of this, 136.01 TWh was accounted for by cavern storage, 117.01 TWh by pore storage and 21.71 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 (251.86 TWh, compared to 22.87 TWh for L-gas).

[162] This figure includes the 7 Fields storage facility and part 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 network in the Netherlands are not taken into account since they have no direct impact on the German gas network.

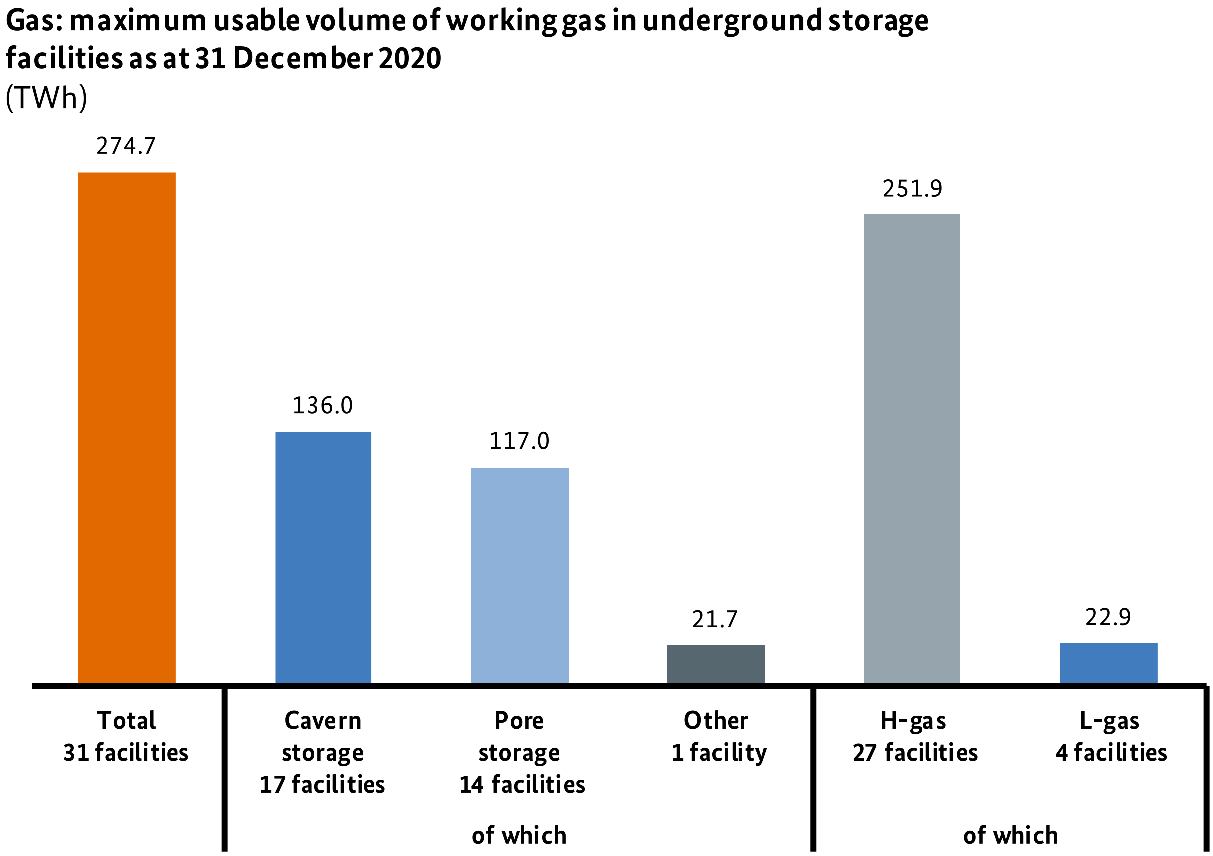


Figure 147: Maximum usable volume of working gas in underground natural gas storage facilities as at 31 December 2020

Around 106 TWh of gas has been injected into German natural gas storage facilities since the beginning of the injection season at the end of March 2021, taking the overall level of storage in the country to about 164.2 TWh. The storage level rose from just over 25% at the end of March to 71.3% as at 31 October 2021, below the curve of previous years at the same time.

Gas: changes in gas storage inventory levels in Germany
storage year 2021/22 in comparison to previous years
(%)

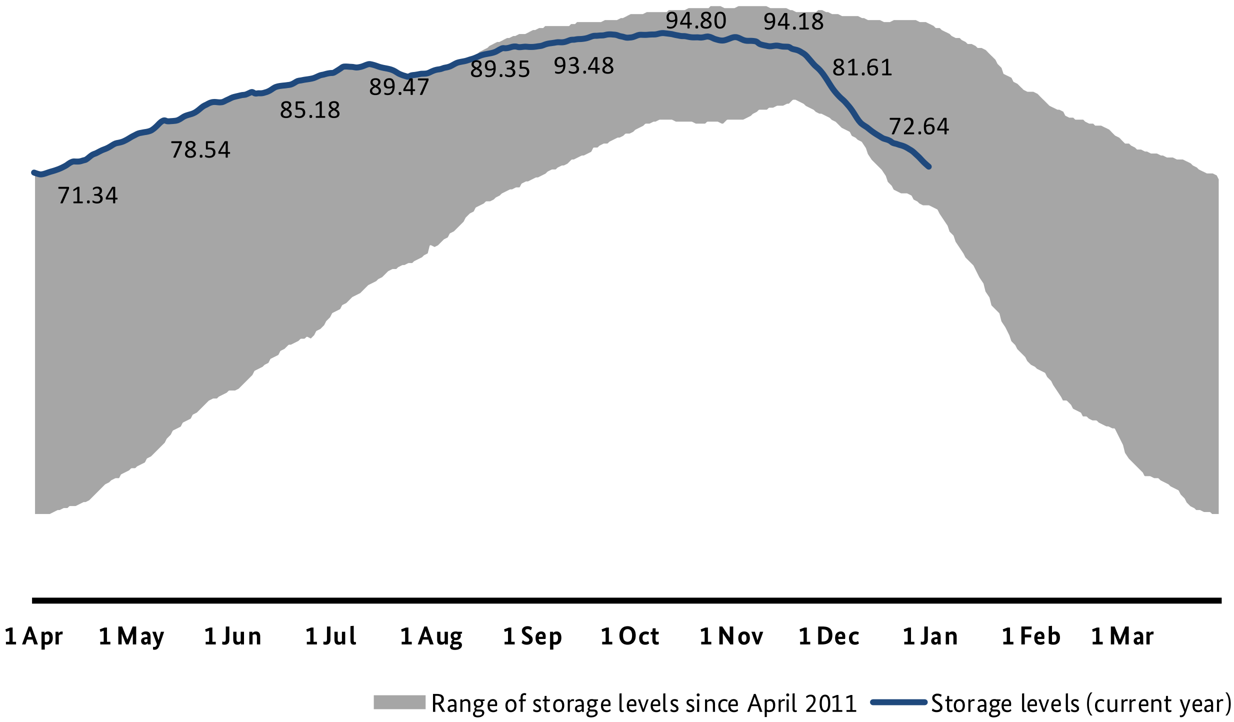


Figure 148: Changes in gas storage inventory levels in Germany – as at 31 October 2021 (source: AGSI+)

Comparing volumes shows that the amounts currently being injected into storage correspond to the figures from the storage year 2015-2016.

Gas: changes in gas storage inventory levels in Germany since April 2014
(TWh)

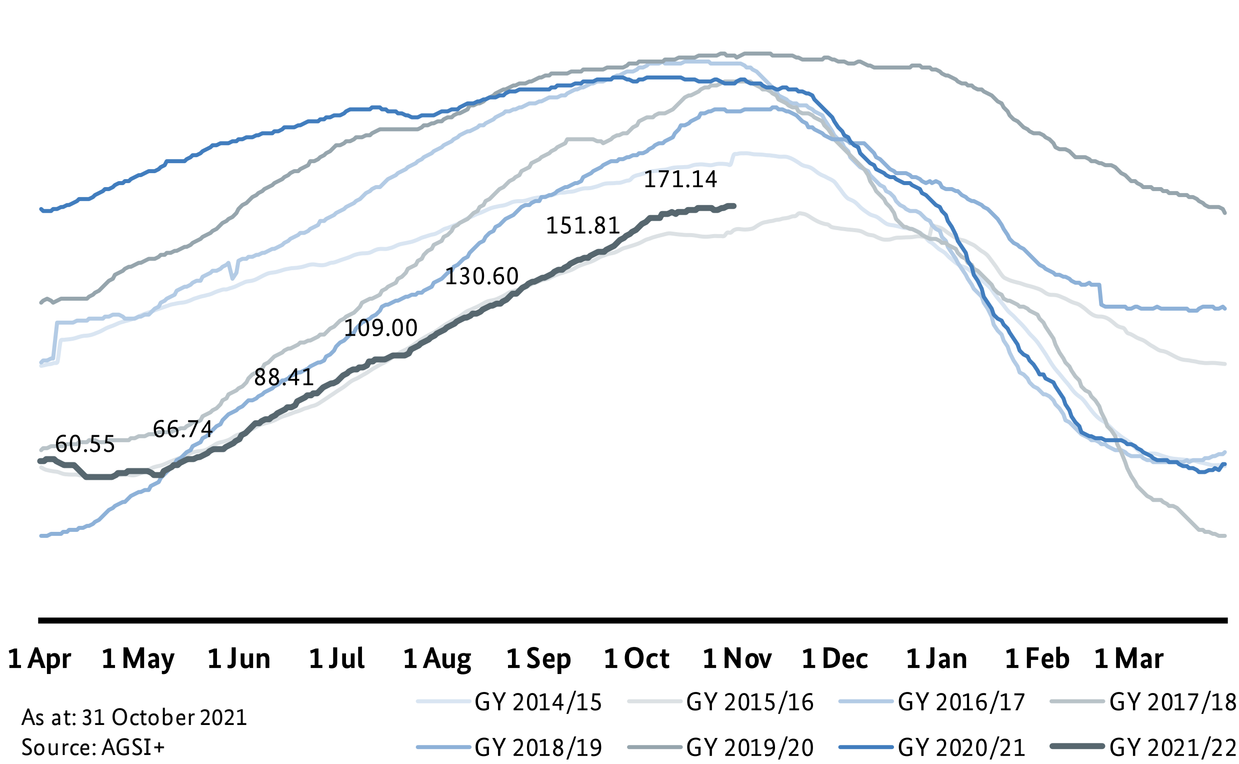


Figure 149: Changes in gas storage inventory levels in Germany each year since April 2014 (source: AGSI+)

However, there was a decisive difference this year.

At the beginning of winter 2015-2016, German storage facilities all had lower levels of gas, but this year the low total is primarily due to the low levels at the Rehden storage facility, operated by astora GmbH. It is barely 9.5% full and its level has fallen to 4.5% of working gas volume at times. As Rehden is Germany's largest natural gas storage facility and its working gas volume amounts to almost 20% of the total in the country (working gas volume at Rehden: 43.68 TWh; whole of Germany: 230.35 TWh), it has a significant impact on overall levels. What is more, the Haidach storage facility, which is located on Austrian territory but connected to the German system, is also very low at the moment (astora's part around 56.2% filled, Gazprom's part 2%).

All the other storage facilities are well-filled for the time of year, given the current gas prices. There are, therefore, regional alternatives to the storage facilities mentioned, which have higher levels. For Rehden, these include the cavern storage in Jemgum, Etzel and Epe and for Haidach, the storage facilities 7Fields, Bierwang and Breitbrunn.

Gas: overview of the five largest German storage facility operators

Storage operator	Total working gas volume (TWh)	Storage level as at 31 October 2021	
		(TWh)	(%)
Uniper Energy Storage	62.00	54.20	87.4
Astora*	51.89	11.25	21.7
VNG Gasspeicher	24.80	21.00	84.8
EWE Gasspeicher	21.70	17.93	82.6
Storengy Deutschland	18.29	15.09	82.5
RWE Gas Storage West	17.72	16.22	91.5

Source: AGSI+

*astora has been a wholly-owned subsidiary of Gazprom Germania since the asset swap between Gazprom and Wintershall; storage facilities Rehden, Jemgum and Haidach

Table 123: Overview of the five largest German storage facility operators (source: AGSI+, as at 31 October 2021)

The possible measures to improve security of supply are discussed in the latest report on the monitoring of security of natural gas supply.

The low levels of storage are partly caused by the development of gas prices this year. Prices have risen sharply, not just in Europe but worldwide, for a variety of reasons.

For one, the global economy is picking back up after the restrictions caused by the Covid-19 pandemic, which has also led to much higher demand for energy resources. The LNG sector has been facing some technical problems, which meant that normal volumes of LNG could not be loaded onto tankers in Australia, South America and Africa. In Europe, spring 2021 saw rather low temperatures for a sustained period, significantly extending the usual heating season and leading to a lot of gas being taken out of storage. Russian supplier Gazprom has sent hardly any volumes to the European market other than those for which it has contractual obligations. There were various reasons for this, too. The long winter led to Russian storage facilities being emptied and these had to be refilled. Moreover, there was restricted availability on the Yamal route following a fire in a processing plant on the Yamal peninsula in August. All these factors caused signs of scarcity on the European gas markets, leading to higher gas prices there, even coming close to the prices for LNG, which is traded worldwide. This in turn led to LNG deliveries reaching Europe in volumes that affected prices. As LNG is currently very expensive for the reasons given above, the high LNG prices are pushing the natural gas prices on the European gas markets up even more overall. In Germany, a year with little wind or sun led to greater use of gas-fired power plants, which increased the demand for gas too.

In recent years, Europe benefited from the fact that gas imported by pipeline was much cheaper than the global market price for (LNG) gas. The Bundesnetzagentur takes the view that the current prices are not a sign of a lack of security of supply but an indication that the European gas market is established and functioning. The agency therefore considers that market invention should be avoided. Whether, and to what extent, measures are taken to offset the high prices for consumers and businesses is not the focus of this report.

No marketed storage facility in Germany was used for production operations in 2020.

5.2 Use of underground storage facilities – customer trends

Of the 23 storage facility operators, 21 of them answered the question about the use of their storage facility by integrated undertakings within the meaning of section 3 para 38 EnWG. The range of their answers went from no use by integrated undertakings to 100% use by them. Overall, about 61% of storage volume (around 167.9 TWh) of the 21 operators that responded was booked by integrated undertakings. For more than half of the storage facility operators that responded (12 of them), the booking rate by integrated undertakings was over 75% (corresponding to 136.0 TWh in total). According to the data provided by 23 companies, the average number of storage customers in 2020 was 6.5 (2019: 5.3). The table below shows the trend in the number of customers per storage facility operator.

Gas: changes in the number of customers per storage facility operator
(number of storage companies)

No. of customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	8	7	9	8	10	11	9	10	11	9
2	2	3	3	4	2	2	2	4	2	3
3 - 9	6	7	7	5	4	6	6	4	6	4
10 - 15	1	2	2	3	3	1	3	4	3	3
16 - 20	1	1	2	1	1	2	3	2	1	2
> 20	1	1	1	2	2	2	0	0	1	2

Table 124: Changes in the number of customers per storage facility operator over the years

5.3 Capacity trends

The following chart shows the working gas capacity still bookable on 31 December 2020 in underground natural gas storage facilities compared to the previous years.

Gas: changes in the freely bookable working capacity, as offered on 31 December, in the subsequent periods from 2016 to 2020
(TWh)

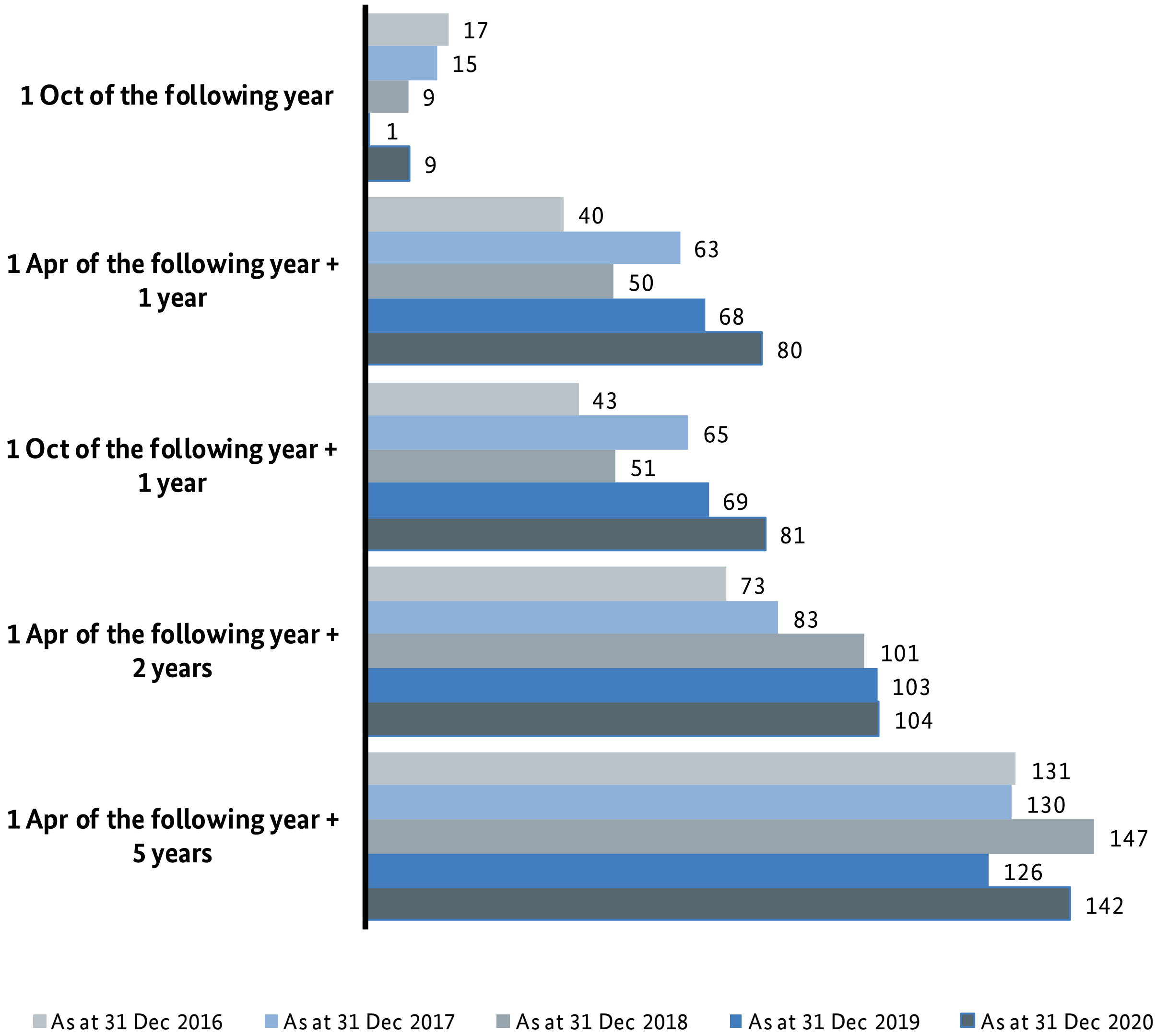


Figure 150: Changes in the freely bookable working gas capacity in the subsequent periods

The volume of short-term (up to 1 October 2021) freely bookable working gas rose again and there was a slight rise in the long-term bookable capacities as well.

C Networks

1. Network expansion

1.1 Gas Network Development Plan

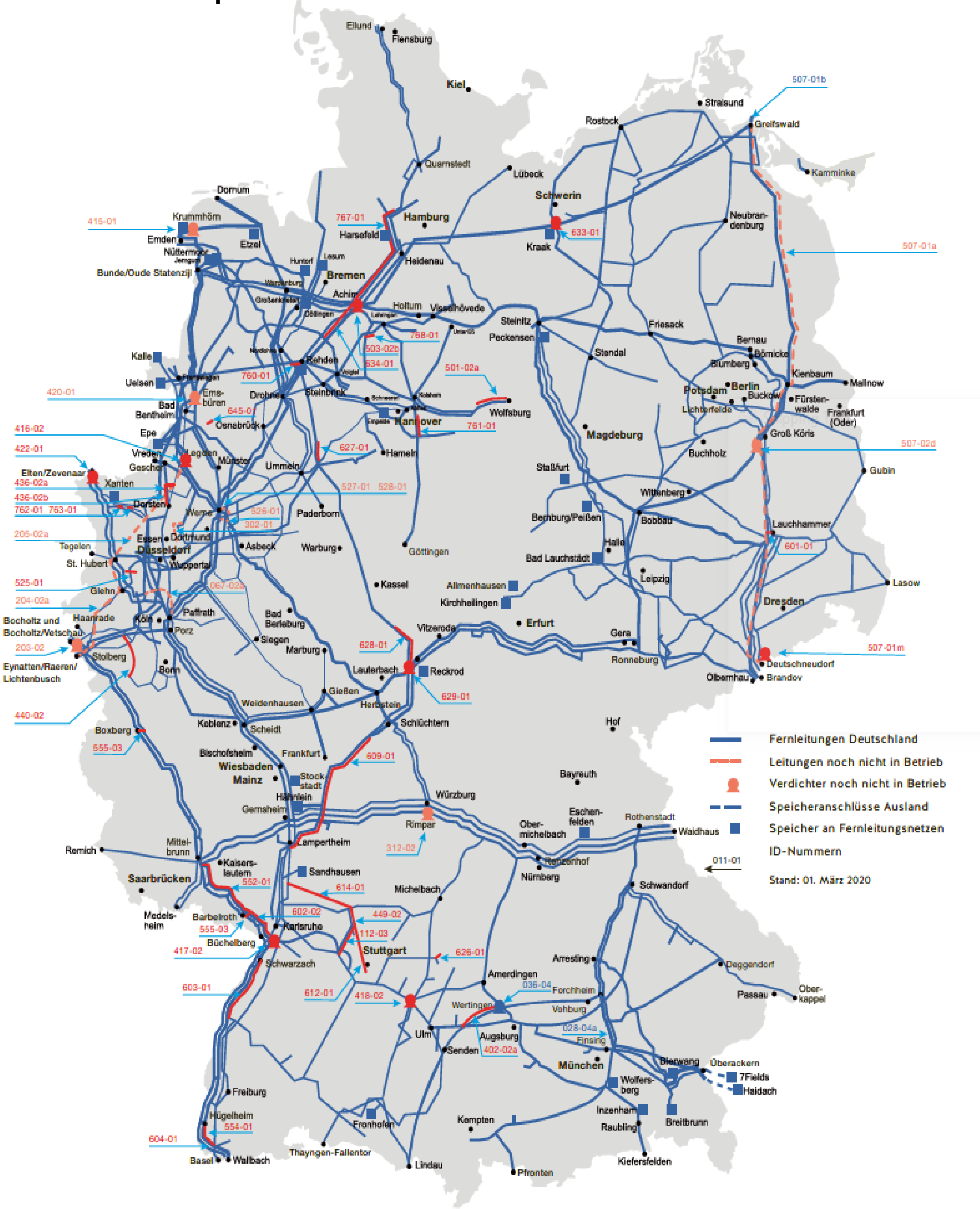
The Gas Network Development Plan (Gas NDP) is used to determine measures for optimisation, reinforcement and expansion of the network in line with demand, and for maintaining security of supply. These will be necessary in the next decade to ensure secure and reliable network operations. The Gas NDP is published every two years (in even-numbered years). It focuses on expansion issues resulting from the connection of new gas power plants – there is an interconnection here with the electricity market – and of gas storage facilities and industrial customers. It also looks at connections between the German gas transmission network and those in neighbouring European countries and at capacity needs in the downstream networks.

For the first time, hydrogen projects were considered and determined as part of the Gas NDP 2020-2030.

The confirmed measures therefore also include projects that involve removing pipelines and/or gas pressure regulating and metering stations from the natural gas network for conversion to hydrogen. This will enable a hydrogen network to be established swiftly where and if pipelines are no longer needed for the transport of natural gas.

This approach also conforms to the provisions on the regulation of hydrogen networks that entered into force on 26 July 2021. According to section 113b EnWG, the Gas NDP can identify pipelines that are to be converted to hydrogen and can also include (minor) expansion measures for the natural gas network that enable the conversion to hydrogen to take place. On 1 July 2020, the TSOs submitted their draft Gas NDP 2020-2030 to the Bundesnetzagentur. On 19 March 2021, after reviewing the plan, the Bundesnetzagentur came to a decision on the Gas NDP 2020-2030 with the formulation of a request for amendment.

Gas: expansion measures according to request for amendment for Gas Network Development Plan 2020-2030



Source: transmission system operators

Figure 151: Expansion measures for the natural gas network according to the request for amendment by the Bundesnetzagentur for the Gas NDP 2020-2030

The Gas NDP 2020-2030 comprises 215 measures with an investment volume of €8.5bn. Compared with the Gas NDP 2018-2028, a total of 60 new measures have been added. Most of the additionally proposed measures are related to the planned liquid natural gas (LNG) facilities, the expansion measures necessary for green gases, gas supply in Baden-Württemberg and security of supply in the Netherlands, Switzerland and Italy.

The ongoing market area merger does not necessitate any network expansion because the transport capacity can be secured within the future single market area using market-based instruments (MBIs). Depending on which assumptions are applied, the TSOs forecast that costs amounting to €1.1m to €27.6m for the 2025/26 gas year and €7.6m to €68.3m for the 2030/31 gas year will arise from the use of MBIs. The wide range in costs is the result of different scenarios being considered. The TSOs, on the other hand, assume comparatively higher costs for the alternative network expansion measures. They therefore do not propose any expansion measures that could reduce the need for MBIs.

In the request for amendment, the Bundesnetzagentur confirms 175 of the measures proposed by the TSOs, with an investment volume of around €7.83bn. The confirmed measures include pipeline extension totalling 1,620 km and increased compressor capacity amounting to 405 MW.

The Bundesnetzagentur is also enabling the establishment of infrastructure for hydrogen. A total of 24 pipelines and/or gas pressure regulating and measuring stations were identified in the natural gas network that are no longer needed for natural gas transport and can be converted to hydrogen. This enables the gas TSOs to establish a hydrogen network without delay and without neglecting their transport tasks in the natural gas network. According to the provisions that entered into force as a result of the EnWG amendment of July 2021 the TSOs can also use the Gas NDP to indicate which pipelines can be converted to hydrogen. In addition, minor expansion measures in the natural gas network for these conversions can also be confirmed.

Furthermore, the new provisions include the possibility of hydrogen network operators opting in to regulation. To this end, the hydrogen network operators must declare to the Bundesnetzagentur that their hydrogen networks should be subject to regulation. The Bundesnetzagentur then carries out an ad hoc demand assessment of all hydrogen pipelines of each network operator. This assessment of the hydrogen network infrastructure by the Bundesnetzagentur is based in particular on a roadmap for hydrogen infrastructure agreed between network users and network operators in the context of negotiated network access.

The process of establishing the Gas NDP 2022-2032 began in June 2021 with the publication of the consultation document on the scenario framework by the TSOs. The scenario framework contains the input variables necessary to prepare the Gas NDP. So far these variables mainly consist of assumptions relating to capacity planning within a ten-year time frame on the basis of future capacity requirements in downstream distribution networks and on the planned connection of new gas-fired power plants, gas storage facilities or LNG facilities to the transmission network. Climate and environmental policy targets have as yet not been integrated into gas network planning.

In order to create a scenario framework for the NDP 2022-2032, the TSOs have carried out a further market survey on hydrogen supply and demand for the purposes of planning the establishment of a hydrogen infrastructure. Reports of 500 projects have been submitted to this survey. The TSOs intend to take account of the great importance of hydrogen and green gases by creating a modelling variant of their own in addition to needs-oriented planning for the gas network.

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 process to assess the market demand for additional gas transport capacity at cross-border interconnection points ("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, starting in April 2017, can be subdivided into three phases: a demand assessment, followed by – if it is found that there is non-binding demand for incremental capacity at cross-border interconnection points – a structured design phase and finally a booking and realisation phase.

Incremental capacity process 2019 to 2021

1) Demand assessment

The market demand assessment process was completed by the TSOs in October 2019. In the course of this process the TSOs evaluated all non-binding demand indications for additional gas transport capacity at the market area borders into Germany (Trading Hub Europe – THE). Demand indications for incremental gas capacity and/or capacity to be upgraded were registered at six market area borders into/out of Germany (Denmark – THE, Russian Federation – THE, Poland – THE (Mallnow), Poland – THE (GCP), THE – Austria (Tirol), THE – Switzerland and THE – Netherlands).

2) Design phase

After the market demand assessment reports were published, the TSOs launched the design phase for these non-binding demand indications. During this period, until August 2020, the TSOs carried out technical studies on projects providing incremental 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 incremental capacity registered in seven locations. During the planning phase it became clear that the THE – Austria (Tirol) capacity demand indicated could be provided by the existing network infrastructure (capacity offer in the 2020 annual auction) and that it was therefore not necessary to initiate a project. In August and September 2020, the TSOs concerned also conducted a consultation on their results to lay the groundwork for concrete project proposals. This second phase of the process concluded with the drafting of project proposals and determination of the parameters for the economic test for the referenced incremental capacity projects.

During the period from October to December 2020 the TSOs concerned submitted these proposals to the responsible national regulatory authorities for coordinated approval. Particularly in light of the market area merger and changes to the framework conditions, and given the interdependency of the individual projects in the event of their realisation, designing and reviewing the projects during the 2019-2021 incremental capacity cycle was especially challenging. The individual projects, coordinated between the neighbouring regulatory authorities, were subsequently approved in April 2021.

3) Booking phase and market testing

After the regulatory authorities granted the approval, the new gas transport capacity was offered to the market participants for binding booking together with any existing capacity. As a rule, auctions are used to allocate additional 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 NDP at the size confirmed by the market. The Bundesnetzagentur has been actively involved in 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.[163]

During the 2019-2021 cycle no bookings were made in any project offering incremental capacity. Consequently, the results of all economic tests were negative. The non-binding transport capacity demand indications determined at the start of the process were therefore not created and the TSOs are not obliged to implement the corresponding network expansion measures.

The 2021-2023 cycle began immediately after the annual auction on 5 July 2021, with the TSOs' market demand assessment.

2. Investments

Investments as defined in the monitoring survey are considered to be gross additions to fixed assets capitalised in 2020 and the value of new fixed assets newly rented and hired in 2020. 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).

2.1 Investments and expenditure by TSOs

In 2020 the 16 German TSOs invested a total of €995m (2019: €1.33bn) in network infrastructure. Of this total, €638m (2019: €1.08bn) was investment in new installations, expansion and extension and €357m (2019: €249m) investment in maintenance and renewal of network infrastructure.

With regard to the distribution of investment expenditure between the two German market areas, the overhang in the GASPOOL market area continues, although the difference is now smaller compared to the previous year. Of the total investments in 2020, a significantly larger share, 58%, was attributed to the transmission systems in the GASPOOL market area and 42% to the NCG market area (2019: 66% GASPOOL, 34% NCG). The investments planned for 2021 amount to a total of €761m, which would equate to a decrease of 24% compared to 2020. This relatively large fluctuation in investment expenditure in network infrastructure and the distribution between the two market areas are a result of capital-intensive investment in a few individual large-scale projects.

Across all TSOs, expenditure on maintenance and repair of network infrastructure amounted to €402m in 2020 (2019: €622m), with expenditure in 2020 and planned expenditure for 2021 shared almost equally between the two market areas.

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[163] https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK09/BK9_21_AV/08_Incr_Cap_abg/BK9_Incr_Cap_abg_.html

The overall total for investments and expenditure in 2020 across all TSOs was approximately €1.40bn (2019: €1.65bn). The chart below shows investments and expenditure both separately and as a sum total since 2013, as well as the planned figures for 2021.

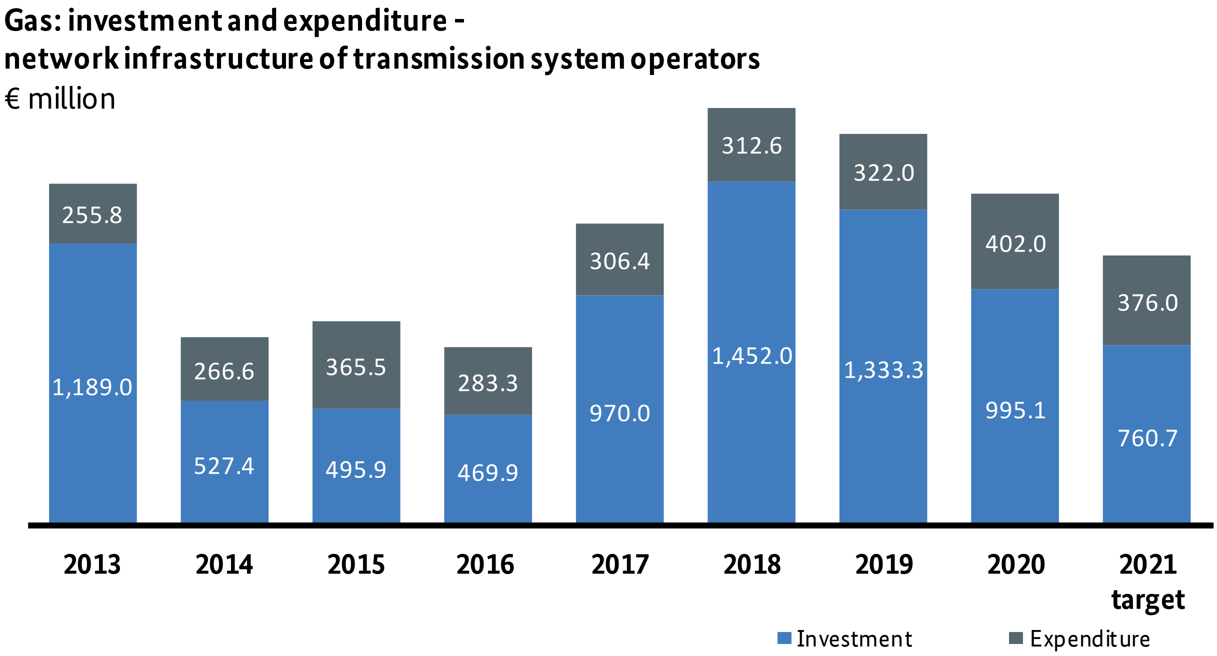


Figure 152: Investments in and expenditure on network infrastructure by TSOs

2.2 Investments in and expenditure on network infrastructure by gas DSOs

In the course of data collection for the 2021 Monitoring Report, more than 600 of the surveyed gas DSOs declared investment in new installations, expansions and extensions (€1,044m compared to €940m in 2019) and maintenance and repair (€631m compared to €549m in 2019) of network infrastructure, totalling €1,674m compared to €1,488m in 2019. The projected total investment for 2021 is €1,689m.

According to the gas DSOs' reports, expenditure on maintenance and repair in 2020 was €1,365m (2019: €1,152m). The projected expenditure on maintenance and repair for 2021 is €1,183m.

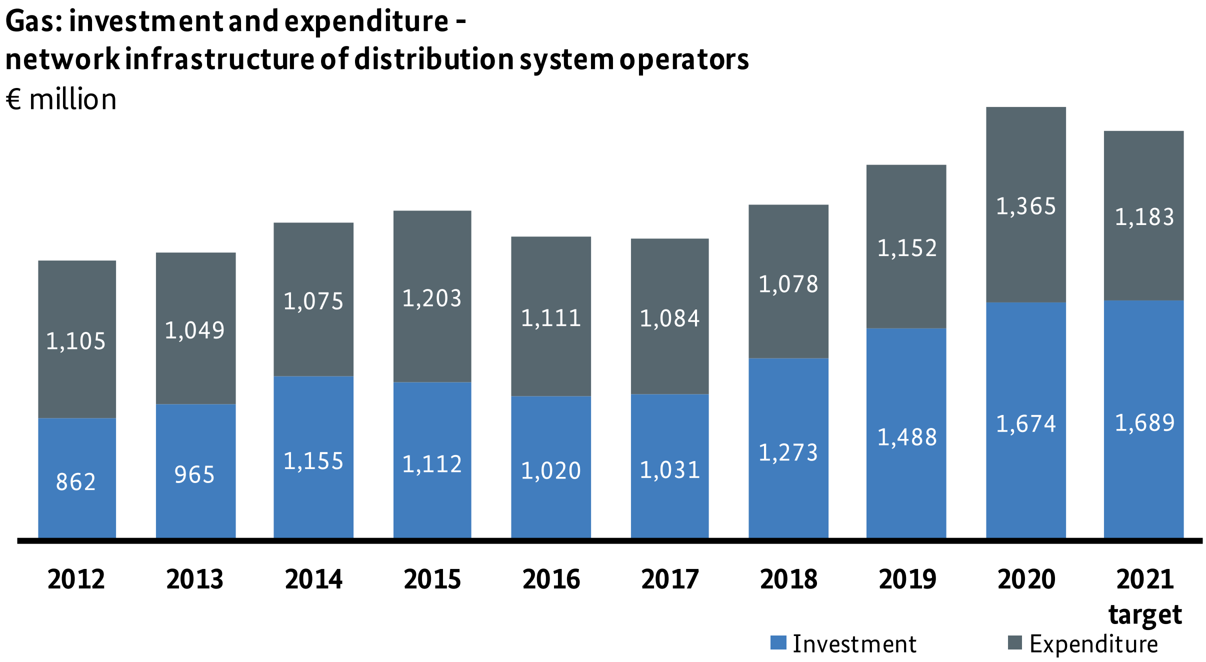


Figure 153: Progression of investments in and expenditure on network infrastructure by gas DSOs over time

The level of DSO investment depends on the length of their gas pipeline network and the number of market locations served as well as other individual structure parameters, including, in particular, geographical circumstances. While 176 of the surveyed gas DSOs reported investments of between €1m and €5m, 62 gas DSOs made investments totalling more than €5m.[164]

Of the surveyed gas DSOs, 236 reported total expenditures in the bracket between €100,001 and €500,000, while 55 gas DSOs reported expenditures totalling more than €5m.[165]

[164] These figures are based on data submitted by 617 DSOs.

[165] These figures are based on data submitted by 599 DSOs.

Gas: DSOs broken down according to level of investment in 2020
Number and %

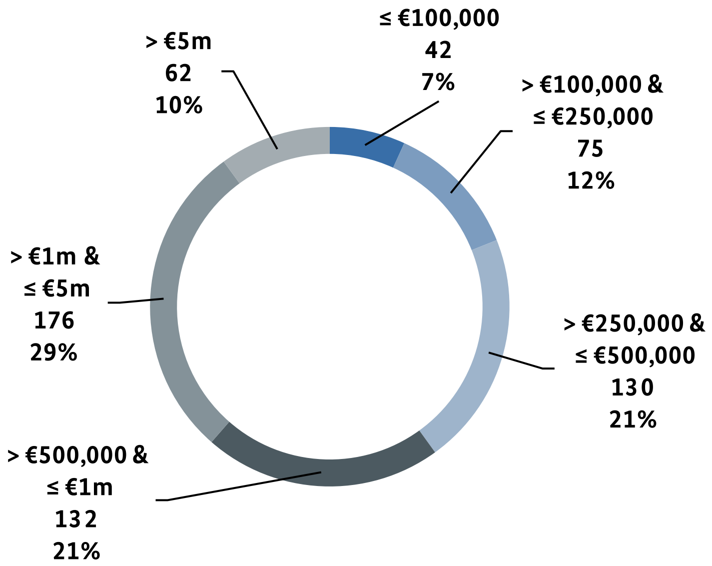


Figure 154: Distribution of gas DSOs according to level of investment in 2020

Gas: DSOs broken down according to level of expenditure in 2020
Number and %

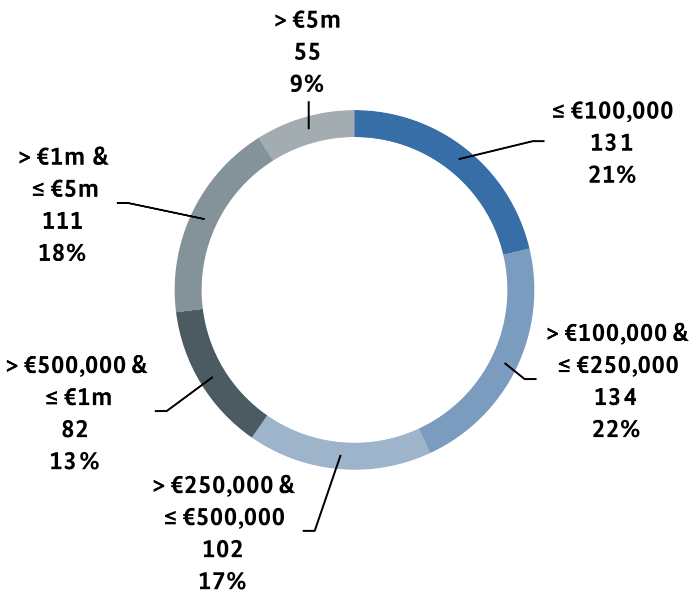


Figure 155: Distribution of gas DSOs according to level of expenditure in 2020

2.3 Investments and incentive-based regulation

The Incentive Regulation Ordinance (ARegV) offers TSOs an opportunity to budget for costs for expansion and restructuring investment in the network charges over and above the level approved in the revenue caps. Based on section 23 ARegV, upon application the Bundesnetzagentur grants approval for individual projects if the prerequisites stated in the Ordinance have been met. Once approval has been granted, the TSOs may adjust their 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.

2.3.1 Investment in network expansion by the TSOs

As of 31 March 2021, the TSOs had submitted 18 applications for investment projects to the competent Ruling Chamber. The costs of acquisition and production linked to these measures amount to €770m. Compared to 2020, the number of applications submitted by the TSOs fell by more than half. In line with the reduced number of applications, the investment volume covered by the applications was also more than halved.

2.3.2 Capex mark-up

The Bundesnetzagentur implemented the capex mark-up, a newly introduced instrument (section 10a ARegV), for the gas distribution networks at the start of the third regulatory period (as of 1 January 2018). This allows DSOs to apply every year for a mark-up on the revenue cap approved by the Bundesnetzagentur with respect to new investments. The application can be made on the basis of the projected costs; in other words, the network operators initiate the refinancing before the investments have actually been made.

The capex mark-up comprises the annual imputed capital costs in the form of depreciation, return on equity and trade tax and is incorporated into the revenue cap of the network operator.

In June 2021, Ruling Chamber 9 received 128 capex mark-up applications that were submitted by the gas network operators under its responsibility, with a total volume of €506m. Individual applications are approved in a timely fashion and thus in accordance with the objective of the ARegV instrument to adjust the revenue cap to match the latest changes.

2.4 Rates of return for capital stock

Investments in electricity and gas networks are extremely capital-intensive. The capital stock formed provides the key assessment basis for calculating the corporate gain, the return on equity and any interest on debt necessary through equity substitution, and the imputed corporate tax. Together with the imputed depreciation, these figures form what is known as the regulatory allowed capital costs.

2.4.1 Rate of return on equity

The assessment basis for the capital costs is essentially determined by the costs of acquisition and production, or the depreciable residual values, of the regulatory asset base (RAB). The cost of equity is calculated by adding the necessary current assets to the residual value of the regulatory asset base and deducting the borrowed capital. The rate of return on equity is determined on the basis of a risk-free base rate supplemented by a risk premium. The risk-entailing return on securities in the market balance can be expected to be derived from the sum of the risk-free return and the risk premium (capital asset pricing model: CAPM). The risk premium is the product of the market price for the risk (market risk premium) and the risk that cannot be eliminated by diversification compared with the market as a whole (beta).

The level of the rate of return on equity is a key figure in regulated markets. The chart below (Rate of return on equity) shows the regulatory rates of return on equity allowed under the ARegV or through actual determinations. Initially successful appeals against the determination proceedings to determine the rate of return on equity for the third regulatory period (RP), separately for both gas and electricity supply networks, were submitted to the Higher Regional Court of Düsseldorf. However, the Federal Court of Justice issued a final decision on 9 July 2019 in which it confirmed in full the legality of the determination by the Bundesnetzagentur.

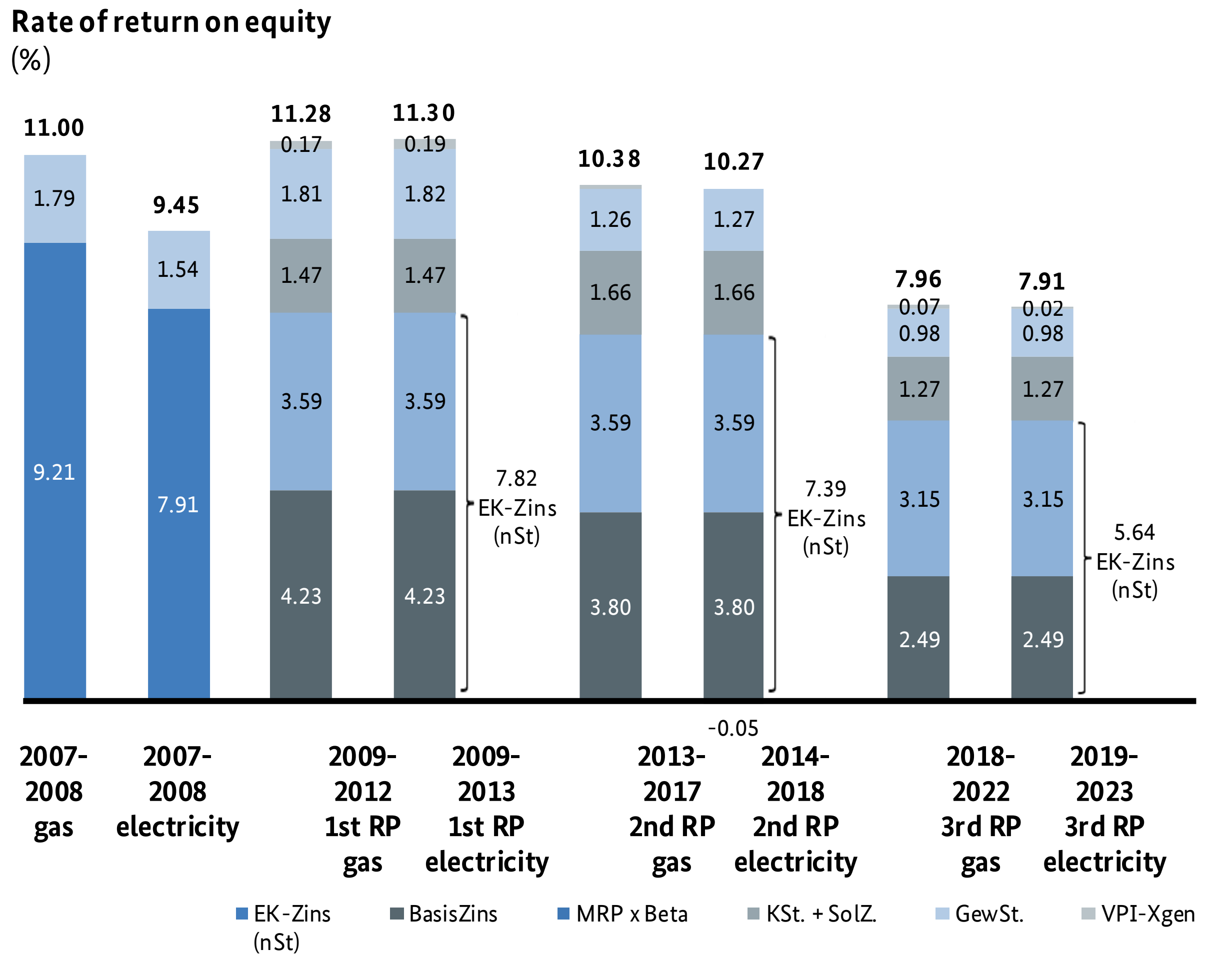


Figure 156: Rate of return on equity

2.4.2 Rate of return on equity II

Equity may be substituted by the use of borrowed capital. In practice, complete substitution by borrowed capital is impossible because no outside creditors are likely to be willing to advance capital without any recoverable assets. The higher the level of equity capital, the lower the rate of return on borrowed capital demanded should tend to be. The GasNEV confirmed the empirical finding that if the level of equity capital exceeds 40%, using equity is no longer worthwhile as this cancels out the lowering effect on the rate of return on borrowed capital. If the equity ratio exceeds 40%, the proportion of equity above 40% is therefore treated like borrowed capital, in other words the return on the equity in the capital structure over and above this is calculated using the rate of return determined in accordance with section 7 para 7 StromNEV or GasNEV (averaging over 10 years) (rate of return on equity EKII).

2.4.3 Rate of return on borrowed capital

Within the scope of the various regulatory areas, borrowed capital is recognised in keeping with the actual interest rates at which financing was obtained unless the interest rates exceed customary market levels. However, assessment of individual cases is defined by a different eligibility limit, dependent on the type of regulation applied. Starting from the third regulatory period, the DSOs have also used the capital expenditure (capex) true-up, for which the rate of return on borrowed capital is calculated in line with the borrowing using the normal incentive regulation system. Accordingly, 3.03% was set for the gas sector and 2.72% for the electricity sector for the third regulatory period.

3. Capacity offer and marketing

3.1 Availability and booking of entry and exit capacities

As in previous years, for the 2019/20 gas year, 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 a transmission network. The volume of gas to be transported when use is made of this right is reported by the shippers by means of nomination. 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 and/or demand for firm capacity at cross-border and market area interconnection points and also at bookable entry/exit points to storage facilities, power stations and final customers. The charging model for gas transmission systems is fundamentally different from the model in electricity networks and gas distribution networks in that the latter do not have entry charges. In addition, the electricity network charging model does not feature capacity bookings at all.

This survey does not include the reserve capacity agreed with the downstream network operators within the internal booking process since the exit points to distribution networks are not marketed directly to shippers (see section 3.5 for more information on internal booking).

The various capacity products are defined in the determination on standardising capacity products in the gas sector (capacity product standardisation, "KASPAR").

Firm, freely allocable capacity (FZK) allows shippers to use booked entry and exit capacity on an unrestricted, firm basis without specifying a transport path.

Conditionally firm, freely allocable capacity (bFZK) allows shippers to use booked entry and exit capacity on a firm basis without specifying a transport path, provided that a pre-defined, external condition is met.

Firm, dynamically allocable capacity (DZK) allows shippers to use booked entry and exit capacity on a firm basis provided that, in the case of entry capacity, gas is injected at the booked entry point for withdrawal at a pre-specified exit point in the same market area and that, in the case of exit capacity, the gas injected at a pre-specified entry point in the same market area is withdrawn at the booked exit point. In addition, it allows shippers to use booked entry and exit capacity on an interruptible basis without specifying a transport path.

Interruptible capacity products: interruptible, freely allocable capacity (uFZK) allows shippers to use booked entry and exit capacity on an interruptible basis without specifying a transport path.

Capacity with limited allocability (BZK) is not defined in the KASPAR determination. From 1 October 2021 onwards it is therefore no longer permitted to offer this capacity. It was still offered, however, during the current period under review and hence in the following evaluations. The definition of the product essentially corresponds to that of the DZK product but with the difference that use without specifying a transport path (access to the virtual trading point) is ruled out.

During the period under review, further virtual interconnection points were created at various borders between neighbouring market areas. The legal basis for this is contained in Article 19 (9) of Regulation (EU) No 984/2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and supplementing Regulation (EC) No 715/2009. Accordingly, as of 1 January 2018, in cases where two or more interconnection points connect the same two adjacent market areas, the TSOs concerned were obliged to offer the capacities available at these interconnection points at one virtual interconnection point (VIP). The aim is that these VIPs should facilitate economic and efficient use of the system. The marketing of capacities at these points changes in as much as the capacities at a VIP are offered by so-called VIP TSOs. Capacities that were not contracted at the time of VIP implementation were therefore transferred to VIPs from various TSOs' physical interconnection points that were previously bookable individually. Although this results in shifts in the TSOs' capacity offers compared to the previous period under review, the implementation of VIP use should not have any appreciable impact on the aggregated figures at the level of market areas. Changes compared to the previous year would only occur in cases where the creation of VIPs itself results in an increase of the capacity offer. A reduction in capacity resulting from the creation of a VIP is ruled out by the network code, as it would mean that one of the conditions required for creating VIPs is not met.

In the 2019/20 gas year the total firm entry capacity offered across both market areas was 541.4 GWh/h, an increase of 24.4 GWh/h compared to the previous year. The offer of firm and freely allocable capacity (FZK) amounted to 137.6 GWh/h, corresponding to about 46.5% of the total entry capacity offered in the GASPOOL market area, a fall of 7.1% compared to the previous year. In the NCG market area the FZK offered was 102.3 GWh/h, corresponding to a share of 41.7% of the total capacity offered. The volume of this product offered (the product which ensures that shippers are able to allocate their entry capacity without restrictions) thus rose by 5.4% in the NCG market area. The total volume of entry capacity offered in the NCG market area equates to around 45.7% of the total entry capacity offered across both market areas. The remaining and larger share of 54.3% is attributed to the GASPOOL market area.

Gas: entry capacity offered in the 2019/2020 gas year
GWh/h

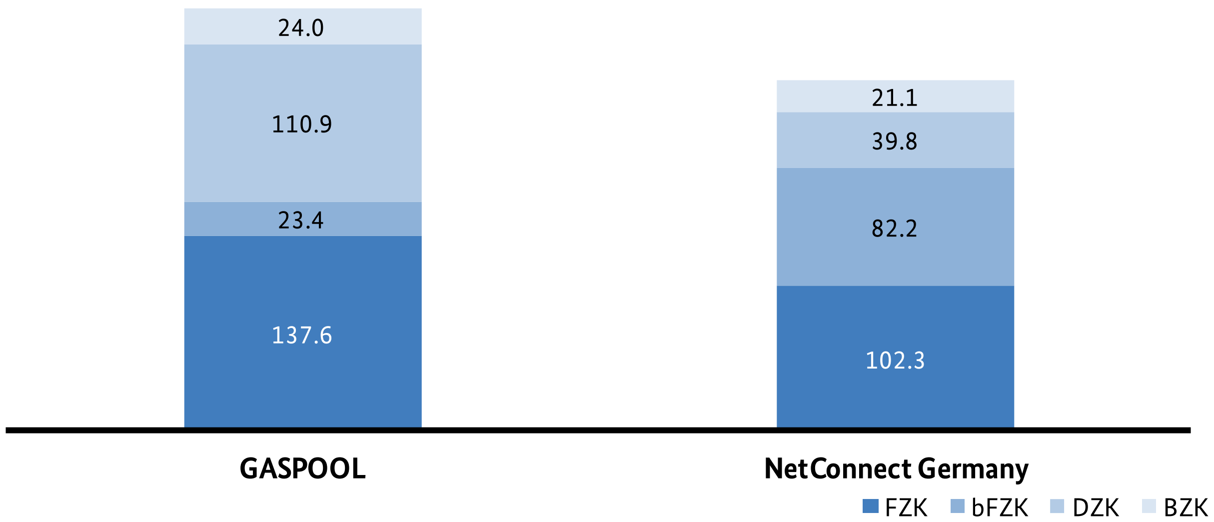


Figure 157: Entry capacity offered

Gas: exit capacity offered in the 2019/2020 gas year
GWh/h

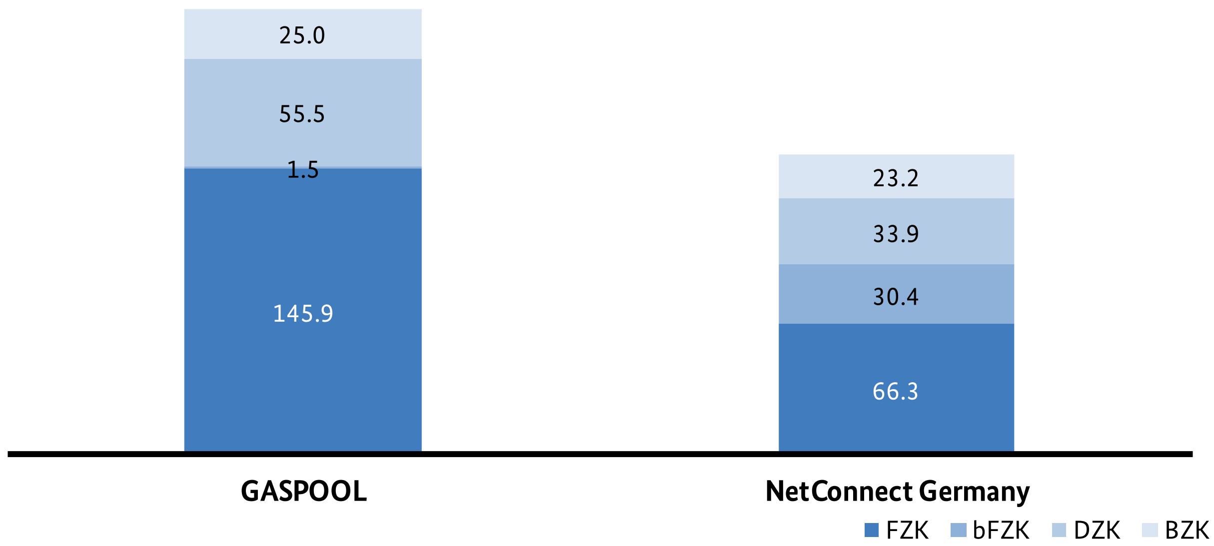


Figure 158: Exit capacity offered

In the 2019/20 gas year the total firm exit capacity offered across both market areas was 381.7 GWh/h, a slight increase of 0.5% compared to the previous year. It should be noted that not every transmission system operator offers all capacity products. The aggregated developments therefore cannot be projected onto each individual TSO.

The period under review includes the commissioning of the first section of the European Gas Pipeline Link (EUGAL), which took place on 1 January 2020. The pipeline connects the Lubmin II natural gas receiving station near Greifswald with the Czech network area. Lubmin II is intended to receive the additional gas volumes delivered through the Nord Stream extension. The entry capacity into the GASPOOL market area at the time of commissioning was 40.1 Gwh/h. By 2026, according to information from the TSOs, this will have increased in several stages to 78.6 Gwh/h under the scenario framework of the Gas NDP 2020-2030. After the market area merger planned for 1 October 2021, these entry capacities will enable access to the Germany-wide market area.

Another development has the opposite effect on the capacity offer in the GASPOOL market area. Shortly before the start of the period under review, OPAL Gastransport GmbH & Co. KG implemented a decision by the Bundesnetzagentur and reduced the capacity of the OPAL natural gas pipeline. The decision prohibited the network operator from marketing the partially regulated, decoupled interconnection capacity with a volume of 15.9 GWh/h. This is reflected in the offer of entry and exit capacity of the DZK quality in the GASPOOL market area.

As described above, the capacities for distribution networks and therefore the majority of final customers are allocated within the internal booking process and are not included in this list. The reason for this is that the distribution networks are also part of the market area so the interconnection capacity between the transmission networks and distribution networks is not commercially marketed. The marketing levels outlined above should therefore not lead to incorrect conclusions being drawn. 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 3.5). In 2020, the total capacity booked with TSOs by downstream DSOs was 271 GWh/h. This is roughly 71% of the bookable exit capacity offered in the 2019/20 gas year considered in this report. As the periods under review are different, however (capacity products are marketed on the basis of gas years, orders by DSOs are by calendar year) it is not appropriate to simply add the two figures together.

The TSOs were asked for information on the average capacity offer and also on the average level of bookings at cross-border and market area interconnection points and entry/exit points to storage facilities, power stations and final customers. These two figures can then be used to calculate the average booking rate at the bookable entry and exit points. The survey showed that in 2020, the year under review, the booking rate for firm capacity products (FZK, bFZK, DZK, BZK) was 49.9% (2019: 48.1%) on the entry side and 50.2% (2019: 55.4%[166]) on the exit side of corresponding capacities offered. The booking rates are subject to natural fluctuations year on year, depending on temperatures but also on market developments.

The relationship between the average offer level and booking level for each capacity product is shown in the two charts below.

[166] This figure has been corrected since last year's report.

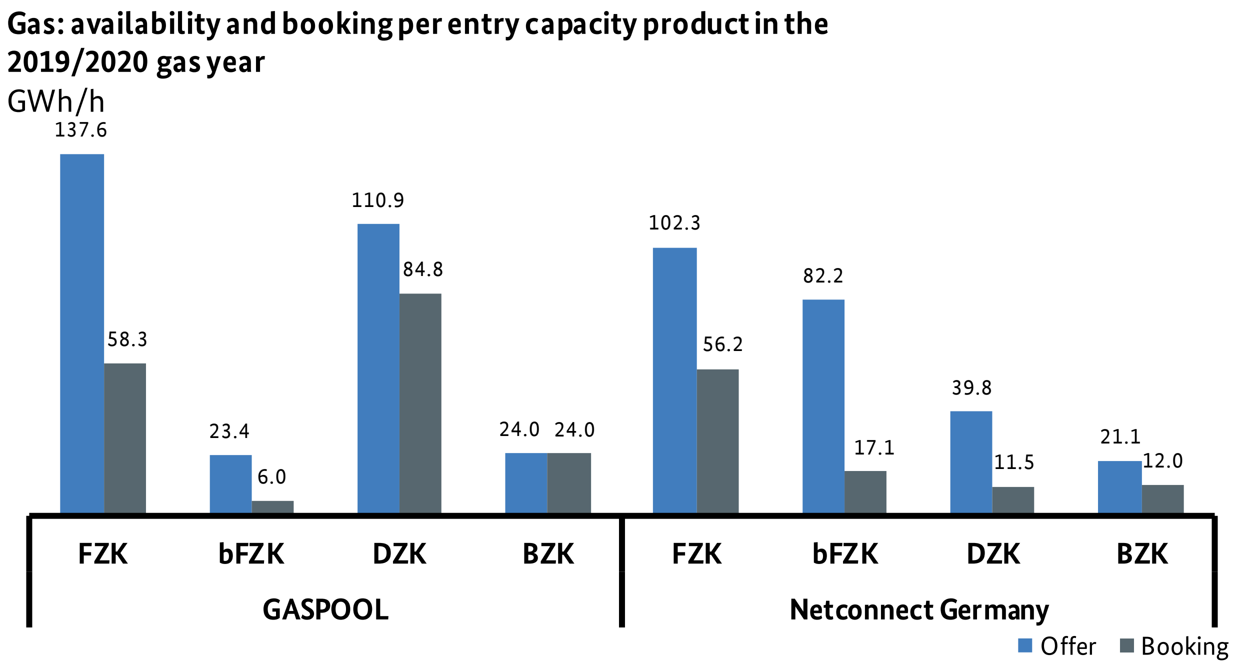


Figure 159: Booking per capacity product (entry)

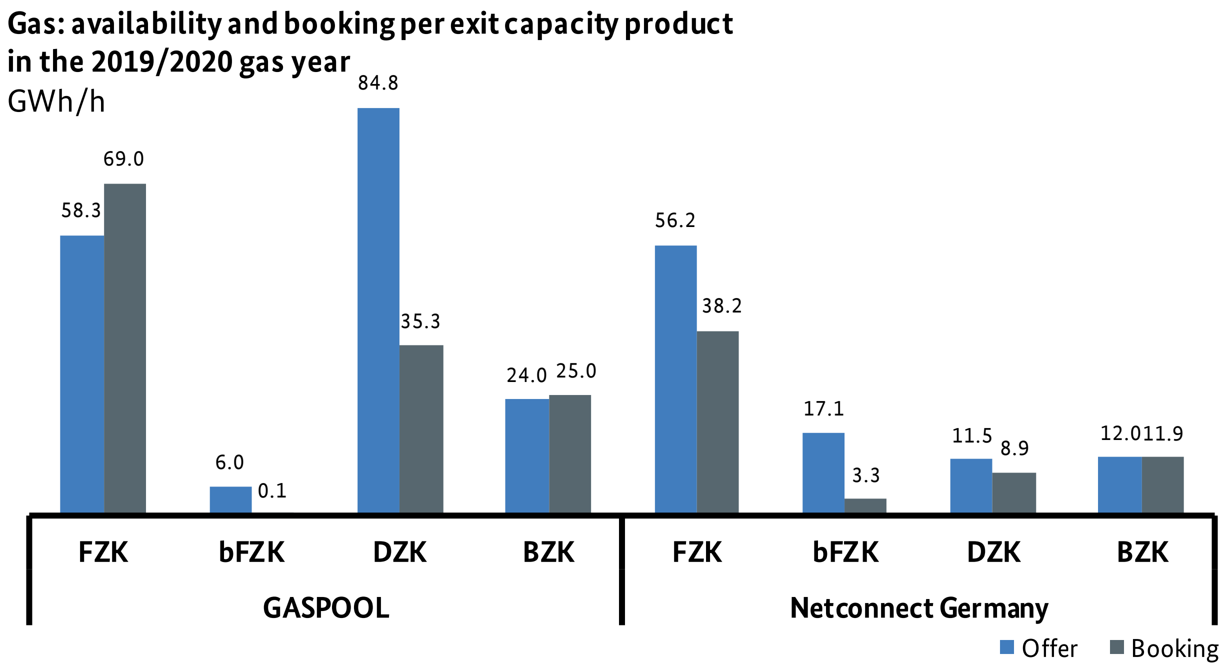


Figure 160: Booking per capacity product (exit)

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 demand for these capacities is lower than the amount offered, the TSOs market the remaining 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.

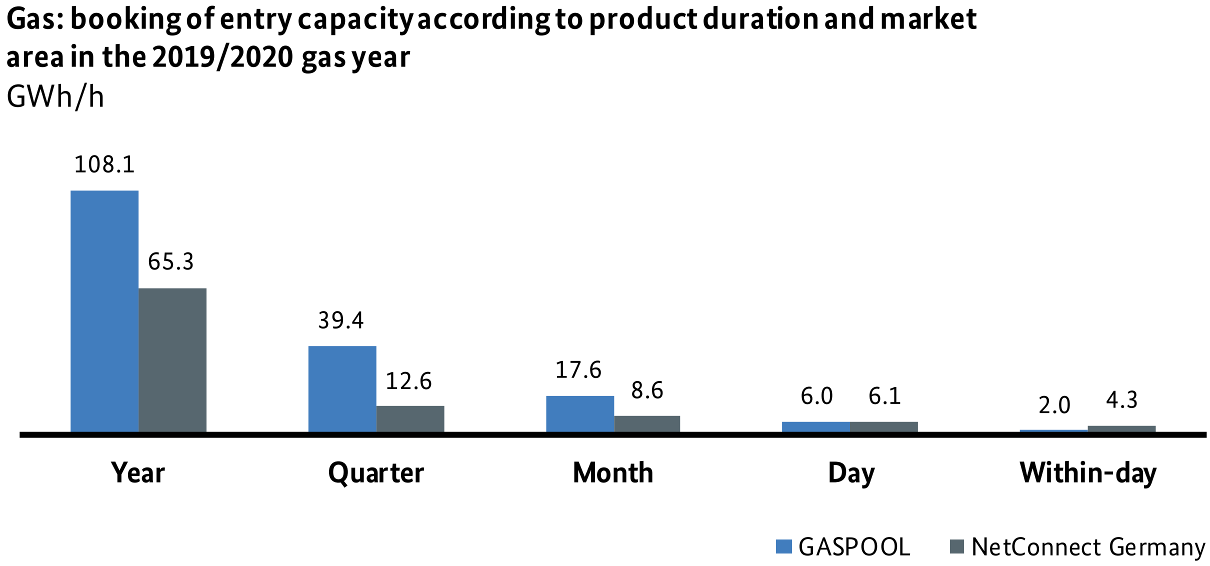


Figure 161: Booking of entry capacity according to product duration and market area

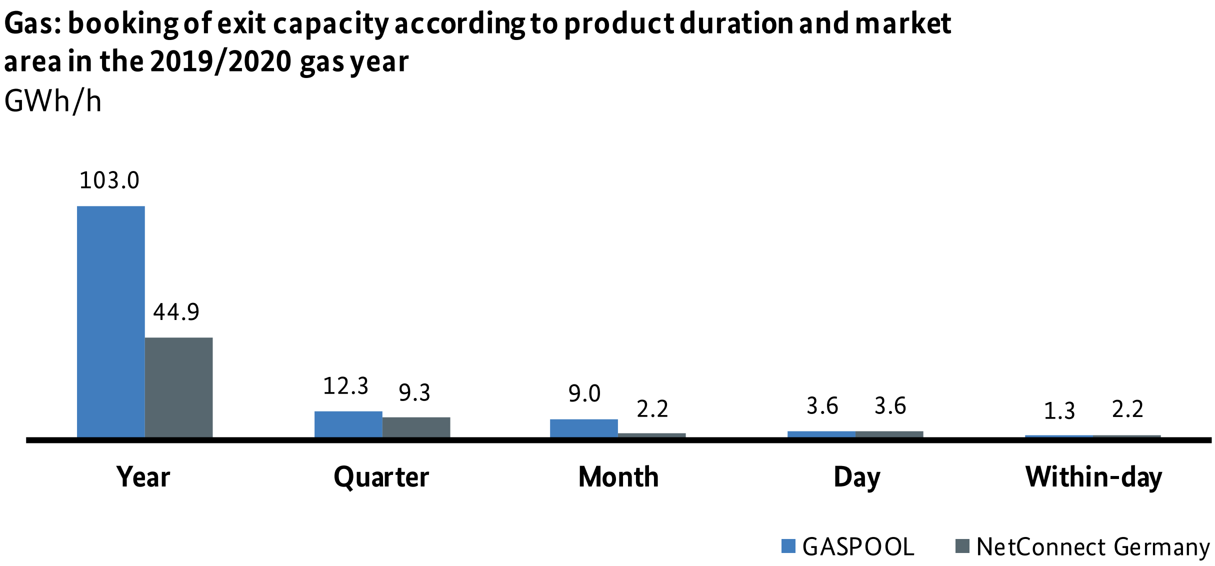


Figure 162: Booking of exit capacity according to product duration and market area

The values shown in the chart relate to the level of bookings in the period under review, regardless of when the corresponding capacities were booked. 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 2019/20 gas year considerably more entry capacity was booked than exit capacity. One reason for this is that a large share of the entry capacity bookings is used to supply final customers connected to downstream distribution networks. However, the German gas network access model does not oblige suppliers to book equivalent exit capacity when supplying gas in this way.[167] This correlation was already apparent in the charts of the corresponding capacity offers.

[167] The maximum firm exit capacity to be reserved at interconnection points or exit zones of the upstream network is ordered by the downstream distribution system operators.

Consequently the total volume of entry capacity booked was 269.9 GWh/h, significantly exceeding the exit capacity booked, which amounted to a total of 191.6 GWh/h.

In addition, the charts showing the entry and exit capacity bookings clearly illustrate 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 211.1 GWh/h (previous year: 220.1 GWh/h) of yearly capacity marketed and 51.7 GWh/(previous year: 28.2 GWh/h) of quarterly capacity marketed, was significantly larger than the long-term capacity booked in the NCG market area, where the corresponding volumes were 121.8 GWh/h (previous year: 110.2 GWh/h) and 22 GWh/h (previous year: 26.1 GWh/h) respectively. A lower level of booking of annual capacity can be observed in comparison with the previous year, whereas the booking of shorter-term capacity products, above all monthly, daily and within-day products, rose in both market areas. The fact that yearly capacity bookings are still the dominant share overall can mainly be explained historically because they also include the long-term capacity agreements with durations of several years that were entered into before the European Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems (NC CAM) entered into force. A simple comparison with the previous year, however, reveals the trend of a shift towards more within-year capacity bookings becoming apparent as these agreements gradually reach the end of their term.

As part of the survey, TSOs were also asked about levels of actual network use in the form of nominations by the shippers during the period under review. Across Germany, the TSOs reported a nominated quantity of 1,882 TWh at all entry points where there is a nomination obligation, a decrease of 5.1% compared to the previous year. In contrast, nominated quantities at exit points were considerably lower, totalling 1,000 TWh (an increase of 0.3%). The reason for the significantly lower figure on the exit side is that gas for domestic use in particular is withdrawn from the transmission network at exit points where there is no nomination obligation. The exit points where there is a nomination obligation are cross-border and market area interconnection points and exit points to storage facilities and domestic production. Exit points where there is no nomination obligation, on the other hand, as a general rule are those to final customers.

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 for good cause, for instance 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 circumstances, for example if capacity charges are increased over and above the rise in the consumer price index published by the Federal Statistical Office. 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 2020, a total of 39 capacity contracts with a duration of at least one month were terminated. This is a significant decrease compared to the previous year, when 67 terminations were reported. As a general rule, in this context it is possible to differentiate between the termination of capacity contracts according to types of product and categories of entry/exit point.

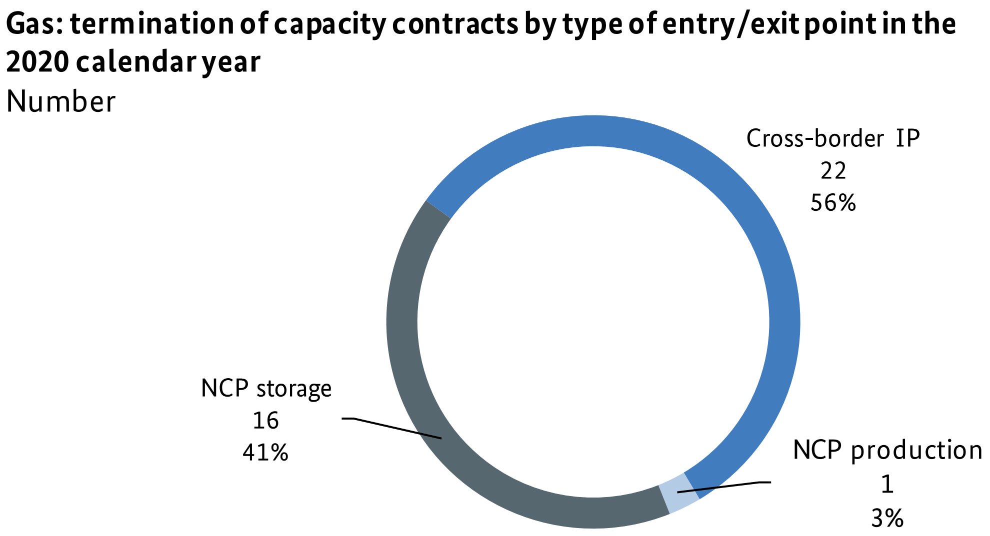


Figure 163: Termination of capacity contracts by category of entry/exit point in the 2020 calendar year

A total of 39 capacity contracts were terminated, of which 22 were contracts at cross-border interconnection points. A further 16 capacity contracts were terminated at storage facility connection points, and one at a gas production connection point. No capacity contracts were terminated at exit points to final customers, whereas in the previous year ten terminated contracts had been reported.

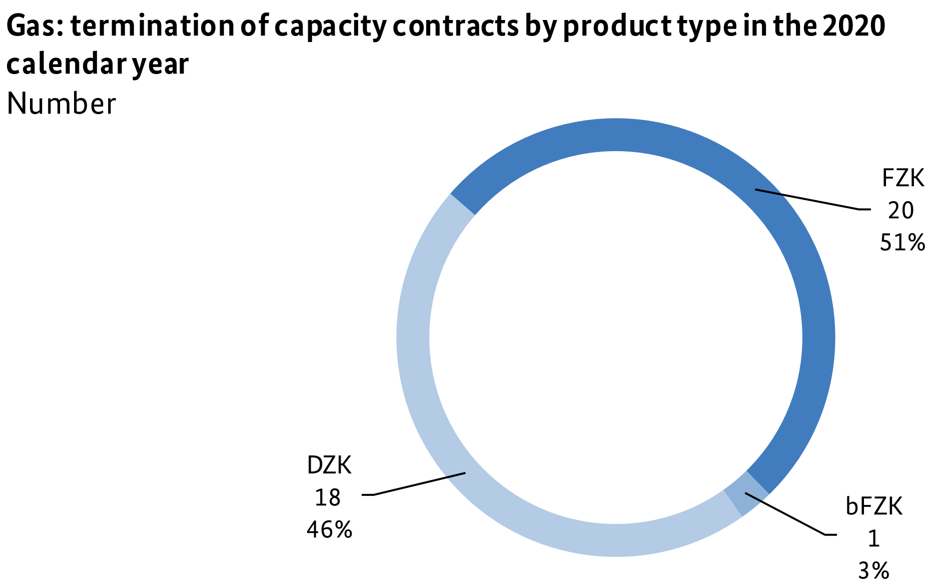


Figure 164: Termination of capacity contracts by product type

Differentiating terminated capacity contracts according to product type shows that most of them, namely 20, were terminated FZK capacity contracts. In contrast to the previous year, no interruptible capacity contracts were terminated.

3.4 Interruptible capacity

Interruptible capacities enable shippers to make use of booked entry and exit capacities on an interruptible basis without having to determine a transport path.

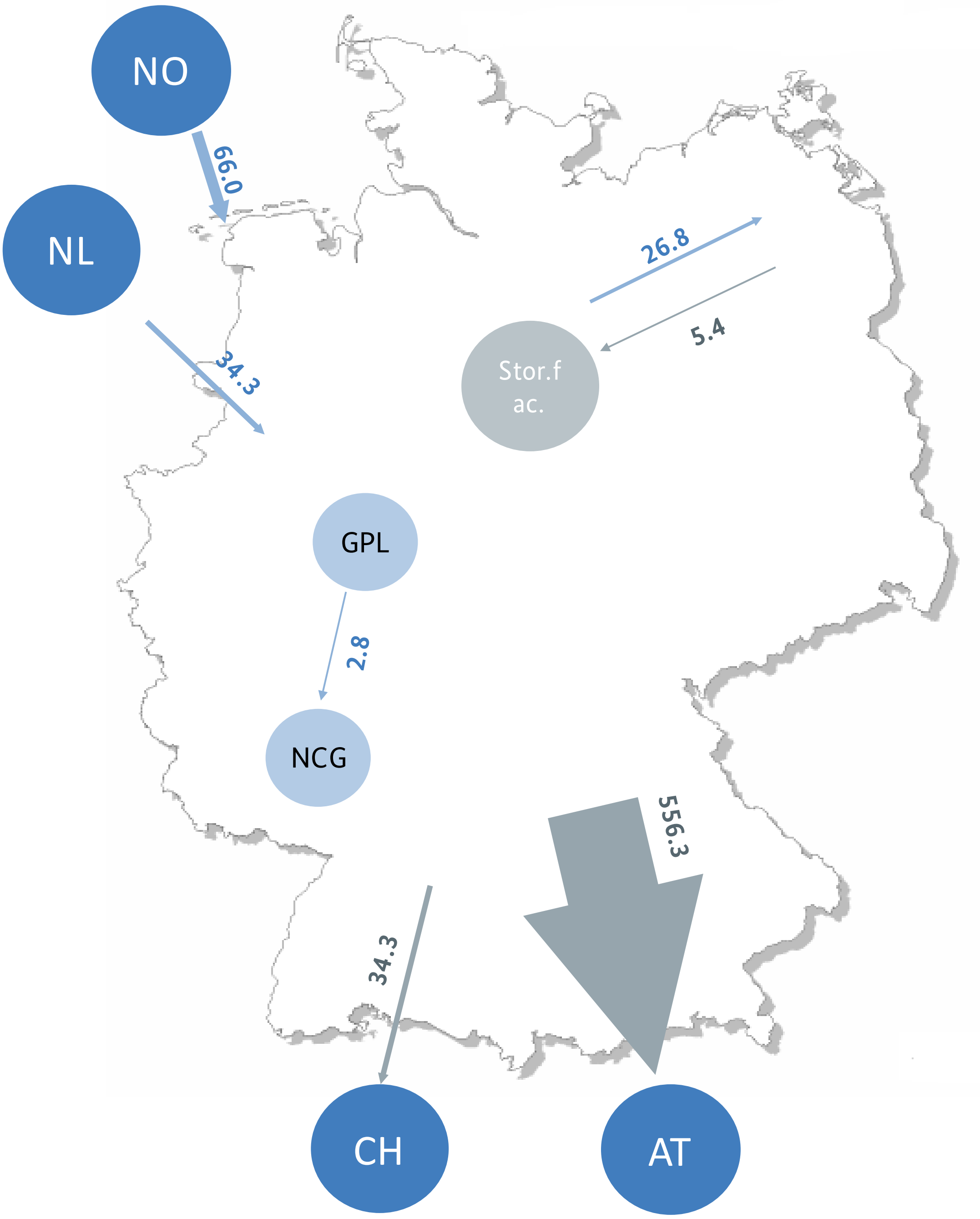
Transmission system operators were surveyed on all interruptions of both interruptible and firm capacity products issued in the 2020 calendar year.

In 2020, 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 726 GWh (2019: 2.4 TWh). While the interruptions actually relate to capacity rights, it is possible to calculate the gas volumes affected by these interruptions based on the most recently applicable (re-)nominations already made for the period to be interrupted, ie the gas volumes corresponding to the valid nomination at the point in time when the interruption was made known. If the nominated volumes for which an interruption was issued are placed in relation to the total nominated volume, the scale of interruptions is shown to be small at approximately 0.02%.

The map below 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 2020 calendar year the volume of gas to be exported from the German NCG market area to Switzerland was 34.3 GWh. The initially (re-)nominated volumes at the exit points into Austria's Eastern market area accounted for the largest proportion of the total interrupted volume, amounting to 556.3 Gwh.

Gas: interruptions in the 2020 calendar year

Interruption volume (GWh)



* Market area borders with interruption volumes below 0.1 GWh are not shown

Figure 165: Interruption volumes according to region

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.

This capacity 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 way this works is as follows: DSOs who are directly downstream of one or more network operators with an entry-exit system book the maximum firm exit capacity to be reserved for processing transports once a year for the following calendar year from the upstream network operator. The declaration of acceptance of the booking obliges the upstream network operator to reserve the contractually agreed capacity at interconnection points to this downstream network. The maximum capacity to be reserved is calculated according to an established computational logic with various input parameters. The network operator immediately downstream of the TSO must issue the internal booking no later than 15 July of the year in question. Every month the upstream network operator invoices the downstream network operator for a network charge in respect of the current internal booking or use of the reserve capacity plus any other levies and taxes that arise. If the internal booking is exceeded, the volume by which the booking is exceeded is charged for the month in which it is exceeded using the charge published for that month.

The figure below shows internal bookings for the 2020 calendar year for the two market areas NCG and GASPOOL respectively.

Gas: capacities agreed between TSOs and DSOs in 2020
GWh/h

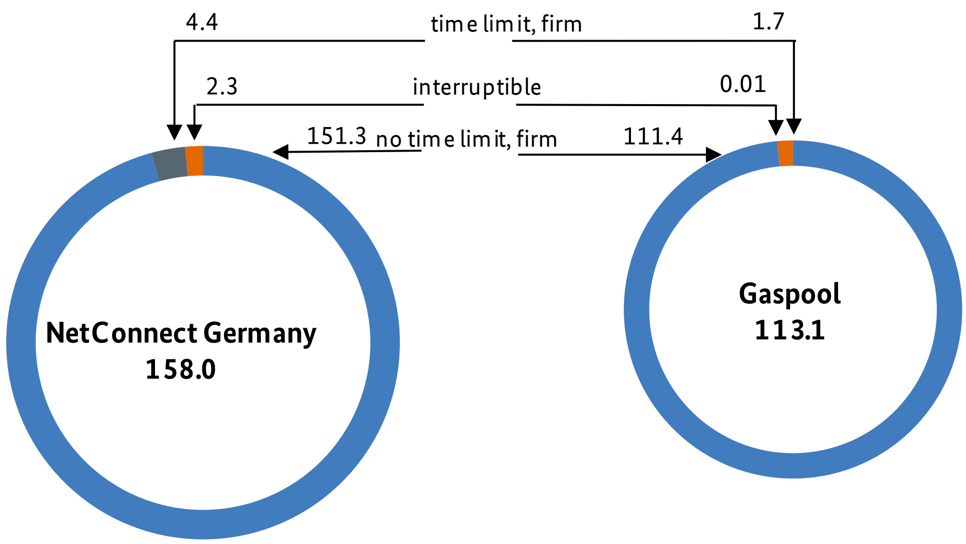


Figure 166: Capacities agreed between TSOs and DSOs

In the 2020 calendar year, the volume of internal bookings in the two market areas fell slightly from a total of 271.4 GWh/h to 271.2 GWh/h compared to the previous year. The fact that the figures have remained constant in recent years indicates that there is currently no reduction in capacity requirements among DSOs, for instance as a result of advancing decarbonisation on the part of final customers. However, this solely considers capacity and does not allow any direct conclusions to be drawn regarding the trend in offtake volumes to distribution networks.

A total reserve capacity of 271 GWh/h (rounded) was agreed between TSOs and downstream network operators. The majority of this capacity, 158 Gwh/h, was agreed in the NCG market area, and the remainder, 113.1 Gwh/h, in the GASPOOL market area. Across Germany the share of firm capacity bookings without a time limit, as a percentage of the total capacity ordered internally, increased slightly from 95.1% in the previous year to 96.9% in the 2020 calendar year. A higher volume of firm capacity to be reserved can be achieved by expanding network infrastructure or by taking other measures, for example relocating capacities. It is thus apparent that a further firming of capacity without a time limit in the context of internal booking has partly come about as a result of corresponding expansion measures included in the network development plans of recent years.

Within the framework of internal booking the DSOs also give a non-binding advance indication of their need for capacity for the ten years following the year of booking or registration. In the context of network development planning, this long-term forecast (checked for plausibility) constitutes an input parameter for the capacity requirements of the downstream DSOs. The chart below shows the forecast capacity for the relevant year under review, also in relation to the actual value that was ultimately agreed.[168] It is apparent that the additional capacity requirements for the gas distribution networks on account of further new connections has tended to be underestimated in the past.

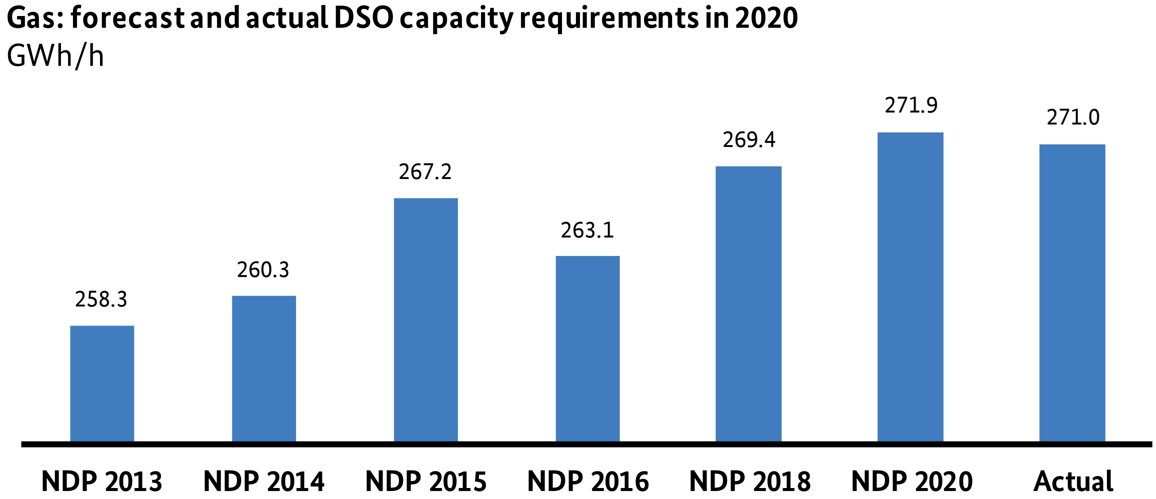


Figure 167: Forecasted and actual capacity requirements for distribution networks in 2020

4. Gas supply disruptions

Every year the Bundesnetzagentur calculates the average gas supply interruption duration for all final customers in Germany (SAIDI: system average interruption duration index). In 2020 the SAIDI was 1.09 minutes, which means that once again it was below the long-standing average of 1.22 minutes. Security of supply for gas in Germany is thus very high.

As in the previous years, the Bundesnetzagentur again conducted a comprehensive survey of all gas supply interruptions throughout Germany. Gas network operators in Germany are obliged to report all interruptions in supply within their systems to the Bundesnetzagentur by 30 April of each year.

The Bundesnetzagentur uses the information to calculate the system average interruption duration per final customer over the course of the year (SAIDI).

Only unplanned interruptions caused by third-party intervention, disturbances in the network operator's area, ripple effects from other networks or other disturbances are included in the calculations.

168 If different scenarios for downstream network operators' requirements were calculated in a particular Gas NDP, the highest figure was used in this chart.

Gas: SAIDI results for 2020

Pressure range	Specific SAIDI	Notes
≤ 100mbar	1.01 min/a	Household and small-volume consumers
> 100mbar	0.08 min/a	High-volume consumers, gas power plants
> 100mbar	0.01 min/a	Downstream network operators (not part of SAIDI)
All pressure ranges	1.09 min/a	SAIDI figure for all final customers

Table 125: Supply disruptions in 2020

The Bundesnetzagentur has calculated the SAIDI figures for gas network operators in Germany since 2006. The trend over time is shown in the figure below.

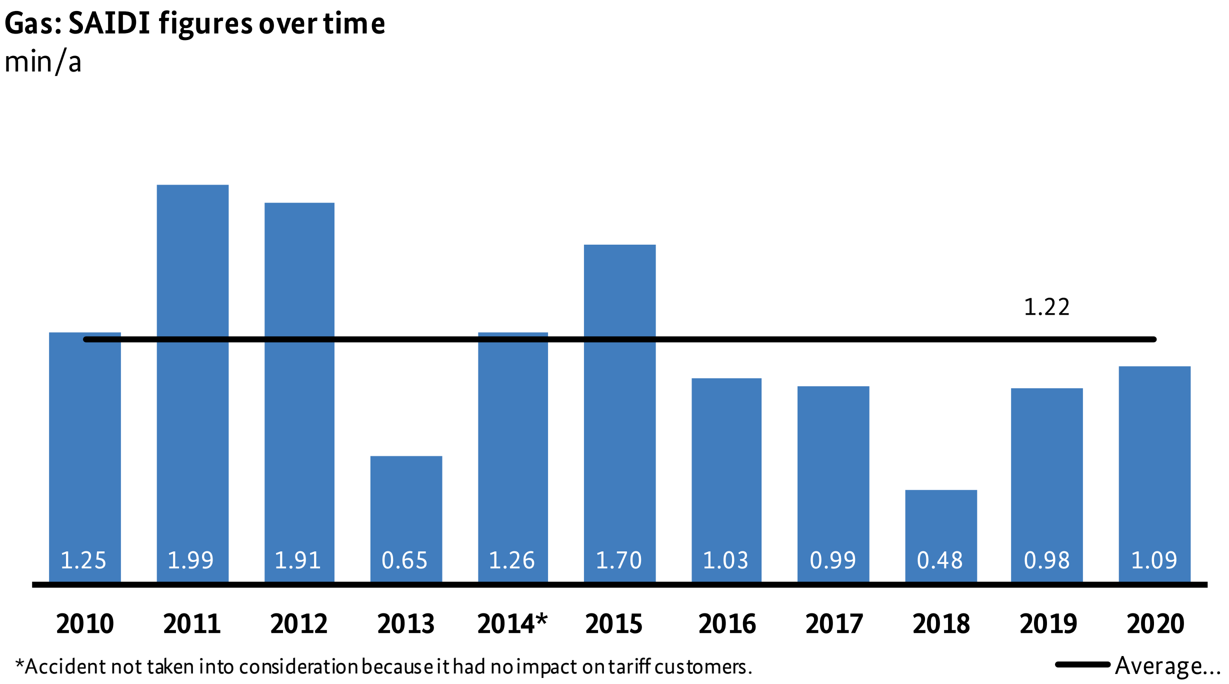


Figure 168: Trend over time of the SAIDI gas figures from 2010 to 2020

5. Network charges

The network charges are the means of spreading the costs of operation, maintenance and expansion of networks among all network users, ie also consumers.

Network charges account for a substantial share (25%) of the total gas price.

For an average household customer, the average network charge irrespective of the type of supply and including charges for metering and meter operation is currently around 1.59 ct/kWh and has changed only slightly compared to the previous year.

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 section **Fehler! Verweisquelle konnte nicht gefunden werden.** Retail (Gas)). The network charges are the means of spreading the costs of operation, maintenance and expansion of networks among all network users. 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 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, imputed 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 so-called "permanently non-controllable" costs, which are not subject to the instruments of incentive regulation. These include, at the transmission network level, costs for investment measures in accordance with section 23 ARegV. "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.

The network charges imposed by the network users are determined on the basis of the calculated revenue caps. In principle, section 3 GasNEV allows for two different tariff systems to be used for this purpose within the framework of cost unit accounting. Entry and exit capacity charges as prescribed by section 13 GasNEV are the norm. These charges apply in the case of TSOs and those DSOs that have capacity charges.
Since 1 January 2020 the provisions of Regulation (EU) 2017/460 (NC TAR), in which harmonised requirements for the tariff structure are laid down Europe-wide, have applied to the TSOs. The network charge system for gas networks at the level of TSOs and of DSOs that have capacity charges differs significantly from the system for electricity networks, which currently has neither entry tariffs nor capacity charges. 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 local distribution networks.

The exit tariffs charged by local DSOs comprise two components, a capacity or base price and a commodity price. The so-called network participation model is often used 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 costs apportionable to a customer with given consumption. Customers with lower consumption require a larger share of the local distribution network, while customers with higher consumption require a lower share of the local distribution network or are directly connected to a local transport pipeline. The tariff system is not based on the customer's actual connection situation. Instead it is assumed that the more the customer makes use of energy and capacity, the less use is made of the local distribution network. This generally corresponds to the actual circumstances, because larger customers increasingly tend to be connected to the local transport network. Two customers with the same consumption volume and the same capacity thus make the same contribution to meeting the network costs regardless of their actual connection situation. They are treated equally, irrespective of their specific connection situation. 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) a typical reserve capacity relative to the volume consumed is set. Non-interval-metered customers are charged a commodity price and 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 2021. 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): these are household customers with an annual consumption of between 20 GJ (5,556 kWh) and 200 GJ (55,556 kWh). Before 2016 the network charges were determined with respect to the average consumption of 23,269 kWh.

- Commercial 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).

As of 1 April 2020, 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 1.59 ct/kWh (2020: 1.56 ct/kWh), only a slight increase of around 2% compared to the previous year. For commercial customers, as of 1 April 2021 the arithmetic mean of the network charge including the charges for metering and meter operation was 1.28 ct/kWh (2020: 1.27 ct/kWh). For industrial customers, as of 1 April 2021 the arithmetic mean of the network charge including the charges for metering and meter operation decreased to 0.32 ct/kWh (2020: 0.37 ct/kWh), a fall of just over 13.5%.

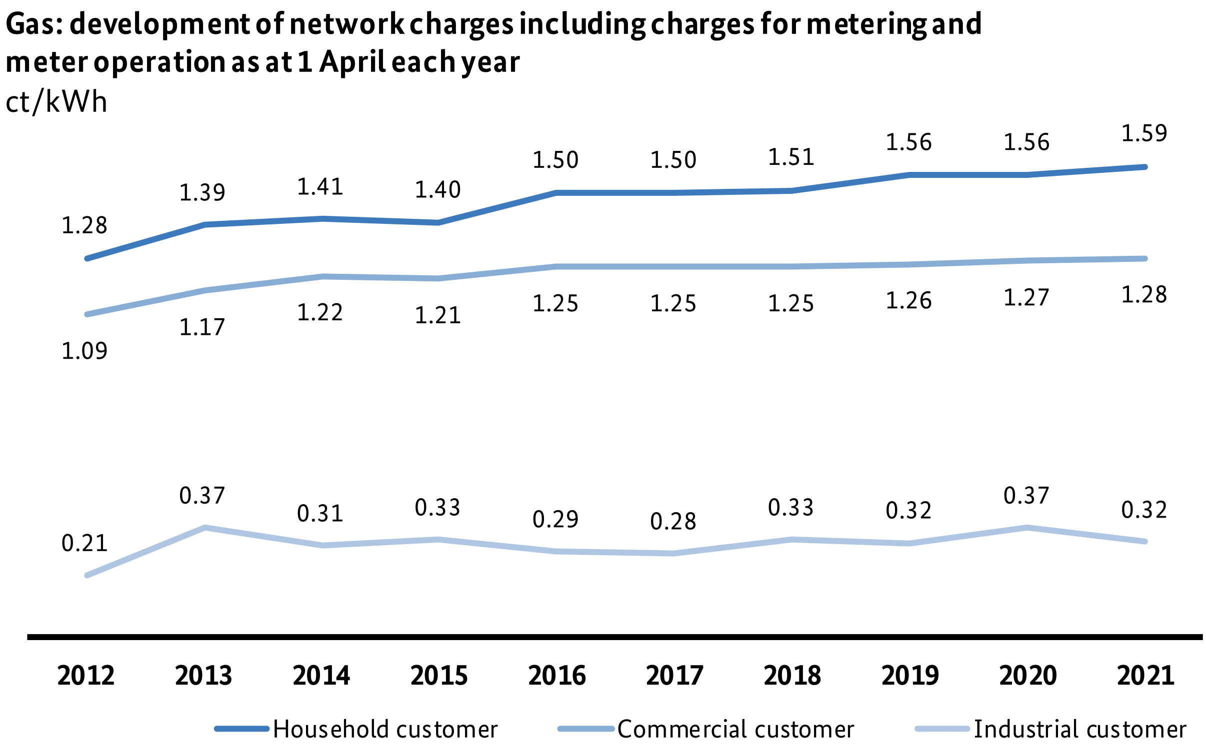


Figure 169: Development of network charges for gas (including charges for metering and meter operation) according to the survey of gas suppliers

For the Germany-wide market area Trading Hub Europe (THE), the TSO's definitive entry and exit tariffs for firm, freely allocable annual capacity for 2022 each amount to €3.51 kWh/h/a. This corresponds to a decline of 7.6% compared with Q4 2021. The Germany-wide market area THE was formed on 1 October 2021 from the merger of the two previous market areas NCG and GASPOOL . The charge on an annual basis for Q4 2021 is €3.80 kWh/h/a.

The distribution network charges provisionally reported on 15 October for 2022 are rising by an average of 1.8% for household and commercial customers. For industrial customers the charges are remaining almost unchanged. The figures are based on a random sample of network operators under the responsibility of the Bundesnetzagentur.

5.3 Regional distribution of network charges

There is regional variation in the level of network charges. For household, commercial and industrial customers the network charges in Saxony-Anhalt, Mecklenburg-Western Pomerania and Saarland are at the upper end of the Germany-wide range.

Gas: net network charges for household customers in Germany for 2021
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Saxony-Anhalt	1.73	0.94	2.54	29
Mecklenburg-Western P.	1.66	1.00	2.35	22
Saarland	1.66	1.03	2.35	16
Brandenburg	1.60	0.75	4.05	26
Baden-Württemberg	1.59	0.99	3.16	96
Saxony	1.57	1.09	2.21	36
Bremen	1.55	1.50	1.60	2
Rhineland-Palatinate	1.54	0.91	2.35	32
Thuringia	1.53	1.05	2.19	26
Bavaria	1.50	0.78	2.78	93
North Rhine-Westphalia	1.45	0.86	2.26	115
Schleswig-Holstein	1.45	0.98	3.77	35
Hesse	1.43	1.09	1.76	40
Hamburg	1.34	1.34	1.34	1
Lower Saxony	1.26	0.67	1.90	60
Berlin	1.16	1.16	1.16	1

* The gas offtake volume of the network operators in the respective network areas was used as the basis for weighting

Table 126: Distribution of gas network charges for the "household customer" consumption category in Germany, as at 1 January 2021

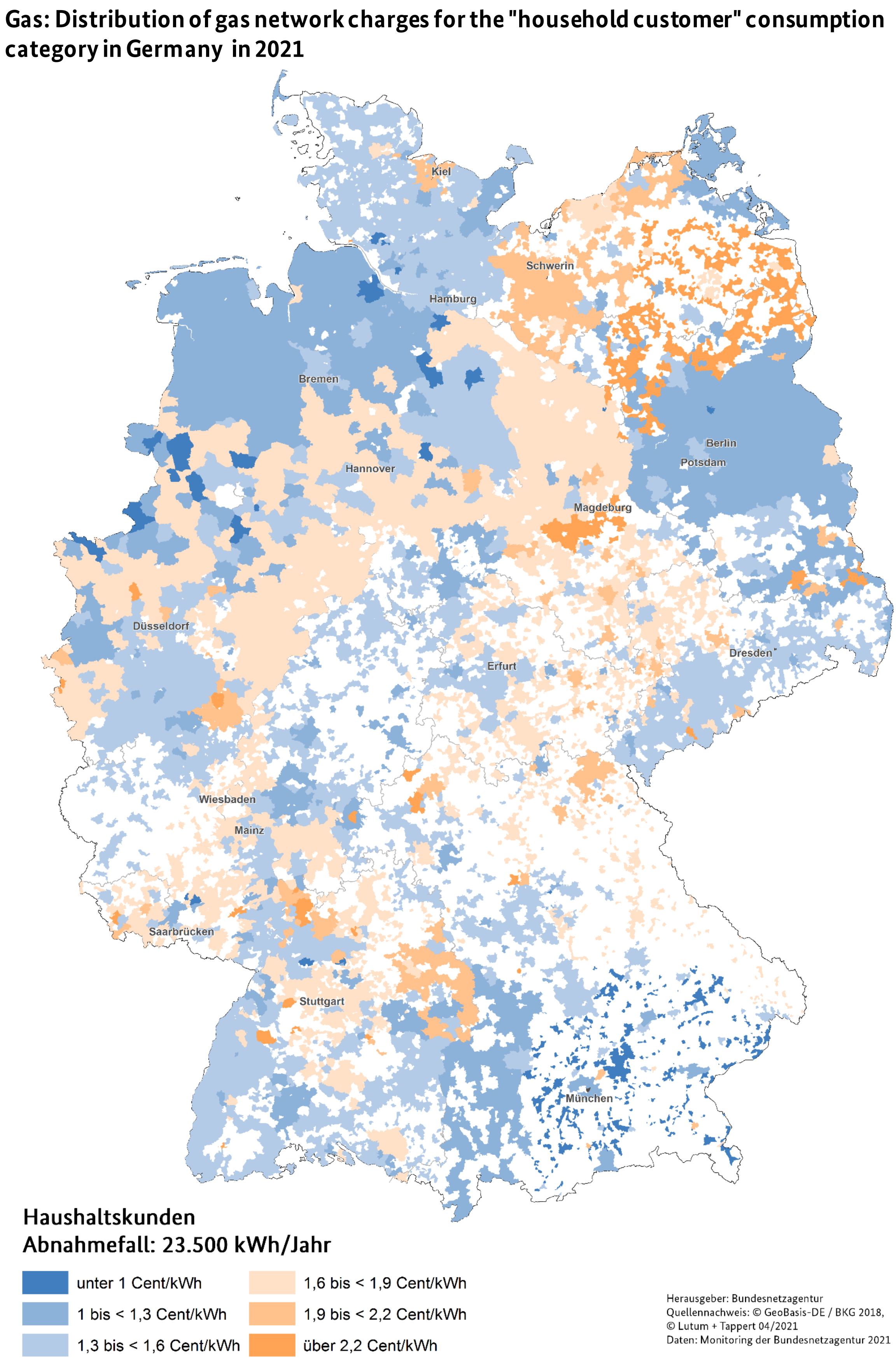


Figure 170: Distribution of gas network charges for the "household customer" consumption category, as at 1 January 2021 (map)

Gas: net network charges for commercial customers in Germany for 2021
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Saxony-Anhalt	1.50	0.83	2.03	30
Mecklenburg-Western P.	1.40	0.88	2.19	22
Saarland	1.40	0.72	2.07	16
Brandenburg	1.36	0.64	3.91	25
Baden-Württemberg	1.34	0.81	2.49	94
Rhineland-Palatinate	1.33	0.82	2.04	32
Saxony	1.32	0.93	1.82	36
Thuringia	1.31	0.87	1.86	28
Bavaria	1.28	0.70	2.46	94
Hesse	1.20	0.94	1.61	40
North Rhine-Westphalia	1.18	0.47	1.96	115
Schleswig-Holstein	1.17	0.81	2.08	36
Hamburg	1.13	1.13	1.13	1
Bremen	1.12	1.11	1.13	2
Lower Saxony	1.09	0.55	1.76	61
Berlin	1.08	1.08	1.08	1

* The number of meter points belonging to the operators in the respective network areas was used as the basis for weighting.

Table 127: Distribution of gas network charges for the "commercial customer" consumption category in Germany, as at 1 January 2021

Gas: Distribution of gas network charges for the "commercial customer" consumption category in Germany in 2021

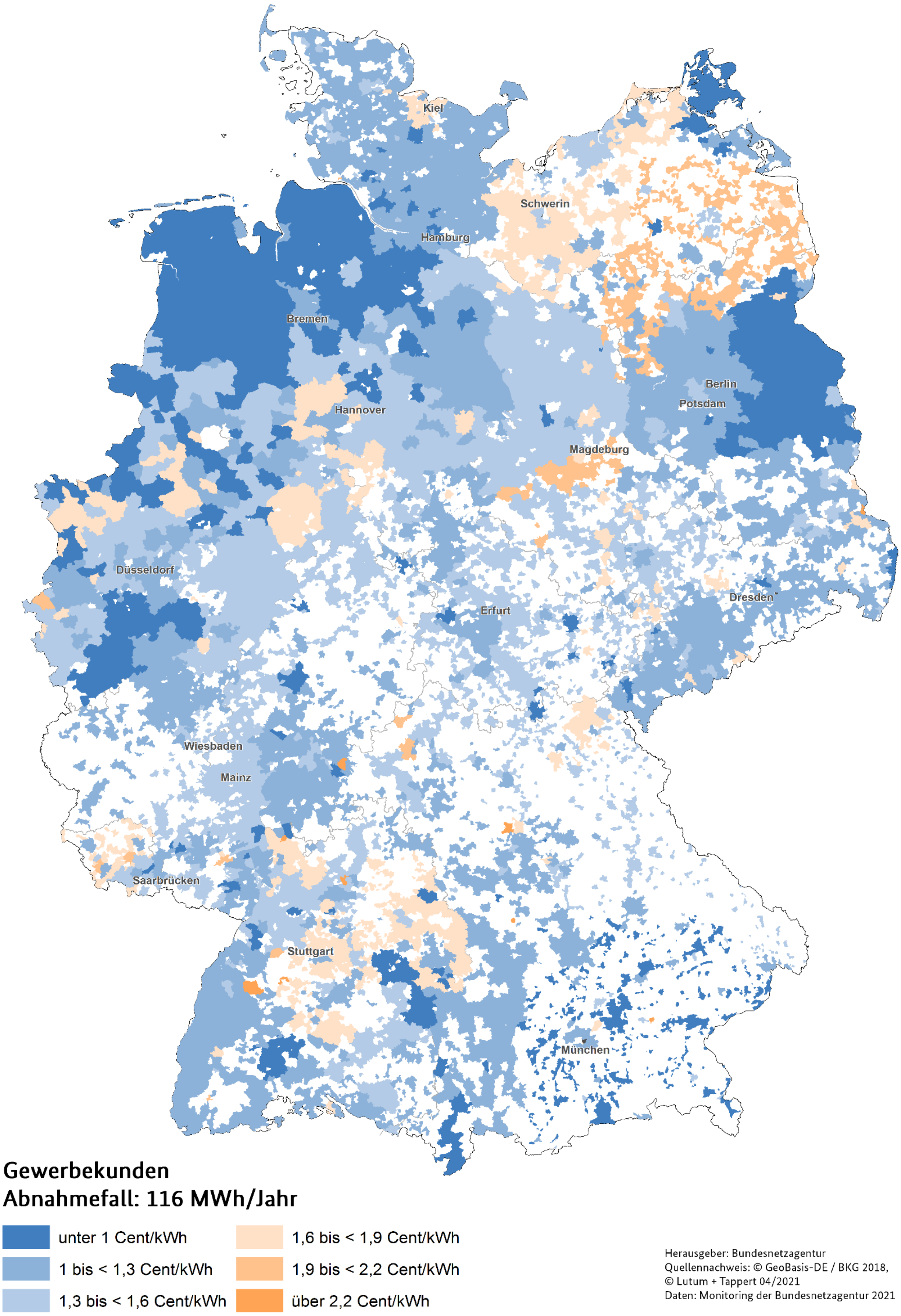


Figure 171: Distribution of gas network charges for the "commercial customer" consumption category in Germany, as at 1 January 2021 (map)

Gas: net network charges for industrial customers in Germany for 2021
ct/kWh

Federal state	Weighted average*	Minimum	Maximum	Number of distribution networks considered
Mecklenburg-Western P.	0.45	0.27	0.88	8
Saarland	0.44	0.35	0.64	8
Saxony-Anhalt	0.39	0.15	0.97	14
Rhineland-Palatinate	0.35	0.27	0.45	13
Baden-Württemberg	0.35	0.13	0.96	43
Bavaria	0.35	0.16	0.56	28
Brandenburg	0.34	0.21	0.68	16
Thuringia	0.34	0.20	0.55	12
Lower Saxony	0.33	0.18	0.71	25
Saxony	0.33	0.18	0.64	11
Northrhine-Westphalia	0.32	0.16	0.90	55
Berlin	0.32	0.32	0.32	1
Hesse	0.31	0.16	0.48	16
Schleswig-Holstein	0.29	0.22	0.33	9
Hamburg	0.24	0.24	0.24	1
Bremen	0.22	0.23	0.20	2

* The quantity of gas supplied by the operators in the respective network areas was used as the basis for weighting.

Table 128: Distribution of gas network charges for the "industrial customer" consumption category in Germany, as at 1 January 2021

Gas: Distribution of gas network charges for the "industrial customer" consumption category in Germany in 2021

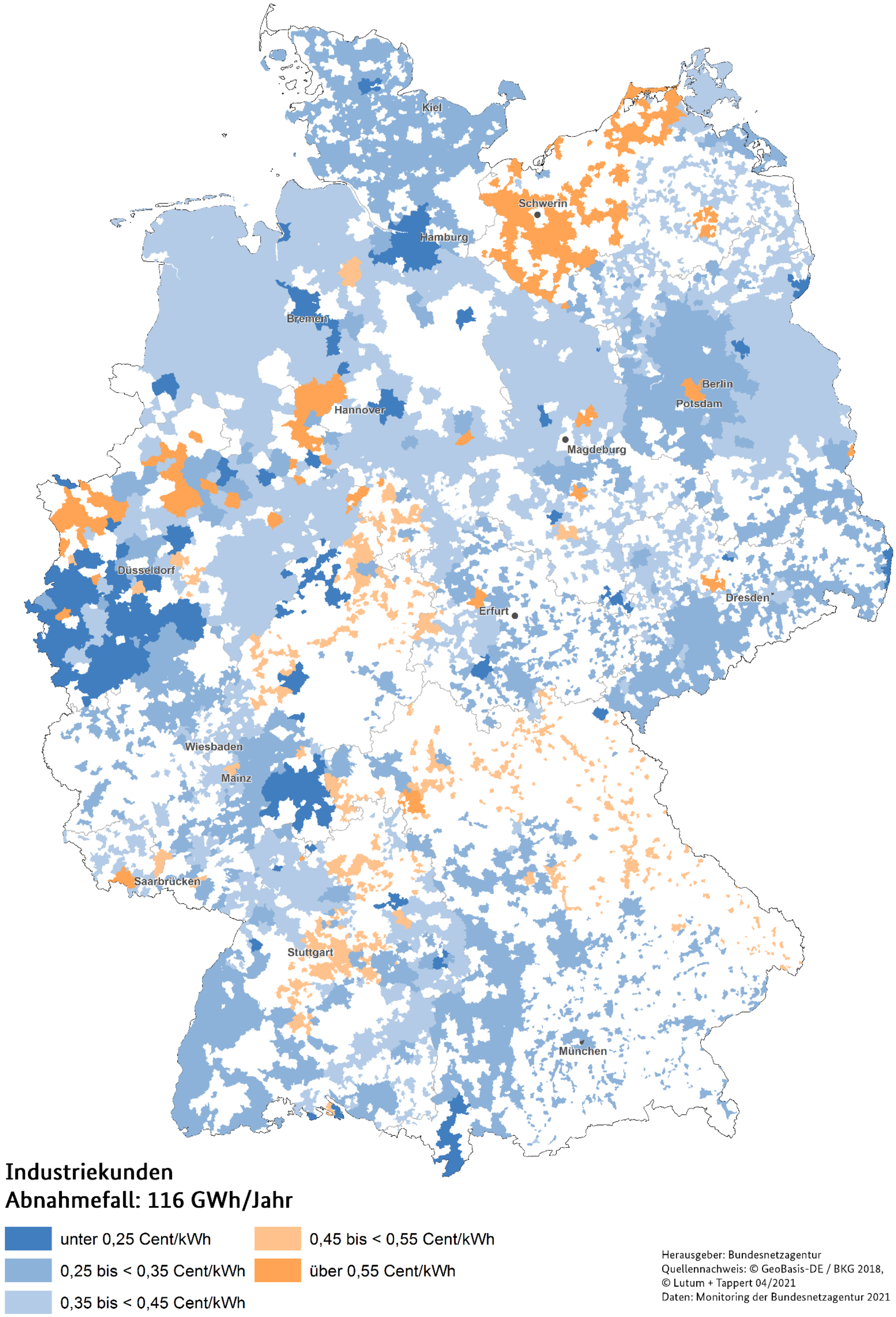


Figure 172: Distribution of gas network charges for the "industrial customer" consumption category in Germany, as at 1 January 2021 (map)

The reasons for the regional differences in network charges are manifold. Key factors are different 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 in densely populated regions the network costs are spread over a large number of network users. The age structure of individual networks also has an impact on the charges. More recently built networks have higher residual values, which increases specific capital costs and in turn leads to higher charges. As a result of their greater depreciation, older networks have lower residual values and therefore lower capital costs, thus in turn leading to lower charges. However, with advancing age, networks incur higher costs for maintenance and repair, which have a corrective effect that tends to equalise the charges.

5.4 Special network charges under section 20(2) GasNEV

According to section 20(2) sentence 1 GasNEV, in order to avoid the construction of a direct pipeline in individual cases operators of distribution networks may, in derogation of the provisions of section 18 GasNEV, apply a separate network charge on the basis of the gas services actually provided (special network charge).

In the case of direct pipeline construction a network user builds its own pipeline link – as a rule – to the upstream network level, in addition to the existing pipeline link belonging to the distribution system operator that may already be in place. The motivation for a network user aiming to build a direct pipeline is that the investment will save the distribution system operator's network charges. However, as the network user pursuing potential expansion is already connected to the gas network via the distribution system operator, without having its own pipeline link, and can be supplied with gas accordingly, a direct pipeline would create a duplicate pipeline infrastructure.

The purpose of the possibility granted to distribution system operators under section 20(2) GasNEV to apply a special network charge in individual cases is initially to avoid the construction of economically inefficient, duplicate pipeline infrastructures in the form of direct pipelines that do not bring about an increase in capacity. At the same time the aim is to balance the conflicting interests of network operators and the network user planning to build a direct pipeline. Offsetting or reducing the potential financial advantage from building a direct pipeline by granting a lower special network charge compared with the charge set on the basis of section 18 GasNEV means that the special network charge constitutes an alternative to building a direct pipeline for network users.

The regulatory authorities of the federal states and the Bundesnetzagentur have drawn up joint guidelines on determining special network charges under section 20(2) GasNEV.

The aim of these guidelines is to establish a reliable, uniform Germany-wide approach in connection with the calculation of special network charges. The application of a standard set of rules available to all network operators and network users in these guidelines is intended not only to create transparency and ensure non-discrimination but also to help achieve the objectives of section 20(2) GasNEV in the best possible way.

5.5 Cost examination in accordance with section 6 ARegV and efficiency benchmarking in accordance with section 12 et seq ARegV and section 22 ARegV for DSOs and TSOs

The Bundesnetzagentur has begun carrying out the cost examination to determine the base level for gas supply network operators for the fourth regulatory period[169].

To this end the transmission system operators were obliged to submit the data for the cost examination to determine the base level for calculating the revenue caps to the Bundesnetzagentur by 1 June 2021 in accordance with determination BK9-20/605, the distribution system operators under the standard procedure likewise by 1 July 2021 and the participants under the simplified procedure by 30 September 2021. The determination sets out requirements for the scope, form and content of the documentation to be submitted by the network operators as the basis for the cost examination.

Ruling Chamber 9 also issued two decisions regarding data collection for efficiency benchmarking for all transmission system operators (BK9-20/604) and distribution system operators (BK9-20/603). In accordance with these decisions, the TSOs and DSOs under the standard procedure were required to submit the structural data for implementation of the respective efficiency benchmark to the Bundesnetzagentur by 30 April 2021.[170]

In 2020, the Bundesnetzagentur started to use this data as the initial basis for determining the base level for gas supply network operators and to conduct efficiency benchmarking.

A final decision on the revenue caps for the fourth regulatory period is due to be taken by the end of 2022.

6. Monitoring security of supply

In accordance with section 63(1) EnWG, on 31 October 2021 the Bundesnetzagentur issued a report on the status and development of security of the natural gas supply for the first time, and shall subsequently do so at least every two years. In previous years this report was produced and published by the BMWi.

The report particularly examines the global resource situation, the supply and demand trend in Europe and specific details of gas supply in Germany over recent years. Technical security is also discussed, on the basis of an analysis of network disruptions and supply interruptions. In a separate chapter the report addresses the special situation at the start of the gas year on 1 October 2021, which was marked by low storage levels and exceptionally high gas prices.

In summary, the report states that the security of gas supply continues to be one of the central issues in Germany and Europe in the face of changing market conditions and increasing global competition on the gas markets. As gas currently accounts for just over 25% of primary energy consumption, with a further upward trend expected in the medium term, securing gas supply remains a matter of great importance.

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[169] https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK9-GZ/2020/2020_bis0999/BK9-20-0605/BK9-20-605_Festlegung_Beschluss_Internet.html?nn=524392

[170] https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK9-GZ/2020/2020_bis0999/BK9-20-0603/BK9-20-0603_Festlegung_Beschluss.html?nn=364474, https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK9-GZ/2020/2020_bis0999/BK9-20-0604/BK9-20-604_Festlegung_Beschluss.html?nn=364474

Guaranteeing security of supply in grid-based energy supply overall as well as measures to cope with the failure of one or more suppliers are primarily the task of the companies operating in the market. How they perform these tasks is in principle a matter for the companies to decide. The German approach of primarily relying on the obligation of companies to guarantee security of supply has hitherto been successful and cost efficient. The measures that were introduced on the basis of the expert opinion on improving the security of supply using storage facilities have proven their worth. At present there is no foreseeable reason to deviate from this approach, either in the near or medium term.

The key pillars of German gas supply are diversification of supply sources and transport routes, domestic extraction for the time being, stable relationships with suppliers, and long-term gas supply contracts, along with what has to date always been a high degree of reliability of the supply infrastructure, including underground storage facilities. In addition, the gas supply companies engage in regular dialogue with the BMWi and the Bundesnetzagentur about further infrastructural (network development planning and the market area conversion measures are particularly worthy of mention) and procurement-side measures that are intended to further improve the security of supply in future.

That said, decarbonisation and the phasing out of fossil fuels will also pose significant challenges for the gas network. The phase-out is set to be completed in 2045, although the political decisions determining the path to achieve this have not yet been taken. Much in the gas supply industry depends on the nature of this transformation pathway. The TSOs already make the assumption in their plans that in the long term the majority of the existing transmission system infrastructure will be used for transporting pure hydrogen, in order to facilitate the use of decarbonised gases. To achieve this, within the framework of the Gas NDP process the TSOs will identify pipelines that can be removed from the natural gas network and repurposed for the potential transport of hydrogen without repercussions for security of supply or the task of transporting natural gas. Over the short and medium term, natural gas is expected to support the transformation as a bridging technology. This transitional process is a challenge for security of supply. Firstly, the pipeline system needs to be converted to transporting pure hydrogen while simultaneously supplying the (remaining) natural gas customers with as little network expansion as possible. This means that two networks will be operated in parallel in future, for which expansion to the minimum possible degree will be required. The future use of hydrogen in the distribution system sector is not yet foreseeable either. Furthermore, as a transitional solution more gas could be used as a fuel for additional peak-load power plants for electricity generation. The intention is to use these power plants rarely, but they must be ready for operation when they are needed. Consequently, the gas network must be able to ensure the supply of gas to these power plants at all times, regardless of what other transport task it has to fulfil at that moment. Depending on the location of the power plant, this could lead to a potential network expansion that will perhaps be required for only a few years.

Further analysis of Germany's gas supply will be conducted in line with the EU regulation on the security of gas supply in the comprehensive assessment of the risks of national and Europe-wide natural gas supply that takes place every four years. The next date for notification of these risk assessments to the Commission is 1 October 2022. The extensive work to produce the risk assessment and model the necessary risk scenarios has already begun again at the Bundesnetzagentur.

The report results lead to the conclusion that the security of supply concept in Germany has proved its worth. In the past, and during the period under review, the gas supply companies have – even in the face of changed conditions – to date ensured a high standard of security of supply such that the supply of gas in Germany has hitherto always been guaranteed. In light of the dependence on imports, the differentiation of the market roles of the companies, the long lead times until projects are completed and the high capital intensity ratio of investments in the gas sector, future developments must be kept under careful observation and analysed, especially with regard to decarbonisation and the associated transformation of the energy system.

7. Merger of market areas

Another important step in the development of the German gas market is the merger of the German market areas on 1 October 2021.

The amendment of the Gas Network Access Ordinance (GasNZV) in 2017 obliged the transmission system operators to form a uniform Germany-wide market area from the current two market areas GASPOOL and NetConnect Germany by 1 April 2022 at the latest. The TSOs and market area managers will meet this obligation six months early, with the launch of the joint market area Trading Hub Europe (THE). The TSOs and market area managers are themselves responsible for carrying out the market area merger process. The Bundesnetzagentur is supporting the process from a regulatory standpoint. Through the KAP+ (Ruling Chamber 7) and KOMBI (Ruling Chamber 9) proceedings completed in the spring of 2020, it has created the preconditions for the market participants to be able to meet the challenges appropriately, in particular the technical network-related challenges.

On account of the geographical enlargement of the market area resulting from the merger and the consequently growing transport options, physical reasons dictate that it will only be possible to offer firm, freely allocable entry capacity across the entire network infrastructure to a limited extent. Under the KAP+ procedure (BK7-19-037)[171] from Ruling Chamber 7, the introduction of an oversubscription and buy-back scheme was approved for a transitional phase until 1 October 2024 so that additional firm, freely allocable capacity can be offered for periods of time after the market area merger. It is planned to use market-based instruments (MBIs) such as the stock-market-based spread product to safeguard this additional firm, freely allocable capacity. With regard to the costs for MBIs and for capacity buy-backs in the context of the oversubscription and buy-back scheme, Ruling Chamber 9 recognised these costs as volatile cost components in the KOMBI determination. As a result of the necessary regulatory framework having been created, the TSOs were already able to offer additional firm capacities for the periods following the market area merger in the 2020 annual auction, such that the capacity offer is roughly equivalent to the level of the offer prior to the merger.

The market area managers and TSOs also designed the MBIs and the standardisation of the future operational processes with regard to other requirements, such as the procurement of balancing gas or the balancing and settlement of gas volumes, and agreed these with the relevant market actors. The results were presented to the market in the course of dialogue events, where they were broadly approved.

In addition, with the participation of the trade associations, adaptations were made to the Gas Cooperation Agreement (KoV) to further entrench the instruments and measures for the merger of the market areas across

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[171] https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK7-GZ/2019/BK7-19-0037/BK7-19-0037_Beschluss.html?nn=360898

the whole market. Moreover, at the end of March 2021 the Bundesnetzagentur published two communications[172] on matters relating to balancing and conversion, thus making an additional contribution to transparency and legal certainty for the market.

In order to ensure that the operational conversion processes run smoothly, the two previous market area managers carried out the merger under company law to form the new company THE GmbH early, on 1 June 2021.

As outlined above, the market area merger has an impact on areas including capacity offer and booking, balancing gas trading and network development planning. During a transitional period up to 2024, the market-based instruments will have to prove their functionality and their safeguarding effect. The report on the use of the instruments up until 1 December 2022 to be drawn up by the transmission system operators for the first time by that date represents the first milestone in this assessment. In addition, the Bundesnetzagentur will support this test phase with particular attention to the impacts on the use of balancing gas.

[172] https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK7-GZ/2014/BK7-14-0020/Mitteilungen/BK7-14-0020_MitteilungNr7.html; https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK07/BK7_74_Konvert/BK7_Konvert.html

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, which 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,[173] (MOL 1 exchange-traded, MOL 2 also exchange-traded but taking account of network aspects – geographical location and gas quality, MOL 4 tender procedure).[174]

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.

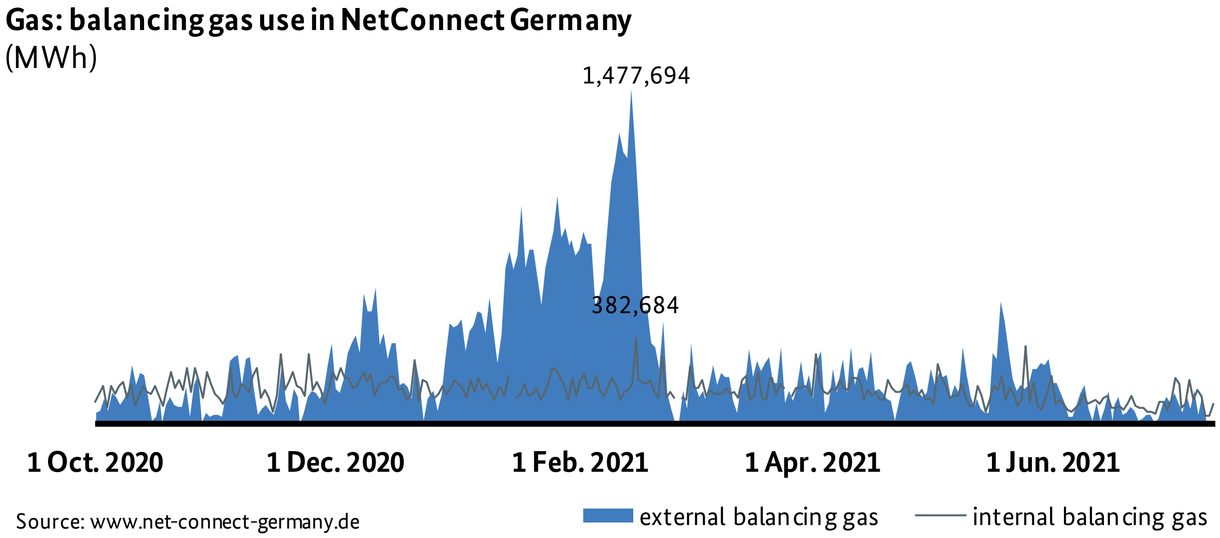

Figure 173: Balancing gas use from 1 October 2020 in the NetConnect Germany market area, as at July 2021

[173] https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK7-GZ/2014/BK7-14-0020/BK7-14-0020_Beschluss_download_BF.pdf?__blob=publicationFile&v=2

[174] The short-term, bilateral balancing gas products previously included in MOL rank 3 were able to be replaced by exchange-traded products. Consequently, there are no products in MOL rank 3 anymore, neither in GASPOOL nor in NetConnect Germany.

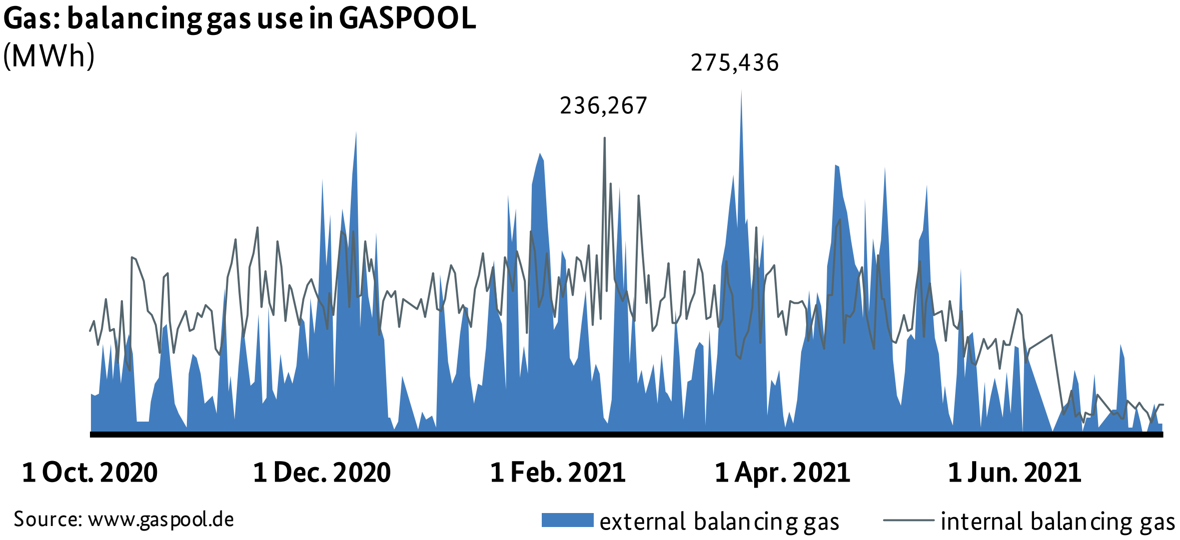

Figure 174: Balancing gas use from 1 October 2020 in the GASPOOL market area, as at July 2021

The purchase prices for balancing gas depicted below are calculated as averages 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.[175]

As purchasing is mainly exchange-traded, the purchase prices are on the same level as general market prices.

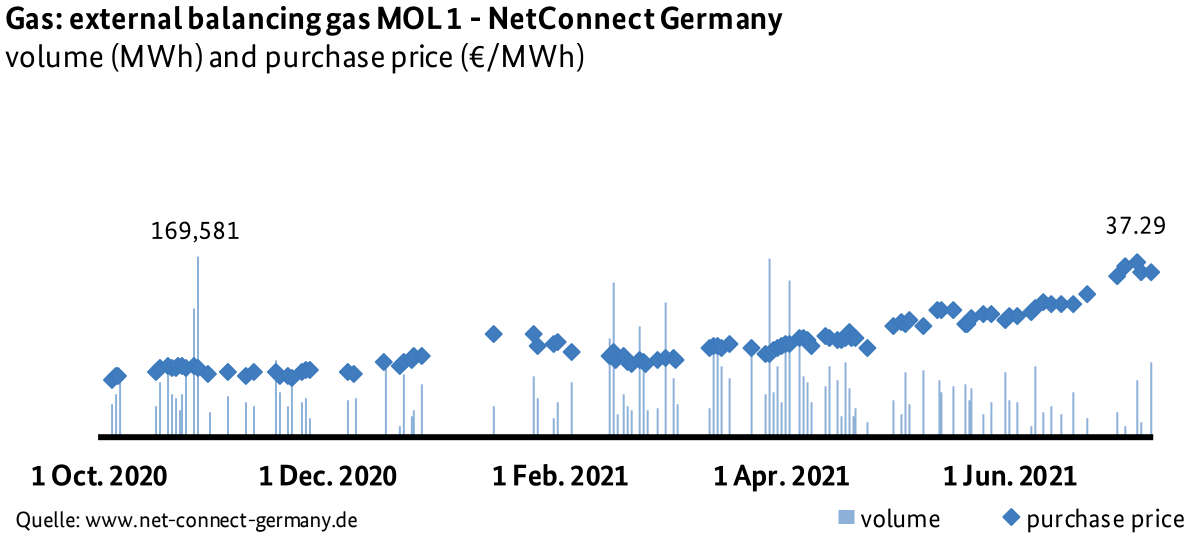

Figure 175: External balancing gas purchase prices and volumes from 1 October 2020 for MOL 1 in the NetConnect Germany market area, as at July 2021

[175] The short-term, bilateral balancing gas products previously included in MOL rank 3 were able to be replaced by exchange-traded products. Consequently, there are no products in MOL rank 3 anymore, neither in GASPOOL nor in NetConnect Germany.

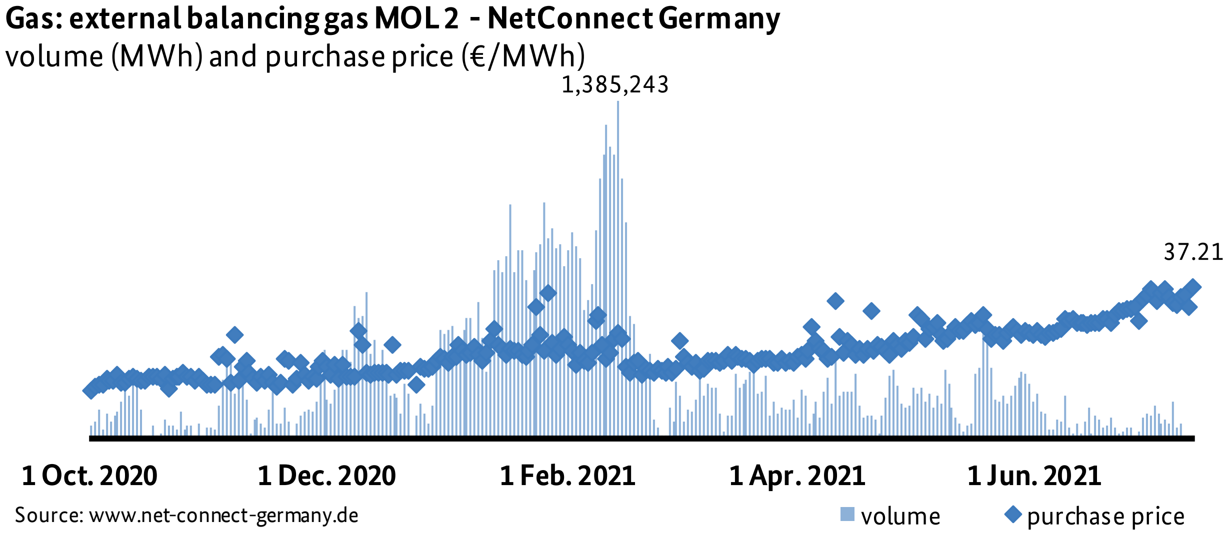

Figure 176: External balancing gas purchase prices and volumes from 1 October 2020 for MOL 2 in the NetConnect Germany market area, as at July 2021

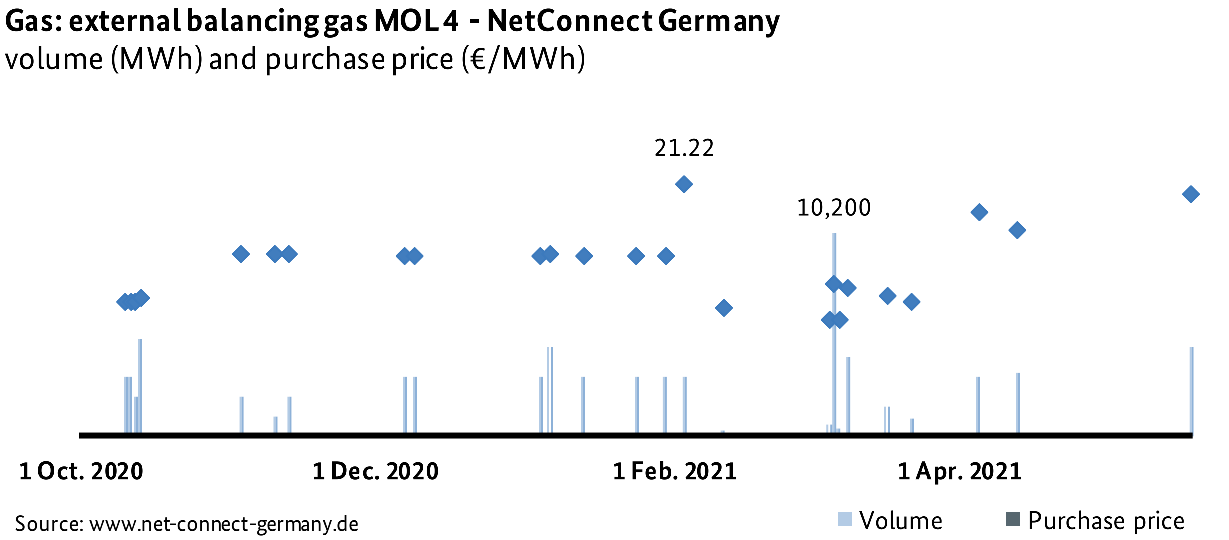

Figure 177: External balancing gas purchase prices and volumes from 1 October 2020 for MOL 4 in the NetConnect Germany market area, as at July 2021

Gas: external balancing gas MOL 1 - GASPOOL
volume (MWh) and purchase price (€/MWh)

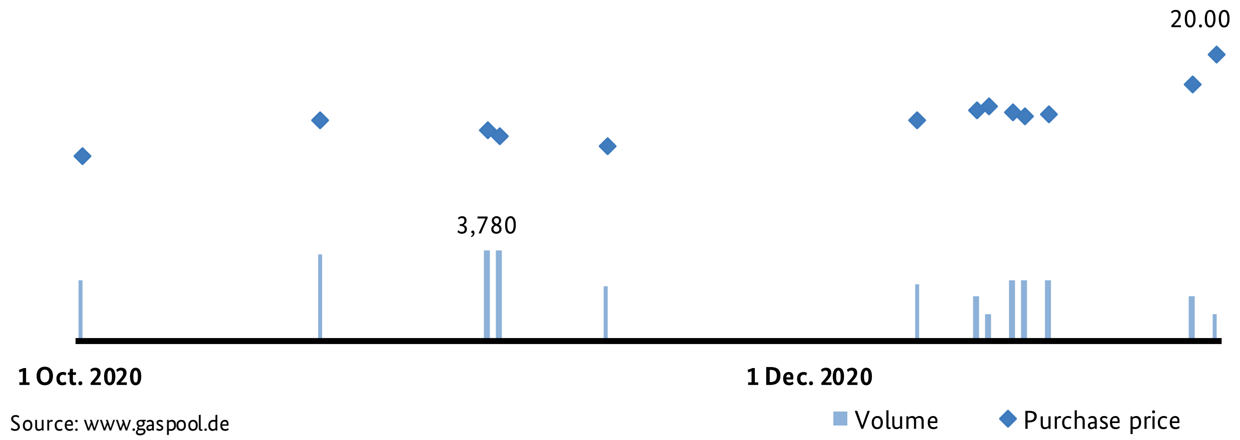

Figure 178: External balancing gas purchase prices and volumes from 1 October 2020 for MOL 1 in the GASPOOL market area, as at July 2021

Gas: external balancing gas MOL 2 - GASPOOL
volume (MWh) and purchase price (€/MWh)

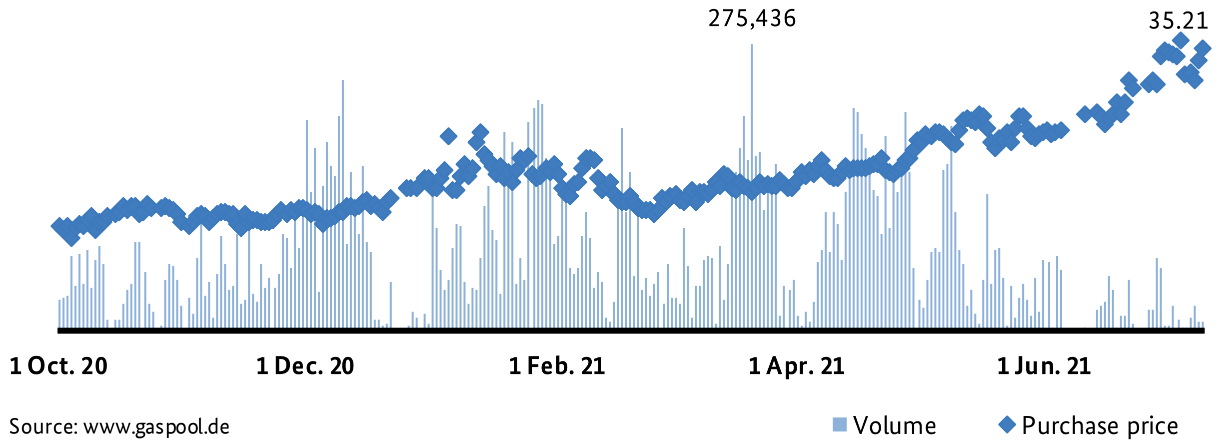

Figure 179: External balancing gas purchase prices and volumes from 1 October 2020 for MOL 2 in the GASPOOL market area, as at July 2021

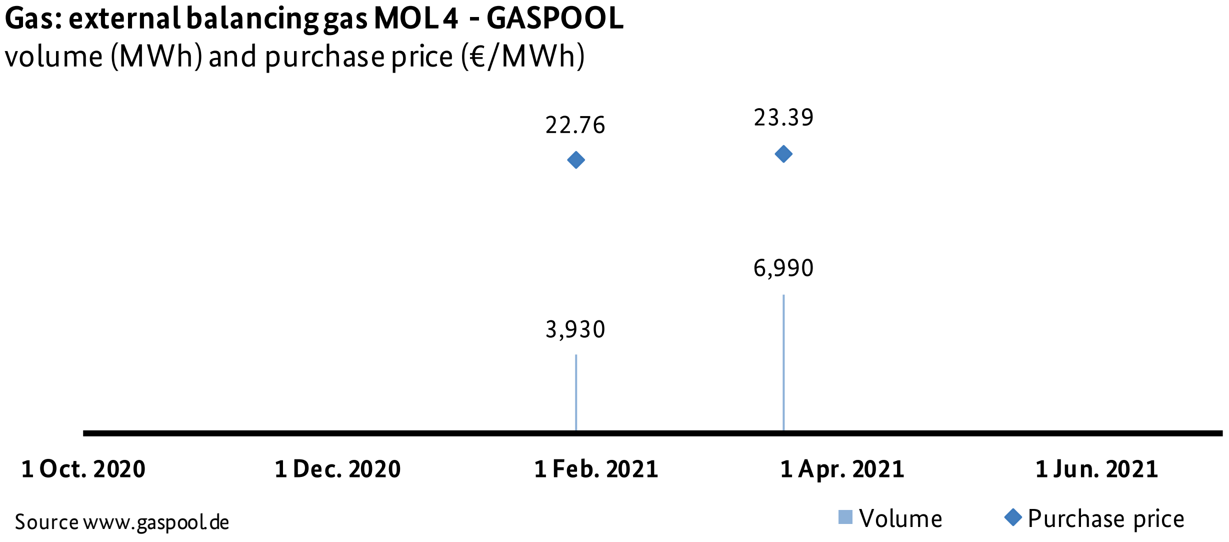

Figure 180: External balancing gas purchase prices and volumes from 1 October 2020 for MOL 4 in the GASPOOL market area, as at July 2021

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 in particular 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 positive imbalance price is the highest balancing gas price paid by the market area manager on the relevant gas day (MOL 1 and MOL 2, excluding local and hourly products) or the volume-weighted average price of gas for that day including a 2% mark-up, whichever is higher. The negative imbalance price is the lowest price for the sale of balancing gas attained by the market area manager on the relevant gas day or the volume-weighted average price of gas for that day including a 2% discount, whichever is lower. The calculation of the imbalance prices is carried out separately in the two German market areas by the respective market area manager. The figure below shows the development of the imbalance prices using the new calculation method.

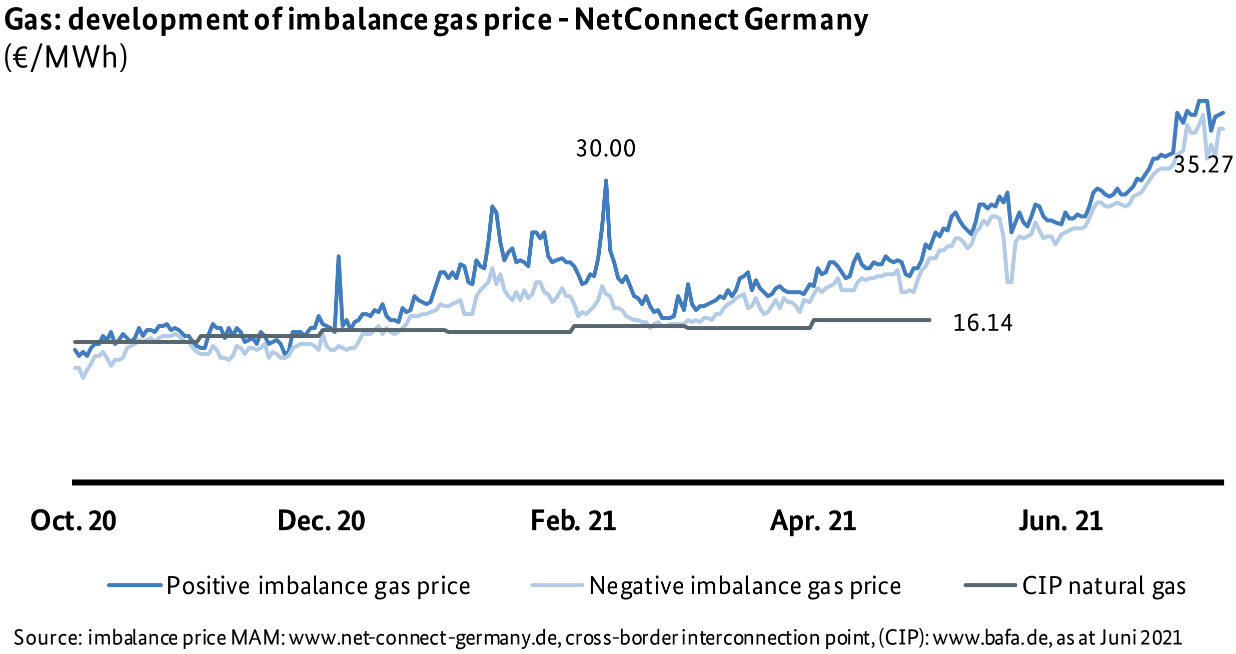

Figure 181: Development of NetConnect Germany imbalance prices since 1 October 2020, as at July 2021

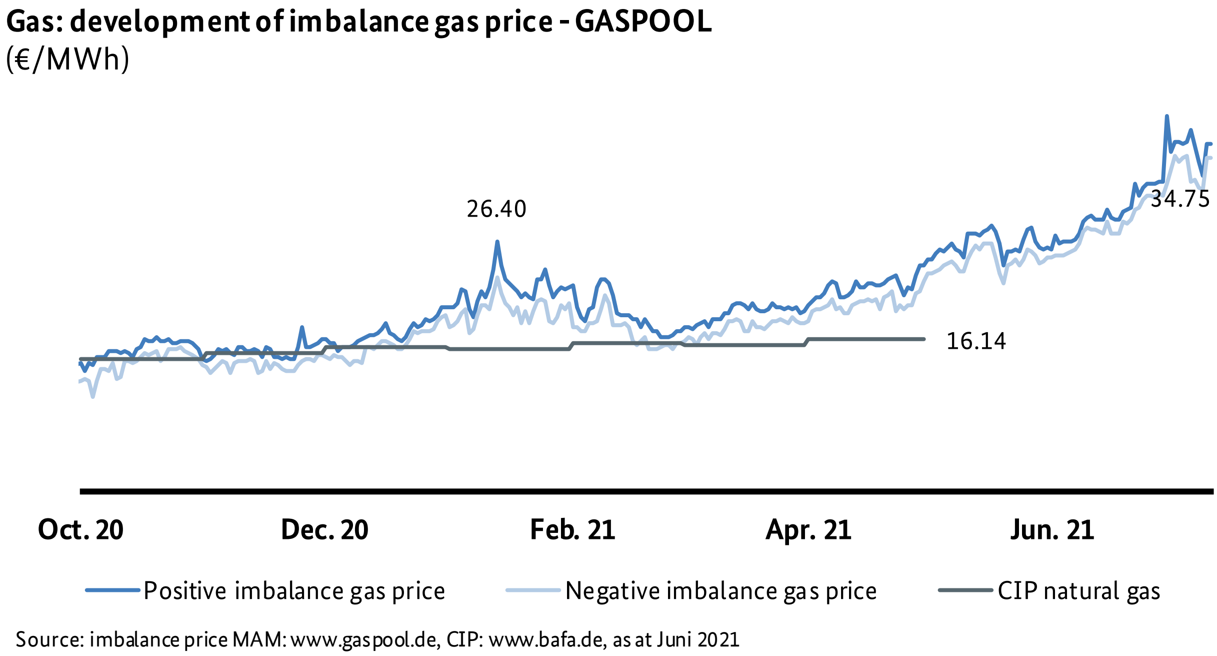

Figure 182: Development of GASPOOL imbalance prices since 1 October 2020, as at July 2021

2. Development of the neutrality charge for balancing

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 their neutrality charge account. If the costs are forecast to exceed revenues, the market area manager levies a 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.

There are two separate neutrality charge accounts, for exit points connecting users with either standard load profiles (SLP) or metered load profiles. 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 metered load profile) each apply for one year.

After the launch of the single German market area Trading Hub Europe (THE), there will only be one metered load profile neutrality charge and one SLP neutrality charge.[176]

For the period of validity as of 1 October 2020, a neutrality charge of €0/MWh will be levied for SLP customers and €0.10/MWh for customers with metered load profiles in the NCG market area. For the same period, a neutrality charge of €0/MWh will be levied for SLP customers and €0/MWh for metered load profile customers in the GASPOOL market area.

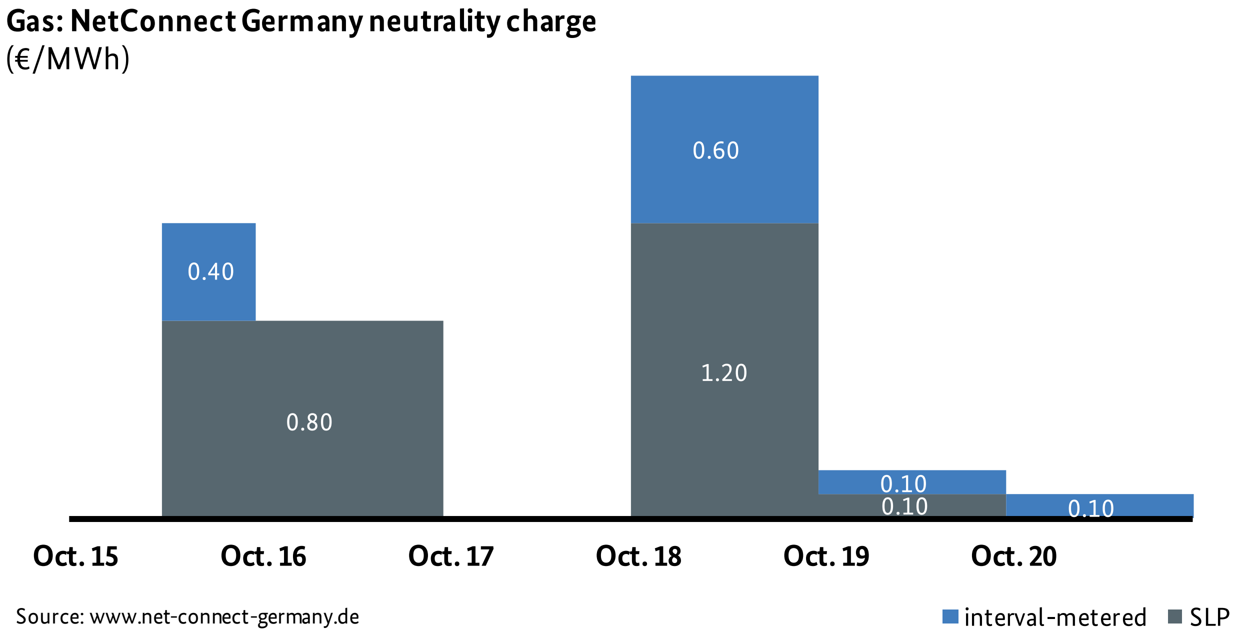

Figure 183: Neutrality charge in the NetConnect Germany market area, as at July 2021

[176] The neutrality charges applicable from 1 October 2021 will be published by the market area manager at https://www.tradinghub.eu/de six weeks before the start of the contribution period.

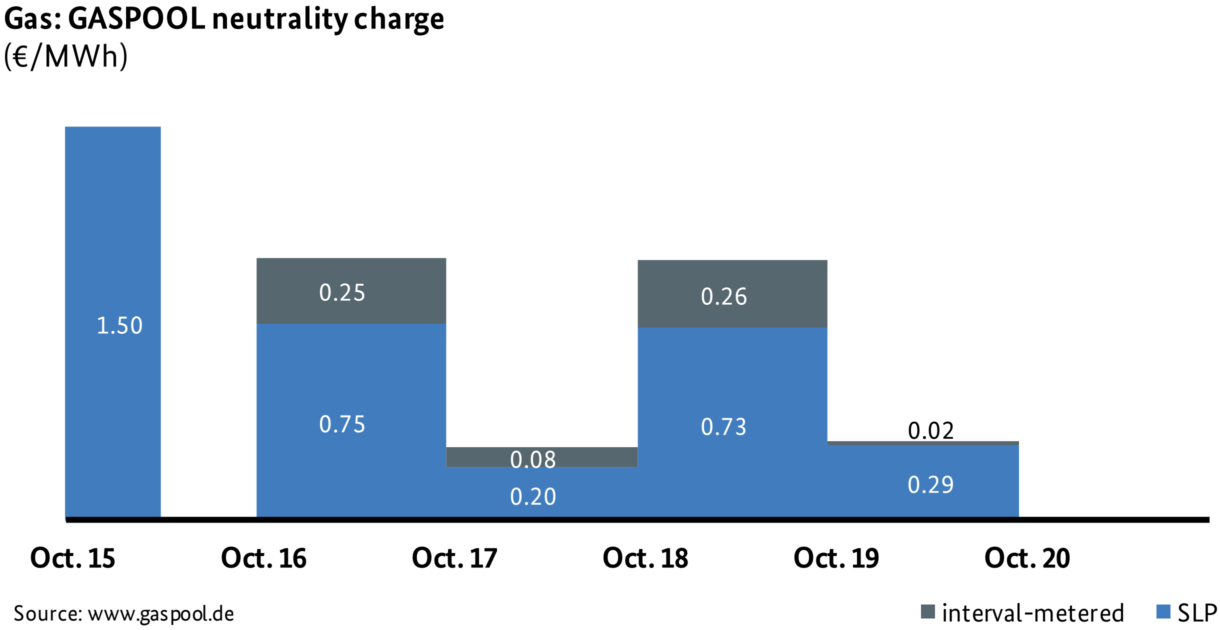

Figure 184: Neutrality charge in the GASPOOL market area, as at July 2021

3. Standard load profiles

Network operators use standard load profiles (SLPs) to forecast the allocation of offtake quantities of final customers, especially household and small business customers. They are used by 97.3% of network operators. Customers with an installed capacity of at least 500 kW or annual consumption of at least 1.5m kWh must generally be interval-metered. The opportunity to deviate from this limit was taken by 3.4% of network operators (2019: 4.2%), of which 26.1% stated that they reduced the limit for network-related reasons. In 56.5% of cases, the limits were agreed individually with shippers. According to the information provided, 53.9% of these agreed figures applied only to individual customer groups.

Network operators can use two types of 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 2020, the synthetic SLPs were used by 85.8% of operators (2019: 80.8%); analytical profiles were used by 14.2% of operators, compared to 14.1% in 2019.

The synthetic profiles of the Technical University of Munich (TU München), used in the versions of 2002 and 2005, are clearly dominant with a market coverage of 96.2%. This figure, too, remains almost unchanged from the previous year (94.3%).

The TU München offers a range of different profiles which reflect the offtake behaviour of various customer groups. In response to the question whether all available profiles were applied, 48.5% of network operators said they were, compared to 46.1% in 2019. As in the previous years, two to three profiles were generally used for household customers, whereas eight profiles were used on average for business customers (2019: nine).

Of network operators using the analytical profiles, 71.4% of them used the two-day delay method, with 24.1% stating they apply an optimisation procedure to minimise the two-day delay.

Whatever method was used, only 2.3% of operators made adjustments to the load profiles owing to large deviations from forecasts, compared to 5.3% in 2019. These adjustments consisted of applying correction factors, changing coefficients or other measures.

The network operator's network account balances all gas injected into a network against the allocated offtake quantities to final customers and transfers to downstream networks, storage facilities, adjacent market areas and foreign networks from the network. The market area managers settle these network accounts in the case of a short or long portfolio.

The network accounts of 48.7% of network operators were settled due to short portfolios in at least one month (no data from the network operator: 14.3%). The previous year, the figure was 48.2%. The average number of months for these network operators was three. The average across all network operators was 1.7 months.

The network accounts of 54.9% of network operators were settled due to long portfolios in at least one month (2019: 57%, no data from the network operator: 15.8%). The average number of months for these network operators was 9.1. The average including those network operators whose accounts were not settled was 6.4 months.

According to 64% of network operators, they had waived the credit from the settling of long portfolios.

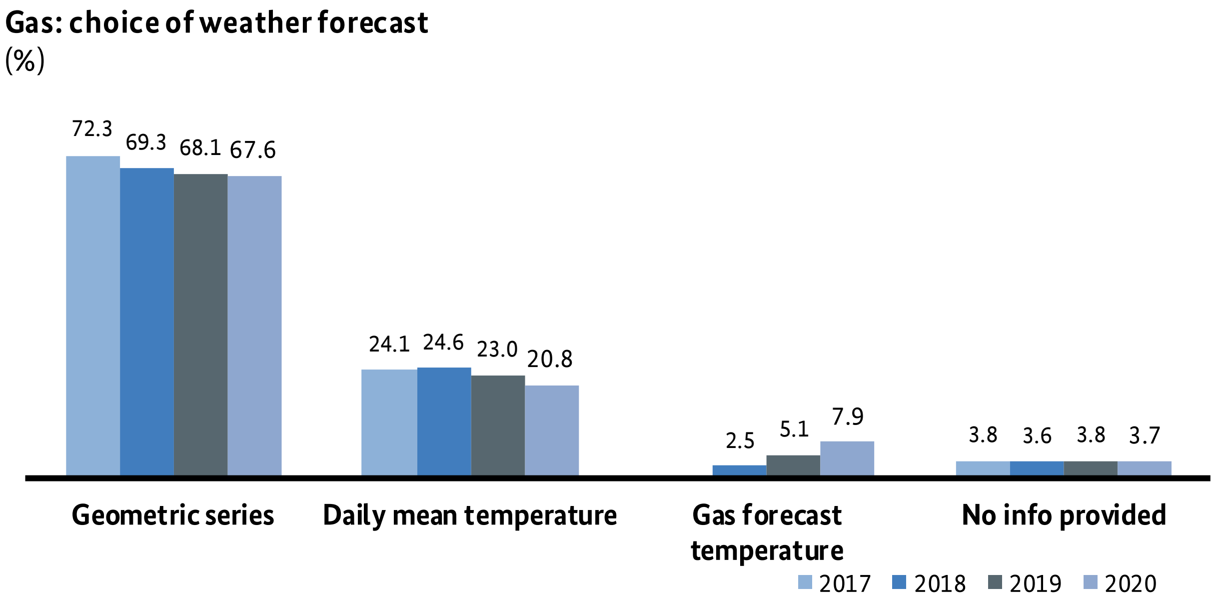

Figure 185: Choice of weather forecast

As SLPs are greatly temperature-dependent, there is a continuing strong preference for 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. The use of the gas forecast temperature was also included in the survey for the third time in the year under review, with 7.9% of network operators stating they used it. This percentage is, again, higher than the previous year (5.1%).

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 the wholesale level makes companies less dependent on a single or several suppliers in the long term. Market players can thus choose from a variety of competing trading partners and hold a diversified portfolio of short-term and long-term trading contracts. Liquid wholesale markets make it easier for new suppliers 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. Natural gas wholesale trading is done to a large extent via off-exchange broker platforms. The volume of brokered wholesale trading and on-exchange gas wholesale trading, of the EEX Group, for example, decreased again in 2020, probably as a result of the COVID-19 pandemic[177]. In addition to EEX there are other gas exchanges such as the CME Group, ICE and Nasdaq, which are prospectively to be included in monitoring activities in the energy sector in the coming years.

In 2020 there was again a significant reduction in gas wholesale trading prices. For example the EGIX, which is used as a reference price for the medium-term procurement market, fell by an unweighted annual average of around 29% compared to 2019.

1. On-exchange wholesale trading

The European Energy Exchange AG already mentioned and its subsidiaries (referred to collectively as EEX below) operate an exchange for natural gas trading in Germany. 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.[178]

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 ahead contract) and for the following weekend (weekend contract) on a continuous basis (24/7 trading). The minimum trading unit is 1 MW so that smaller volumes of natural gas can also be procured or sold at short notice. Quality-specific contracts (for high calorific gas or low calorific gas) are also tradable. Market participants mainly use the futures market to hedge against price risks, optimise portfolios and, to a much lesser degree, ensure long-term gas procurement.

Up to 31 December 2019 all EEX and Powernext trade on the European gas market was operated on the joint platform PEGAS. PEGAS allowed its members to trade spot and futures market products for the German,

[177] EEX Group Annual Report 2020, p. 22

[178] As a result of the merging of these two market areas on 1 October 2021 these will now form a single market area for Germany under the name Trading Hub Europe (THE).

Austrian, Belgian, Czech, Danish, Dutch, French, Italian, Spanish and UK gas market areas. On 1 January 2020 Powernext's business was integrated into EEX AG under one exchange licence. On this date EEX took over the operation of the former Powernext spot and futures markets for natural gas.

Futures can be traded for specific months, quarters, seasons (summer/winter) and years (so-called calendar years). In addition, in the second half of 2017 EEX introduced a new European spot market index "European Gas Spot Index" (EGSI) to enable 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 (TRF, up to October 2018: PEG Nord and TRS), Austria (CEGH VTP), Denmark (ETF) and Belgium (ZTP). A total volume of 2,379 TWh was traded on the EEX Group's European gas markets in 2020 (2019: 2,542 TWh). The spot market accounted for 1,411 TWh (2019: 1,454 TWh); a total volume of 968 TWh was traded on the futures market (2019: 1,088 TWh).[179] Due to the reduced demand for natural gas, presumably due to the COVID-19 pandemic, the total volume on both submarkets was less than in the previous year which resulted in a decrease in EEX's trading volume (approx. 6 %).[180] The entire trading volume relating to the two German market areas GASPOOL and NCG, including "cleared" volumes was around 486 TWh in 2020, a decline of around 11.3% on the previous year's figure of 548 TWh. The trading volume decreased in both market areas compared to 2019. The trading volume for the GASPOOL market area decreased by 5.5 TWh or around 3%, and by 56 TWh or around 16% for the NCG market area. The on-exchange volume traded on the spot market also fell in 2020 and was around 429 TWh (2019: around 472 TWh). In 2020, as in previous years, the majority of spot market transactions for both market areas focused on day-ahead contracts (NCG: 148.7 TWh, 179.5 TWh in the previous year; GASPOOL: 117.6 TWh, 121.5 TWh in the previous year). The trading volume of futures contracts decreased from about 75 TWh in 2019 to about 58 TWh, corresponding to a decline of 22.7%.

[179] EEX Group Annual Report 2020, p. 6

[180] EEX Group Annual Report 2020, p. 26

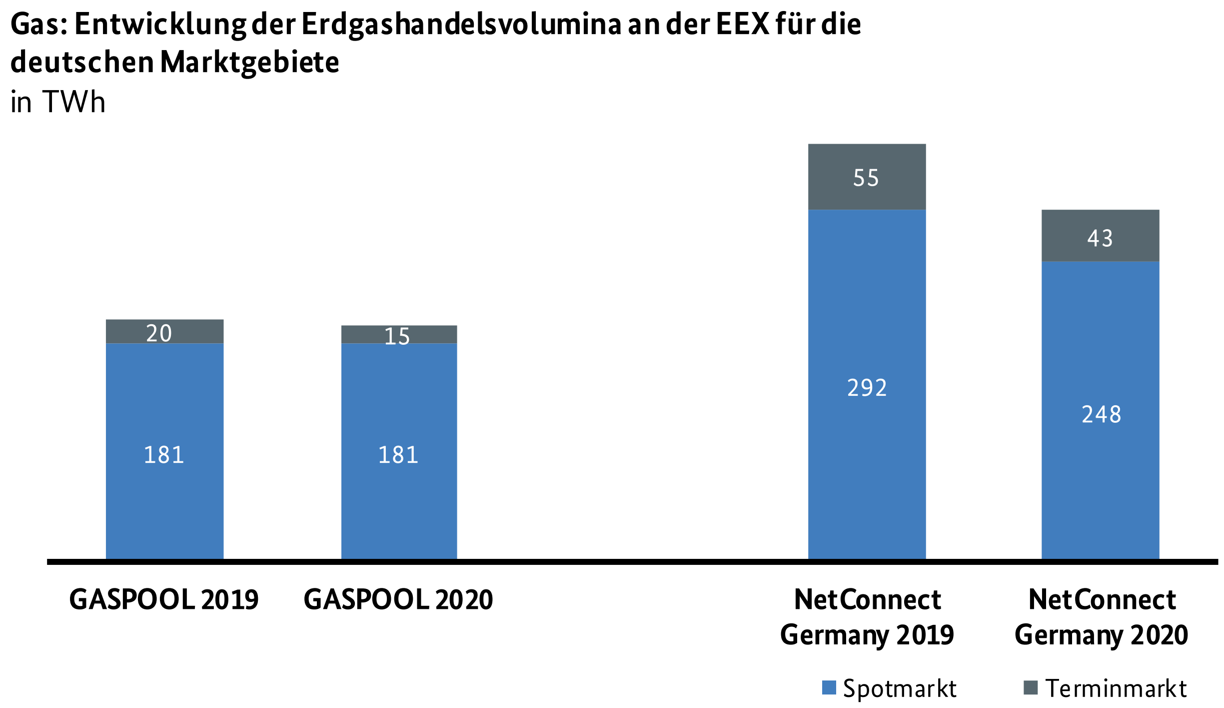

Figure 186: Development of natural gas trading volumes on EEX for the German market areas

The annual average number of active[181] participants on the spot market per trading day was 86 for NCG contracts (2018: 89 participants) and 77.5 for GASPOOL contracts (2019: 77). By contrast, the average number of active participants on the futures market per trading day was around 8.1 for the NCG market area (2019: 7.5) and around 3.5 participants for the GASPOOL market area (2019: 3.9). The comparison of these figures has to take account of the fact that, based on their term, futures contracts are geared towards higher quantities purchased than spot contracts.

2. Off-exchange wholesale trading

By far the largest share of wholesale trading in natural gas is carried out off-exchange ("over the counter" – OTC). Off-exchange trading offers the advantage of flexible bilateral or multilateral transactions, which, in particular, do not rely on the usual limited set of contracts on exchange markets. 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 supply of and demand for short-term and long-term natural gas trading products. Engaging a broker can reduce search costs and make it easier to effect larger transactions. At the same time this allows greater risk diversification because brokers offer services to register trading transactions brokered by them for clearance on the exchange to hedge the counterparty default risk of the parties. Electronic broker platforms are used to bring interested parties on the supply and demand sides together and so increase the chances of the parties reaching an agreement.

[181] Participants are considered to be active on a trading day if at least one of their bids has been fulfilled.

Ten broker platforms (nine in the previous year) took part in this year's collection of wholesale trading data. The natural gas trading transactions brokered by these broker platforms in 2020 with Germany as the supply area comprised a total volume of 2,898 TWh (2,8 TWh in the previous year)[182] of which 1,114 TWh were contracts to be fulfilled in 2020 (fulfilment period of one week or more).

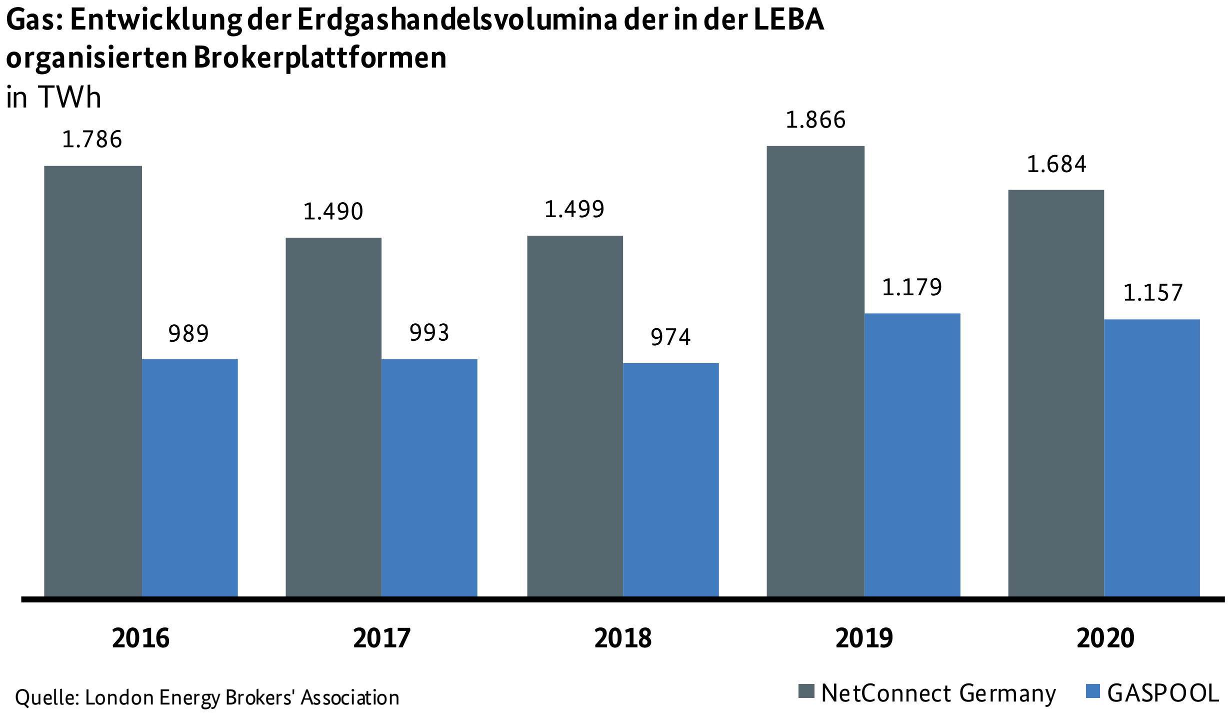

Figure 187: Development of natural gas trading volumes of LEBA-affiliated broker platforms for the German market areas

There was a slight increase in the total volume of the brokers compared to the previous year, which is primarily due to the inclusion of a further broker in this year's assessment. The majority of the brokers already surveyed in 2019 experienced reductions in volume. A decline in the gas trading volume in 2020 is also confirmed by the figures relating to brokered natural gas trading for the GASPOOL and NCG market areas published by the London Energy Brokers Association (LEBA). Seven of the ten broker platforms that provided data on which the above evaluation was based are members of LEBA. All the LEBA-affiliated broker platforms accounted for a total of 2,841 TWh for the two German market areas in 2020 (3,045 TWh in 2019), representing a decrease of around 7% compared to the previous year.[183]

On the spot market short-term transactions with a fulfilment period of less than one week only accounted for around 7% (previous year: 13%) of the trade brokered by the ten broker platforms whereas 93% were 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 2020 (including spot trading) constitutes as much as 47% (2019: 56%) of the total volume and still as much as around 29% for the subsequent

[182] Value corrected due to revised 2019 data.

[183] See London Energy Brokers` Association, Monthly Volume Report, https://www.lebaltd.com/monthly-volume-reports/ (retrieved on 7 July 2021).

year 2021 (32% in the previous year), the share of transactions with supply dates in 2022 and later is 24% (previous year: 12%).

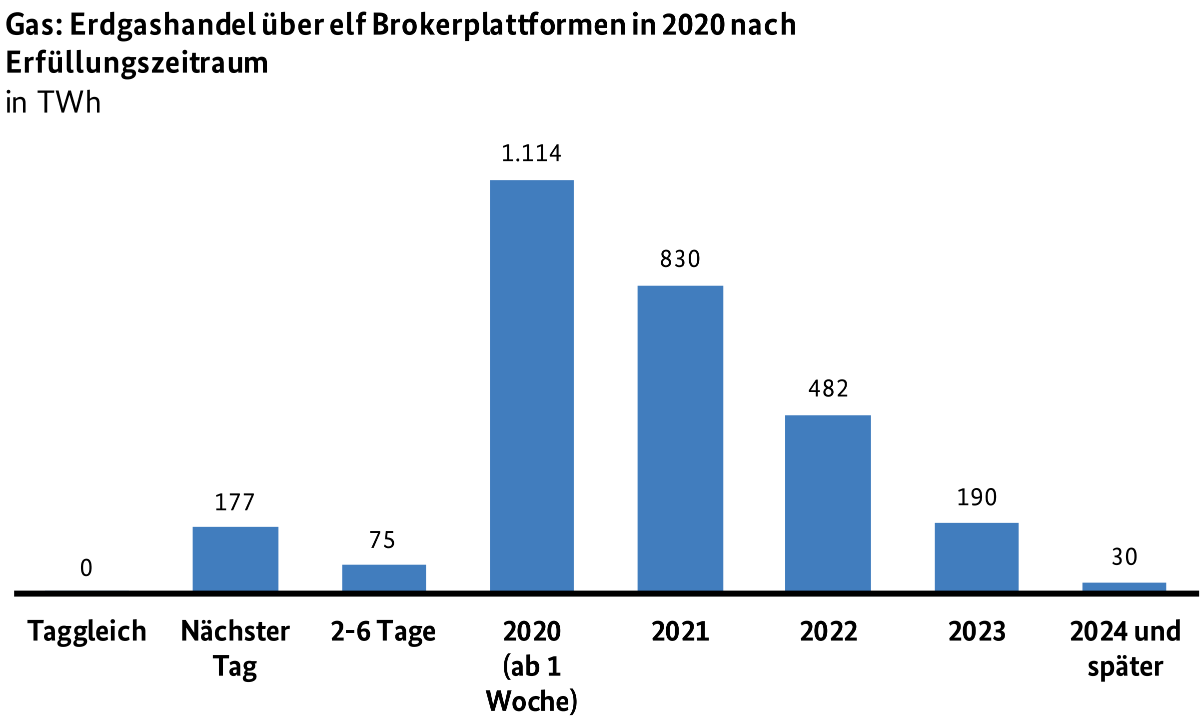

Figure 188: Natural gas trading for the German market areas via nine broker platforms in 2019 by fulfilment period

2.2 Nomination volumes at virtual trading points

The nominated volumes at the two German virtual trading points (VTPs) of NCG and GASPOOL are also 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 balancing groups of the same company.

As in the previous year the two parties responsible for the two market areas, NCG and GASPOOL, took part in this year's collection of gas wholesale trading data. The gas volumes nominated at the two VTPs fell from a total of 4,033 TWh in the previous year to 3,806 TWh in 2020, representing a decrease of about 5.6%. The

GASPOOL VTP accounted for about 46% of the nomination volume, and the NCG VTP for 54%. Almost 91% of the nomination volume consisted of high calorific gas, the remaining 9% of low calorific gas.[184]

The nomination volume of high calorific gas at the GASPOOL VTP decreased by about 59 TWh (around 3.5%) compared to 2019. The nomination volume at the NCG VTP fell by 131 TWh to 1,839 TWh (6.7%). 20 TWh less low calorific gas was traded at the GASPOOL VTP, which represents a decrease of around 13%, based, however, on much lower trading volumes. A decrease of 17 TWh (7.6%) was also registered at the NCG VTP in 2020.

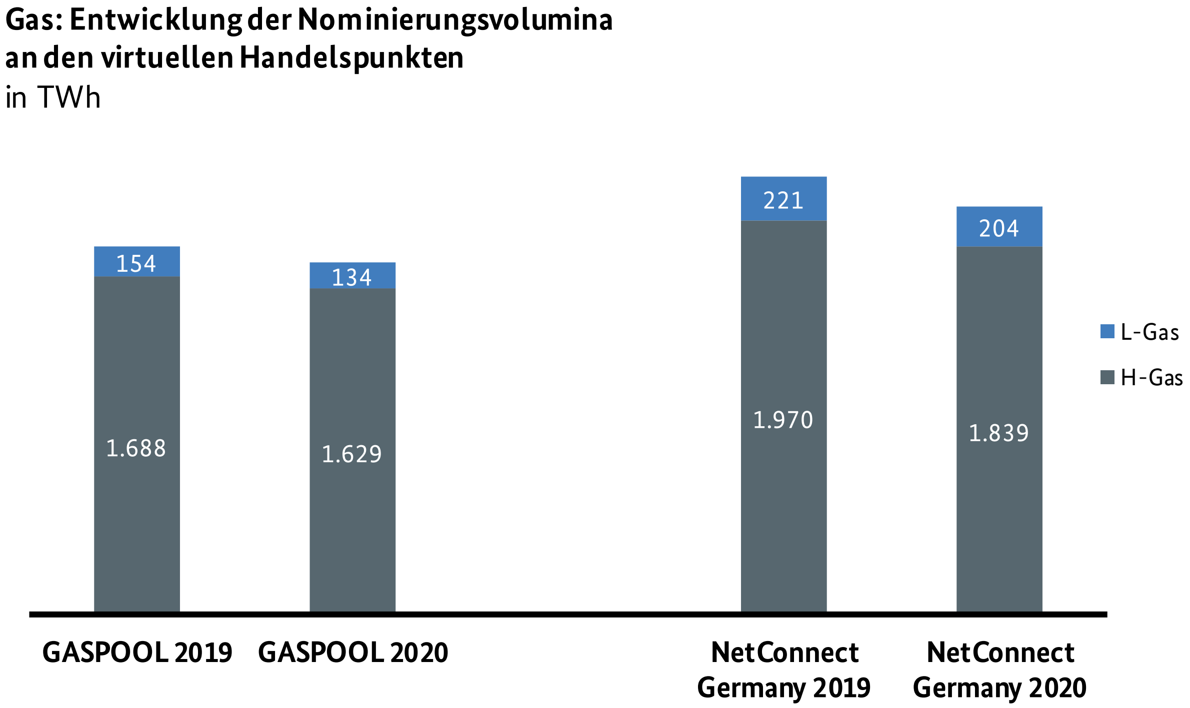

Figure 189: Development of nomination volumes at the German virtual trading points

As in previous years, the monthly nomination volumes reflect seasonal differences. The (aggregated) monthly nomination volume of both VTPs peaked at 272 TWh between July and September 2020. The lowest nomination volume was around 255 TWh in June 2020; the annual peak of 404.2 TWh was reached in December 2020.

[184] As a result of the merging of the NCG und GASPOOL market areas in 2021, there will only be one virtual trading point, the "Trading Hub Europe"; cf. https://www.energate-messenger.de/news/195040/deutsches-marktgebiet-wird-trading-hub-europe-heissen, https://www.tradinghub.eu/de-de/

Gas: Jahresverlauf der Nominierungsmengen
in TWh

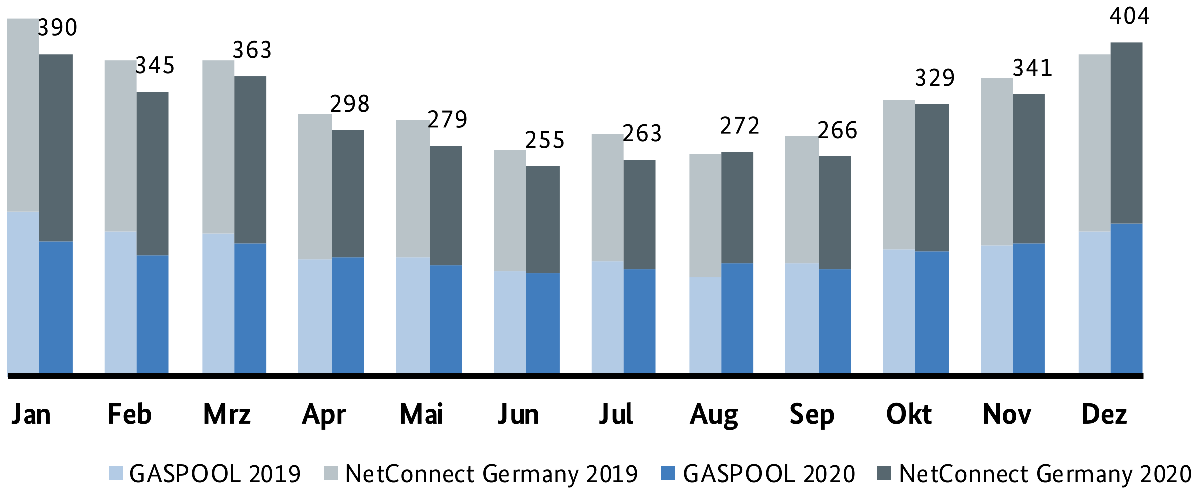

Figure 190: Annual development of nomination volumes at virtual trading points in 2019 and 2020

The number of active trading participants, i.e. companies that carried out at least one nomination in the relevant month, changed only marginally in 2020. The number of active trading participants in the NCG market area rose from 340 to 341 for high calorific gas whereas the number of active trading participants for low calorific gas remained at 179. The annual average number of active participants in the GASPOOL market area fell year-on-year from 289 to 279 for high calorific gas and from 142 to 139 for low calorific gas.

3. Wholesale prices

As an important exchange for natural gas trading in Germany EEX publishes several price indices as bases for reference prices for gas contracts with different procurement periods. The EGSI 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 XX of this section, gives an approximate indication of the price of natural gas procurement on the basis of long-term supply contracts.

In September 2017 EEX introduced the European Gas Spot Index (EGSI), which has since replaced the daily reference price as a short-term price index. The EGSI is determined by calculating the volume-weighted average. Unlike the daily reference price, the EGSI is calculated at least one day before the date of fulfilment. This differs if a trading day is preceded by a weekend or bank holiday. For ease of comparison the EGSI is analysed in this report exclusively on the basis of trading prices and volumes of so- called “day ahead” products. In 2020 the EGSI amounted to €9.58/MWh as the (unweighted) annual average for the NCG market area and €9.71/MWh for the GASPOOL market area. In 2019 the comparative figures for the daily reference price were €14.18/MWh for NCG and €13.75/MWh for GASPOOL. The EGSI fluctuated in the course of 2020 between €3.34/MWh (in May 2020) and €19.05/MWh (in December 2020) in both market areas.

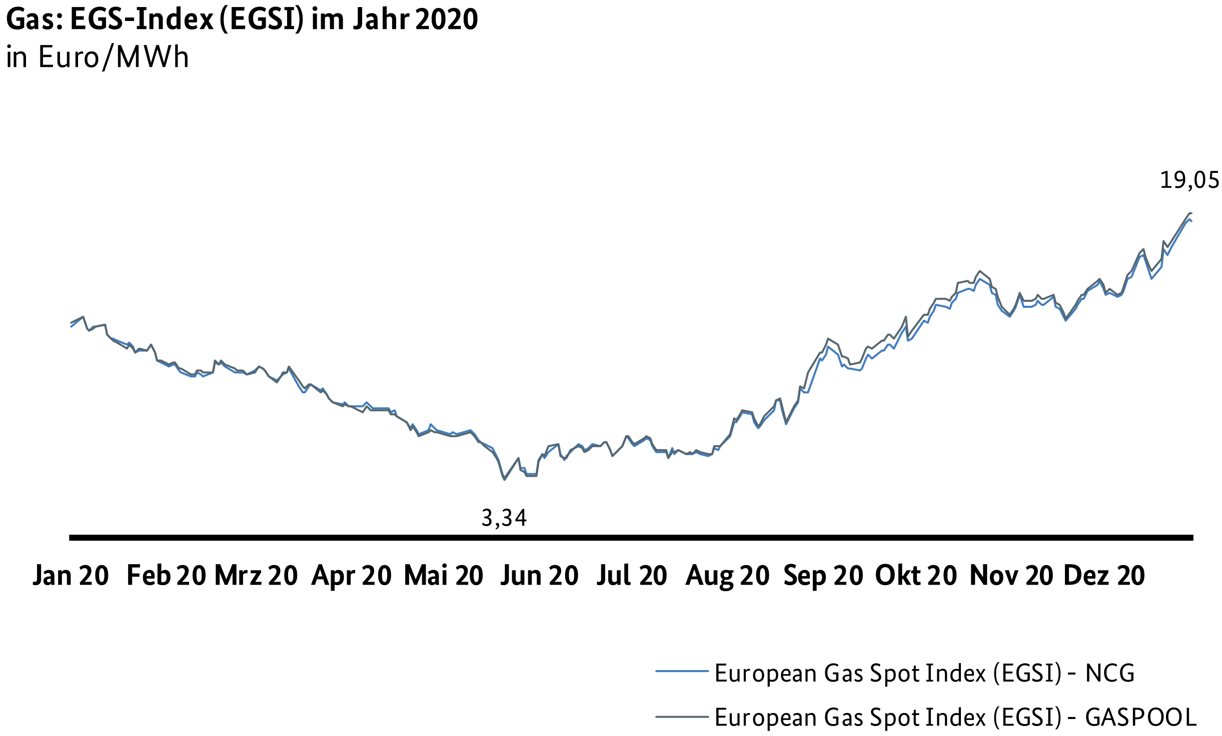

Figure 191: EEX-EGSI in 2020

The deviations between the EGSI for NCG and GASPOOL in 2020 were again significantly smaller than in the previous year. On only 15 trading days the price difference was 3% (2019: 42 trading days) and 4% on only 2 trading days (2019: 25). On 171 of 249 exchange trading days (2019: 162 of 251 exchange trading days) the difference was no more than 2%.

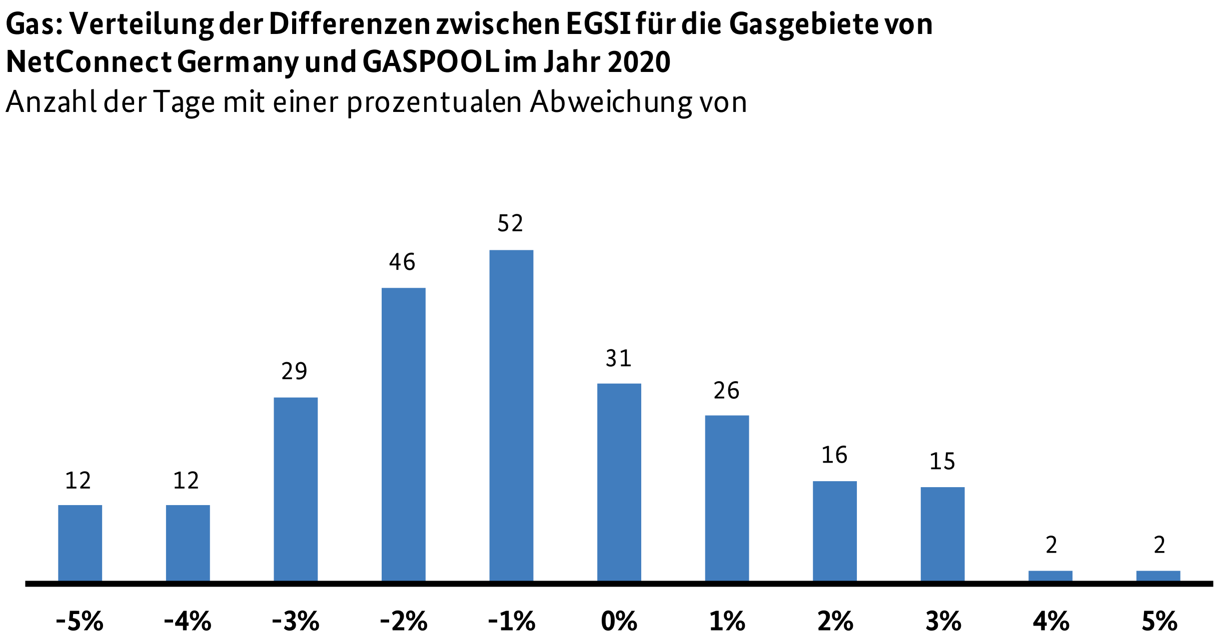

Figure 192: Distribution of the differences between the EGSI for GASPOOL and NCG in 2020

The EGIX Germany is a monthly reference price for the futures market for medium-term trading contracts. 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[185].

In 2020 the EGIX Germany ranged from €5.20/MWh in July to €14.85MWh in January. The arithmetic mean of the twelve monthly figures was €9.59/MWh, a decrease of approximately 39% compared to the previous year's figure of €15.75/MWh. The cross-border price for each month is calculated by the Federal Office for Economic Affairs and Export Control (Bundesamt für 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[186], spot volumes and prices are largely disregarded.

The monthly BAFA cross-border prices for natural gas ranged from €8.65 /MWh to €21.68/MWh between 2016 and 2020. The (unweighted) average of the monthly cross-border prices was €12.07/MWh in 2020, down by 24.5% from the 2019 figure of €15.99.

Gas: Entwicklung des BAFA-Grenzübergangspreises und des EGIX Deutschland
in Euro/MWh

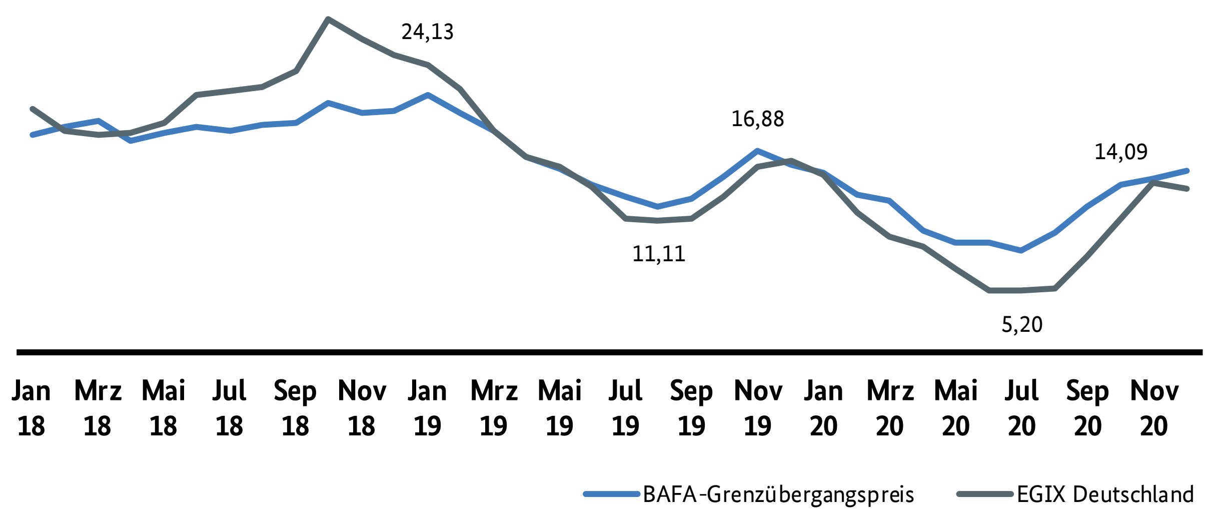

Figure 193: Development of the BAFA cross-border price and the EGIX Germany between 2018 and 2020

Older gas import contracts were usually based on price agreements linked to oil prices. In recent years oil prices have been increasingly disregarded in new contracts and contract amendments. Price indices such as

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185 For a detailed calculation of the values see https://www.eex.com/fileadmin/EEX/Downloads/Trading/Specifications/Indeces/2014-02-06---beschreibung-egix-pdf-data.pdf (retrieved on 30 August 2021).

186 See https://www.bafa.de/SharedDocs/Downloads/DE/Energie/egas_aufkommen_export_1991.html (retrieved on 30 August 2021).

the EEX EGSI reference price or the EGIX allow long-term contracts to be indexed according to exchange prices.

F Retail

1. Supplier structure and number of providers

A total of 1,020 gas suppliers were surveyed for the 2021 Monitoring Report. In the evaluation of the data provided by gas suppliers, each gas supplier is considered as an individual legal entity without taking possible company affiliations or links into account, showing that the gas market is highly heterogeneous with regard to the supplied market locations.

Gas: suppliers by number of market locations supplied (number and percentage)
figures do not take account of company affiliations

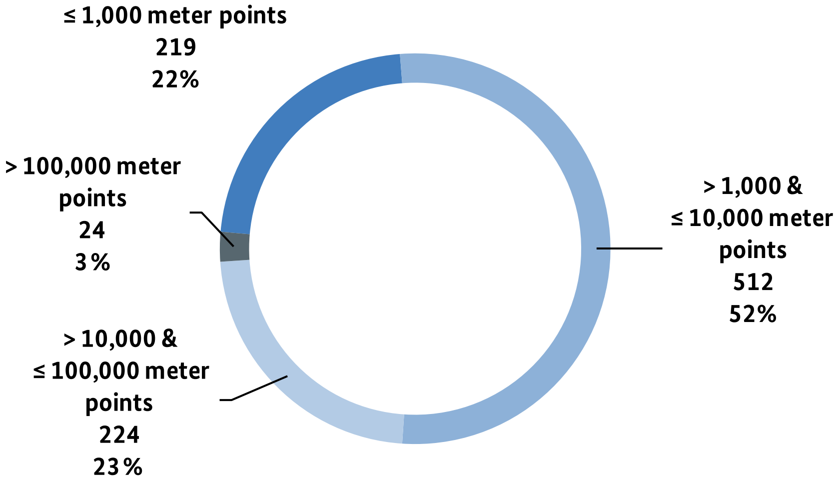

Figure 194: Gas suppliers by number of market locations supplied (number and percentage) – as at 31 December 2020

One indicator of the degree of choice for gas customers is the number of suppliers in each network area. In the 2020 survey, the gas network operators were asked to report on the number of suppliers serving at least one final customer 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 an efficient supplier switch, there has been a steady rise in the number of active gas suppliers for all final customers in the different network areas. This positive trend was maintained in 2020 as well.

On average, final customers in Germany can choose from 133 suppliers in their network area (2019: 129); household customers can, on average, choose between 113 suppliers (2019: 109 suppliers) (these figures do not take account of corporate groups).

Gas: breakdown of network areas by number of suppliers operating
(all final customers (left) and household customers (right)

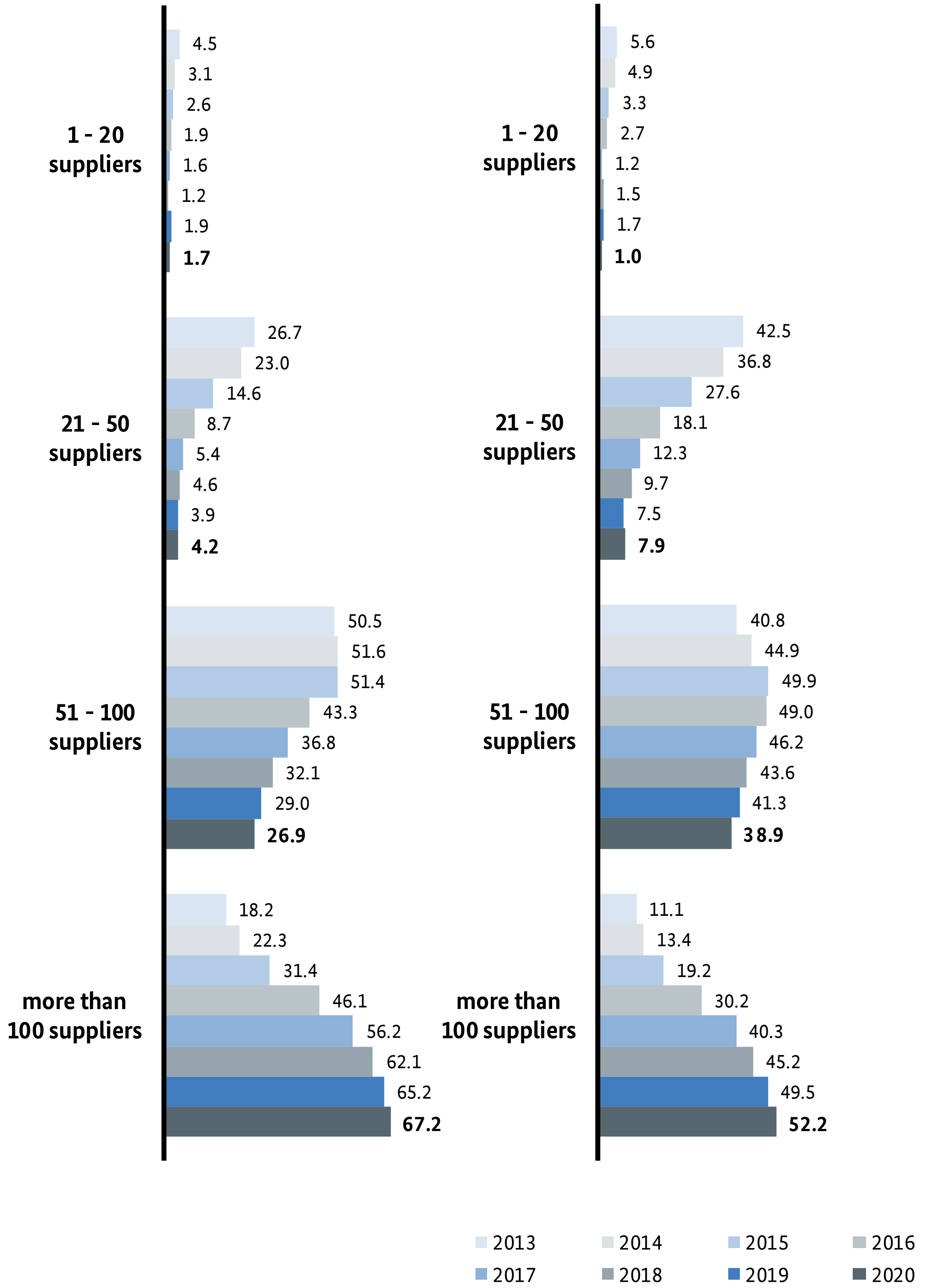

Figure 195: Breakdown of network areas by number of suppliers operating according to the survey of gas DSOs – as at 31 December 2020

Suppliers were also asked about the number of network areas in which they supply final customers with gas. 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 57 gas suppliers (6%) fulfil this criterion and are regarded as suppliers that are active nationwide.

Gas: suppliers by number of network areas supplied (number and percentage)
figures do not take account of company affiliations

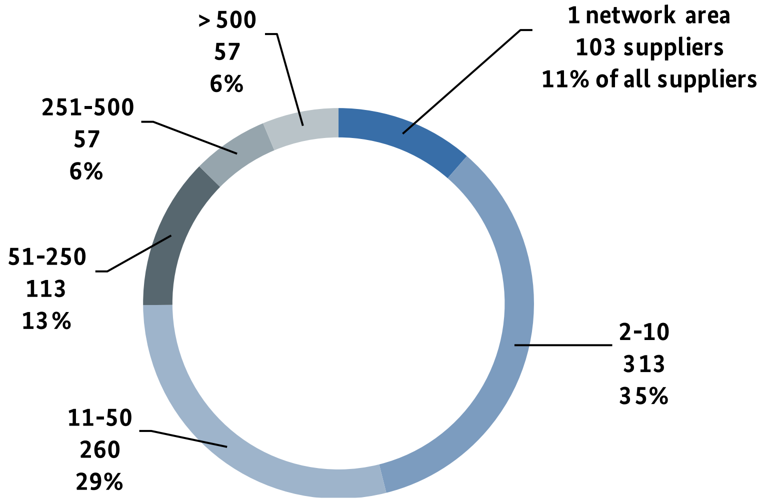

Figure 196: Gas suppliers by number of network areas supplied (number and percentage), according to the survey of gas suppliers – as at 31 December 2020

2. Contract structure and supplier switching

About half of Germany's 12.8m household customers have a non-default contract with the local default supplier. About 17% have a standard contract with their default supplier. Around a third of household customers have a gas supply contract with a supplier that is not the local default one.

The proportion of expensive default contracts had been falling for years, but stabilised in 2020. The proportion of contracts with a supplier other than the local default supplier is rising steadily.

More than 1.65m household customers switched gas supplier in 2020. People moving house or moving into new homes, in particular, are more and more likely to turn directly to a supplier that is not the local default one and thus to access a cheaper gas contract.

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. Switching contracts with the existing supplier or changing supplier can usually save customers money.

Changes in switching rates and processes are important indicators of the level of competition. There are challenges involved with the collecting and differentiating of such data, however, and the relevant data collection thus has to be limited to data that best reflect the actual switching behaviour.

Final customers 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 customers can also be divided into household and non-household customers. Household customers are defined in the Energy Industry Act (EnWG) according to qualitative characteristics.[187] All other customers are non-household customers, which include 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 to all final customers in 2020 reached 853 TWh (2019: 857.7 TWh). Based on the reported volumes of gas sold to SLP and interval-metered customers, about 493.5 TWh went to interval-metered customers and about 356 TWh to SLP customers, compared to 500.5 TWh and 361 TWh respectively in the previous year.[188] The majority of SLP customers are household customers. In 2020 household customers within the meaning of section 3 para 22 EnWG were supplied with around 245 TWh (2019: 253.1 TWh).

In the monitoring survey, data is collected from the gas suppliers on the volumes of gas sold to various final customer 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.[189] Supply outside the framework of a default contract is either designated as a non-default contract or is

[187] Section 3 para 22 EnWG defines household customers as final customers 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.

[188] The difference between the amount of 849.5 TWh (total of interval-metered and SLP volumes) and the total volume of 853 TWh is due to different data from the suppliers surveyed.

[189] In addition to household customers, final customers 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".

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 (see section 1(4) of the Electricity and Gas Concession Fees Ordinance, 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".[190] Gas suppliers were also asked how many household customers have switched or changed their energy supply contract in the 2020 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 2020. A supplier switch, as defined in the monitoring survey, means the process by which a final customer's meter location 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.

2.1 Non-household customers

2.1.1 Contract structure

Gas volumes for non-household customers are predominantly supplied to interval-metered customers whose gas consumption is recorded at short (e.g. quarter hourly) intervals, ("load profile"). Such customers are characterised by high consumption and/or high energy requirements.[191] All interval-metered customers are non-household customers with a high level of consumption, such as industrial customers or gas power plants.

In the reporting year 2020, 922 gas suppliers (separate legal entities) provided information on metering points and on the volumes supplied to interval-metered customers (2019: 907). The 922 gas suppliers include a number of affiliated companies, so that the number of suppliers is not equal to the number of actual competitors.

[190] It is also possible that further ambiguities may arise, for example if the local default supplier changes.

[191] In accordance with Section 24 of the Gas Network Access Ordinance (GasNZV), interval metering is generally required for customers with an hourly consumption rate exceeding 500 KW or an annual consumption of 1.5 GWh.

Overall these suppliers sold over 493.5 TWh of gas to interval-metered customers via more than 42,384 metering points in 2020. Over 99% of this volume was supplied under non-default contracts with the default supplier[192] (112.5 TWh) and under contracts with suppliers other than the local default supplier (380.8 TWh). It is unusual but not impossible for interval-metered customers to be supplied under default or fallback supply contracts. Around 0.2 TWh of gas was supplied to interval-metered customers with a default or fall-back supply contract. This corresponds to about 0.04% of the total volume supplied to such customers.

About 22.8% of the total volume supplied to interval-metered customers in 2020 (24.1% in 2019) was sold under non-default contracts with the default supplier and about 77.2% (75.9% in 2019) was sold under supply contracts with a legal entity other than the default supplier. The figures show that default supplier status is of only minor importance for the acquisition of interval-metered gas customers.

Gas: Vertragsstruktur bei RLM-Kunden im Jahr 2020
Menge und Verteilung

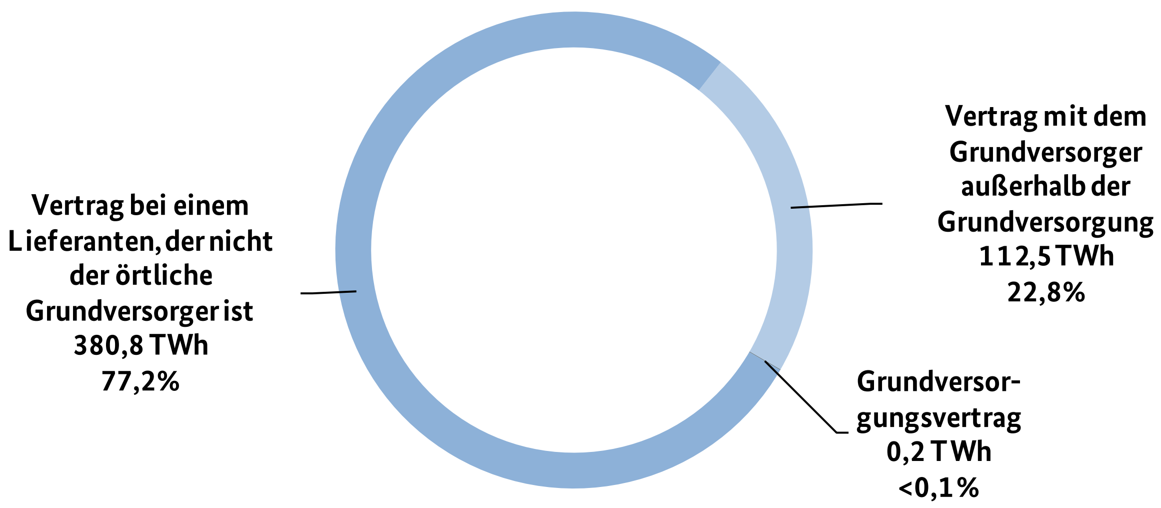

Figure 197: Contract structure for interval-metered customers in 2020

2.1.2 Supplier switching

Data on the supplier switching rates (as defined for monitoring, see above) of different customer groups in 2020 was collected in the TSO and DSO surveys. This did not include the percentage of industrial and commercial customers which 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 the four highest consumption categories with a final consumption exceeding 0.3 GWh/year, including gas-fired power plants. The survey produced the following results:

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[192] 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 “fallback supply”.

Gas: Lieferantenwechsel nach Verbrauchskategorien im Jahr 2020

Letztverbraucher-kategorie	Anzahl der Zählpunkte, bei denen der Lieferant wechselte	Anteil an allen Zählpunkten der Verbrauchs-kategorie	Entnahmemenge an den Zählpunkten, bei denen der Lieferant wechselte	Anteil an Gesamt-entnahmemenge der Verbrauchs-kategorie
< 0,3 GWh/Jahr	1.531.205	10,9%	37,1 TWh	11,7%
≥ 0,3 GWh/Jahr < 10 GWh/Jahr	15.020	11,9%	14,9 TWh	12,6%
≥ 10 GWh/Jahr < 100 GWh/Jahr	723	18,0%	13,8 TWh	13,6%
≥ 100 GWh/Jahr	64	11,4%	13,3 TWh	4,9%
Gaskraftwerke	4	1,0%	1,5 TWh	1,4%
Gesamt	**1.547.014**		**80,6 TWh**	

Table 129: Supplier switching by consumption category in 2020

The total number of metering points with a change of supplier in 2020 increased from 1,488,442 in 2019 to 1,547,014 in 2020 (+3.8%); however, the total gas volume affected by supplier switching fell by around 8. TWh to approx.80.6 TWh (-9.3%). This change suggests that household customers and smaller businesses in particular switched supplier in 2020.

Gas: Entwicklung Lieferantenwechsel bei Nicht-Haushaltskunden
Mengenbezogene Quote für alle Verbraucher >300 MWh/Jahr

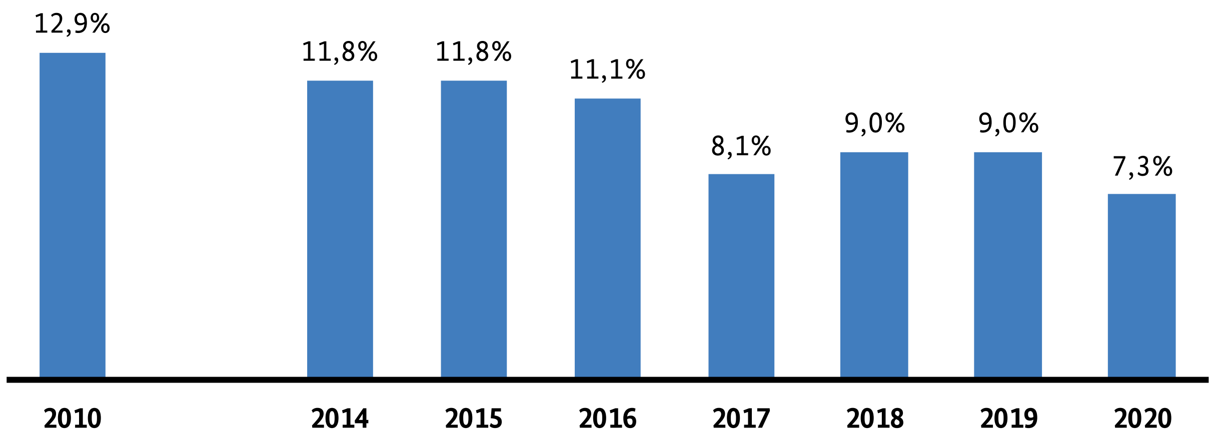


Figure 198: Supplier switching among non-household customers

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 fell in 2020 for the first time in three years to 7.3%.

2.2 Household customers

2.2.1 Contract structure

In the data survey for the 2021 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 up to 20 GJ (5,556 kWh)
- band II (D2): annual consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh)
- band III (D3): annual consumption of 200 GJ (55,556 kWh) or more.

Overall, the amount of gas supplied to household customers remained largely the same. In particular, the proportion of default supply, which had been falling steadily, rose slightly in 2020.

Gas: contract structure for household customers in 2020
volume and breakdown

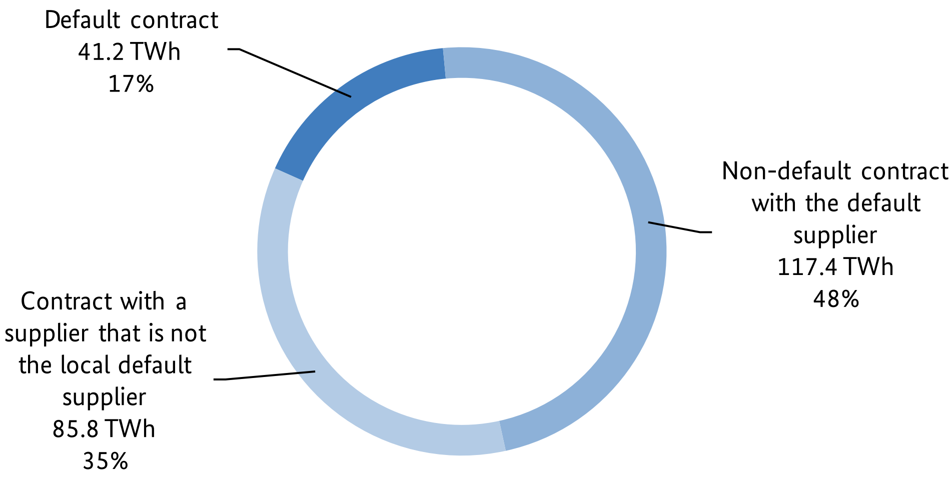


Figure 199: Contract structure for household customers (volume of gas delivered) according to survey of gas suppliers– as at 31 December 2020

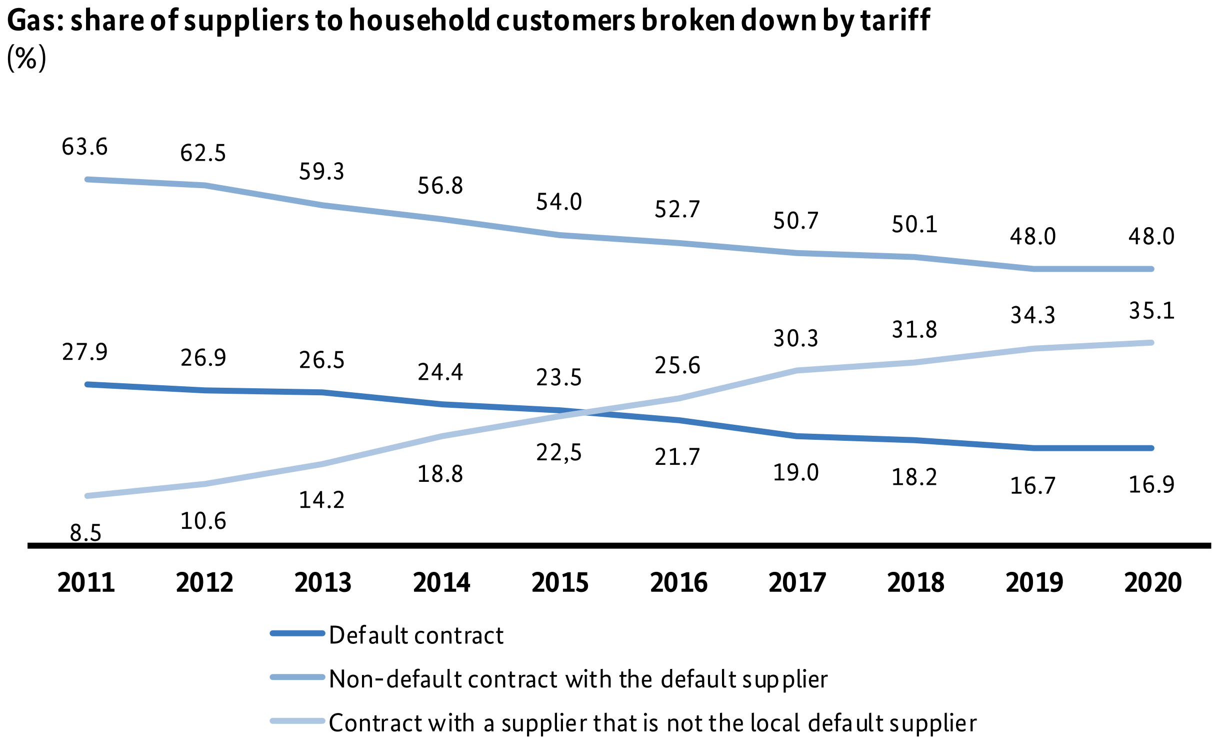


Figure 200: Share of gas supplies to household customers broken down by tariff according to survey of gas suppliers – as at 31 December 2020

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.

Gas: contract structure for household customers (volume and distribution) broken down into consumption bands I, II and III in 2020

Contract type	Band I with consumption of < 5,556 kWh (20 GJ)		Band II with consumption of ≥ 5,556 kWh (20 GJ) and < 55,556 kWh (200 GJ)		Band III with consumption of ≥ 55,556 kWh (200 GJ)	
	Volume (TWh)	Distribution (%)	Volume (TWh)	Distribution (%)	Volume (TWh)	Distribution (%)
Default contract	2.3	38	31.2	18	5.8	11
Non-default contract with default supplier	2.0	33	85.8	49	26.1	49
Contract with a supplier other than the local default supplier	1.7	23	57.9	33	21.4	40
Total	6.0	100	174.9	100	53.3	100

Table 130: Contract structure for household customers (volume) broken down into consumption bands – as at 31 December 2020

When focusing on the number of household customers supplied in 2020, it becomes clear that a relative majority of 42% of them had a non-default contract with the local default supplier.

Gas: contract structure for household customers in 2020
number in millions and percentage

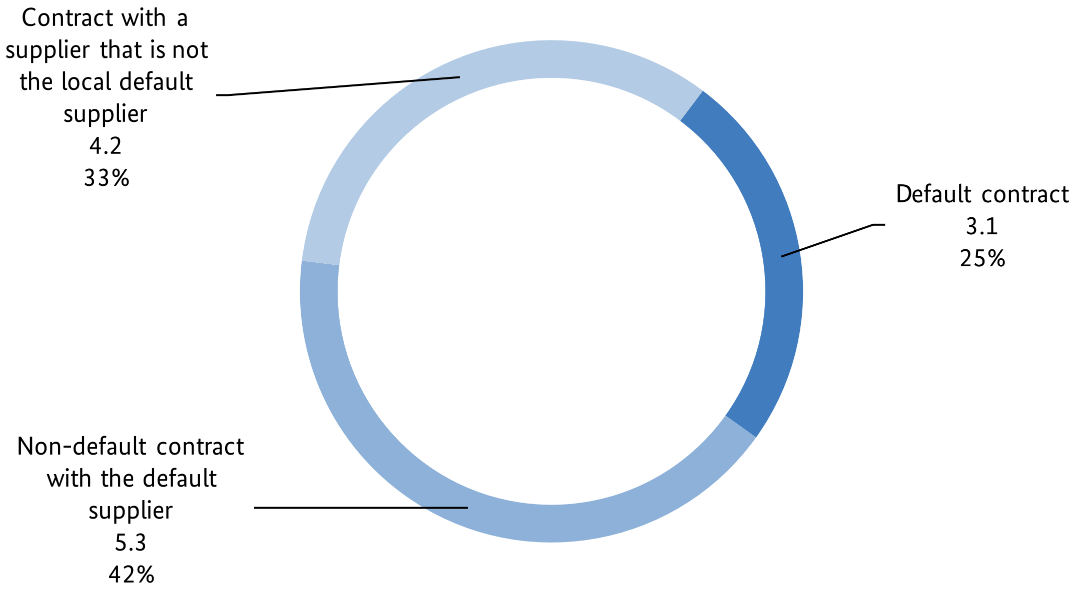


Figure 201: Contract structure for household customers (number of customers supplied) according to survey of gas suppliers – as at 31 December 2020

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.

Gas: contract structure for household customers (number and distribution) broken down into consumption bands I, II and III in 2020

Contract type	Band I with consumption of < 5,556 kWh (20 GJ)		Band II with consumption of ≥ 5,556 kWh (20 GJ) and < 55,556 kWh (200 GJ)		Band III with consumption of ≥ 55,556 kWh (200 GJ)	
	Number (m)	Distribution (%)	Number (m)	Distribution (%)	Number (m)	Distribution (%)
Default contract	1.1	50	1.8	22	0.1	17
Non-default contract with default supplier	0.6	27	4.3	47	0.2	50
Contract with a supplier other than the local default supplier	0.5	23	3.1	30	0.2	33
Total	2.2	100	9.2	99	0.6	100

Table 131: Contract structure for gas household customers (number of customers supplied), broken down by consumption bands– as at 31 December 2020

2.2.2 Change of contract

Gas suppliers were asked about household customers that changed contract at their own request in 2020.[193] The number and volume of contract switches both fell for the first time. The volume-based switching rate was down to 4.8% in 2020 from 5.4%.

Gas: household customers that changed their contracts

Category	Subsequent consumption in 2020 (TWh)	Share of total consumption (245 TWh) (%)	No. of contracts changed in 2020	Share of all household customers (12.5m) (%)
Household customers that changed their contract with their existing supplier	11.9	4.9	0.6m	4.8

Table 132: Gas household customers that changed their contracts in 2020 according to survey of gas suppliers

[193] 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.

2.2.3 Supplier switch

The total number of supplier switches by household customers hit a new high in 2020, passing the 1.6m mark. Around 1.3m of these household customers changed by cancelling the contract with their previous supplier. The remaining around 0.3m chose an alternative supplier rather than the default one right away when moving home.

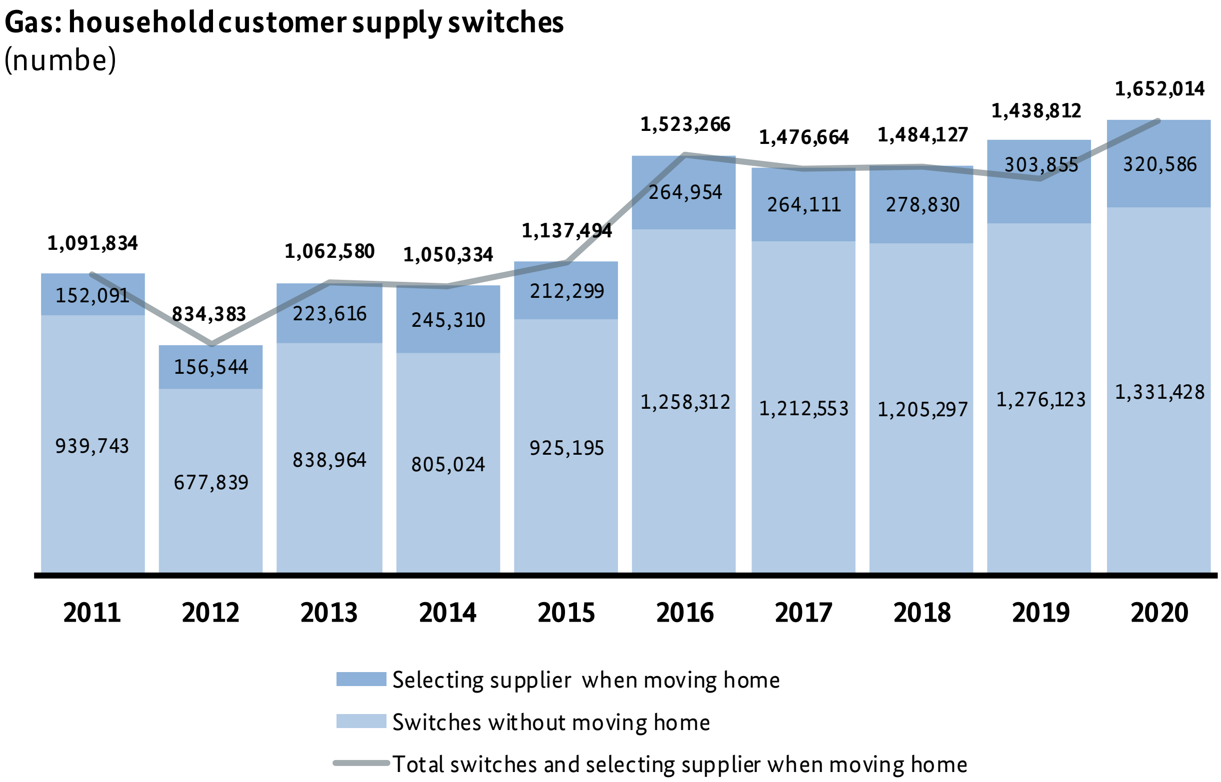


Figure 202: Household customer supplier switches according to the survey of gas DSOs

When looking at 12.8m household customers (according to DSO figures), the resulting overall numbers-based supplier switching rate for household customers is 12.9% (2019: 11.3%). The volume of gas supplied to these customers who switched supplier was 36.4 TWh (2019: 35.1 TWh), which corresponds to a rise of about 3.6%. The volume-based switching rate of 13.5% is above the numbers-based rate, which may be due to the fact that high-consumption customers exhibit a greater willingness to switch. The following figure shows the numbers-based switching rates since 2009:

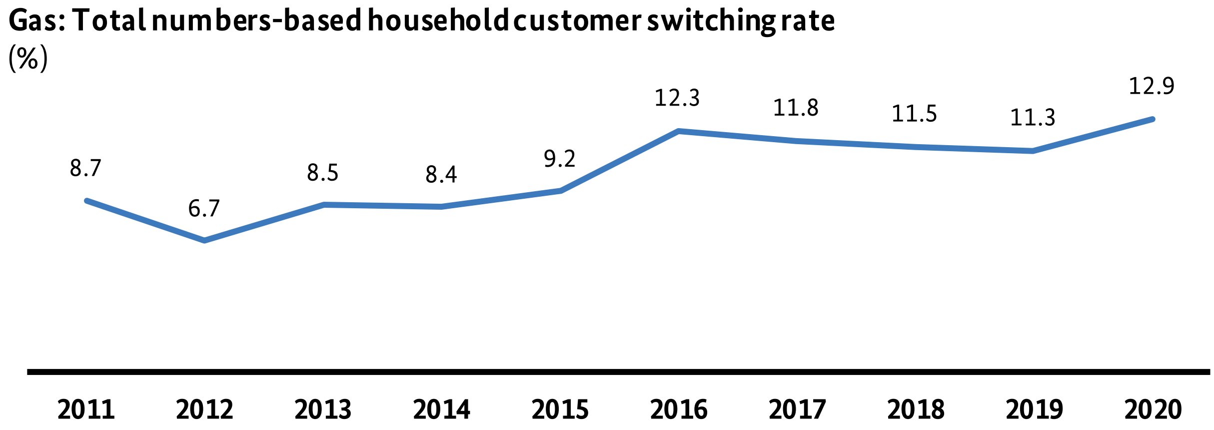


Figure 203: Total numbers-based household customer switching rate based on DSO data survey

Gas: household customer supplier switches, including customers selecting supplier when moving home

Category	2020: subsequent consumption (TWh)	Share of total consumption (270.3 TWh) (%)	2020: No. of contracts changed	Share of all household customers (12.8m) (%)
Household customer supplier switches without moving home	30.3	11.2	1.3m	10.2
Household customers who immediately chose a supplier other than the default supplier when moving home	6.1	2.3	0.3m	2.3
Total	36.4	13.5	1.6m	12.5

Table 133: Gas household customer supplier switches in 2020, including switches by customers when moving home

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.

3. Gas supply disconnections and contract terminations, cash/smart card meters and non-annual billing

Around 24,000 gas customers were affected by disconnections in 2020.

Customers owing money to their supplier are sent a reminder with a fee, together with or followed by a disconnection notice.

The gas supply cannot actually be disconnected (interrupted) until at least four weeks after a disconnection notice has been issued, with customers being given three working days' notice of the disconnection date.

Unlike for electricity, for gas there is no lower limit for debt that can lead to the supply being disconnected. Irrespective of this, default suppliers are required to check that any action is proportionate. Suppliers can charge their customers for reminders, disconnections and reconnections, with the costs varying considerably between suppliers and network operators. Customers on default supply contracts have a right to an itemised bill for these costs.

Consumers expecting changes in their consumption can avoid large back payments by changing their instalment payments. Consumers can also lower their energy costs by switching tariff or supplier. Advice about energy costs is available from consumer advice centres, amongst others.

3.1 Disconnections and terminations

In 2020, the Bundesnetzagentur asked network operators and gas suppliers about disconnection notices, disconnection requests, disconnections that were actually carried out and the costs each action incurred. The number of disconnections actually carried out by the network operators in 2020 was 23,991, representing a strong decrease of about 22.6% compared to the previous year (2019: 30,997). This corresponds to 0.2% of gas connections based on all market locations of final customers. It may be assumed that this drop was partly due to the right to withhold performance set out in Article 240 section 1 EGBGB, which applied from 1 April to 30 June 2020 because of the Covid-19 pandemic to provide temporary relief for consumers. Around 75% of the gas suppliers surveyed also said they had voluntarily decided not to disconnect their customers in 2020, at least for a time. Gas suppliers also accommodated customers by offering them special or individual payment arrangements. Some suppliers extended their criteria for disconnections to make them more customer-friendly.

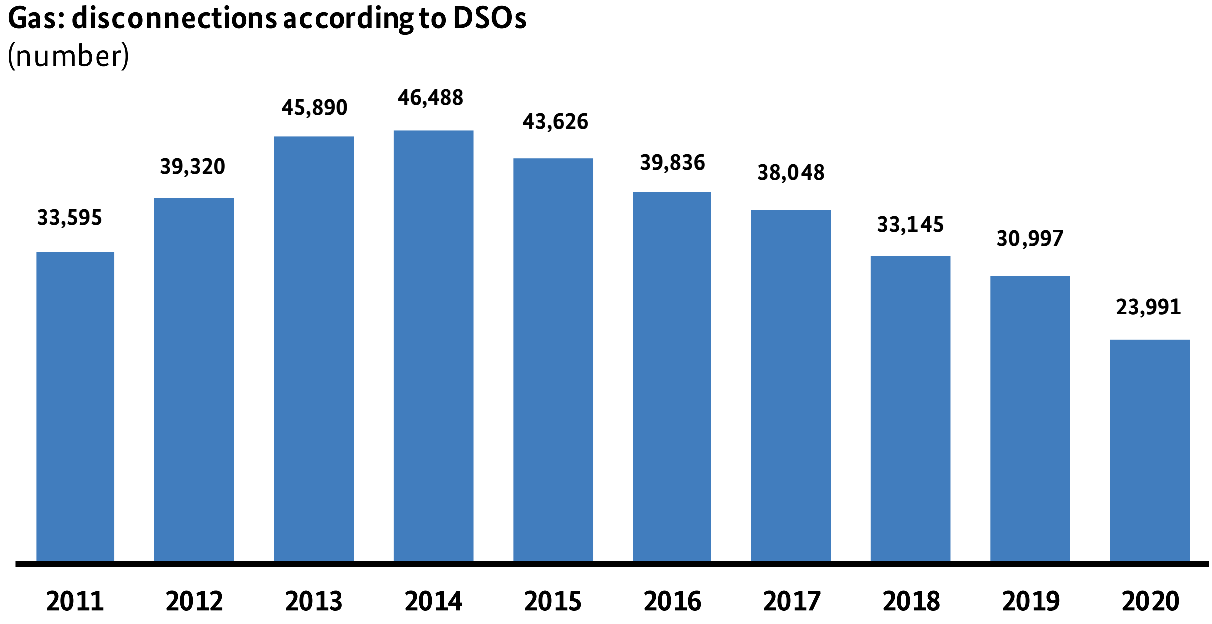


Figure 204: Gas disconnections according to DSOs, from 2011 to 2020

The chart below shows how often suppliers issued disconnection notices to customers that had failed to meet payment obligations in 2020 and how often they requested the network operator responsible to disconnect supplies or carried out the disconnection. It can be seen that the requests for disconnection issued by gas suppliers was down about 22%, which correlates to the decline in disconnections actually carried out by network operators.

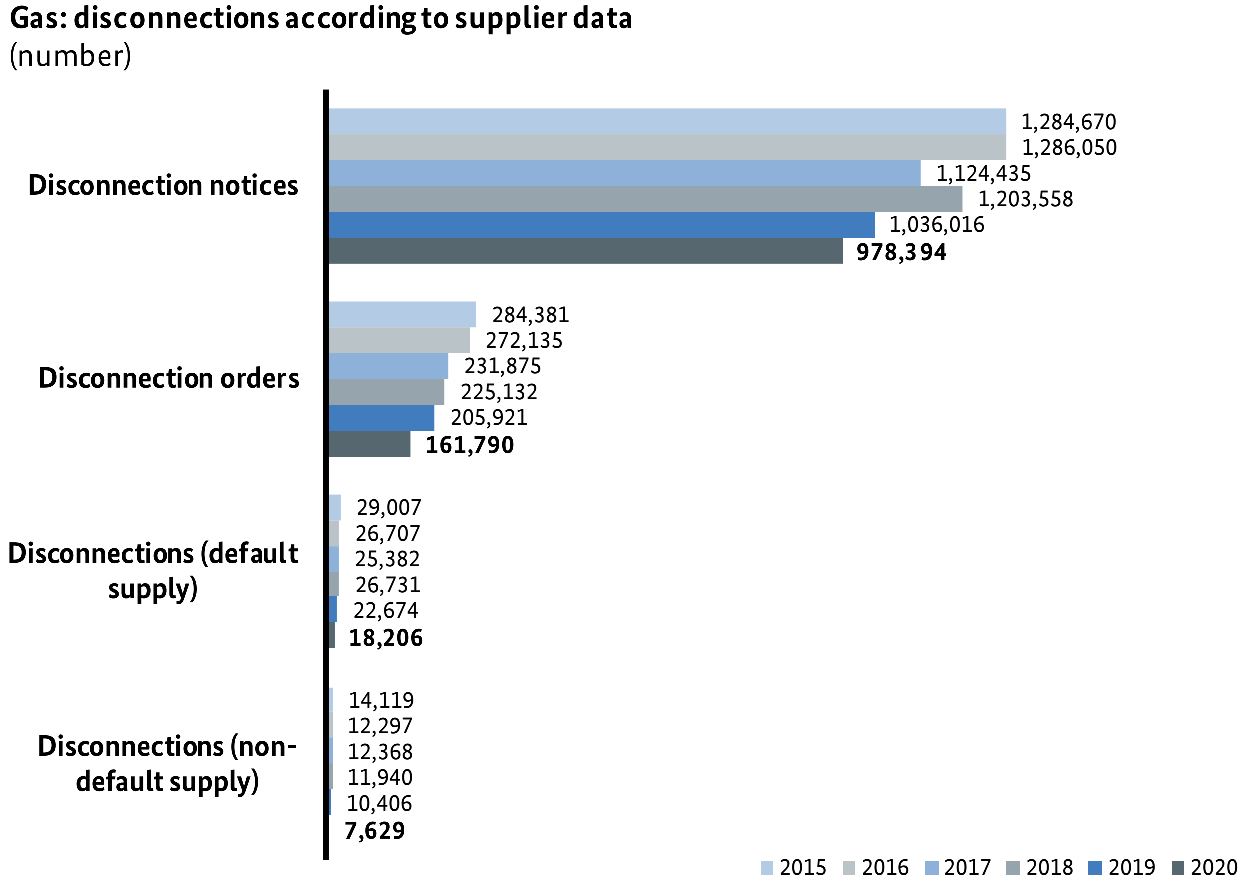


Figure 205: Disconnection notices, disconnection orders and disconnections for gas within and outside default supply, according to data from suppliers

According to the gas suppliers' data, a disconnection notice is issued when a customer is on average around €120 in arrears. While some suppliers only passed on the costs of the network operator that carried out the disconnection/reconnection, a proportion of suppliers additionally charged their customers for carrying out a disconnection. Suppliers were asked if they use a general calculation in accordance with section 19(4) of the Gas Default Supply Ordinance (GasGVV) for such a charge. Suppliers applying this general calculation charged customers an average of about €47 (including VAT), although the charge ranged from €1.40 to €210. Suppliers not applying the general calculation charged customers an average of about €50 (including VAT), although the charge ranged from €3.50 to €210. Customers were charged an average reconnection fee of about €56 (including VAT) by suppliers applying the general calculation, with the actual fees charged again ranging from €1.40 to €222. Suppliers not applying the general calculation charged an average of about €60 (including VAT), with a range from about €4 to €210. Gas suppliers imposed a reminder fee averaging €3.50 on household customers who were late paying their bills.

The following table shows the distribution of disconnections carried out by DSOs broken down by federal state:

Gas: number of disconnections in 2020 by federal state according to data from DSOs

	Number of disconnections (default and non-default supply)	Share of market locations of final customers in Germany (%)
North Rhine-Westphalia	10,184	0.27%
Berlin	1,266	0.21%
Hesse	1,973	0.20%
Rhineland Palatinate	1,629	0.19%
Saarland	317	0.16%
Saxony-Anhalt	659	0.15%
Schleswig-Holstein	825	0.14%
Lower Saxony	2,943	0.13%
Saxony	707	0.12%
Brandenburg	610	0.11%
Baden-Württemberg	1,521	0.11%
Thuringia	393	0.11%
Bavaria	1,507	0.11%
Mecklenburg-Western Pomerania	177	0.06%
Hamburg	86	0.04%
Bremen	10	0.006%
Germany total	**24,807**	0.17%

Table 134: Gas disconnections by federal state in 2020, according to data from DSOs[194]

The network operators charged gas suppliers an average fee of about €58 (excluding VAT) for disconnecting a supply, with the actual costs charged ranging from €12.50 to €216. They charged suppliers an average fee of about €68 (excluding VAT) for reconnecting a supply, with the actual costs charged ranging from €15 to €260.

The average length of time between an actual disconnection and a reconnection was 33 days (for reasons of clarity, this figure only includes cases in which both disconnection and reconnection took place in 2020). Around 2,500 disconnections were for more than 90 days. The survey did not ask about the reason for these longer periods of disconnection, which may have been due to customers' long-term inability to pay, vacant properties or faulty customer facilities that could not be reconnected for safety reasons.

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

[194] The small difference between the sum of the disconnections reported for each federal state (24,807) and the total number of disconnections reported by the DSOs (23,991) is due to statistical differences.

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 2020, gas suppliers (default suppliers and their competitors) terminated their contractual relationship with a total of 45,462 gas customers (2019: 54,463) due to the customers' 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. The average level of arrears for a household customer that led to a contract being terminated was about €175 in 2020, although this figure ranged from €5 to €5,000.

3.2 Cash meters and smart card meters

Gas metering operators and gas suppliers answered questions on prepayment systems, as per section 14 GasGVV, such as cash meters or smart card meters. According to 41 suppliers, a total of 1,008 household customers had cash or smart card meters, or comparable prepayment systems, in 2020 compared to 1,093 in 2019. There were 141 new installations of prepay systems and 2002 existing ones were removed in 2020. The numbers of such systems are therefore still very low. Costs for meter operation and metering averaged €28 and €6 respectively per year and meter. The average annual base price charged to customers was €149, with the costs charged ranging from €18 to €250. The average kilowatt-hour rate for gas billed using a prepayment meter was 6.70 ct/kWh and ranged from 4.88 ct/kWh to 9.4 ct/kWh.

3.3 Non-annual billing

Section 40(3) EnWG in the version that was applicable in 2020 required gas suppliers to offer final customers monthly, quarterly or half-yearly bills. The survey showed that demand for bills that are not the usual annual ones remains low.

Gas: non-annual billing in 2020

	No. of requests	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)
Total other forms of billing for household customers	19,086	€15 (€1.85 - €163)	€19.50 (€1.28 - €187)
of which monthly	330		
of which quarterly	161		
of which semi-annual	1,173		
Other (no exact infomation)	17,422		

Table 135: Non-annual billing for gas household customers in 2020 according to gas supplier survey

4. Price level

The gas prices for household customers across all types of supply as at 1 April 2021 were higher compared with the previous year and averaged 6.68 ct/kWh. The new carbon levy amounting to 0.4551 ct/kWh, which was introduced on 1 January 2021, was partly responsible for the rise as it was passed on to final customers almost completely and paid by them as part of the gas price.

Even changing contracts with the local default supplier can lead to average savings of about 12%, while savings of about 15% can be achieved by switching supplier. The average household customer can save up to €200 a year by switching to a different contract with their local default supplier. **The average potential saving from switching supplier is up to €240 a year.**

Suppliers of gas to final customers in Germany were asked the retail prices their companies charged on 1 April 2021 for various consumption levels. Household customers' consumption levels were divided into three consumption bands.[195] Prices for these bands were surveyed in various categories. 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[196], 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, and

[195] Customer category according to Eurostat: the lowest category covers an annual gas consumption of up to 20 GJ (5,556 kWh), while the highest category is for annual consumption of at least 200 GJ (55,556 kWh). The typical household customer has consumption in the band from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh)..

[196] Since 1 January 2017, the component "charge for billing" has been part of the network charges and is no longer reported separately.

– 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 2021 and 1 April 2020, 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 94 and 777 suppliers respectively).

4.1 Non-household customers

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 that 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 gas retail and wholesale trading is inherently fluid as supply prices are often indexed against wholesale prices. There are types of contracts where customers themselves are responsible for settling network charges with the network operator. In extreme cases, these types of contracts may in terms of their economic effect even result in suppliers merely providing balancing group management services for their customers.

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 whose annual consumption ranges 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 was based on data from 94 suppliers (98 in the previous year).

Gas: Preisniveau am 1. April 2021 für den Abnahmefall 116 GWh/Jahr

	Streuung zwischen 10 und 90 Prozent der größensortierten Lieferantenangaben in ct/kWh	**Mittelwert** (arithmetischer) in ct/kWh	**Anteil am Gesamtpreis**
Nicht vom Lieferanten beeinflussbare Preisbestandteile			
Nettonetzentgelt	0,15 - 0,47	0,32	10,9%
Messung, Messstellenbetrieb	0,00 - 0,004	0,002	0,1%
Konzessionsabgabe[1]	0,00	0,00	0,0%
CO_2-Abgabe	0,46	0,46	15,4%
Gassteuer	0,55	0,55	18,7%
Vom Lieferanten beeinflussbarer Preisbestandteil (Restbetrag)	0,91 - 2,03	1,54	52,1%
Gesamtpreis (ohne Umsatzsteuer)	2,31 - 3,45	2,95	

[1] Nach § 2 Abs. 5 Nr. 1 KAV fallen bei Sondervertragskunden nur für die ersten 5 GWh Konzessionsabgaben an (0,03 ct/kWh). Bei Umlage dieses Preisbestandteils auf die gesamte Abnahmemenge ergibt sich ein entsprechend geringer Mittelwert, d.h. beim Abnahmefall von 116 GWh ein Durchschnitt von (gerundet) 0,00 ct/kWh.

Table 136: Price level for the 116 GWh/year consumption category on 1 April 2021

This data was used to calculate the arithmetic mean of the overall price and of the individual price components. The data spread for each price component was also determined in 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 average overall price (excluding VAT) for an annual consumption of 116 GW/h (“industrial customer”) was 2.95 ct/kWh (2020: 2.53 ct/kWh). An average of 11% of the average overall price relates to cost items outside the supplier’s control: network charges, charges for metering and meter operation, and concession fees. Gas tax and carbon tax[197], which is to be paid for the first time in 2021, are other cost items which are outside the supplier’s control. Together they account for 34.1% of the average overall price (excluding VAT). Only 52.1% (2020: 63.9%) of the price is made up of price components that can be controlled by the supplier

[197] The German Federal Government has introduced carbon pricing applicable in the heating and transport sectors as from 1 January 2021. Starting in 2021 companies providing the market with fuel oil, natural gas, petrol and diesel have to pay a carbon price. In 2021 this amounts to 25 euros per tonne and will gradually increase to 55 euros by 2025.

(gas procurement costs, supply costs and the margin). The share of the price components that cannot be controlled by the supplier is much higher than in the case of household customers or non-household customers with low consumption (see below).

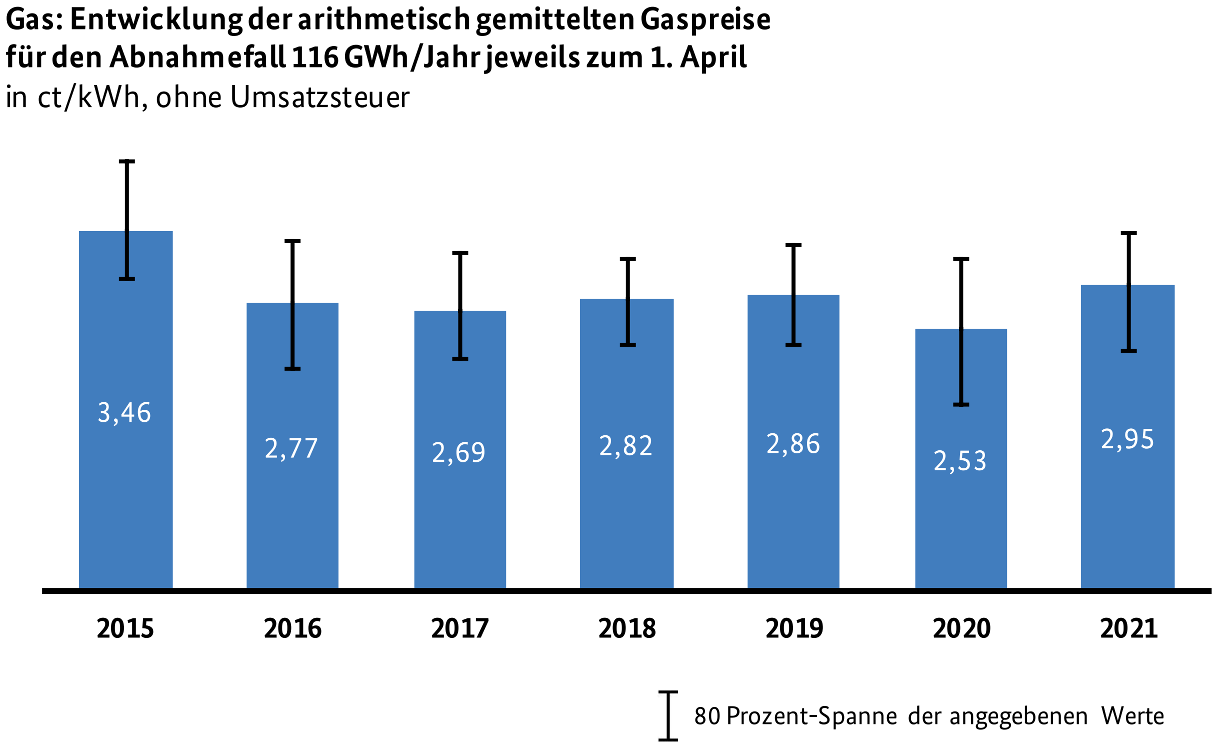


Figure 206: Development of the average gas prices for the 116 GWh/year consumption category

116 MWh/year consumption category ("commercial customers")

The non-household customer category based on an annual consumption of 116 MWh includes e.g. 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 threshold 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 provide 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 2021. 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 altogether 777 suppliers, exactly the same number of suppliers as in the previous year.

Gas: Preisniveau am 1. April 2021 für den Abnahmefall 116 MWh/Jahr

	Streuung zwischen 10 und 90 Prozent der größensortierten Lieferantenangaben in ct/kWh	**Mittelwert** (arithmetischer) in ct/kWh	**Anteil am Gesamtpreis**
Nicht vom Lieferanten beeinflussbare Preisbestandteile			
Nettonetzentgelt	0,90 - 1,59	1,24	26,2%
Messung, Messstellenbetrieb	0,01 - 0,07	0,04	0,9%
Konzessionsabgabe[1]	0,03 - 0,03	0,04	0,9%
CO_2-Abgabe	0,4551	0,4551	9,4%
Gassteuer	0,55	0,55	11,6%
Vom Lieferanten beeinflussbarer Preisbestandteil (Restbetrag)	1,80 - 3,12	2,41	51,0%
Gesamtpreis (ohne Umsatzsteuer)	4,03 - 5,50	4,74	

[1] 64 der 777 Lieferanten haben in ihrer Antwort einen Konzessionsabgabenwert von über 0,03 ct/kWh angegeben. Es handelte sich hierbei um Lieferanten mit eher geringen Abgabemengen. Eine Konzessionsabgabe von über 0,03 ct/kWh ist auch bei der Belieferung eines Nicht-Haushaltskunden denkbar, wenn die Belieferung im Rahmen eines Grundversorgungsvertrages erfolgt (vgl. § 2 Abs. 2 Nr. 2 b KAV).

Table 137: Price level for the 116 MWh/year consumption category on 1 April 2021

As in the case with the industrial customers, this data was used to calculate the averages of the overall price and of the individual price components and the data spread for each price component was also determined in ranges. As in the industrial customer consumption category, 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.

An average 49% (2020: 41%) of the overall price in the commercial customer category (116 MWh) consists of cost items which are outside the supplier's control (network charges, gas tax, concession fees and, for the first time, carbon tax[198]). Around 51% (2020: 59%) relates to price elements that provide scope for commercial decisions.

[198] The German Federal Government has introduced carbon pricing applicable in the heating and transport sectors as from 1 January 2021. Starting in 2021 companies providing the market with fuel oil, natural gas, petrol and diesel have to pay a carbon price. In 2021 this amounts to 25 euros per tonne and will gradually increase to 55 euros by 2025.

The arithmetic mean of the overall price of 4.74 ct/kWh (excluding VAT) is 0.22 ct/kWh higher than the previous year's figure. The average net amount of the price components outside the supplier's control rose to 2.33 ct/kWh, 0.47 ct/kWh higher than in the previous year due to the introduction of the carbon tax. The remaining balance that can be controlled by the supplier fell by 0.25 ct/kWh (from 2.66 ct/kWh on 1 April 2020 to 2.41 ct/kWh on 1 April 2021) or by about 9.6%.

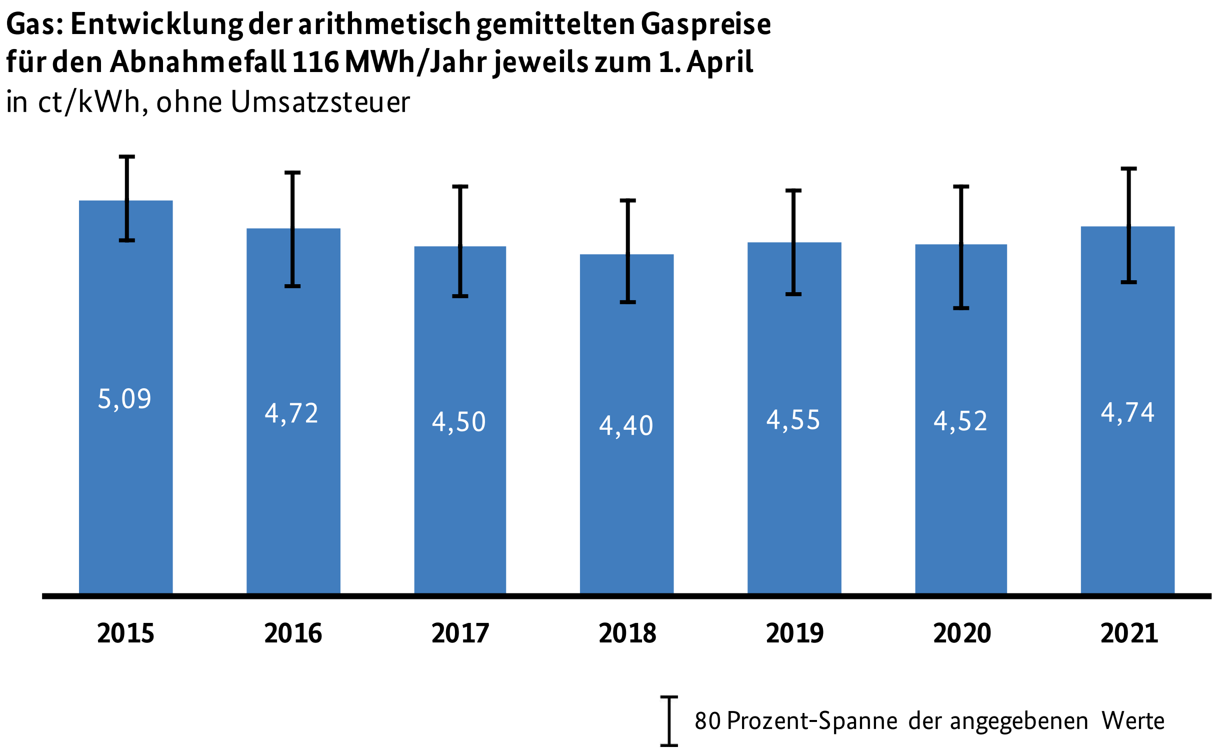


Figure 207: Development of the average gas prices for the 116 MWh/year consumption category

4.2 Household customers

Household customer prices were divided into three bands for the survey:

- - band I (D1)[199]: annual consumption up to 20 GJ (5,556 kWh),
- band II (D2): annual consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh), and
- band III (D3): annual consumption of 200 GJ (55,556 kWh) or more.

The survey of gas prices in consumption bands took into consideration the European survey of prices carried out by Eurostat. The total quantities of gas that were delivered by each supplier as at 31 December 2020 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

[199] "D1", "D2" and "D3" refer to the consumption bands defined by Eurostat.

the three types of supply contract. The new carbon levy has been part of the gas price since 1 January 2021. It is passed on to final customers almost completely and paid by them.

4.2.1 Volume-weighted price across all contract categories for household customers

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. The middle category[200], which best reflects the typical 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 2021.

Gas: breakdown of the volume-weighted gas price across all contract categories for household customers - consumption band II
as at 1 April 2021 (%)

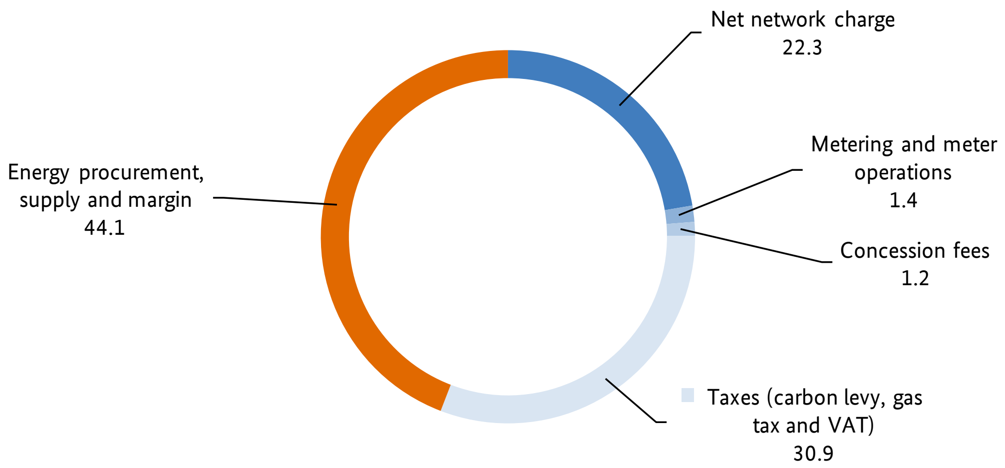


Figure 208: Breakdown of the volume-weighted gas price across all contract categories for household customers – consumption band II according to the gas supplier survey

[200] Customer category according to Eurostat: band II (D2): annual consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh).

Gas: average volume-weighted price across all contract categories for household customers for an annual consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh) per year (band II; Eurostat: D2) as of 1 April 2021 (ct/kWh)

Price component	Volume-weighted average across all tariffs (ct/kWh)	Share of total price (%)
Price component for energy procurement, supply and margin	2.95	44.1%
Network charge including upstream network costs	1.49	22.3%
Charge for metering	0.03	0.4%
Charge for meter operations	0.07	1.0%
Concession fees	0.08	1.2%
Carbon levy	0.4551	6.8%
Current gas tax	0.55	8.2%
VAT	1.06	15.9%
Total	6.68	100.0%

Table 138: Average volume-weighted price across all contract categories for household customers in consumption band II according to the gas supplier survey.

Gas: change in the volume-weighted price across all contract categories for household customers. Consumption band from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh), (band II; Eurostat: D2)

Price component	Volume-weighted average across all tariffs on 1 April 2020 (ct/kWh)	Volume-weighted average across all tariffs on 1 April 2021 (ct/kWh)	Change in the price component	
			ct/kWh	%
Price component for energy procurement, supply and margin	3.12	2.95	-0.17	-5.4%
Network charge including upstream network costs	1.47	1.49	0.02	1.4%
Charge for metering	0.02	0.03	0.01	50.0%
Charge for meter operations	0.07	0.07	0.00	0.0%
Concession fees	0.08	0.08	0.00	0.0%
Carbon levy	-	0.4551	-	-
Current gas tax	0.55	0.55	0.00	0.0%
VAT	1.01	1.06	0.05	5.0%
Total	6.31	6.68	0.37	5.9%

Table 139: 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 2020 and 1 April 2021 according to the gas supplier survey

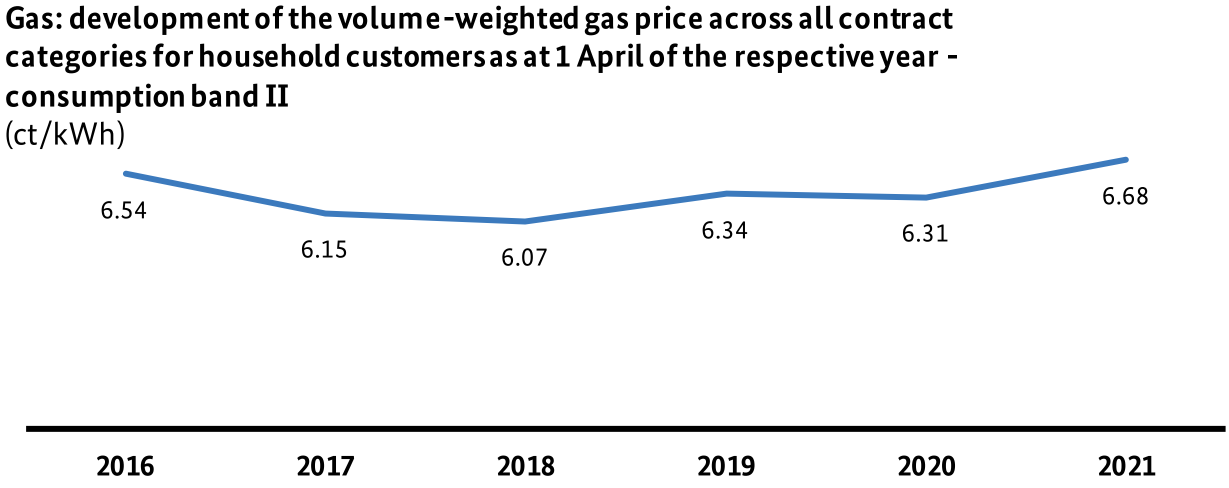


Figure 209: Volume-weighted gas price across all contract categories for household customers according to the gas supplier survey

The volume-weighted gas price for household customers across all contract categories rose about 6% year-on-year from 6.31 ct/kWh to 6.68 ct/kWh. The new carbon levy amounting to 0.4551 ct/kWh, which was introduced on 1 January 2021, was partly responsible for the rise as it was passed on to final customers almost completely and paid by them as part of the gas price.

4.2.2 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.

Gas: average volume-weighted price per contract category for household customers with a consumption up to 20 GJ (5,556 kWh) per year (band I; Eurostat: D1) as of 1 April 2021
(ct/kWh)

Price component	Default contract	Non-default contract with default supplier	Contract with a supplier other than the local default supplier
Price component for energy procurement, supply and margin	4.88	4.24	4.31
Network charge including upstream network costs	2.57	2.24	2.21
Charge for metering	0.20	0.13	0.15
Charge for meter operations	0.63	0.44	0.35
Concession fees	0.53	0.04	0.03
Carbon levy	0.4551	0.4551	0.4551
Current gas tax	0.55	0.55	0.55
VAT	1.86	1.51	1.53
Total	11.68	9.61	9.59

Table 140: Average volume-weighted price per contract category for household customers in consumption band I according to the gas supplier survey

Gas: average volume-weighted price per contract category for household customers with a consumption from 20 GJ (5,556 kWh) to 200 GJ (55,556 kWh) per year (band II; Eurostat: D2 as at 1 April 2021 (ct/kWh)

Price component	Default contract	Non-default contract with default supplier	Contract with a supplier other than the local default supplier
Price component for energy procurement, supply and margin	3.41	2.91	2.72
Network charge including upstream network costs	1.48	1.49	1.50
Charge for metering	0.02	0.02	0.04
Charge for meter operations	0.07	0.06	0.09
Concession fees	0.27	0.04	0.03
Carbon levy	0.4551	0.4551	0.4551
Current gas tax	0.55	0.55	0.55
VAT	1.19	1.05	1.02
Total	7.45	6.58	6.41

Table 141: Average volume-weighted price per contract category for household customers in consumption band II according to the gas supplier survey

Gas: average volume-weighted price per contract category for household customers with a consumption over 200 GJ (55,556 kWh) per year (band III; Eurostat: D3) as at 1 April 2021 (ct/kWh)

Price component	Default contract	Non-default contract with default supplier	Contract with a supplier other than the local default supplier
Price component for energy procurement, supply and margin	3.05	2.60	2.32
Network charge including upstream network costs	1.25	1.29	1.28
Charge for metering	0.01	0.01	0.02
Charge for meter operations	0.03	0.02	0.03
Concession fees	0.28	0.04	0.03
Carbon levy	0.4551	0.4551	0.4551
Current gas tax	0.55	0.55	0.55
VAT	1.07	0.94	0.89
Total	6.69	5.90	5.58

Table 142: Average volume-weighted price per contract category for household customers in consumption band III according to the gas supplier survey

Supply under a default contract

The volume-weighted gas price for customers on a default contract as at 1 April 2021 was 7.45 ct/kWh in band II (2020: 6.99 ct/kWh), corresponding to an increase of around 6.5% compared to the previous year.

Gas: development of gas prices for household customers under a default contract - consumption band II (volume-weighted averages) as at 1 April of the respective year (ct/kWh)

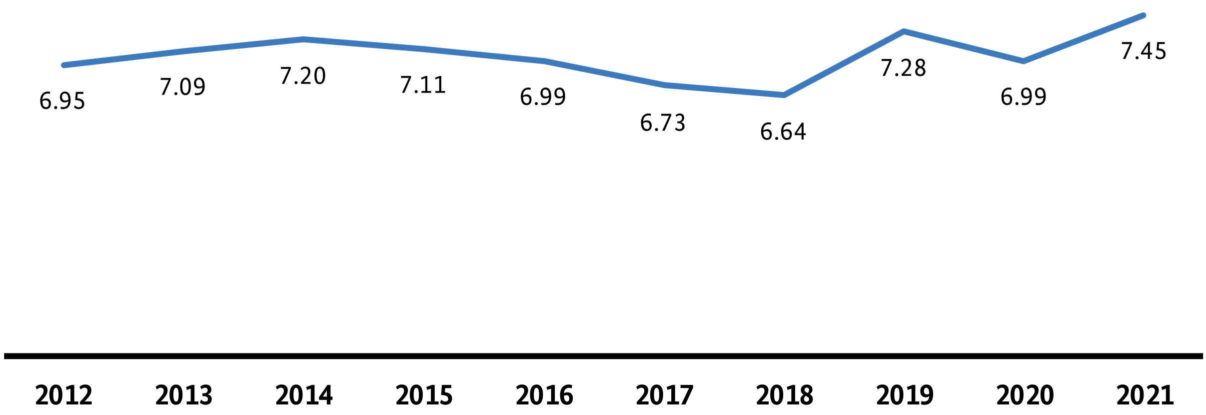


Figure 210: Gas prices for household customers under a default contract (volume-weighted averages) – consumption band II according to the gas supplier survey

Supply by the default supplier under a non-default contract

On 1 April 2021, the volume-weighted price for customers under a non-default contract with the default supplier in consumption band II was 6.58 ct/kWh, an increase of about 4.6% compared to 2020 (6.29 ct/kWh).

Gas: development of gas prices for household customers under a non-default contract with the default supplier - consumption band II (volume-weighted averages) as at 1 April of the respective year
(ct/kWh)

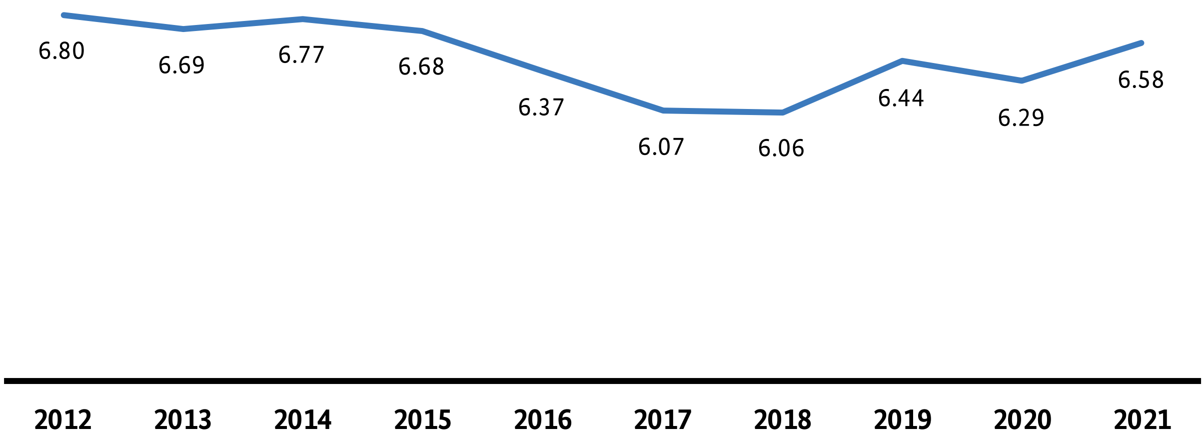


Figure 211: Household customer gas prices under a non-default contract with the default supplier (volume-weighted averages) – consumption band II according to the gas supplier survey

Supply under a contract with a supplier other than the local default supplier

On 1 April 2021, the volume-weighted price for a contract with a supplier other than the local default supplier was 6.41 ct/kWh in band II, an increase of just over 7.6% compared to the previous year (2020: 5.96 ct/kWh).

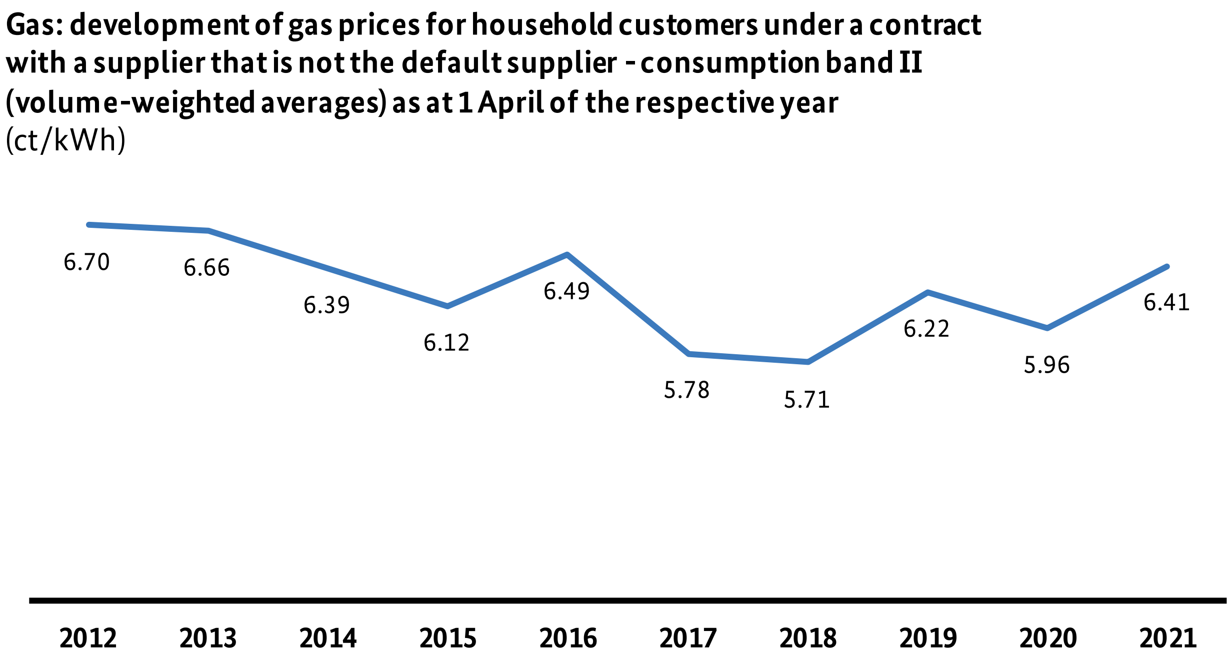


Figure 212: Gas prices for household customers under a contract with a supplier other than the local default supplier (volume-weighted averages) – consumption band II according to the gas supplier survey

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 about €200 a year as at 1 April 2021 by changing contract. The average potential saving for the year from changing supplier was €240.

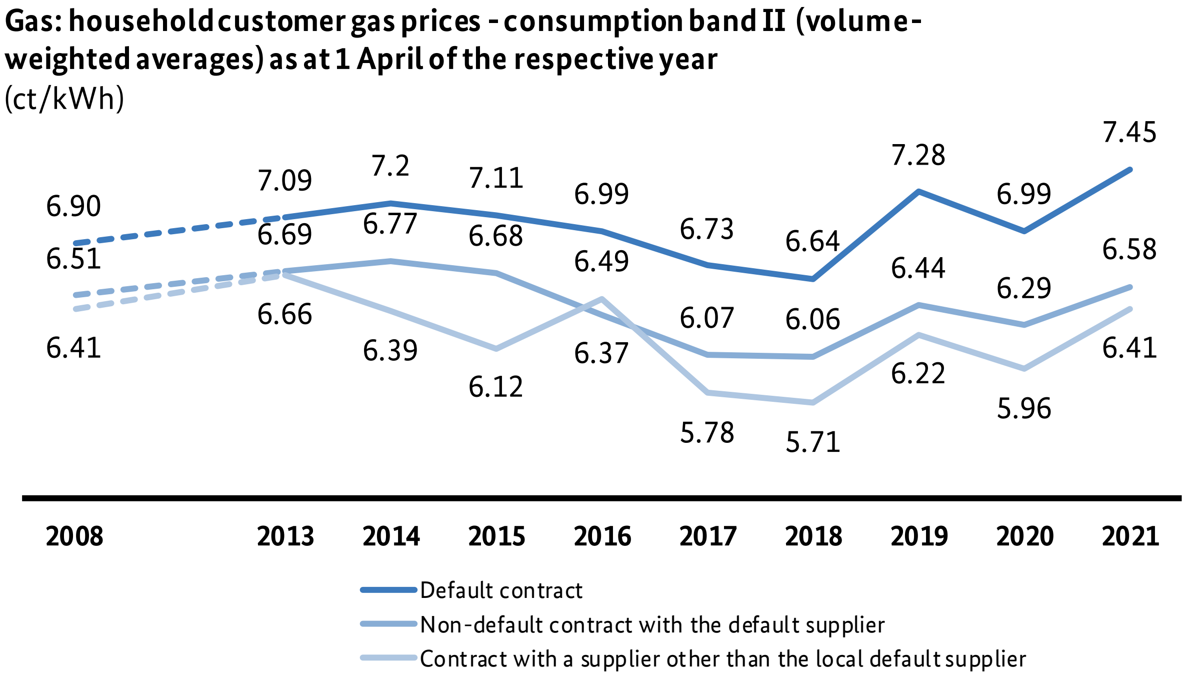


Figure 213: Household customer gas prices – consumption band II according to gas supplier survey

The following chart shows the gas prices compared with the percentages of the three types of supply – default contract, non-default contract with the default supplier and contract with a supplier other than the local default supplier.

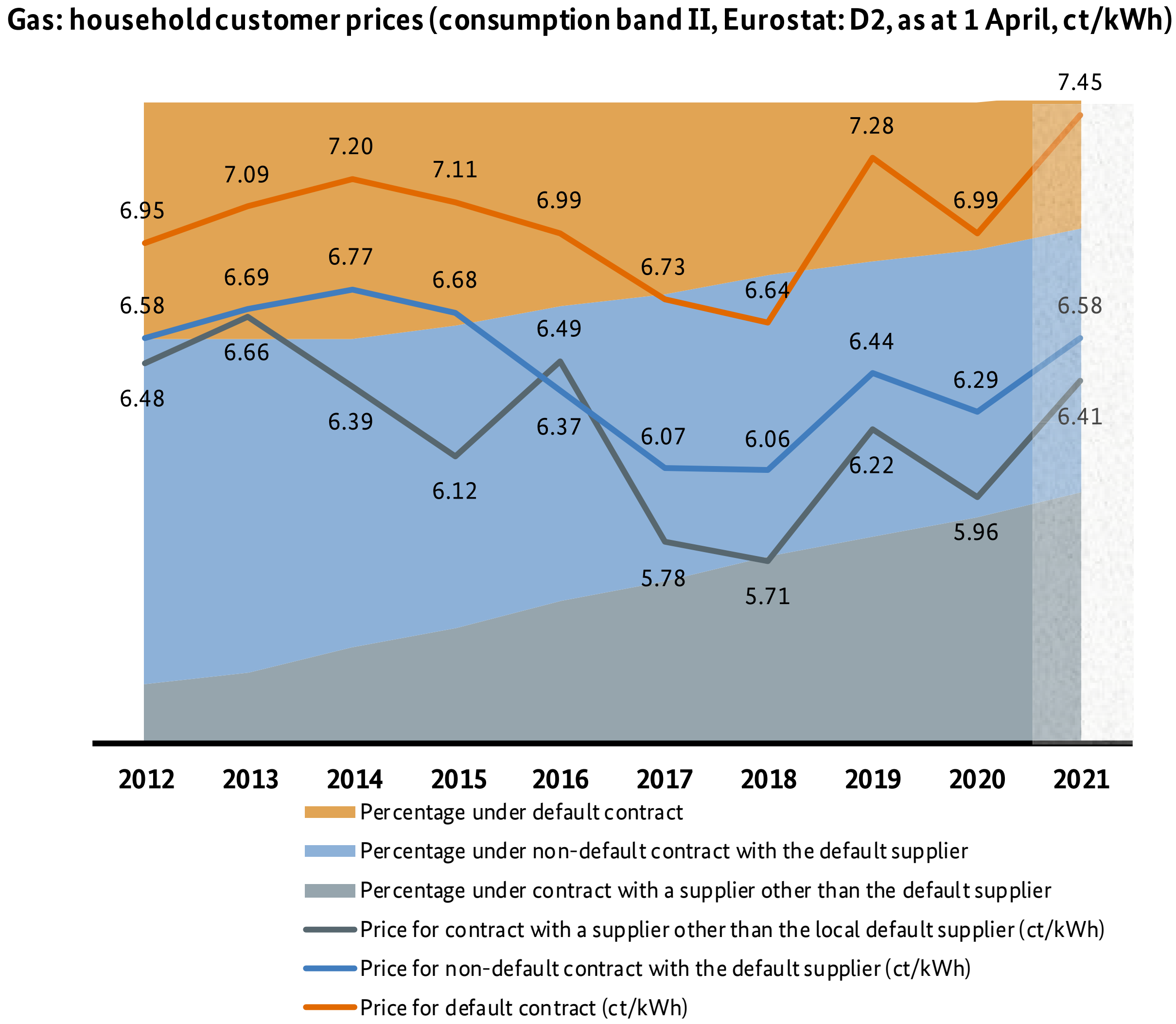


Figure 214: Household customer gas prices and percentages for each type of contract

The falling wholesale prices on the procurement level are passed on to household customers in different ways. The largest price component, "energy procurement, supply and margin", for default supply customers was 3.41 ct/kWh as at 1 April 2021 (2020: 3.51 ct/kWh) and made up around 45%. That corresponds to a drop of just over 3% in gas procurement costs. The gas procurement costs in the price for customers supplied under a non-default contract with the default supplier fell by slightly more than 8.5% from 3.18 ct/kWh to 2.91 ct/kWh. The gas procurement costs for customers supplied under a contract with a supplier other than the local default supplier decreased by just over 3% to 2.72 ct/kWh (2020: 2.80 ct/kWh).

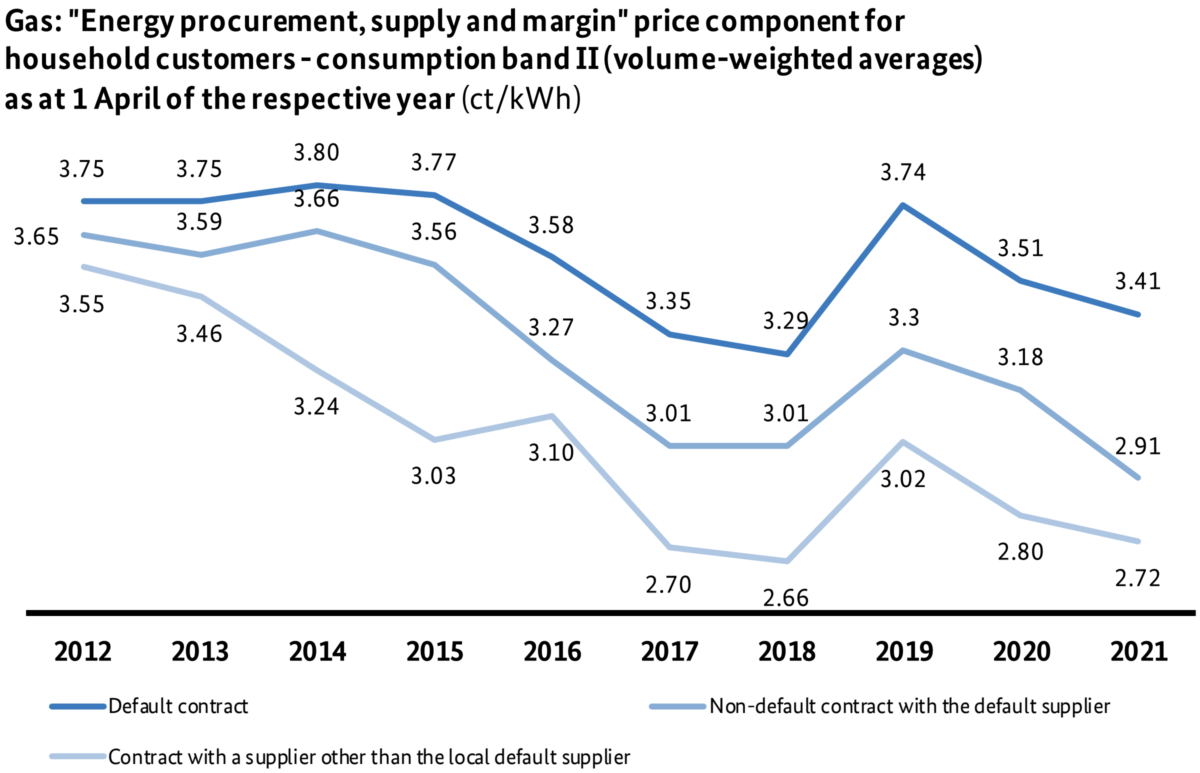


Figure 215: "Energy procurement, supply and margin" price component for household customers – consumption band II according to the gas supplier survey

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 €330. These one-off payments amount to an average of €70 to €80.

Gas: special bonuses and schemes for household customers

	Non-default contract with default supplier		Contract with a supplier other than the local default supplier	
	No. tariffs reported by surveyed companies	Average length/amount	No. tariffs reported by surveyed companies	Average length/amount
Minimum contract period	344	12 months	388	12 months
Price stability	320	16 months	380	16 months
Pre-payment	55	10 months	40	9 months
One-off bonus payment	130	€ 70	200	€ 80
Free kilowatt hours	10	1,300 kWh	10	510 kWh
Deposit	6	-	8	-
Other bonuses	90	-	95	-
Other special arrangements	33	-	30	-

Table 143: Special bonuses and schemes for household customers

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, for Germany on data provided by the Federal Statistical Office.[201] These are not comparable with the data collected during monitoring because of the different survey method used by the Federal Statistical Office. Rules on the classification, analysis and presentation of the price data aim to ensure European-wide comparability. However, the relevant Regulation (EU) No 2016/1952, Article 3, allows the individual Member States a certain degree of freedom in the choice of survey method, which can lead to national differences.

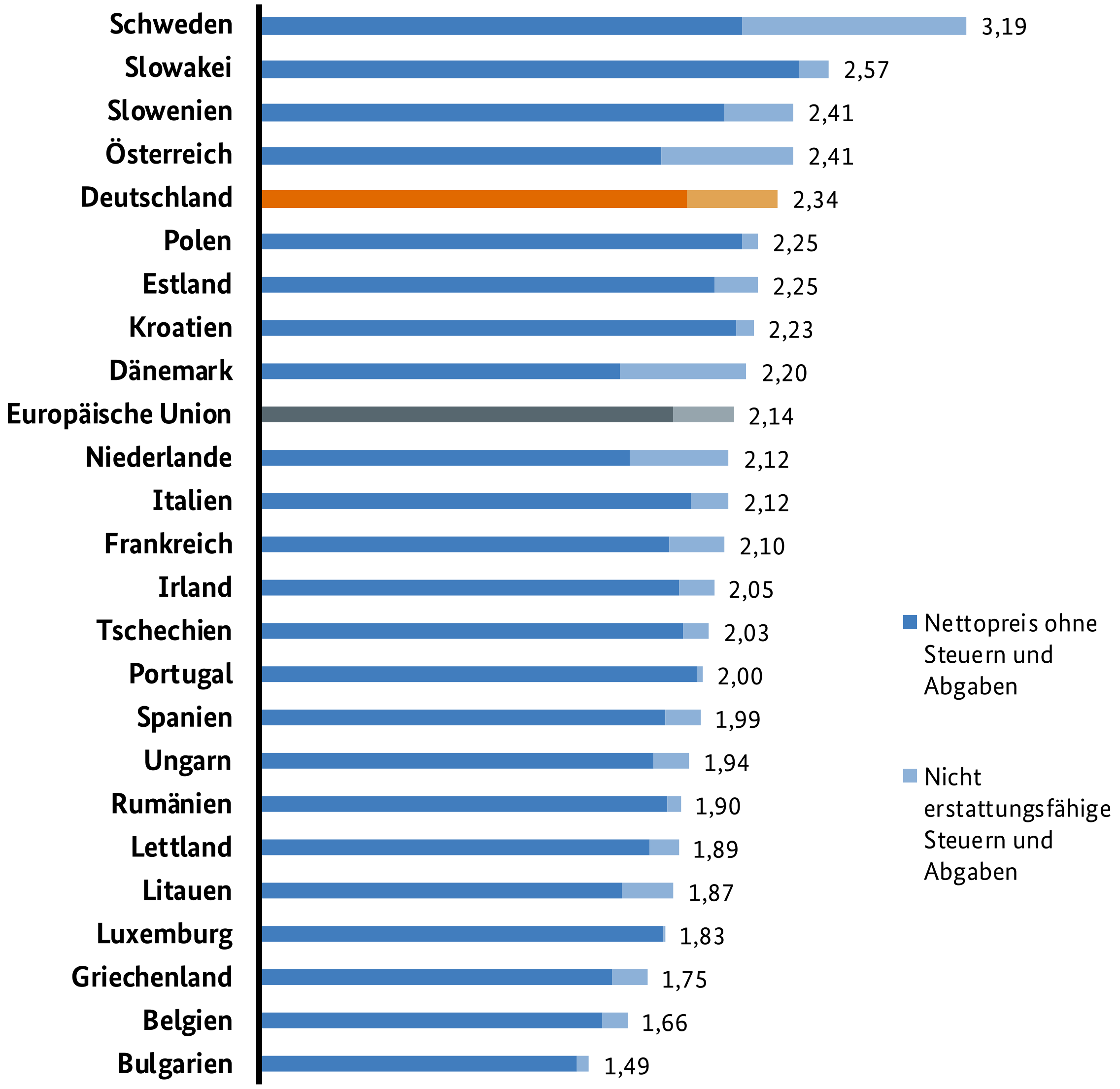
5.1 Non-household customers

Eurostat publishes price statistics for six different consumer groups in the non-household customer 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

[201] The average prices for electricity and natural gas in Germany have been determined by the Federal Statistical Office since the second six-month period of 2019. Before this the price data were collected by the German Association of Energy and Water Industries on behalf of the Federal Ministry for Economic Affairs and Energy. This change naturally also brought about changes in the survey methods, e.g. size and composition of the sample or the fact that administrative and tax data can now be used to determine the amount of tax, levies and surcharges actually paid.

consumption bands. The 116 GWh/year category ("industrial customers"), for which specific price data are collected during monitoring, falls into this consumption range.

Gas: EU-Vergleich Gaspreise im 2. Halbjahr 2020 für Nicht-Haushaltskunden mit einem Jahresverbrauch zwischen 27,8 GWh und 278 GWh
in ct/kWh ; ohne erstattungsfähige Steuern und Abgaben



Quelle: Eurostat

Figure 216: Comparison of European gas prices in the second half of 2020 for non-household customers with an annual consumption between 27.8 GWh and 278 GWh[202]

The customer group with this level of consumption consists mainly of industrial customers. These customers 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

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[202] The Eurostat comparison does not include prices in Finland, Malta and Cyprus. The price for Romania is an estimate.

circumstances which can typically be recovered by this customer group. These components have also been deducted from the gross price in accordance with the Eurostat classification.[203] Most Member States impose additional taxes and levies that are not recoverable (e.g. gas tax and concession fee in Germany 2020).

Across Europe, prices for non-household customers vary to a much lesser extent than those for household customers. According to prices published by Eurostat, the volume-weighted[204] average EU price[205] for non-household customers with an annual consumption of between 27.8 and 278 GWh in the second half of 2020 was 2.14 ct/kWh. The net gas price paid by German non-household customers in the second half of 2020 in this consumption category was 2.34 ct/kWh, i.e. 6% less than in the second half of 2019 (2.50 ct/kWh). In spite of this fall in price, the German net gas price paid by non-household customers in the second half of 2020 no longer matched the European average like in the previous year but was the fifth most expensive in Europe. In a European comparison taxes and levies which Member States impose for gas consumption vary to a large extent. Non-recoverable taxes and levies amounted to an average of approx. 11% (0.24 ct/kWh) of the net price in Europe. The figure of about 17.5% (0.41 ct/kWh) for Germany in 2020 is above average in this respect.

5.2 Household customers

Eurostat takes three different consumption bands into consideration when comparing household customer prices: annual consumption (i) 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 category, for which specific price data are collected during monitoring, falls into the medium Eurostat consumption band. The following shows an EU 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.

In contrast to gas prices in the industrial customer sector, gas prices for household customers vary greatly in Europe. Household customers in Sweden paid around 58% more for natural gas than customers in Germany and more than three times as much as customers in Lithuania, Romania and Hungary. According to prices published by Eurostat, the volume-weighted average EU price[206] for household customers in the second half of 2020 was 6.98 ct/kWh. The gas price paid by household customers in Germany was 6.20 ct/kWh. The price paid by German consumers of natural gas per kilowatt hour was therefore around 12.5% less than the EU average price.

The percentage of the overall price for household customers made up by taxes and levies also varied widely across the EU. While taxes and levies accounted for only about 8% of the price in Greece, they make up about 62% of the price in Denmark. Germany's figure of about 24% again matched the European average in this respect. Around 1.49 ct/kWh of the overall price in Germany consisted of taxes and levies; the EU average is 1.64 ct/kWh (about 28.5%).

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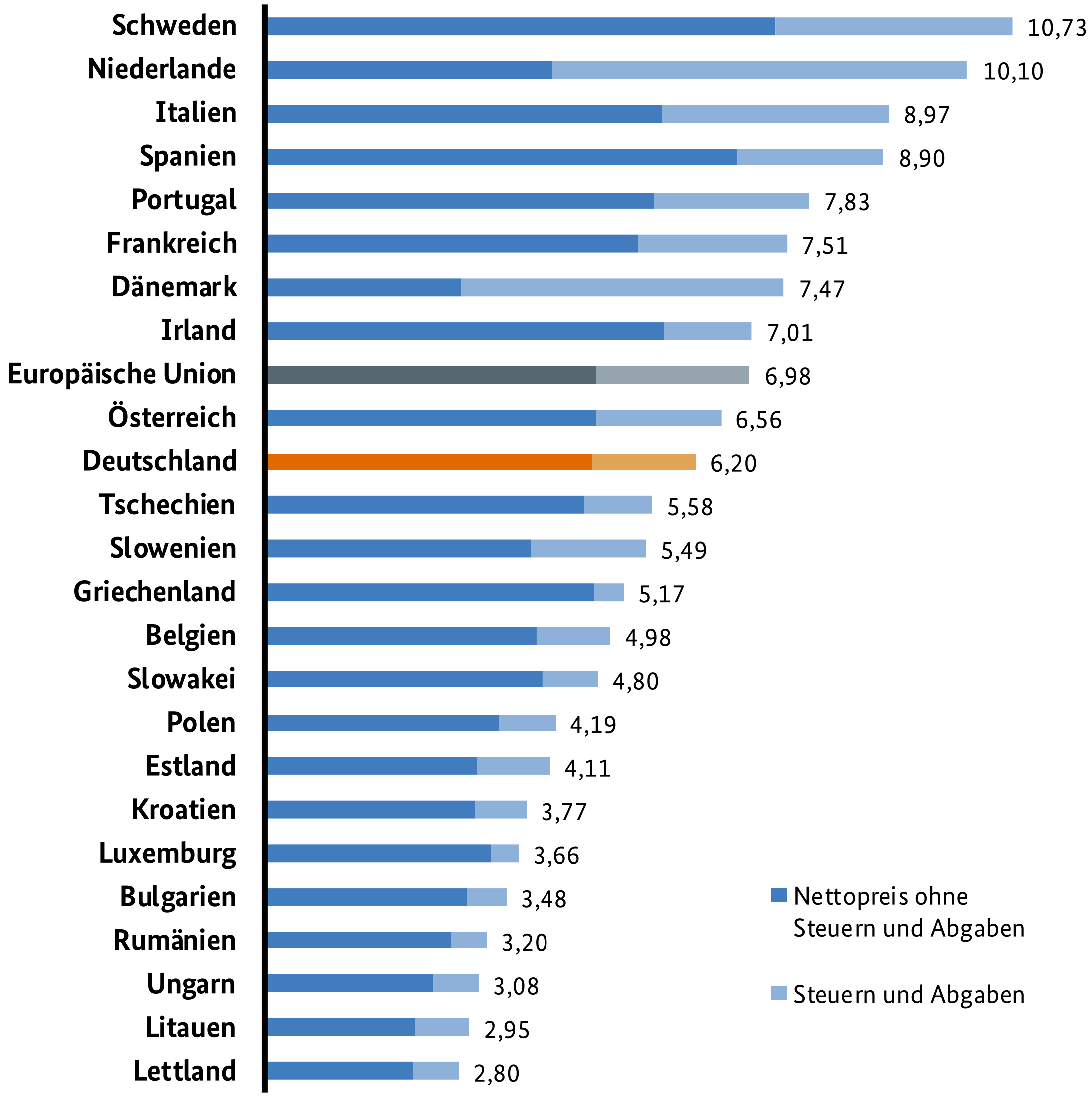
[203] For more information on country-specific deductions see Eurostat, Gas Prices – Price Systems 2014, 2015 edition: https://ec.europa.eu/eurostat/documents/38154/42201/Gas-prices-Price-systems-2014.pdf/30ac83ad-8daa-438c-b5cf-b52273794f78 (retrieved on 2 September 2021).

[204] For details on the calculation method of the EU aggregates in para. 18.1: https://ec.europa.eu/eurostat/cache/metadata/en/nrg_pc_202_esms.htm#stat_process1554804191624 (retrieved on 2 September 2021)

[205] Without the United Kingdom

[206] See above.

Gas: EU-Vergleich Gaspreise im 2. Halbjahr 2020 für Haushaltskunden mit einem Jahresverbrauch zwischen 5.555 kWh und 55.555 kWh
in ct/kWh ; inkl. Umsatzsteuer



Quelle: Eurostat

Figure 217: Comparison of European gas prices in the second half of 2020 for household customers with an annual consumption between 5,555 kWh and 55,555 kWh[207]

[207] The Eurostat comparison does not include prices in Finland, Malta and Cyprus. The price for Romania is an estimate.

G Metering

1. The network operator as the default meter operator and independent meter operators

The results presented in this chapter take into account information collected from 660 companies. This paints the following picture for 2020 with regard to the distribution of market roles:

Gas: meter operator roles

Function	2020
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)	645
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)	7
Supplier with meter operator activities	12
Independent third party that provides metering services	8

Table 149: Distribution of network operator roles according to data provided by gas meter operators as at 31 December 2020

The table below shows the total reported meter locations broken down by federal state.

Gas: number of meter locations by federal state in 2020

Bundesland	Anzahl
Baden-Württemberg	1,311,221
Bavaria	1,430,466
Berlin	593,011
Brandenburg	546,182
Bremen	155,831
Hamburg	230,210
Hesse	996,567
Mecklenburg-Western Pomerania	282,803
Lower Saxony	1,885,894
North Rhine-Westphalia	3,581,019
Rhineland-Palatinate	821,929
Saarland	202,613
Saxony	593,461
Saxony-Anhalt	335,705
Schleswig-Holstein	524,238
Thuringia	369,809

Table 150: Number of meter locations by federal state in 2020

2. Metering technology used for household customers

As at 31 December 2020, approximately 6.9 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 para 19 MsbG.

Gas: metering equipment used by SLP customers in 2020

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+
Diaphragm gas meters with mechanical counter	4,848,104	165,249	19,742
Diaphragm gas meters with mechanical counter and pulse output	7,501,786	252,710	25,006
Diaphragm gas meters with mechanical counter and manufacturer-specific output (eg Cyble, Absolute ENCODER)	795,520	23,637	4,598
Diaphragm gas meters with electronic counter	2,720	8	180
Ultrasonic gas meters	4,391	-	182
Load/interval meters as for interval-metered customers	44	158	2,918
Other mechanical gas meters	8,425	2,683	26,121
Other electronic gas meters	2,192	-	361
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	6,628,029	220,455	30,623
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	222,902	6,210	2,650

Table 151: Breakdown of metering equipment used by SLP customers as at 31 December 2020, according to meter size

The overwhelming majority of meters use pulse generators as their communication technology.

Gas: communication technology used for meters for SLP customers in 2020
(number and percentage)

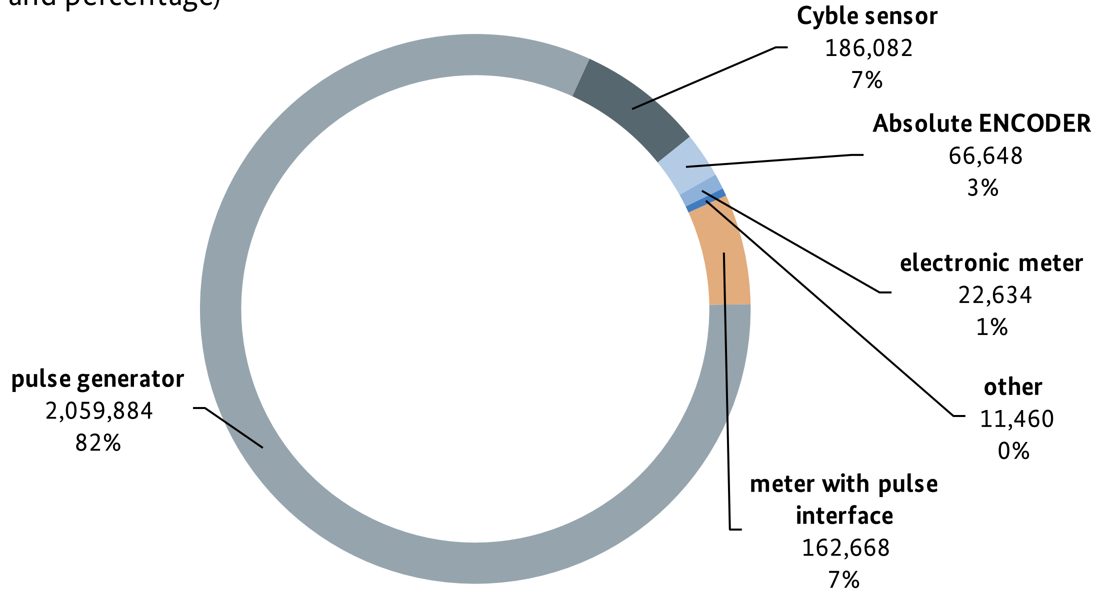


Figure 218: Communication technology used for meters for SLP customers – as at 31 December 2020

3. Metering technology used for interval-metered customers

The distribution of metering technology employed for interval-metered customers in 2020 is as follows:

Gas: metering technologies used for interval-metered customers in 2020

Function	No. of meter locations
Transmitting meter with a pulse output/encoder meter + a recording device/data storage	15,283
Transmitting meter with a pulse output/encoder meter + gas volume converter	9,211
Transmitting meter with a pulse output/encoder meter + combustion value quantity converter	380
Transmitting meter with a pulse output/encoder meter + gas volume converter + recording device/data storage	15,645
Transmitting meter with a pulse output/encoder meter + temperature volume converter + recording device/data storage	762
Transmitting meter with a pulse output/encoder meter + smart meter gateway	-
Other	148

Table 152: Breakdown of metering technologies used for interval-metered customers – as at 31 December 2020

Gas: communication link-up systems used for interval-metered customers in 2020
(number and percentage)

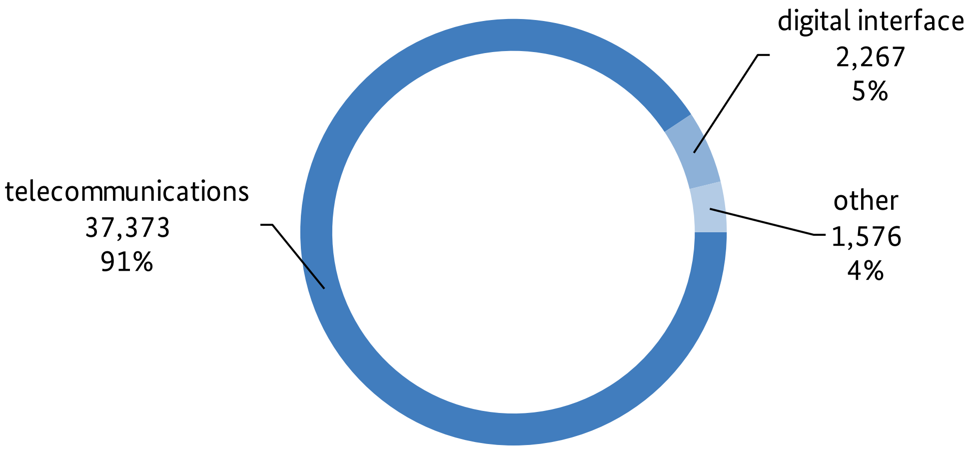


Figure 219: Number and percentage of communication link-up systems used for interval-metered customers – as at 31 December 2020

The metering technology used by interval-metered customers transmits data almost exclusively via telecommunication systems (90.7%). Telecommunications include mobile communications up to 2.5G (GSM, GPRS, EDGE), mobile communications from at least 3G (UMTS, HSDPA, LTE), telephone lines, DSL and broadband as well as power lines. The digital interface for gas meters must be mentioned as an alternative technology used to transfer meter data, with 5.5% of interval-metered customers using this interface.

4. 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 660 gas meter operators.

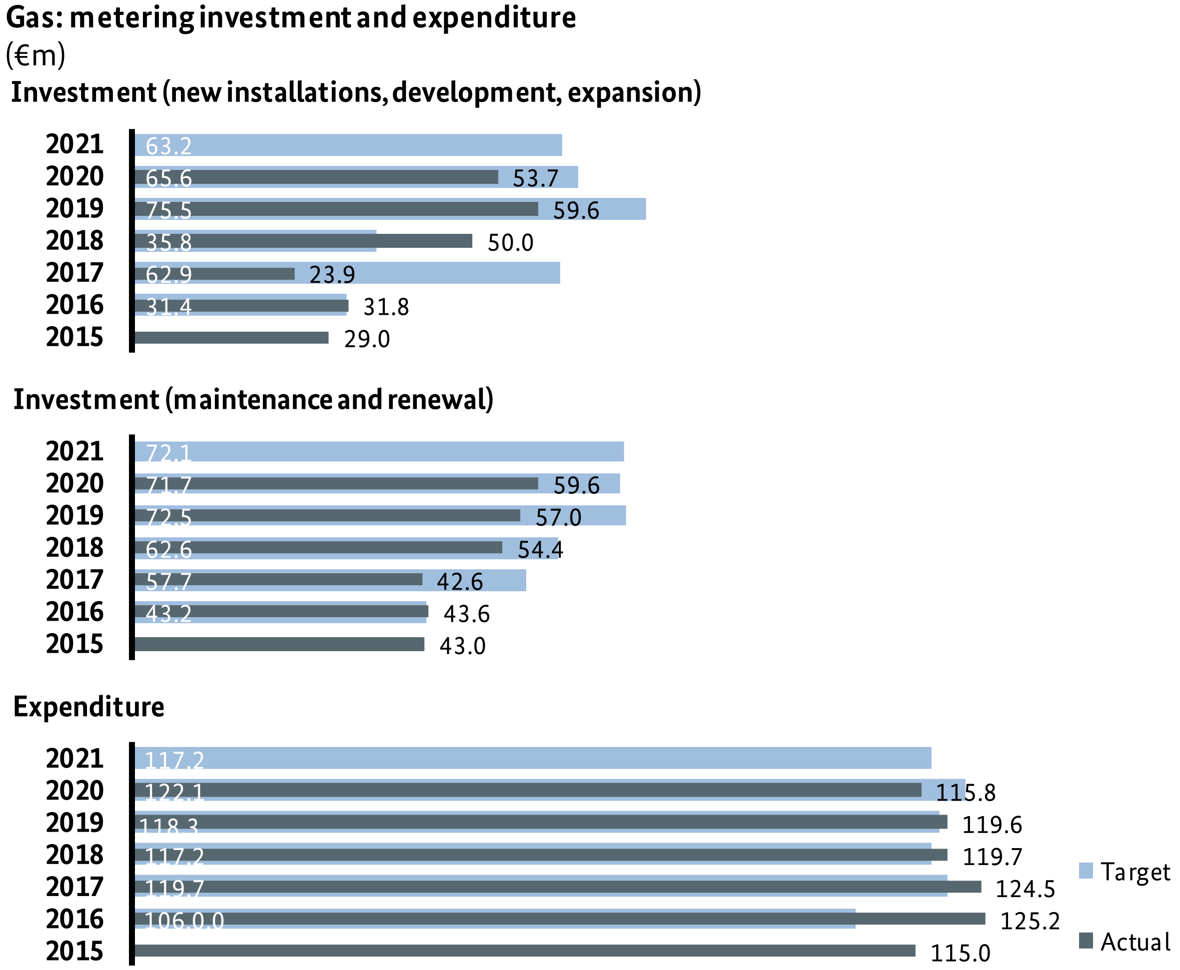


Figure 220: Metering investment and expenditure

III General topics

A Market Transparency Unit for Wholesale Electricity and Gas Markets

The Bundesnetzagentur and the Bundeskartellamt carry out joint monitoring within the Market Transparency Unit for Wholesale Electricity and Gas Markets with the aim of ensuring fair pricing on the wholesale markets. The joint market monitoring is based on the transaction and fundamental data reported by the market participants.

Registered market participants

Market participants entering into electricity or gas wholesale transactions that require reporting must register with the competent energy regulator in accordance with Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT). The Bundesnetzagentur has been registering market participants for Germany since March 2015. At present, 4,910 market participants are registered in Germany, and 15,028 market participants are registered in the whole of the EU.[208] The majority of the market participants registered in 2015 and 2016 after the reporting obligations first came into force. The number of new registrations made each year since 2017 has been considerably smaller.[209]

New registrations under REMIT

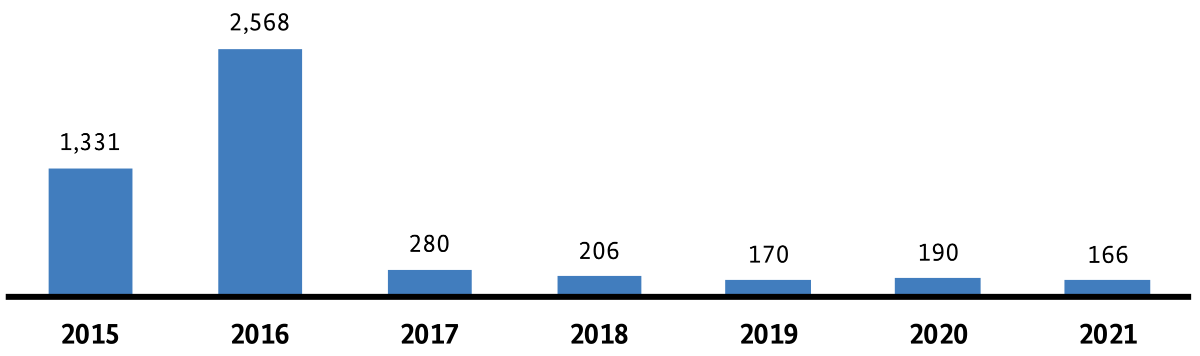


Figure 221: New registrations under REMIT in Germany per year[208]

Data reporting

ACER[210] receives data from all the registered market participants on their trading activities in the wholesale electricity and gas markets. The data relate to both transactions for electricity and gas products and

[208] As at: 11 November 2021.

[209] Some registered market participants have been deleted since registering began, for example because of changes in the legal form of the companies.

[210] Agency for the Cooperation of Energy Regulators

transactions for entry, exit and transmission capacity. ACER also collects fundamental data from transmission system operators (TSOs) relating to networks and generation.

The Market Transparency Unit receives the transaction data relevant for monitoring the German markets from ACER. It also receives the fundamental data for all EU countries.

Most of the data transmitted to the Market Transparency Unit relate to transactions for electricity and gas products. The transaction data comprise orders to trade and trades concluded. An order is a market participant's offer to buy or sell electricity or gas. If an order is accepted by another market participant, a trade is concluded between the two market participants. The following data was transmitted for the period given below:

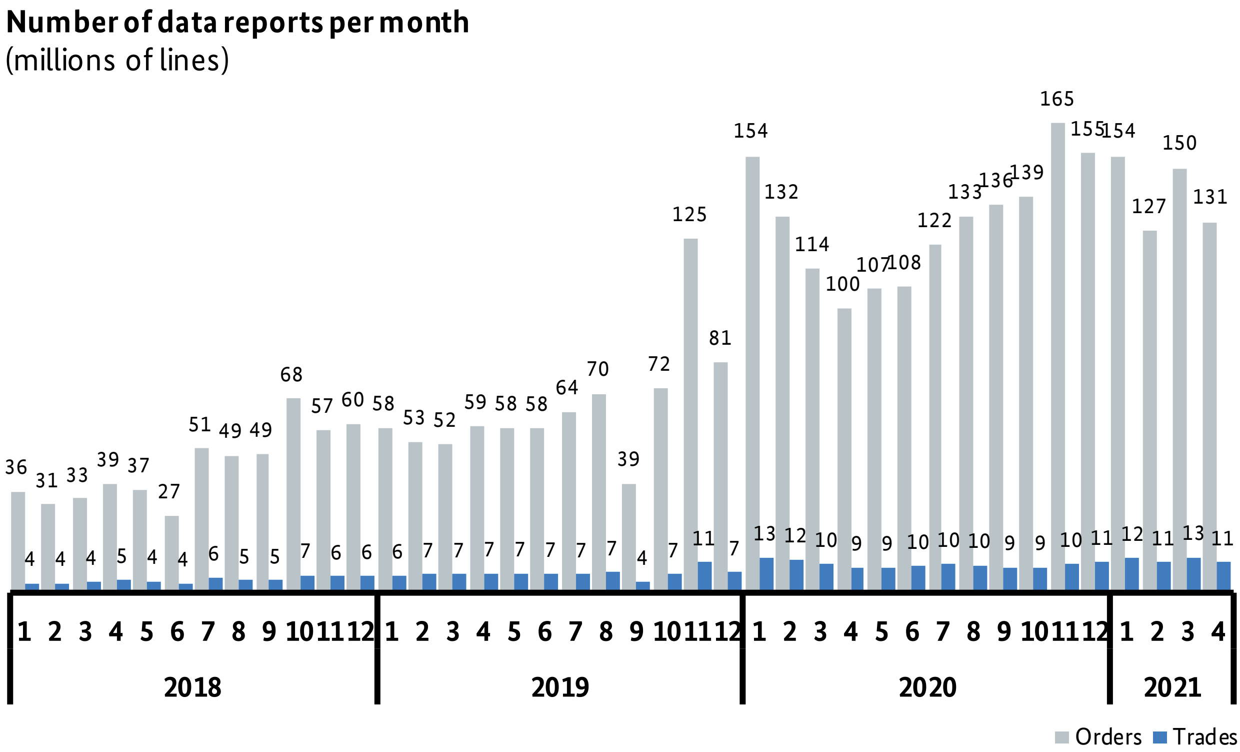


Figure 222: Number of data reports on orders and trades received per month by the Market Transparency Unit[211]

The number of reports is not directly related to the number of orders issued or transactions concluded. This is because the reports also include corrections and deletions, and one order may therefore be the subject of several technical reports. It should also be noted that the number may increase due to reports received at a later date. This affects in particular the most recent months before the time of reporting.

[211] Due to technical delays in the transmission of data, reports relating to previous reporting periods may be received at any time. The figures presented may have been updated and may therefore differ from those published in previous monitoring reports.

Since the Market Transparency Unit started collecting data there has been a significant increase in the number of reports as well as the number of related orders and trades. This is due to increased trading activity, a rise in automated trading (known as algo trading) and improved opportunities for cross-border trading.

The number of reports on orders is considerably higher than the number of reports on trades. This is mainly because each market participant aims to secure the most favourable conditions possible for their transaction and may therefore change an order several times or cancel an order, for instance in response to orders from other market participants or changes in market conditions.

The chart shows a steady increase in the number of reports on orders since 2018 (2018: 45m; 2019: 66m; 2020: 130m and Q1 2021: 140m on average per month). There has also been a continuous increase in the number of reports on trades concluded (2018: 5m; 2019: 7m; 2020: 10m and Q1 2021: 12m on average per month).

The actual number of orders and trades related to the technical reports received can only be estimated. For this purpose the following methodology is applied, which is linked to the unique identification numbers (IDs) reported by market participants. Each ID is counted only once, regardless of how many reports have been received for it. Incorrect reports are not taken into account. The IDs are assigned by the marketplaces and market participants, which is why some IDs may occur twice, or the same trade or order may be registered under different IDs.

Number of unique trade and order identification numbers (IDs) reported per month
(in millions)

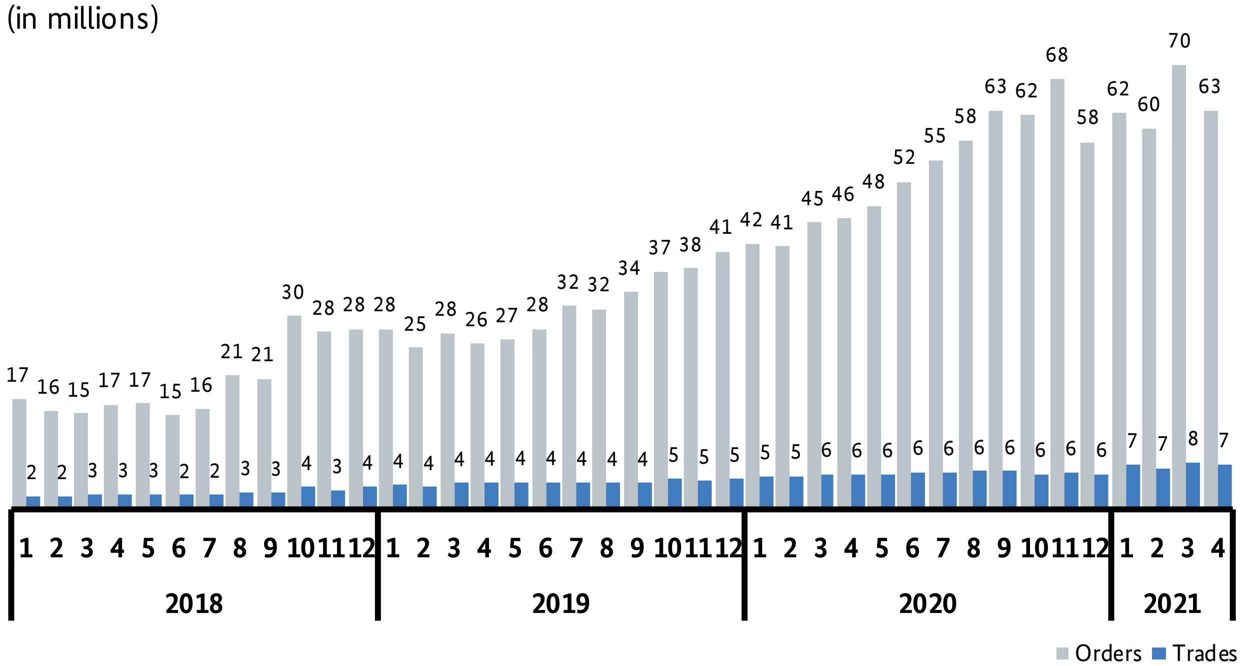


Figure 223: Number of unique trade and order identification numbers (IDs) reported by market participants per month

The following diagram shows a breakdown of the data reported in the period from January 2018 to March 2021 into the categories exchange trading, trades via broker platforms, and bilateral contracts.

Breakdown of the data reports on trades and orders from December 2018 to the first quarter of 2021 (%)

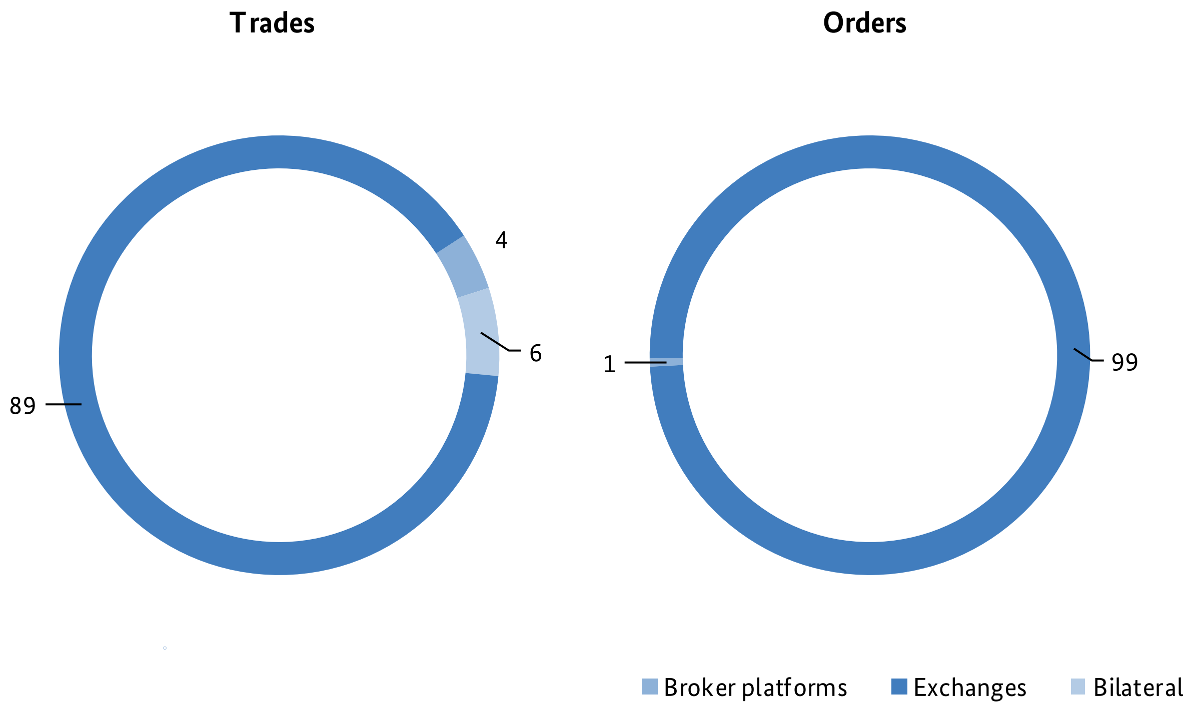


Figure 224: Reports on trades and orders by marketplace (%)

The diagram shows that the vast majority of data reports on both orders and trades were transmitted by energy exchanges. This is because a large number of low-volume and short-duration transactions are concluded on the electricity and gas exchanges. The exact opposite is true for transactions concluded via broker platforms and bilateral contracts: a smaller number of these trades are concluded but for high volumes and usually longer durations. An analysis of the volumes traded on the individual energy exchanges and broker platforms is included in the sections on electricity and gas wholesale trading.

B Selected activities of the Bundesnetzagentur

1. Tasks under REMIT

The Bundesnetzagentur monitors the wholesale energy market in accordance with Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT). The prohibitions on insider trading (Article 3) and market manipulation (Article 5) form the core of REMIT. Energy exchanges, broker platforms, market participants, ACER[212] and anonymous sources can report suspicious trading activity by one or more market participants. Reports received by the Bundesnetzagentur are referred to below as "suspected breaches", in other words cases where there is suspicion of a breach of REMIT.

Insider trading may refer, for example, to transactions concluded prior to the publication of power plant failures. Market manipulation can include placing orders with no intention of executing them or making wash trades, where the same person is both the buyer and the seller in a transaction.

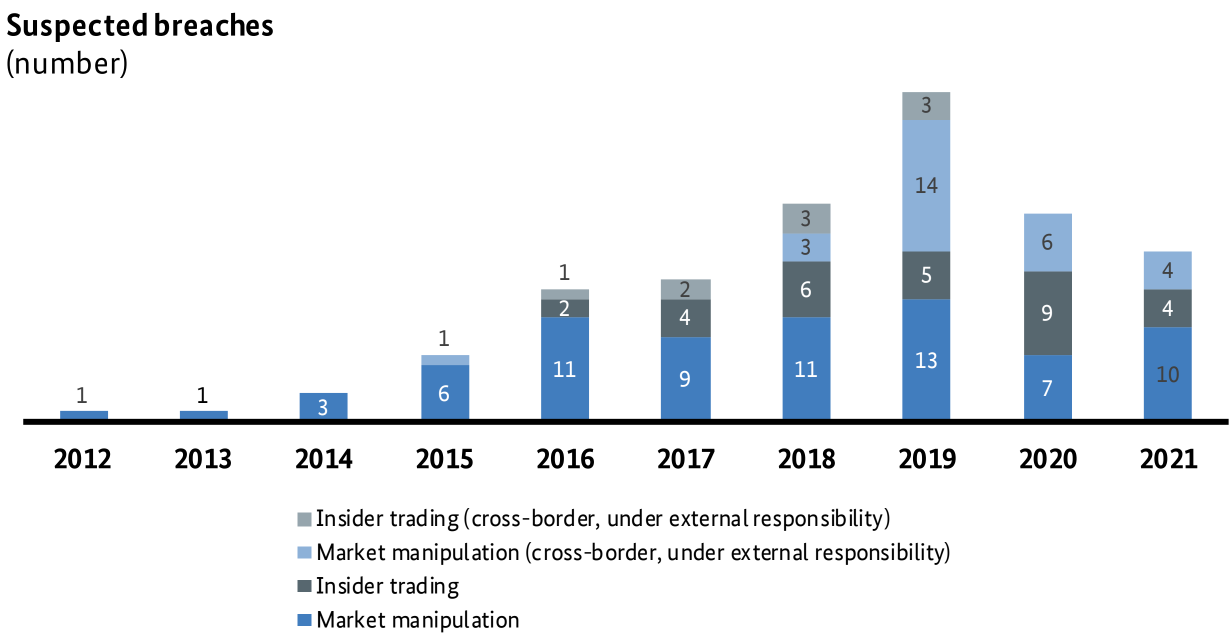


Figure 225: Suspected breaches, 2012 to 2021

The initial increase in the number of suspected breaches does not necessarily mean that there has been an increase in the number of actual breaches. Rather, it can be assumed that it has just taken time for the new regulations in REMIT to become established and to be taken into account at energy exchanges and other marketplaces. The market monitoring bodies have improved their processes and regulatory authorities have published their first decisions, which is why it is possible to identify an increasing number of irregularities.

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[212] Agency for the Cooperation of Energy Regulators

Cross-border cases

If a suspected breach has cross-border aspects, for example if the trading activity relates to a product of a different Member State to the one in which the market participant is registered and has its headquarters, the case is processed with the involvement of or under the lead responsibility of energy regulators in other Member States.

Internal processing

The cases received by the authority are first subjected to an initial analysis using trading data provided by ACER and, where necessary, other data surveys and analyses. If the analysis does not confirm the indication of a breach of REMIT, the case is discontinued. In the case of a regulatory offence, other factors like insignificance or lack of risk of repetition may also lead to the case being dropped.

If the initial analysis confirms the indication of a breach of REMIT, the Bundesnetzagentur conducts a further investigation. If this investigation provides sufficient evidence to confirm the suspicion, the Bundesnetzagentur can start regulatory offence proceedings. If the breach may have criminal law consequences, the Bundesnetzagentur passes it on to the prosecution service.

The Bundesnetzagentur has so far carried out six administrative fines proceedings. Five of these were concluded with orders imposing fines, while one case was discontinued. The Bundesnetzagentur has not yet passed on any cases to the prosecution service.

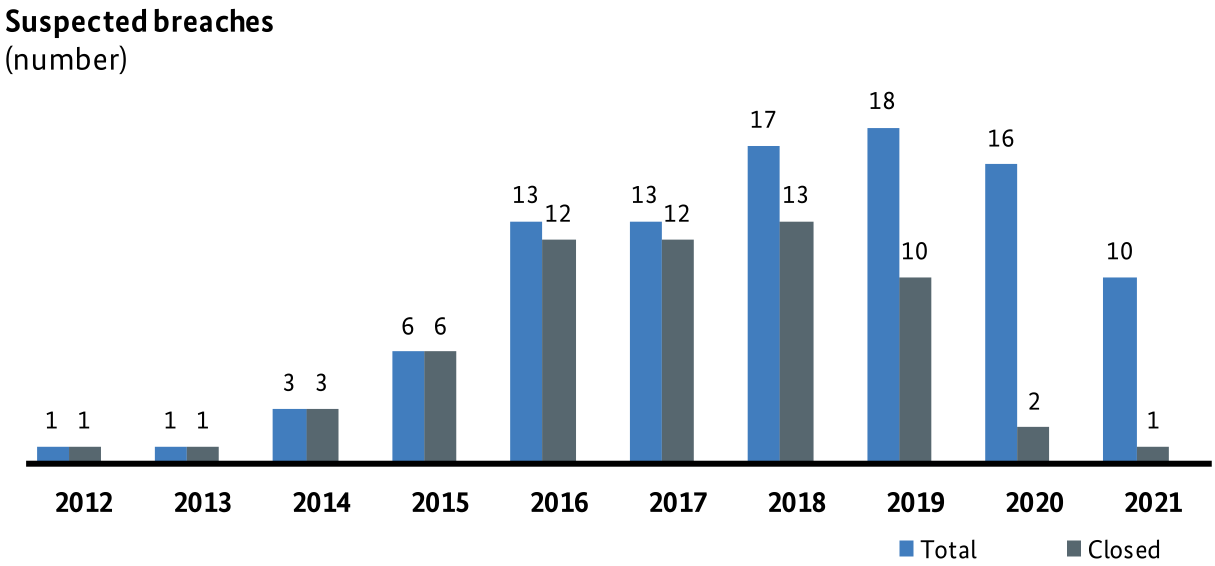

Figure 226[213]: Suspected breaches, 2012 to 2021

Market manipulation by selling electricity that was not available

[213] The figures shown as the total are the total number of cases processed internally and therefore differ from the totals presented in previous monitoring reports.

On 6, 12 and 25 June 2019 there were serious imbalances in the German electricity grid over longer periods of time. The German TSOs activated the entire amount of balancing capacity held but this was not sufficient to balance out the severe shortfalls in the system, making it necessary for the TSOs to take further support measures, including activating "emergency reserves" from foreign TSOs and buying electricity on the intraday market. This in turn led to very high prices in intraday trading on EPEX SPOT (up to €1,300/MWh) in the periods in question.

Detailed evaluations in particular of the trading and balancing group data from the three days in June 2019 identified manipulative trading behaviour in a number of situations. Eight situations involved Energi Danmark A/S and seven situations Optimax Energy GmbH. The companies were found to have continued offering and, in some cases, selling electricity at the end of the trading periods at especially high prices, which were higher than the imbalance price, without the electricity actually being available and despite severe shortfalls in the relevant balancing groups. There may be an economic incentive for companies to sell electricity at a price higher than the expected imbalance price without actually intending to procure the electricity. A company has to pay the imbalance price for any electricity not procured, but it can still make a profit if, as it expects, the exchange price goes above the imbalance price.

The companies' trading behaviour gave misleading signals to the market as to the supply of electricity, which constitutes market manipulation within the meaning of Article 5 in conjunction with Article 2 para 2(a)(i) REMIT. Market participants are considered to give false or misleading signals when they sell or offer electricity in the market even though they know that the electricity is not available and they will not be able to procure or generate it by the delivery time. In this case, the false signals led other market participants to believe that there were offers in the market at the relevant prices that could still physically be fulfilled.

Fines of €200,000 (Energi Danmark A/S) and €175,000 (Optimax Energy GmbH) were imposed in September 2021. An appeal was filed against the administrative fine imposed on Optimax Energy GmbH.

2. Core energy market data register

The Bundesnetzagentur launched the core energy market data register on 31 January 2019. Since then, operators of electricity and gas generating and consumption installations have been required to register themselves and their installations for the core energy market data register in accordance with sections 3 and 5 of the Core Energy Market Data Register Ordinance (MaStRV). They can register online at www.marktstammdatenregister.de and find all the necessary information on the "help" page.

The registration requirement applies even if no financial support is claimed and if the installation does not feed any electricity into the grid.

2.1 Registration and access

Since the beginning of 2020, the average number of units registered each month has been around 100,000.[214] The following chart shows that a particularly large number of installations were registered in December 2020 and January 2021. This is due to the deadline of 31 January 2021 for registering any installations that were already in operation at the end of January 2019.

Monthly registrations of units
(number)

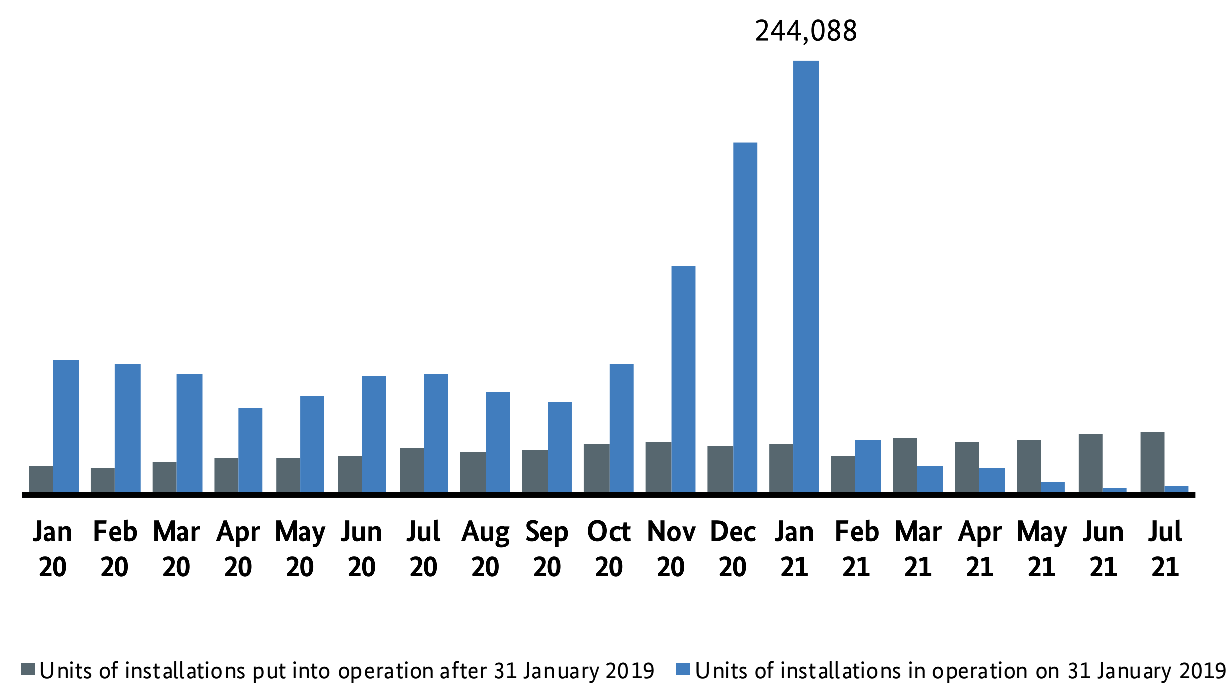

Figure 227: Monthly registrations of units

There has been a decrease in the number of registrations since February 2021; since then, only about 42,000 units have been registered each month. The majority of registrations in the period under review are for units of installations already in operation at the end of January 2019. The number of registered units of new installations has remained more or less the same over the whole period, at an average of 25,000 installations each month.

The table below shows a breakdown of the units registered as at 3 August 2021 by unit type and operation status. The fact must be taken into account that all electricity or gas generating units that are (planned to be) directly or indirectly connected to the electricity or gas network must be registered, regardless of their capacity and regardless of whether or not they receive financial support. Consumption units only need to be registered if they are connected to an HV or EHV electricity network or to a gas transmission network.

[214] Installations are registered as units. In the case of electricity generating installations, for example, one unit needs to be registered for each generator. Biomass installations or power plants can be made up of more than one unit.

Number of registered units in the core energy market data register

Unit type As at: 3 August 2021	Total	In operation	Planned	Permanently closed down	Temporarily closed down
Electricity generating unit	**2,481,899**	**2,464,664**	**12,752**	**3,922**	**561**
Solar	2,088,685	2,079,725	7,186	1,478	296
Storage	259,602	255,896	3,104	557	45
Combustion or biomass[1]	71,355	69,589	475	1,168	123
Wind	32,671	30,503	1,737	419	12
Biomass	20,491	19,965	203	258	65
Hydro	8,218	8,147	36	17	18
Other[2]	507	483	8	14	2
Other renewables[3]	364	350	3	11	0
Nuclear	6	6	0	0	0
Electricity consumption unit	**346**	**306**	**40**	**0**	**0**
Gas generating unit	**310**	**301**	**7**	**0**	**2**
Gas storage	54	53	0	0	1
Biomethane	221	216	5	0	0
Fossil natural gas extraction	26	23	2	0	1
Other generation	9	9	0	0	0
Gas consumption unit	**689**	**661**	**18**	**9**	**1**

[1] Lignite, hard coal, natural gas, mineral oil products, non-biogenic waste, other gases
[2] Pressure from gas pipelines, pressure from water pipes, heat
[3] Geothermal energy, solar thermal energy, mine gas, sewage sludge

Table 144: Number of registered units

Almost all of the data in the register are publicly available. Only the street name and number and the details of an installation operator, if the operator is a natural person, are kept confidential. The data in the register are accessible manually via the web portal and also automatically via a web service. The web service is recommended for users wanting to evaluate large amounts of data on a regular basis. There has been a steady increase in the number of users accessing the data automatically via the web service, from around 200 companies in March 2020 to the current number of 420.

The chart below shows the number of times the register's data has been accessed manually via the web portal, automatically via the web service and in total in each month in the period. The chart shows that the system was accessed very frequently in December 2020 and January 2021 and then not as often. The high access rates at the beginning were because the web service users first had to get to know how to use the service. Access rates are not expected to be as high in the future, although the system is still accessed about 50 million times a month, which puts a continuously high demand on the register.

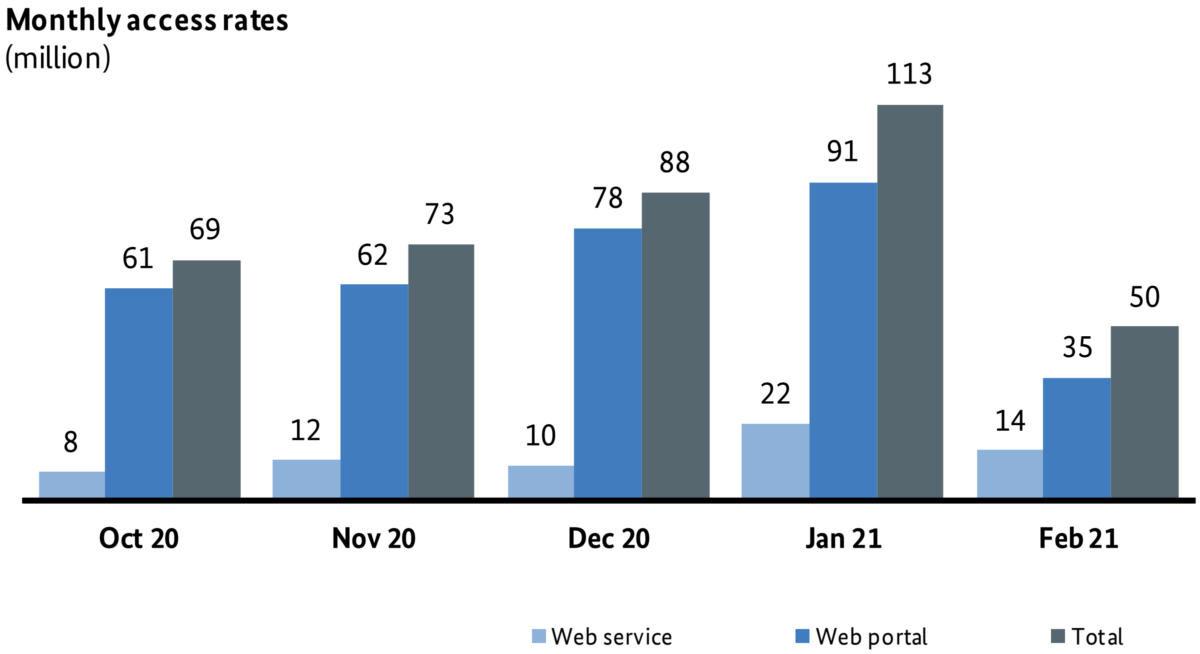

Figure 228: Monthly access rates

2.2 Quality management

The charts below illustrate monthly figures for the tasks related to managing the register. The unusual fluctuations and peak figures mostly at the end of 2020 and beginning of 2021 are due to the deadline of 31 January 2021 for registering any installations that were already in operation at the end of January 2019.

2.2.1 Validation

One of the Bundesnetzagentur's tasks is to validate that certain market players accessing the register's confidential data actually exist and perform their specified function in the electricity or gas markets. These market players may be network operators, authorities, associations or institutions.

The chart below shows that the average number of market players validated per month is around 190. The high number is mainly due to the fact that many installation operators incorrectly register as network operators. The large decrease in the number of validations as shown in the chart is expected to continue in the future.

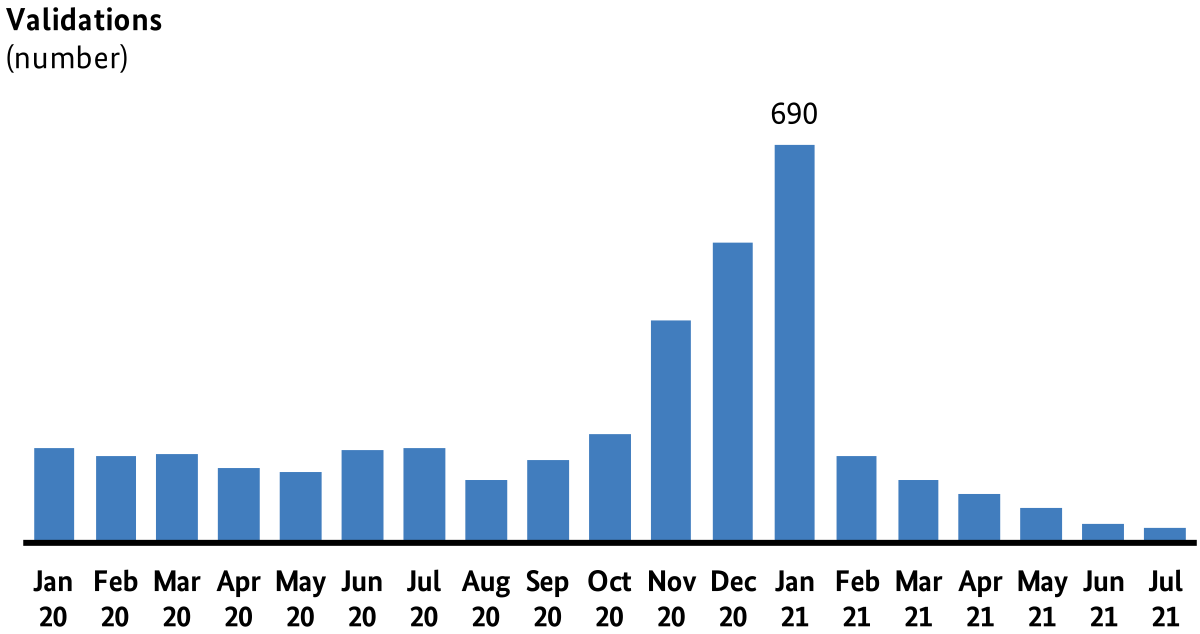

Figure 229: Monthly validations

2.2.2 Network operator checks

A key part of the quality management process is the checks on certain data by the network operators to whose networks the installations are connected. Section 13 MaStRV requires network operators to check certain data relating to the units, installations and installation operators. The Annex to the MaStRV specifies exactly which data need to be checked. If a network operator finds data that need to be corrected, the operator can notify the installation operator via the portal.

The chart below shows the status of the checks as at 1 July 2021: 68.7% of the checks had been completed; 13.1% had not been started; 12.6% had been referred to and were still with the installation operator; and 5.3% had been referred back from the installation operator to the network operator.

Status of network operator checks
(%)

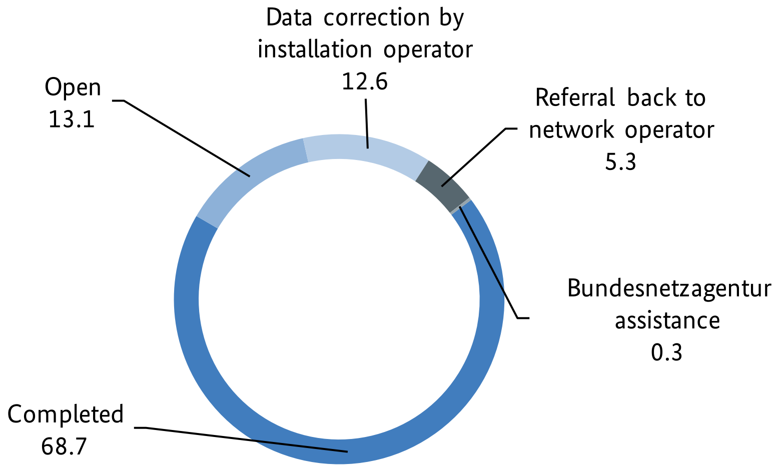

Figure 230: Status of network operator checks

In some instances, the network or installation operators need the Bundesnetzagentur's assistance with the checks. This was the case with 0.3% of the checks; 60% of the requests for assistance involve incorrect data being reported by the network operator (see below) and 40% involve other issues such as help with mismatched data, choosing the correct network operator, or installations not reported to the network operator. The chart below shows the number of such requests, which average at 310 each month.

Requests for the Bundesnetzagentur's assistance
(number)

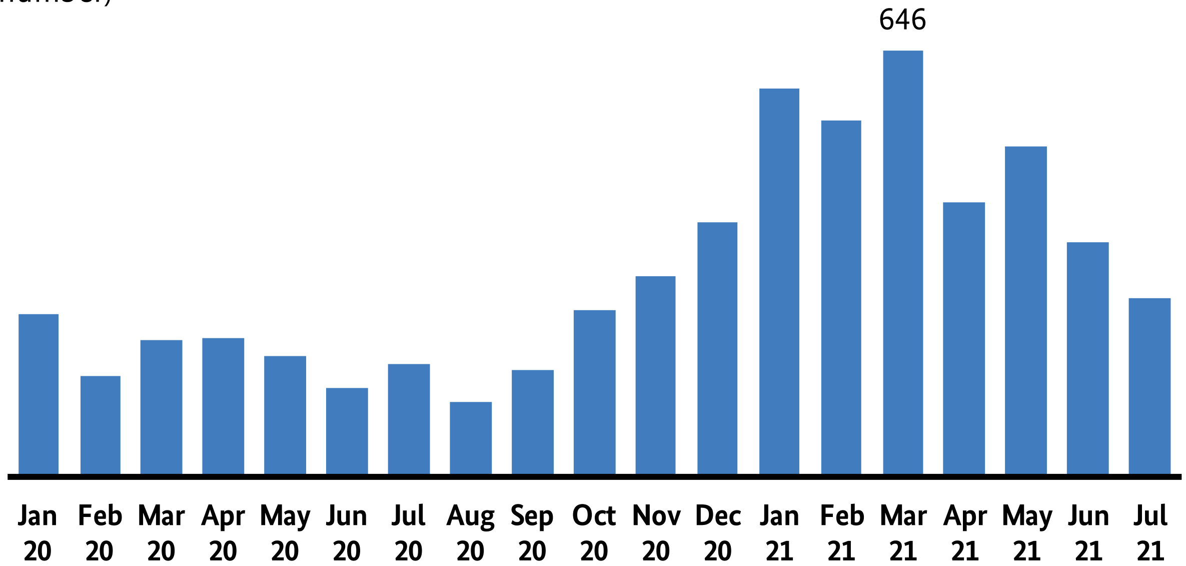

Figure 231: Requests for the Bundesnetzagentur's assistance

2.2.3 Requests for data deletion and reports of duplicate data

Another step in the quality management process is making sure that once units and installations have been registered, the data are not just deleted again. All the unit/installation data should be kept in the register to make it possible for historical data analyses to be made. However, registration errors can occur for various reasons, and so it may be necessary to delete a registered unit/installation because it simply never existed. In this case, the installation operator can request the Bundesnetzagentur to delete the data, and the Bundesnetzagentur will examine the request. Network operators can also report incorrect registrations to the Bundesnetzagentur, and the Bundesnetzagentur will also examine these reports.

The chart below shows that the Bundesnetzagentur receives an average of about 1,350 requests for data deletion and about 600 reports about incorrect data from network operators each month.

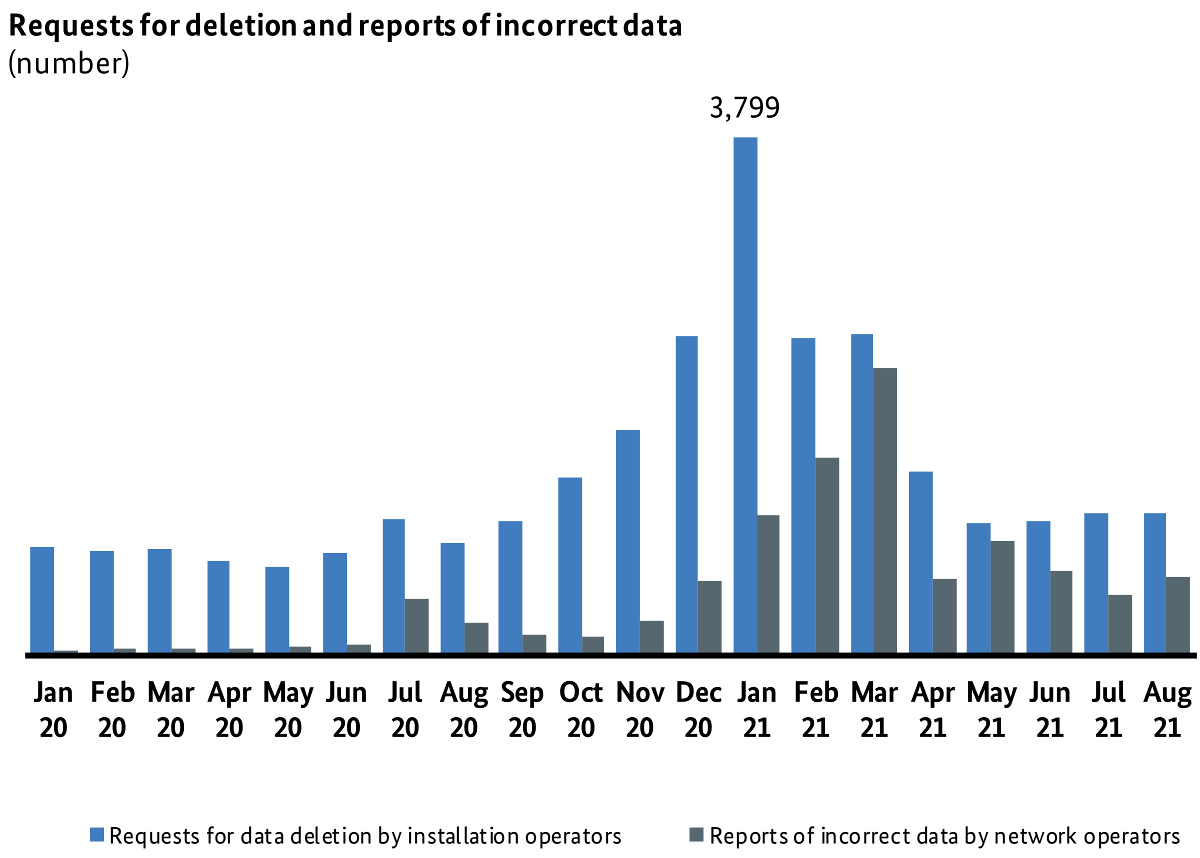

Figure 232: Requests for data deletion and reports of incorrect data

2.2.4 Data correction by the Bundesnetzagentur

The Bundesnetzagentur itself checks the registered data for plausibility regardless of whether or not the network operator has already checked them. The checks currently focus on the capacity (gross capacity, net rated capacity and installed capacity) of all new installations and of electricity generating installations with a capacity exceeding 100 kW that were in operation at the end of January 2019. If these data have obvious errors, the Bundesnetzagentur will correct the errors and inform the installation operator, who has the opportunity to object. On average, the Bundesnetzagentur corrects about 600 such obvious errors each month. Another focus is on incorrect registrations due to the wrong unit type being chosen; for example, solar installations are often incorrectly registered as electricity consumption installations. In this case, the Bundesnetzagentur will contact the installation operator and advise on how to register the unit correctly to make sure that the unit is registered on time. This happens on average around 180 times each month.

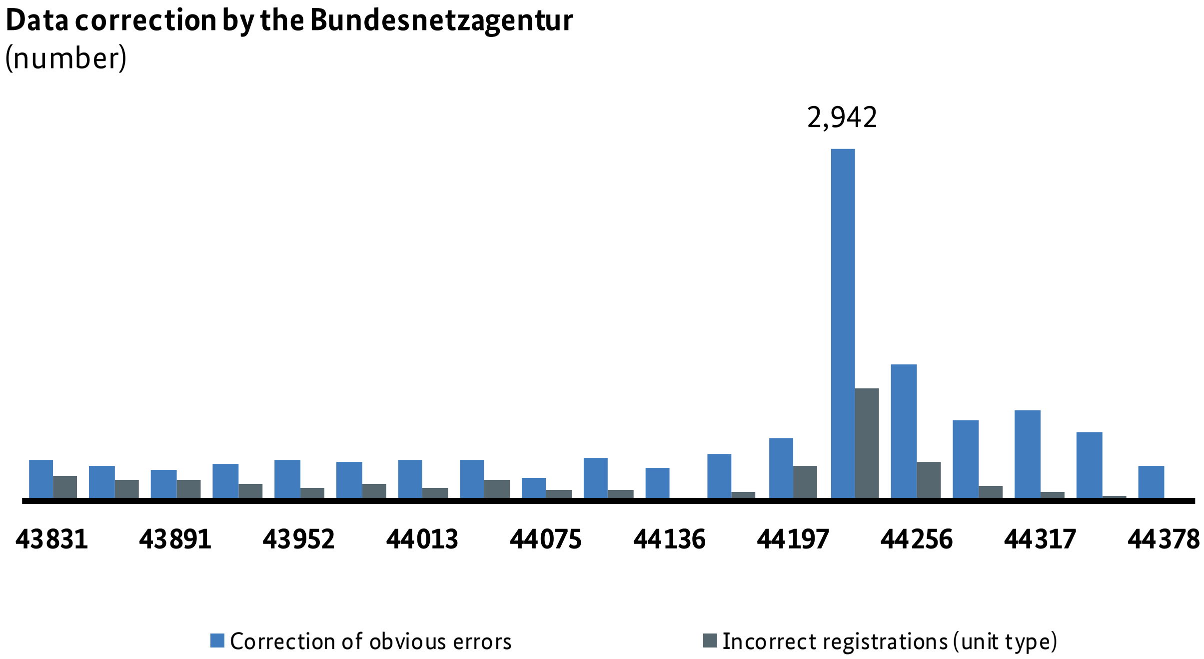

Figure 233: Data correction by the Bundesnetzagentur

2.3 Changes in operator

If the operator of an installation changes, the change also has to be entered in the register. If, for example, a house with solar panels is sold, the change in operator must be registered. These changes can generally be registered by the old and new operators themselves without involving the Bundesnetzagentur. The Bundesnetzagentur's help is needed, however, in a variety of cases where one of the two operators is not available or not willing to make the registration, for instance when someone has died or when there is an insolvency or a court proceeding.

The average number of registrations each month due to a change in operator in the period from January 2020 to July 2021 was 1,600. The Bundesnetzagentur's assistance was needed in around 10% of the cases. In total, 96% of the registrations due to a change in operator had been successfully completed.

The chart below shows a high number of these registrations as well in January 2021.

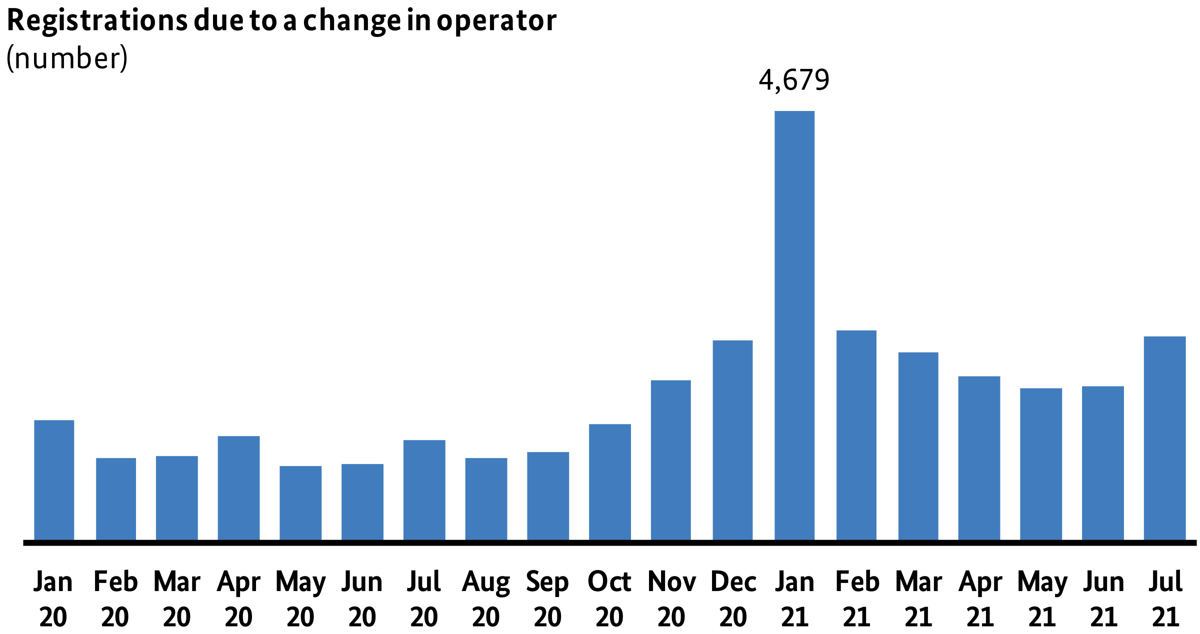

Figure 234: Registrations due to a change in operator

The decrease in the number of these registrations after January 2021 is not as large as with other tasks related to managing the register; the number is expected to increase further in future as and when operators become aware that they also have to register changes in operator. In addition, the increase in the total number of installations means an increase in the total number of changes in operator.

2.4 Outlook

The register is still relatively new. It has largely been complete since February 2021 and so can be – and is – used for economic and political energy questions. The register's access rates are proof that it is highly useful. In addition, there has been a large increase in enquiries about how to use and interpret the data.

The legislature introduced the register with two aims in mind. Firstly, to gain a much better overview of which installations are in operation with which capacity and at which locations, and to use this improved data basis for grid expansion, political strategies and energy statistics. Secondly, to reduce the bureaucracy for installation operators and market players with uniform data storage and coherent quality management, in turn enabling more efficient implementation of the much-discussed models for a more digital and smaller-scale distributed electricity supply.

The register is well on its way to achieving the legislators' objectives.

C Selected activities of the Bundeskartellamt

Sector inquiry into publicly accessible charging infrastructure for electric vehicles

On 12 October 2021 the Bundeskartellamt published a progress report on its ongoing sector inquiry into charging infrastructure ("Sector inquiry on the provision and marketing of publicly accessible charging infrastructure for electric vehicles"). The sector inquiry was launched in July 2020 with the aim of identifying structural competition problems in an early market phase of charging infrastructure development. The inquiry was launched, among other reasons, after consumers and market participants had raised complaints about impediments to obtaining access to areas for the purpose of establishing charging infrastructure, the lack of possibilities for third-party access to charging points as well as the prices and conditions at charging points.

In its inquiry the Bundeskartellamt is examining all levels of publicly accessible charging services, including the provision of suitable areas and the effects of access to such areas on competition between charging point operators (CPO), issues relating to the access of e-mobility providers (EMP) to charging infrastructure and the conditions of use of charging infrastructure applicable to end consumers.

The preliminary findings of the sector inquiry show that little use has yet been made of public tender procedures for public areas, particularly at municipal level. In some cases, these areas are awarded fully or for the most part to one and the same operator, e.g. the municipal utility. A legal requirement to award these areas in a non-discriminatory manner, e.g. by way of a tender procedure, could help to improve conditions for the emergence of competitive market structures in the area of public charging infrastructure for electric vehicles.

The investigations carried out so far have also highlighted the importance of a non-discriminatory award of government funds to ensure access to the market and a level playing field for all charging point providers. From the Bundeskartellamt's point of view it is thus to be welcomed that the government is making use of the instrument of public tender procedures for the allocation of funds for a Germany-wide network of fast charging stations, the so-called "Germany network" ("Deutschlandnetz"). However, the specific tender specifications should take sufficient account of the competitive objectives. In particular, the chosen lot size and structure are key factors in the development of competitive structures. In the Bundeskartellamt's view, setting upper price limits for charging rates as intended for the nationwide "Germany network" of fast charging stations, is not conducive to competition. Such regulatory-type requirements distort competition and could squeeze out existing or planned private offers and stand in the way of quick expansion.

The progress report also explains the existing approaches under competition law to ensuring competitive structures and reviewing practices of providers which could potentially impede competition. Competition law provides a generally suitable toolbox to promote and ensure the competitive operation of public charging infrastructure. Apart from merger control, the control of abusive practices in particular provides the Bundeskartellamt with additional tools which were further enhanced by the 10th amendment to the German Competition Act (GWB) to protect dependent companies. Since from an economic point of view charging infrastructure is not a natural monopoly, establishing a regulated third-party access system to charging points does not seem expedient especially also in light of the regulatory burden associated with this.

The investigations carried out so far have not presented any proof that excessive prices are systematically demanded for charging electricity throughout Germany. Should individual cases of abusively excessive prices emerge, the authority could effectively intervene with the existing competition law tools. As to the transparency of charging prices and usability of charging stations, the preliminary investigation results show that, in addition to intensive competition, targeted regulatory provisions could bring about improvements. In the Bundeskartellamt's view, it is currently not necessary to establish a market transparency unit for ad-hoc charging rates similar to the already existing Market Transparency Unit for Fuels, although individual calls to do so have been voiced. The effects of such a price information system on competition would have to be examined prior to its introduction.

In the course of its sector inquiry the Bundeskartellamt collected extensive information by surveying the companies and local authorities that are active at individual market levels. In addition, further data that are partly publicly available, such as the number of electric vehicle registrations, data on the stage of development and use of regular and quick charging infrastructure as well as information on how customers use charging infrastructure, have been and are still being analysed. Relevant publications, expert opinions and professional discussions with relevant stakeholders are also being taken into account as important sources of information.

The final results of the investigation and recommendations for action will be presented in a final report after the extensive information and data collected in the sector inquiry have been fully evaluated. The progress report, including a summary of the key findings, is available on the Bundeskartellamt's website (www.bundeskartellamt.de).

Lists

List of authorship

Joint texts

Key findings

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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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List of abbreviations

Begriff	Definition
Abbreviation	**Definition**
A	**ampere**
AbLaV	Interruptible Loads Ordinance
AC	alternating current
ACER	Agency for the Cooperation of Energy Regulators
aFRR	frequency restoration reserves with automatic activation
AktG	Stock Corporation Act
ARegV	Incentive Regulation Ordinance
AT	Austria
BAFA	Federal Office for Economic Affairs and Export Control
BBPlG	Federal Requirements Plan Act
BE	Belgium
bFZK	conditionally firm, freely allocable capacity
BGH	Federal Court of Justice
BMWi	Federal Ministry for Economic Affairs and Energy
bn	billion
BSH	Federal Maritime and Hydrographic Agency
BSI	Federal Office for Information Security
BZK	firm capacity with restricted allocability
C	**Celsius**
capex	capital expenditure
CAPM	capital asset pricing model
CH	Switzerland
CHP	combined heat and power
CIGRE	Conseil International des Grands Réseaux Électriques
CIS	Commonwealth of Independent States
CO2	carbon dioxide
CPI	consumer price index
CR	concentration ratio
ct/kWh	cents per kilowatt hour
CWE	Central Western Europe
DC	direct current
DSL	digital subscriber line
DSO	distribution system operator

DVGW	German Technical and Scientific Association for Gas and Water
DZK	dynamically allocable capacity
EDGE	Enhanced Data Rates for GSM Evolution
EEG	Renewable Energy Sources Act
EEX	European Energy Exchange
EGBGB	Introductory Act to the Civil Code
EGIX	European Gas Index
EGSI	European Gas Spot Index
EHV	extra-high voltage
EnLAG	Power Grid Expansion Act
EnWG	Energy Industry Act
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
EU	European Union
F	France
FAQs	**frequently asked questions**
FBA	**flow-based allocation**
FCR	frequency containment reserves
FFAV	Ground-mounted PV Auction Ordinance
FBMC	flow-based market coupling
FZK	firm and freely allocable capacity
GasNEV	Gas Network Charges Ordinance
GasNZV	Gas Network Access Ordinance
GasGKErstV	Gas Appliance Reimbursement Ordinance
GasGVV	Gas Default Supply Ordinance
GEEV	Cross-Border Renewable Energy Ordinance
GJ	gigajoule
GPRS	general packet radio service
GSM	Global System for Mobile Communications
GW	gigawatt
GWB	Competition Act
GWh	gigawatt hour
HSDPA	High Speed Downlink Packet Access
HV	high voltage
HVDC	high voltage direct current
ID	identification number
IP	interconnection point
IGCC	International Grid Control Cooperation

KAV	Electricity and Gas Concession Fees Ordinance
KBA	Federal Motor Transport Authority
km	kilometre
KraftNAV	Power Plant Grid Connection Ordinance
kV	kilovolt
kVA	kilovolt ampere
KVBG	Act to Reduce and End Coal-Fired Power Generation
kW	kilowatt
kWh	kilowatt hour
KWKG	Combined Heat and Power Act
LBEG	Lower Saxony State Authority for Mining, Energy and Geology
LNG	liquid natural gas
LSV	Charging Station Ordinance
LTE	Long Term Evolution
LV	low voltage
m	million
m3	cubic metre
MARI	Manually Activated Reserves Initiative
MaStRV	Core Energy Market Data Register Ordinance
MBI	market-based instrument
mFRR	frequency restoration reserves with manual activation
MinRAM	minimum remaining available margin
MOL	merit order list
MsbG	Metering Act
MV	medium voltage
MW	megawatt
MWh	megawatt hour
NABEG	Grid Expansion Acceleration Act
NAV	Low Voltage Network Connection Ordinance
NC CAM	Network Code on Capacity Allocation Mechanisms
NCG	NetConnect Germany
NCP	network connection point
NC TAR	Network Code on Harmonised Transmission Tariffs
NDAV	Low Pressure Network Connection Ordinance

Glossary

Es gelten die Begriffsbestimmungen gemäß § 3 Energiewirtschaftsgesetz, § 2 Stromnetzzugangsverordnung, § 2 Gasnetzzugangsverordnung, § 2 Stromnetzentgeltverordnung, § 2 Gasnetzentgeltverordnung, § 3 Erneuerbare-Energien-Gesetz, § 2 Kraft-Wärme-Kopplungsgesetz. Ergänzend gelten folgende Definitionen:

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 AktG	As set out in the German Stock Corporation Act (AktG): 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 customer)	Peak load, expressed in kilowatt (kW), as metered in 15 minute readings, in the course of a year.
Annual usage time (final customer)	The annual usage time is the quotient of the energy withdrawn from the network in an accounting year and the annual peak load 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) sentence 2 StromNEV).
Balancing capacity	Balancing capacity is maintained to ensure a constant balance between electricity generation and consumption.
Balancing energy (imbalance gas)	*electricity*: The activated energy that is settled with the balance responsible parties 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 balance responsible parties (see section 23(2) GasNZV).
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 and output by its mix and enabling the conclusion of trading transactions (see section 3 para 10a 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	Artificial hollows in salt domes created by drilling and solution mining. 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 meter operations	Charge for meter installation, operation and maintenance. In accordance with section 17(7) sentence 1 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) sentence 1 GasNEV).
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.
CO2 emissions from power generation	The CO2 released during power generation. For CHP plants the proportion of CO2 emissions that are to be allocated to power generation according to Working Sheet AGFW FW 309 Part 6 "Energy rating of district heating– Determining the specific CO2 emission criteria" (December 2014).
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 level of market concentration.

Consumption	Amounts of electricity delivered by electricity suppliers to final customers.
Conventional meter operation	Conventional meter operation includes all metering systems that are not modern metering equipment or smart metering system (eg Ferraris meters, electronic household meters, EDL21 and EDL40 meters, meters for interval-metered customers, etc.)
Core data	Company data for the successful processing of business transactions. These include contract data such as a customer’s name, address and meter number.
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.
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 volume	Amount of electricity or gas delivered by electricity or gas suppliers to final customers.
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 more than 50% of the shares in a company are held 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 customer 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.
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, CO2 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). Since November 2017 EEX has been the sole shareholder in Powernext SA, also based in Paris, which operates short-term gas trading (see EEX). Because Powernext has been fully integrated into EEX since 1 January 2020, EEX offers all its products in a single marketplace.
Electric heating	Electricity for heating is the electricity supplied to operate controllable consumer devices for the purposes of room heating. Controllable consumer devices essentially comprise overnight storage heaters and electric heat pumps.
Energy information network (EIN)	Communication of power plant deployment planning data for conventional generating installations with a nominal capacity of at least 10 MW and a connection to networks with a nominal voltage of at least 110 kV to the TSO for ensuring that the network and system is operated securely (see Bundesnetzagentur decision BK6-13-200).
Energy price component	The price component that is controlled by the supplier, made up of energy procurement, supply and margin.
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.
ENTSO-E	ENTSO-E is the association of European transmission system operators (TSOs) with the objective of creating a liberalised European internal market for electricity. The association is headquartered in Brussels. The EU Transparency Regulation (Regulation (EU) No 543/2013) was adopted by the European Commission. The Regulation sets out the obligation that from January 2015 ENTSO-E must operate a central information transparency platform for fundamental data in the European electricity market. All market participants named in the Regulation such as operators of power plants and storage facilities, consumption units, electricity network operators and other market participants such as electricity exchanges and auction offices for transmission capacities are required to comply with the Regulation's reporting requirements. In Germany the Market Transparency Unit of the Bundesnetzagentur and the Bundeskartellamt (Article 4(6) EU Transparency Regulation) ensure compliance for the German market.
Exit point	The point at which gas can leave an operator's network for delivery to final customers, downstream networks (own and/or other) 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 congestion management 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) sentence 2 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) sentence 3 EnWG in conjunction with sections 14 and 15 EEG and, in the case of CHP installations, section 4(1) sentence 2 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.
Generation costs (energy costs)	The necessary costs for the actual feed-in adjustments. These include - Re-supplying of fuels and other raw materials and consumables - Procurement of gas (if not included in production costs); byproduct costs - Emission allowances / emissions costs, costs (and revenue) for firing up the plant (including test starts and test runs) - Energy tax refunds for heavy or light heating oil - Consumption costs - Renewable energy surcharges and network charges for the plant's own use - Imbalances electricity and gas (balancing energy costs and revenue) - Distributed feed-in remuneration - Revenue from avoided network charges - Heating and auxiliary steam costs - Gas fees
Green electricity tariff	Tariff for electricity which, 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 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 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 but located within the customer's system.
Grid reserve capacity	Grid reserve capacity is a price element for customers with their own generation or network operators into whose network such generating installations feed. For failures due to disruptions or routine inspections, a grid reserve capacity of up to 600 hours per billing year can be contractually agreed.
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/m³ and a Wobbe index from 12.8 kWh/m³ to 15.7 kWh/m³.
Hub	An important physical node in the gas network where different pipelines, networks and other gas infrastructures come together and where gas is traded.
Immediately interruptible loads	Immediately interruptible loads are interruptible loads with a verifiable interruptible capacity that can be instantaneously controlled remotely by the TSO and automatically frequency controlled if the supply frequency is not met.
Interval-metered customer	electricity: Final customers with an annual electricity offtake exceeding 100,000 kWh. gas: Final customers with an annual gas offtake exceeding 1.5m kWh 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, 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, 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 or overhead lines leased by, or otherwise made available to the network operator, should be included to the extent they are operated by the network operator. Lines with share of external use 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 and the lines of street lighting systems. Circuit lengths of street lighting systems are only included if the costs for electricity distribution are part of the fiscal year's activity report. Planned cables, those under construction or leased out to third parties, and cables or overhead lines that have been decommissioned are not included.
L-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 (MsbG) regarding the communicative integration of the controllable loads. (section 14a EnWG)
Load-metered final customers	Measurement of the power used by final customers 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.
Load-variable price plan	A load-variable price plan is a tariff for electricity where the price of electricity depends on electricity demand and network utilisation.
Loss energy	The energy required for the compensation of technical power losses.

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 customers 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.
Market maker	Trading participants who, for a minimum period of time during a trading day, have both a buy and a sell quote in their order book at the same time. Market makers ensure basic liquidity.
Maximum usable volume of working gas	The total storage volume less the cushion gas required.
Meter location Meter point	A meter location is a location at which energy is measured and that has all the 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 MsbG. Point in the grid at which the flow of energy, or the amount of gas transported, is recorded for billing purposes (see section 2(28) MsbG).
Metering service	Metering the energy supplied in accordance with verification regulations and processing the metered data for billing purposes.
Modern metering equipment	A metering system reflecting actual electricity consumption and actual time of use that can be safely connected to a communication network via a smart meter gateway.
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 meter operations, VAT, concession fees, surcharges payable under the EEG and KWKG as well as other surcharges. *gas*: Gas network charge, from 1 January 2017 including billing charge, not including charges for metering and meter operations, VAT and concession fees.
Net thermal capacity	The maximum useful heat generation under rated conditions that a CHP installation can supply.
Net Transfer Capacity (NTC)	Net transfer capacity of two neighbouring countries (calculated as total transfer capacity minus transmission reliability margin).
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
Network losses	The energy lost in the transmission and distribution system is the difference between the electrical energy physically delivered to the system and the energy drawn from the system within the same period (see VGB, 2012).)
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 rated 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.
Non-CHP electricity (net)	Gross condensing electricity is the part of the gross electricity generated in a reporting period that occurs when the working fluid in a steam turbine unit is cooled to the ambient temperature and thus the full, possible enthalpy change is used to generate electricity. Electricity generation in gas turbines, CHPS operated by combustion engines and fuel cells without heat recovery is "uncoupled electricity generation" and can therefore be equated to condensing electricity generation. The net condensing electricity generated by a generating installation is the gross condensing electricity generation less the condensing electricity for self-consumption (in a reporting period).
Normal cubic metre (Ncm)	Section 2 para 11 GasNZV defines a normal cubic metre as the quantity of gas that, free of water vapour and at a temperature of 0°Celsius and an absolute pressure of
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.
Online tariff	A tariff that can be concluded online (eg on the company's website or through a price comparison platform) and for which bills are available online.
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)	*spot market*: 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. *futures market*: The EEX has the Phelix-DE year future for electricity contracts for the next calendar year or subsequent years for the market area of Germany (both base and peak). All contracts can be traded for baseload or peak load.
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.

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".
Quickly interruptible loads	Quickly interruptible loads are interruptible loads with a verifiable interruptible capacity of no more than 15 minutes that can be controlled remotely by the TSO.
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 secure and reliable operation of the electricity supply networks. The aim is either to prevent or to 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 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.
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. Most of the funds required are passed on to electricity consumers through the renewable energy surcharge. As from the renewable energy surcharge for 2021, federal government assistance also contributes to the funding. 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 it has been determined properly.
SLP customer (standard load profile customer)	*electricity*: Section 12 StromNZV defines standard load profile customers as final customers with an annual offtake 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.).
Spot market	Market where transactions are handled immediately (intraday and day-ahead auctions).
Storage system 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 that 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.
Usage time (final customer)	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). 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).
Useful heat	The heat extracted from a CHP process that is applied outside the CHP plant for space heating, hot water systems, cooling or process heat (see section 2(26) KWKG).
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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